Petition: 21-07-012
(U 39 E)
Exhibit No.:
Date: October 20, 2026
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

PETITION OF THE CITY AND COUNTY OF SAN FRANCISCO FOR A VALUATION OF CERTAIN PACIFIC GAS AND ELECTRIC COMPANY PROPERTY PURSUANT TO PUBLIC UTILITIES CODE SECTIONS 1401-1421

PREPARED TESTIMONY

PUBLIC VERSION

PACIFIC GAS AND ELECTRIC COMPANY
PETITION OF THE CITY AND COUNTY OF SAN FRANCISCO FOR A VALUATION OF CERTAIN PACIFIC GAS AND ELECTRIC COMPANY PROPERTY PURSUANT TO PUBLIC UTILITIES CODE SECTIONS 1401-1421
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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

POLICY AND SUMMARY

WITNESS: CARLA PETERMAN

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
POLICY AND SUMMARY
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A. Introduction

Pacific Gas and Electric Company ("PG&E") has had the honor of serving San Francisco for more than 120 years. Throughout this time, the City and County of San Francisco ("CCSF" or the "City") has extended offers to buy PG&E's assets and initiated political efforts to take them. PG&E always has rejected the City's offers and voters have rejected the City's prior political efforts.[1]

PG&E is committed to continuing to provide safe, clean, reliable, affordable service to its customers in San Francisco and will not sell its assets voluntarily. If CCSF wants to acquire PG&E's electric assets (including the associated real estate, tangible assets, and non-tangible assets) (the "Subject Assets" or "Assets") serving San Francisco, CCSF must pay PG&E "just compensation" for those Assets, which includes not just fair market value but also severance damages to ensure that PG&E's remaining customers are left neutral and PG&E's shareholders are made whole.

PG&E's opening testimony demonstrates that as of July 2021 the City would have to pay PG&E **$22.49 billion** to acquire PG&E's electric assets, consisting of **$13.88 billion** for the assets themselves and an additional **$8.61 billion** in severance damages.[2] CCSF's overall financial burden (that is, its total costs

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[1] SFPUC, "A Look Back in History: The SFPUC and PG&E 'Back in the Day'" (Apr. 13, 2020) (eight rejected bond measures from 1927 to 1941), https://waterpowersewer.wordpress.com/2020/04/13/a-look-back-in-history-the-sfpuc-and-pge-back-in-the-day/; S.F. Bd. of Supervisors Resolution No. 2-02 (Jan. 7, 2002) (noting failure of 2001 Propositions F and I); CCSF's Petition ¶¶ 72–78 (July 27, 2021) (2019 offer and 2020 renewal).

[2] State law mandates that the Commission calculate PG&E's just compensation as of the petition date, July 27, 2021, and—if CCSF elects to move forward with condemnation—that the parties subsequently participate in a separate proceeding to update these numbers. Pub. Util. Code §§ 1411, 1417. This means that the assets and severance damages at issue are based on PG&E's 2021 electric asset inventory and 2021 economic data, such as the then-applicable interest rate. PG&E has adhered to these requirements and, accordingly, all of my valuation references in this Chapter, and in PG&E's testimony generally, are valued "as of July 2021" (unless stated otherwise).

beyond the just compensation that it would owe to PG&E) is even greater: adding the hundreds of millions of dollars that CCSF will incur in startup costs (conservatively, **~$300 million**)[3] and eliminating the annual tax and franchise fee payments that PG&E pays CCSF each year (with a net present value over the next 30 years of approximately **$2.5 billion**) increases CCSF's overall burden to approximately **$25.29 billion**.

TABLE 1-1
CCSF COSTS/LOSSES FROM TAKEOVER OF PG&E ASSETS

Line No.	Description	Amount
1	Just Compensation Due to PG&E for Subject Assets	$13.88B
2	Business Severance Due to PG&E	$7.61B
3	Physical Severance Due to PG&E	$1B
4	CCSF Estimated Startup Costs	$300M
5	CCSF Loss of Taxes/Franchise Fees from PG&E	$2.5B
6	**Total Financial Burden**	**$25.29B**

CCSF's takeover would not be economic. With a 2026–27 budget of $16.9 billion,[4] it is apparent that paying PG&E its true just compensation would burden

PG&E recognizes that we are 5 years past the petition date and that these values will require updating. We have continued to invest in our system, changing the actual equipment that CCSF ultimately would condemn, and economic conditions have changed. Interest rates were lower in post-COVID 2021 than they are in the fall of 2026, and they likely will be different at the time of the update proceeding that the Public Utilities Code requires. All of these factors will affect the bottom line just compensation number, underscoring the need for a future update proceeding.

3 In 2020, in CCSF Public Utilities Commission Resolution No. 20-0011 § 1 (Jan. 14, 2020), the City authorized issuance of $3,065,395,000 in revenue bonds to acquire PG&E's Subject Assets for $2.5 billion, leaving over $565 million for "work to separate the PG&E assets from the remainder of the PG&E grid; expanding personnel capacity; acquiring equipment inventory and software; and establishing operating reserves, and funding bond financing costs."

CCSF witness Grant Rabon's firm, NewGen, estimated the startup costs for a potential municipalization in San Diego at $300 million. NewGen Strategies, Report on Public Power Feasibility Study Phase II at 2–5 (Apr. 3, 2026) (noting "transition investment" for San Diego to municipalize SDG&E assets of "$612 million in physical separation plus $300 million for other upfront implementation and operational separation costs").

4 Office of the Mayor, "Mayor Lurie Signs Balanced Budget Strengthening San Francisco's Social Safety Net, Advancing City's Economic Recovery" (July 30, 2026), available at https://www.sf.gov/news-mayor-lurie-signs-balanced-budge-strengthening-san-franciscos-social-safety-net-advancing-citys-economic-recover.

San Franciscans for decades. CCSF contends that the just compensation is much lower, asserting that the value of PG&E's assets is only $3.4 billion,[5] but it reaches that amount by systematically understating the components of PG&E's due compensation. For example, CCSF assigns a zero value to PG&E's roughly 2,000 easements in San Francisco. It arbitrarily reduces one of its valuations by $1.8 billion to make it equal its preferred valuation methodology. And it ignores the possibility that other government buyers could potentially purchase PG&E's assets despite the California Public Utilities Commission's ("CPUC" or "Commission") finding that PG&E is entitled to "the highest price" to which a willing buyer and seller would agree.[6] Correcting these and other errors reveals that CCSF's valuation is unreasonably low and that its takeover effort is uneconomic.

B. CCSF's Forced Takeover Would Harm Customers Throughout California and Undermine State Energy Policy.

The City's spending $22.49 billion to compensate PG&E and forgoing $2.5 billion in revenues would have significant impacts on City residents. San Francisco's departure from the CPUC's jurisdiction also would harm PG&E's customers, both within and outside of San Francisco, in multiple ways. It makes sense, therefore, that the Coalition of California Utility Employees ("CUE") and its member union, IBEW Local 1245, also oppose CCSF's proposed municipalization.

- CCSF's departure from Commission jurisdiction would deprive San Francisco customers of the benefits of the Commission's regulatory oversight and the programs that the Commission implements through PG&E to support clean energy, climate resiliency, consumer protection, environmental and social justice, and other important statewide policies.
- Nor is CCSF's proposal good for the State's broader energy policy. PG&E is a worldwide leader in clean energy practices, energy conservation, and wildfire risk mitigation. Many of PG&E's costs in these areas will remain largely the same after a takeover but will be borne by a reduced number of

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[5] CCSF has not yet submitted any values on severance damages, on which the Commission has set a February 22, 2027 deadline.

[6] Decision Establishing Methods and Standards for Just Compensation and Valuation, D.25-10-039 at 25 (Oct. 30, 2025) ("Interim Decision").

remaining customers, creating a risk that those customers incur increased costs over time. While the Interim Decision attempts to address those immediate financial implications in this proceeding, a large-scale municipalization like this one (and any others that may follow) will likely result in long-term harms to the State's energy policy goals.[7]

- It is also noteworthy that municipalizations take years (CCSF filed the Petition on July 27, 2021, yet released its separation plan in April 2026, and as of this filing is still working to comply with its California Environmental Quality Act ("CEQA") obligations).[8] Moreover, municipalizations typically cause significant disruption (including construction and traffic), unnecessary duplication of facilities, and negative environmental impacts. Consider that CCSF has stated that its proposed work to separate PG&E's Martin Substation would take *seven years* (in addition to, at minimum, the five years that it already has spent on this Petition).[9] All this on top of lost programs and energy policy disruption underscores the real harm that this municipalization would impose on customers.

If CCSF plans to proceed with this forced takeover to the detriment of both the City and the State, then it will need to complete all required steps to do so, including completing this valuation process, complying with CEQA, obtaining a condemnation judgment in Superior Court, securing Commission approval pursuant to the Public Utilities Code Section 851 public interest review process, obtaining approval from the Federal Energy Regulatory Commission to acquire

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7 *Id.* at 36.

8 Notably, as PG&E has pointed out in filings in the CEQA proceeding, there are significant inconsistencies between CCSF's EIR project definition and its project definition in this case, creating the potential for significant rework that would waste substantial time, money, and effort.

9 CCSF has stated that this work "will be driven primarily by completion of the New PG&E Distribution Substation, which would be completed within seven years from the decision to construct the facilities …." Ex. CCSF-007C – Prepared Direct Testimony of Manho Yeung and Ryan Wu on Behalf of the City and County of San Francisco, App. II, Vol. 1 at 10 (Apr. 20, 2026) (errata May 21, 2026). And, as PG&E notes in Chapter 9 of its testimony, the construction work on the New PG&E Substation would not be able to begin until such time as PG&E is able to relocate its Martin Service Center to a new location because the new substation is proposed to be constructed on the site of PG&E's existing Martin Service Center.

and operate PG&E's transmission assets—and paying PG&E full just compensation.

C. PG&E's Testimony Includes Both Its Asset Valuation and Severance Damages Calculation; CCSF's $3.43 Billion Valuation Does Not Yet Account for Severance Damages.

Notwithstanding the considerable negative effects of a forced takeover, CCSF's Petition requires the Commission to determine in this proceeding the "just compensation" that CCSF must pay PG&E to acquire the Subject Assets as of the July 27, 2021 Petition date. Just compensation consists of both:

(1) the fair market value of the Subject Assets; and

(2) the severance damages caused by the taking, including both:

(a) Physical Severance damages, *i.e.*, the costs of separation and restoration of PG&E's grid; and

(b) Business Severance damages, *i.e.*, the financial harm that CCSF's condemnation would cause to PG&E's business and remaining customers.[10]

As the Commission already has decided, "the standard for just compensation must leave remaining ratepayers"—that is, the customers outside of San Francisco that PG&E would continue to serve—"unharmed by cost shifting."[11]

As I explain in Section F, and as PG&E's other witnesses thoroughly discuss throughout PG&E's testimony, the just compensation that CCSF would owe PG&E as of July 27, 2021 is $22.49 billion, consisting of $13.88 billion in compensation for the Subject Assets and an additional $8.61 billion in severance damages.[12] CCSF's testimony, which valued PG&E's assets at $3.43 billion, does not yet include an analysis of severance damages (consistent with the case schedule), which means that even applying CCSF's faulty asset-only valuation, CCSF would have to pay PG&E approximately $12 billion.

The parties already have spent tens of millions of dollars litigating the value of PG&E's assets when our collective time and money would be better spent supporting San Franciscans. PG&E hopes that CCSF will instead choose to

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10 Interim Decision at 2, 39–41.

11 *Id.* at 26.

12 As noted in footnote 2, these amounts will require updating.

collaborate on energy practices and policies that will improve the lives of San Franciscans. But if CCSF continues to pursue this effort, it must recognize that any taking will be far more expensive than CCSF's testimony suggests, ultimately burdening City residents with extraordinary debt.

In the remainder of this Chapter, I provide (1) my professional background; (2) context regarding CCSF's efforts to take PG&E's assets in San Francisco, including flaws underlying its valuation testimony in this proceeding; (3) a summary of PG&E's testimony; (4) a discussion of the need to update the valuation numbers from this proceeding; and (5) an analysis of the impacts of CCSF's efforts on the Commission's ESJ goals and ability to provide regulatory oversight in San Francisco and statewide.

D. Witness Background

My name is Carla Peterman. I have spent my career working in California's energy sector, including serving as a CPUC Commissioner from 2012 through 2018 and a California Energy Commissioner from 2011 through 2012.

I currently serve as President of PG&E Corporation and Executive Vice President of Customer & Corporate Affairs at PG&E,[13] and previously served as PG&E's Executive Vice President, Corporate Affairs and Chief Sustainability Officer.

Before joining PG&E in 2021, I served as Senior Vice President of Strategy and Regulatory Affairs at Southern California Edison Company. Before that, as noted above, I served a six-year term as a Commissioner of the California Public Utilities Commission and also served as a California Energy Commissioner. I hold a B.A. from Howard University, a Ph.D. in Energy and Resources from UC Berkeley, and M.S. and M.B.A. degrees from Oxford University, where I was a Rhodes Scholar. I base my testimony not only on my experience at PG&E, but on my long career in energy policy and regulation.[14]

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[13] PG&E Corporation is the corporate parent of PG&E.

[14] My resume is included in Appendix A to PG&E's testimony submission, which includes all witnesses' statements of qualifications.

E. Overview Of CCSF's Efforts To Force A Takeover Of PG&E's Assets

1. CCSF's Prior Attempts to Take PG&E's Electric Assets Have Failed.

CCSF has many times tried to supplant PG&E by forcing a takeover of PG&E's property. This proceeding follows nearly a dozen such efforts by CCSF within the last century. PG&E always has declined CCSF's offers, and with good reason: departing PG&E service and CPUC regulation would harm PG&E's customers both within and outside of San Francisco and undermine the State's ability to achieve its energy policy goals.

In 2019, shortly before initiating this proceeding, CCSF sought to acquire certain of PG&E's assets by intervening in PG&E's Chapter 11 bankruptcy proceeding. Then-Mayor London Breed and then-City Attorney Dennis Herrera sent PG&E a letter expressing a so-called non-binding indication of interest in purchasing the PG&E assets needed to provide service to San Francisco customers. The letter estimated PG&E's rate base for these assets at $1 billion and offered to pay PG&E 2.5 times rate base, or $2.5 billion, for the assets.[15] The letter reflected CCSF's willingness to additionally pay PG&E to "buy down" the non-bypassable energy policy charges applicable to San Francisco customers.[16]

PG&E rejected CCSF's overture, explaining that the Subject Assets were not for sale and that we could not accept CCSF's proposal because:

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15 In a September 6, 2019 letter to PG&E's William Johnson and Andrew Vesey, CCSF Mayor London Breed and City Attorney Dennis Herrera extended the following offer:

> The City is pleased to submit an indicative purchase price for the Targeted Assets of $2.5 billion to be paid in cash upon the closing of the Proposed Transaction. Based on the City's key assumptions described below, this indicative purchase price represents a 2.5x multiple of estimated year end 2019 rate base . . . . The City's proposal and the indicative purchase price are based upon . . . the following key assumptions: . . . Rate base for the Targeted Assets totaling $1.00 billion as of December 31, 2019.

See Ex. G to CCSF's Petition ("CCSF's Sept. 6 Letter") at 2–3.

In a subsequent letter dated September 19, 2019, CCSF reiterated its $2.5 billion indicative purchase price, which it expressed as a "2.2x rate base multiple" of "an assumed $1.15 billion 2021 average rate base." *See* Ex. H to CCSF's Petition ("CCSF's Sept. 19 Letter") at 2.

16 CCSF's reference to "a 'buy down' of any non-bypassable charge obligations that may be applicable to the City's customers" included "charges such as the Power Charge Indifference Adjustment (PCIA), DWR Bond Charge, New System Generation Charge (NSGC), Competition Transition Charge (CTC) and new non-bypassable charges that may arise from state legislation." CCSF's Sept. 6 Letter at 3 & n.1.

- The offer reflected an amount significantly below the fair market value of the Assets;
- The offer vastly underestimated the separation and impairment costs that CCSF would cause, and have to bear, as part of the transaction;
- A sale would unnecessarily and unfairly shift enormous costs to PG&E's remaining customers outside of San Francisco; and
- A sale would not serve the best interests of PG&E's San Francisco customers, who rely on PG&E to deliver safe, reliable, affordable, and clean power.[17]

In August 2020, after PG&E emerged from Chapter 11, CCSF reiterated its desire to take PG&E's Assets in and serving San Francisco.[18] PG&E responded that its position had not changed.[19]

2. CCSF's Current Effort to Take the Assets Relies on a Flawed Valuation.

San Francisco's current proposal rests on an unrealistically low valuation of PG&E's Assets. PG&E's testimony explains the flaws in CCSF's valuation to reveal PG&E's true just compensation. While CCSF's highly inaccurate asset valuation may at one point have persuaded some that a takeover made financial sense, it does not. Correcting for these gaps demonstrates that CCSF's paying PG&E just compensation would burden San Franciscans with debt for decades.

In its July 27, 2021 Petition, CCSF failed to articulate which assets it wanted to take or how it would separate a local CCSF grid from PG&E's integrated transmission and distribution system. Nor did CCSF identify the assets that it wanted to take in its original (April 2023) written testimony, instead listing three alternative separation scenarios and reducing its $2.5 billion valuation from 2019 to just $2.2 billion.

In the ensuing two years, CCSF identified more than ten different separation scenarios and continued to consider which Assets it might want

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[17] Letter from PG&E's William Johnson to Mayor Breed and Mr. Herrera, Oct. 7, 2019 (attached as Ex. J to CCSF's Petition) at 2.

[18] Letter from Mayor London Breed and City Attorney Dennis Herrera to PG&E's William Smith and Michael Lewis, Aug. 14, 2020 (attached as Ex. L to CCSF's Petition).

[19] Letter from PG&E's William Smith to Mayor Breed and Mr. Herrera, Aug. 19, 2020 (attached as Ex. M to CCSF's Petition).

to purchase (with the various separation scenarios identifying different assets to take), while still pursuing CEQA compliance. CCSF and PG&E engaged in workshops that the Commission's Energy Division and consultant (Filsinger Energy Partners) led, in which PG&E's experts explained the complexity, and at times the practical impossibility, of CCSF's proposed taking scenarios. In October 2025, the Commission directed CCSF to identify a single taking scenario in its testimony.[20] In February 2026, the Commission set an April 2026 deadline for that testimony.[21] CCSF's CEQA compliance efforts are ongoing.

In its April 2026 Amended and Restated Testimony, CCSF for the first time defined the scope of its taking and valued the Subject Assets that it seeks to take at $3.43 billion—a $900+ million increase from its original "indication of interest" and more than a billion dollars above its 2023 valuation—even though CCSF's valuation does not yet account for severance damages, including the non-bypassable charges that in 2019 it had committed to "buy down."

As PG&E's testimony demonstrates, even CCSF's new, higher dollar valuation drastically undervalues PG&E's Assets. The following are just a few examples of how CCSF's flawed analysis would inappropriately eliminate billions of dollars of value to which PG&E is entitled as just compensation.

- <u>CCSF fails to consider that other government buyers could potentially purchase PG&E's Assets, reducing its asset valuation calculation by $3.8 billion.</u>[22] California condemnation law requires CCSF to pay PG&E the *highest* price for its assets that any hypothetical buyer and seller would agree to in a voluntary transaction on the open market,[23] yet CCSF fails to consider that government buyers other than itself *(e.g.*, municipal utility districts, irrigation districts, and the State of California)

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20 Interim Decision at 32–33.

21 ALJ Ruling Setting Schedule at 2 (Feb. 18, 2026).

22 As PG&E's witness John Williams of EPS explains in Chapter 5.

23 Interim Decision at 25.

potentially could seek to purchase or condemn the Subject Assets.[24] Indeed, the State of California has repeatedly considered purchasing PG&E.[25] Since government buyers are unregulated and tax-exempt, they would be willing to pay more for PG&E's Assets. Correcting this and other errors, and consistent with the Interim Decision, PG&E has calculated the highest price for the income approach is $12.00 billion (subject to reconciliation with cost and market approaches).

- CCSF disregards its own cost approach, reducing that amount by $1.8 billion (over 35%) to match its income valuation. Notwithstanding the Commission's directive that the parties submit three separate valuations—income, market, and cost (*i.e.*, Replacement Cost New Less Depreciation ("RCNLD"))—CCSF disregards the cost valuation methodology, with its witnesses claiming (without supporting analysis or data) that a hypothetical buyer would not pay RCNLD.[26] CCSF witness Grant Rabon reduces his RCNLD valuation by more than $1.8 billion to artificially equate CCSF's cost valuation with its separate income valuation.[27] This circular argument—that any RCNLD calculation above the income value constitutes "economic obsolescence" and therefore must be reduced to the income value—is inconsistent with standard asset valuation principles as well as with State law, with the Commission

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24 A joint December 13, 2019 letter sent by CCSF, Nevada Irrigation District, South San Joaquin Irrigation District and Valley Clean Energy mentioned the existence of a proposal for a governmental entity to acquire PG&E's northern and central California electric facilities.

25 *Legislators Considered Acquisition of PG&E*, SFGate (June 8, 2001), https://www.sfgate.com/news/article/legislators-considered-acquisition-of-pg-e-2910935.php; *State Senator Introduces Plan for California to Take Over PG&E*, KQED (Feb. 3, 2020), https://www.kqed.org/news/11799335/state-senator-introduces-plan-for-california-to-takeover-pge.

26 Ex. CCSF-005 – Prepared Direct Testimony of Scott Beicke on Behalf of the City and County of San Francisco at 7:22–8:8 (Apr. 20, 2026) (errata May 15, 2026) (opining that hypothetical buyers would not "focus on the direct cost to replace the Subject [Assets]"); Ex. CCSF-004C – Prepared Direct Testimony of Grant Rabon at 8:14–25 (Apr. 20, 2026) (Errata May 21, 2026) ("Rabon Testimony") (concluding "that the RCNLD (without adjustment for functional/economic obsolescence) generated a value that could not be justified vis-à-vis the income earning capability of the Subject Property or the sales comparison approach").

27 Rabon Testimony at 4, Table 1.

in this very proceeding requiring the parties to submit three separate valuations.

- CCSF effectively assigns zero value to thousands of PG&E's real estate interests, without any evidence or data, artificially reducing its valuation by more than $1.7 billion. Easements and licenses are real property interests with significant value, particularly in dense urban areas like San Francisco. CCSF of course understands this—it owns and commonly negotiates the cost of easement rights that it grants—yet CCSF here claims that PG&E's more than 2,000 easements, licenses, and other land use rights are worth $0. This unrealistic and unfounded disregard of PG&E's property rights and their value artificially reduces CCSF's RCNLD valuation by $1.7 billion.
- CCSF significantly understates the undergrounding costs associated with replacing PG&E's system. CCSF also makes a number of unrealistic assumptions about how much it would cost to rebuild a system like PG&E's in a dense urban environment like San Francisco. For example, in calculating RCNLD, CCSF claims that installation of underground conduit in San Francisco will cost approximately $247 per foot when actual prior, similar underground construction efforts in San Francisco have involved costs closer to $1,000 per foot. Since the bulk of San Francisco's electric grid is underground, CCSF's decision to rely upon a unit cost that is significantly below actual San Francisco costs has significant impacts on its ultimate RCNLD valuation. The result of this calculation and similar errors in its testimony is that CCSF materially undervalues the replacement costs across many categories of physical assets, including underground conduits (by $2.4 billion) and subsurface structures (by $2.1 billion).[28]

The bottom-line result of these and other errors is that CCSF's overall valuation understates the value of the Subject Assets by approximately **$10.5 billion**. The below table provides a brief overview of the differences

[28] These are just some of the flaws in CCSF's testimony. Other significant flaws are addressed in Chapters 3 through 7.

between CCSF's and PG&E's valuations and the key drivers of those differences:

TABLE 1-2
PG&E AND CCSF VALUATION RESULTS
(BILLIONS OF DOLLARS)

Line No.	Valuation Approach	CCSF	PG&E	Substantial Drivers of Difference
1	Market Approach	$3.09B	$14.26B	CCSF values assets based upon regulated rate base, while PG&E relies on utility acquisition data showing that assembled utility systems command substantially higher market values than rate base.
2	Cost Approach	$3.43B	$14.55B	CCSF undervalued most of PG&E's underground assets based upon incorrect unit costs (~$4.5B), valued all of PG&E's easements and licenses at $0 (~$1.7B), ignored the corridor enhancement value of PG&E's real estate assets (~$870M) and arbitrarily subtracted $1.8B from its valuation so that its cost and income valuations would match.
3	Income Approach	$3.43B	$12.00B	CCSF did not analyze the highest price because it did not consider a hypothetical government buyer, which would be willing to pay a higher price.
4	Weighted Valuation	$3.43B	$13.88B	CCSF assigned a 100% weight to its income valuation. PG&E weights the cost approach most heavily (65%). The cost approach provides the most direct evidence of value because it is asset-specific and captures the capital-intensive, special-purpose character of the Subject Assets and the fact that they form a complex, operative system.

Even CCSF's original valuation formula from its 2019 "indication of interest" reflects a much higher valuation than its current testimony. When CCSF offered to purchase PG&E's Assets in September 2019, it justified its $2.5 billion offer by claiming that it represented 2.5 times PG&E's rate base.[29] But CCSF now applies a valuation closer to just 1.4 times PG&E rate base, valuing PG&E's assets at $3.43 billion when it has determined the

[29] CCSF's Sept. 6 Letter at 2–3. To be clear, the offer in CCSF's September 6th letter was itself very low. CCSF had not yet identified the assets that it sought to purchase; it underestimated PG&E's rate base; and CCSF could not have anticipated the significant investments that PG&E made from September 2019 through the Petition filing date in July 2021, which increased the value of PG&E's Assets. Notably, PG&E has continued to invest in San Francisco's infrastructure, although the current proceeding focuses on just compensation as of July 2021.

July 2021 rate base value of the Subject Assets is $2.4 billion.[30] CCSF's original formula would dictate a $6 billion valuation (2.5 times $2.4 billion)—still well below the Subject Assets' fair market value—before addressing the severance damages that CCSF would owe PG&E.[31]

F. Summary of PG&E's Testimony

The Commission's statutory responsibility in this proceeding is (1) to determine just compensation to PG&E (i) "for the lands, property, and rights" to be taken, *i.e.*, the value of PG&E's Assets and (ii) for "severance damages," *i.e.*, the impact to PG&E's existing business and customers; and (2) to determine the appropriate allocation between shareholders and ratepayers.[32] In this section, I provide an overview of PG&E's testimony on these topics, laid out as follows:[33]

TABLE 1-3
OVERVIEW OF PG&E TESTIMONY

Chapter(s)	Topic	Summary
Valuation of the Subject Assets		
2	Subject Assets Overview	Overview of PG&E's integrated electric system and the Assets that CCSF seeks to acquire.
3, 4	RCNLD Valuation	Valuation of PG&E's assets (Chapter 3) and real estate (Chapter 4) under RCNLD approach.
5	Market Valuation, Income Valuation, and Appraiser Weighting	Valuation of PG&E's assets under the market and income approaches and appraiser weighting of the three valuation approaches to determine fair market value of the Subject Assets.
6	Rate Base and Growth Forecast	Overview of PG&E's net book value and rate base for the Subject Assets and the capital expenditure and plant growth forecast assumptions underlying its testimony.
7	Public Purchasers	Discussion of the hypothetical government buyers for the Subject Assets.

30 Rabon Testimony at 4 (Table 1). This is an undervaluation as explained in Chapter 6.

31 Moreover, the 2019 offer of $2.5 billion was CCSF's opening, all-cash offer, not a negotiated selling price, and CCSF made its offer during PG&E's Chapter 11 proceedings, presumably hoping that PG&E would sell its assets at a discount to facilitate resolving its bankruptcy.

32 Pub. Util. Code § 1411.

33 I have included a table of the complete set of witnesses and their respective areas of testimony at the end of my testimony.

Quantification of Severance Damages		
8	Business Severance	Analysis of PG&E's Business Severance damages, with subchapters addressing categories of Business Severance, avoided and unavoided costs, and NTP&S[34] net revenue.
9	Physical Severance	Analysis of PG&E's Physical Severance damages based upon consideration of CCSF's proposed separation plan.
Allocation of Just Compensation Award and Analysis of Whole/Remainder		
10	Allocation of Award	PG&E's proposed allocation of the total just compensation award and PG&E's analysis of the whole versus remainder, as required by the Interim Decision.

1. CCSF Must Pay PG&E Just Compensation for the Assets, including Lands, Tangible and Intangible Property, and Property Rights.

a. PG&E's San Francisco Based Assets are Extensive.

CCSF now has identified the Assets that it wants to acquire in its Amended and Restated Testimony and (per the request of the Energy Division) through stipulations between the parties. In ***Chapter 2*** of PG&E's Testimony, Electric Engineering Vice President Shay Bahramirad, Director of Corporate Real Estate Strategy and Services Marcelo Romano, Senior Director of Land Management Aimee Crawford, and Senior Director of Electric Asset Knowledge Management Jadwindar Singh further describe these Assets, which include, among others:

- ***The Martin Substation***, a critically important electric transmission and distribution substation (with co-located gas assets and an adjacent service center that CCSF does not plan to take) located outside of CCSF's borders—in San Mateo County—that serves customers throughout the peninsula;
- ***31 additional substations within San Francisco***, including the associated land, buildings, and electric transmission and distribution assets located in those substations, such as transformers, switches, feeders, circuit breakers, capacitors, and reactors;

34 NTP&S revenue refers to revenues PG&E receives from existing non-tariff products and services, such as revenue from renting space on PG&E's electric transmission towers to cellular telephone companies.

- ***Substantial additional real property***, including a parcel that PG&E currently plans to develop into another substation, plus more than 125 miles of easements traversing private property within San Francisco and between the Martin Substation and the San Francisco boundary;
- ***PG&E's extensive transmission and distribution network***, including approximately 67 miles of transmission lines and nearly 3,000 miles of primary and secondary distribution lines, together with over 38,000 support structures (largely poles), over 50,000 subsurface structures, and nearly 1,400 miles of underground conduit;
- ***IT and telecommunications assets***, including local Supervisory Control and Data Acquisition ("SCADA") servers, radio system assets, and fiberoptic cables; and
- ***Voluminous and critical intangible assets***, such as safety records, operating and maintenance records, customer records, maps, drawings, engineering procedures, and GIS databases.

As Chapter 2 explains, PG&E did not build its integrated electric grid based on city, county, or other municipal boundaries. PG&E's grid is an overarching network that serves millions of customers across thousands of miles of Northern and Central California territory, such that excising San Francisco—essentially, cutting a hole out of the existing integrated grid—will cause significant impacts both to the system and neighboring customers. Consequently, this is an important valuation issue in PG&E's severance testimony.

b. The Commission's Interim Decision Mandates Application of All Three Valuation Methodologies.

To determine just compensation for the Subject Assets, the Commission must determine their fair market value.[35] As the Commission explained in its Interim Decision, fair market value means

[35] *See, e.g.*, Interim Decision at 26, 33–37.

the *highest* price that a hypothetical buyer and seller would agree to in a voluntary transaction on the open market.[36]

The Interim Decision required each party to present valuation testimony under each of three methodologies: (1) the cost approach, which values assets based on the cost that a hypothetical buyer would incur to replicate the assets in their current condition; (2) the market approach, which values the assets based on recent comparable sales; and (3) the income approach, which values income-producing assets based on the stream of future income that one would expect those assets to produce, discounted to present value.[37]

PG&E applies each of these approaches in ***Chapters 3 through 5*** (with supporting material in Chapters 6 and 7) and weights these valuations in ***Chapter 5*** to arrive at a fair market value of $13.88 billion for the Subject Assets.

c. PG&E's Cost Approach Valuation (RCNLD) Equals $14.55B.

PG&E demonstrates the RCNLD values of its physical Assets in ***Chapter 3*** ($10.24 billion) and its real property Assets in ***Chapter 4*** ($4.3 billion), which (after adding the value of PG&E's intangible assets) combine to a $14.55 billion RCNLD valuation. PG&E's RCNLD analysis involves multiple steps:

- Identifying the Subject Assets that CCSF plans to take—the identity/quantities of which the parties agreed to by stipulation—including real property and non-real-property assets (both tangible and intangible);
- For Assets other than real property and intangible assets, determining their "Replacement Cost New" and remaining useful life (*i.e.*, physical depreciation);
- For PG&E's real property Assets, completing an appraisal, accounting for any depreciation of buildings and other site improvements, and adding a corridor enhancement factor to reflect the increased value of this assemblage of real estate assets; and

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36 *Id.* at 25.

37 *Id.* at 33–35.

- Summing the RCNLD values of the various categories of Subject Assets and providing a total RCNLD valuation.

Chapter 3 focuses on the RCNLD value of PG&E's Subject Assets other than real property and intangible assets:

- In ***Chapter 3.1***, Sargent & Lundy ("S&L") expert Matthew Thibodeau presents an overview of the Subject Assets and provides the Replacement Cost New ("RCN") for each asset type, based on industry-wide material and labor costs with a focus on the estimated cost to construct electric transmission and distribution facilities in San Francisco and, where applicable, PG&E's actual costs. Mr. Thibodeau also addresses errors in CCSF's RCN analysis.
- In ***Chapter 3.2***, GFT Infrastructure, Inc. ("GFT") expert Ned Allis presents an evaluation of the conditions of the Subject Assets to determine their remaining useful life, which he supports through detailed records reviews and in-field physical inspections. Mr. Allis also applies physical depreciation to the RCN value in Chapter 3.1, providing PG&E's RCNLD valuation for the Subject Assets.

Chapter 4 assesses the RCNLD value of the real property components of the Subject Assets, namely, the land, buildings, easements, and other PG&E real property that CCSF intends to take from PG&E. Valbridge Property Advisors expert Walter Carney and Waldron & Associates expert Michael Waldron appraise the fair market value of PG&E's fee simple property and easements, respectively. They also calculate the RCNLD associated with the buildings on PG&E's fee property and apply a corridor enhancement factor to account for the increased value of an assembled land corridor. Based on that analysis, they conclude that the fair market value of PG&E's property and easements is $4.3 billion.

In ***Chapter 5***, Dr. John A. Williams of EPS, an Accredited Senior Appraiser of the American Society of Appraisers ("ASA") in Machinery and Technical Specialties ("MTS") and a licensed Professional Engineer, assesses adjustments to the cost approach, and in particular why economic obsolescence—on which CCSF relies—is inappropriate.

Dr. Williams also provides the RCNLD-based value of the Subject Assets.

PG&E has calculated the RCNLD-based value of the Subject Assets at $14.55 billion.

d. PG&E's Market Approach ($14.26 billion), Income Approach ($12.00 billion), and Appraiser Weighting (Establishing a Fair Market Value of $13.88 billion).

In ***Chapter 5***, Dr. Williams provides an analysis of the Subject Assets' market-approach valuation, income-approach valuation, and the proper weighting of the three approaches to arrive at the fair market value of the Subject Assets of $13.88 billion.

- *Market Approach.* Dr. Williams applies the market approach, which shows a $14.26 billion valuation. Dr. Williams conducts his market approach by first searching for comparable transactions and then calculating the price-cost ratio paid in those market transactions and applying it to the Subject Assets. Dr. Williams also explains that CCSF's market analysis significantly understates the value of the Subject Assets by relying on transactions that are not comparable and employing an unreliable methodology.
- *Income Approach.* Dr. Williams, along with Richard Gerger (a financial and valuation expert from Cornell/Gerger Consulting), applies the income approach, which shows a $12.00 billion valuation. Dr. Williams provides a discounted cash flow analysis that forecasts revenue based on PG&E ownership of the assets and one or more hypothetical governmental buyers that are unregulated and tax-exempt.
- *Economic Obsolescence.* Dr. Williams discusses economic obsolescence and explains its application in valuing the Subject Assets, concluding that, contrary to CCSF's testimony, there is no justification for a substantial "economic obsolescence" adjustment to RCNLD.
- *Weighting.* Dr. Williams evaluates and weights each of the three approaches to valuation required by the Interim Decision, concluding that the fair market value of the Subject Assets is $13.88 billion as of the July 27, 2021 Petition Date.

e. Supporting Chapters Regarding Rate Base and Public Purchasers.

Chapters 6 and 7 provide support for Dr. Williams' analysis.

- In ***Chapter 6***, PG&E witness Kerry Hegarty, Senior Manager in PG&E's Capital Recovery organization, explains the derivation of the net book value and rate base of the Subject Assets as of the Petition Date, which are $2.68 billion and $2.44 billion, respectively. PG&E witness Bryon Winget, Vice President of Integrated Planning, explains PG&E's forecast of capital expenditures (replacement and growth of plant) as of the Petition Date, which reflects continued, steady growth over the coming decades. Ned Allis of GFT addresses issues related to the calculation of depreciation and errors in CCSF's rate base and capital forecast. And PG&E witness Tim Wedlake, an in-house tax lawyer and manager in PG&E's Tax Department, addresses the ADIT allocation in PG&E's rate base.
- In ***Chapter 7***, David Rubin, former Director of Service Analysis at PG&E, explains the categories of governmental buyers that could purchase the Subject Assets and provides an overview of recent transactions and municipalization efforts concerning electric assets, supporting PG&E's inclusion of governmental entity buyers in its valuation analysis.

2. PG&E's Just Compensation for Severance Damages, Consisting of Business and Physical Severance Damages, Equals $8.61 billion.

a. The Commission Set Valuation Guidelines for Severance Damages in Its Interim Decision.

In addition to valuing the Subject Assets that CCSF intends to take, PG&E's testimony also quantifies its severance damages, which are the damages that CCSF's taking would cause. As the Commission required in its Interim Decision, PG&E's severance damages testimony includes both Business Severance damages and Physical Severance damages, including:

- "[A] specific sum that represents PCIA, safety, reliability, wildfire mitigation, public benefit, stranded asset costs, joint and common costs, public purpose charges, and other pass-through costs;" and
- The "cost PG&E will incur to separate and reintegrate its system based on the separation plan filed by CCSF."[38]

With respect to PG&E's Business Severance damages, the Commission's Interim Decision explained that "the standard for just compensation must leave remaining ratepayers unharmed by cost shifting."[39] This is a central element of PG&E's severance analysis. Customers throughout PG&E's service territory rely on numerous programs that PG&E provides, and which are core to the State's energy policy. CCSF's proposed taking would remove more than 400,000 customers from these centralized efforts, reducing PG&E's and the Commission's abilities to provide such core benefits to electric consumers outside of San Francisco. Accordingly, as the Commission itself recognized, CCSF's proposed acquisition is apt to significantly harm PG&E's non-San Francisco based customers.

> If CCSF were to depart and immediately cease to share in paying for the same cost drivers that it currently pays, PG&E's remaining customers may suffer significant harm. PG&E's revenue requirement includes many mandated fixed costs to maintain its safety, reliability, wildfire mitigation, public benefit, and other critical programs, that are passed through to customers. If sales decline due to the departure of load, then the rates increase for remaining ratepayers.[40]

To prevent this outcome, the Commission concluded that "CCSF should pay its share of the costs necessary to keep remaining ratepayers neutral to the potential acquisition, including costs which it was already paying, or committed to pay, at the time of CCSF's Petition."[41] Unless CCSF pays these charges, or collects them from San Franciscans and

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38 *Id.* at 26, 35–36.

39 *Id.* at 26.

40 *Id.* at 22.

41 *Id.* at 41 (Conclusions of Law ¶ 1).

remits them to PG&E, then customers outside of San Francisco will incur harm.

b. PG&E's Business Severance Valuation Equals $7.61 billion.

Just compensation includes the severance damages that the taking would cause to PG&E's business, including resulting declines in revenues and asset values, which we describe as Business Severance damages.[42] PG&E summarizes its severance damages calculation in ***Chapter 8*** based on analysis of data and quantified economic impacts, with supporting testimony as laid out below.

Categories of Business Severance Damages. In ***Chapter 8.1***, expert David Rubin and Marcus Keller (PG&E's Director, Portfolio Forecasting and Cost Recovery) evaluate several categories of Business Severance damages,[43] most notably damages associated with the public policy charges that the Commission has directed investor-owned utilities ("IOUs") to collect in rates to support various beneficial state energy policies.[44] CCSF's departure from Commission jurisdiction would only fractionally reduce the costs associated with PG&E's energy policy programs, but it would reduce the number of customers supporting these programs. As described above, the Commission has correctly recognized that such costs are a compensable part of Business Severance damages and necessary to prevent shifting these costs to PG&E's non-San Francisco based customers.

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42 This category of severance damages is sometimes also called "financial severance damages."

43 Chapter 8 also discusses severance damages stemming from, among other things, bills that PG&E's San Francisco customers have received but not yet paid and consumed energy that has not yet been billed.

44 These include, for example: the Public Purpose Program ("PPP") charge, which largely supports low-income rate discounts and energy efficiency programs; the Power Charge Indifference Adjustment ("PCIA"), which covers the above-market portion of specific power supply commitments that PG&E undertook as part of its universal service obligation; the Wildfire Hardening Charge, which pays for important investments in infrastructure to reduce statewide wildfire risk; and other irrevocable charges to amortize securitization bonds.

Inadequacy of TMDL Tariff. Also in ***Chapter 8.1***, PG&E's Director of Billing Operations, Shaun Hoppes, addresses why the Transferred Municipal Departing Load ("TMDL") tariff does not mitigate or eliminate the damages that PG&E would suffer as the result of a takeover. The TMDL tariff is a mechanism by which an investor-owned utility can recover certain costs from former customers even after those customers have transferred to a publicly owned utility's service. But the TMDL tariff does not include recovery of all costs; moreover, it is both unrealistic and infeasible for PG&E to collect such costs directly from CCSF's customers after a taking. At that point, PG&E no longer provides electric service or remits electric bills to those customers, and PG&E's efforts to collect such costs from prior departed customers have been largely unsuccessful.

Tax Impacts and Considerations. Also in ***Chapter 8.1***, PG&E witness Tim Wedlake evaluates the tax impacts of PG&E's financial severance damages. As he explains, PG&E's San Francisco customers have benefitted from lower rates due to flowed-through tax benefits, with the deferred amounts to be collected from customers years—often decades—later. As a result, CCSF needs to compensate PG&E for these deferred amounts to avoid burdening PG&E's non-San Francisco customers. Mr. Wedlake also notes that a tax gross-up will be required on Business Severance amounts paid to PG&E to ensure that PG&E's customers are truly made whole; without such a "gross up," PG&E's net damages (after taxes) will be less than the damages owed, leaving PG&E customers or shareholders in a worse position after the taking.

Avoided and Unavoided Costs. In ***Chapter 8.2***, expert Whitney Alary, a partner at HKA Consulting, describes the costs that CCSF's proposed condemnation would cause PG&E to avoid as well as certain costs that PG&E would not be able to avoid. Her study concludes that, on balance, PG&E would avoid just 1.17% of its total system-wide electric costs as a result of CCSF's proposed taking.

NTP&S Revenues. In ***Chapter 8.3***, PG&E witness Michael Delaney, Vice President of Strategy and Innovation, evaluates the net revenues from existing non-tariff products and services that PG&E

would lose due to condemnation, such as the revenue that PG&E receives from renting space on its towers to telecommunications companies. PG&E's non-tariffed net revenues serve to reduce PG&E's overall revenue requirement, thereby reducing the rates that PG&E's customers pay. Mr. Delaney's testimony concludes that CCSF would need to compensate PG&E this amount to prevent PG&E's remaining customers from paying higher rates. The lost net revenue is included within the overall calculation of Business Severance damages.

c. PG&E's Physical Severance Valuation

In ***Chapter 9***, Stephen Teran (Senior Director of Integrated System Planning at Danovo Energy Solutions) details the significant physical separation steps that PG&E would need to take, and Matthew Thibodeau (S&L), Dewey Day (PG&E's Infrastructure and Cloud Service Director), Marcelo Romano (PG&E's Director of Corporate Real Estate Strategy and Services), and Tim Wedlake (a PG&E in-house tax lawyer) tabulate the costs (including tax gross up) that PG&E would incur to separate the assets CCSF plans to take from PG&E's remaining assets and to restore PG&E's system after a takeover. As I explain above, separating the Subject Assets in and serving electric customers in San Francisco is tantamount to carving a hole in the middle of PG&E's integrated grid. Doing so would require PG&E to incur significant costs to reconfigure and rebuild its physical electric facilities, modify its support systems, and relocate certain of its operations to maintain service to its electric customers outside of San Francisco. Most significantly, CCSF's proposed taking at the Martin Substation would require PG&E to construct an entirely new substation to serve its customers in San Mateo County and maintain the same electric system reliability—particularly to serve the peninsula—after CCSF's contemplated taking.

Taken together, the costs that PG&E would incur to separate the Subject Assets from the rest of its system, and to restore its electric and gas system to existing levels of safety and reliability would be $1 billion. As is the case with Business Severance, this total includes a tax gross

up, which is necessary to avoid customers or shareholders being inadequately compensated due to taxes.

3. Allocation of Just Compensation and Whole/Remainder Analysis

In ***Chapter 10***, PG&E witness Sienna Rogers, Senior Director of Financial Planning and Analysis, presents testimony regarding two additional topics required by the Interim Decision: (1) how the just compensation award should be allocated; and (2) an income approach value of the whole and the remainder before and after the taking.[45]

Allocation. Ms. Rogers' testimony first articulates (1) PG&E's "proposed regulatory accounting of the recommended just compensation award . . . demonstrating which portions of the award will be returned to shareholders and which will be returned to ratepayers," and (2) "[a] rate impact analysis . . . demonstrating that the proposed regulatory accounting of the recommended just compensation award will result in rate neutrality for PG&E's remaining customers."[46] Ms. Rogers testifies that the gain on sale associated with the fair market value of the Subject Assets would accrue to shareholders, while both Business and Physical Severance damages would hold PG&E's remaining customers harmless. Ms. Rogers also confirms that, pursuant to the Commission's mandate, PG&E's valuation of just compensation would leave PG&E's remaining customers rate-neutral.

Whole and Remainder. Ms. Rogers also addresses the value of the whole PG&E system and the remainder "[f]or the purposes of validating the calculation of severance damages,"[47] as instructed by the Interim Decision. As she explains, in that context, the result of the calculations reduces, mathematically, to the same calculation of lost revenue from customers in San Francisco minus avoided costs that is already performed in Chapter 8.

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45 Interim Decision at 35 (requiring that PG&E testimony provide an "[i]ncome approach calculating the value of the whole property before the taking, the value of the remainder of the property before and after the taking, and the value of the part taken").

46 *Id.* at 36.

47 *Id.* at 42 (Conclusions of Law ¶ 7).

G. Need for Update To Condemnation Date

PG&E (and CCSF) calculated their respective valuations as of the date on which CCSF filed its Petition, July 27, 2021, as required by law.[48] But applying a specific valuation date underscores that the values at issue in this proceeding will require update. For example, PG&E has continued to expand its assets in San Francisco; progressed on construction that was in progress on the valuation date; and started or interconnected new PG&E-owned and third-party projects. And of course, prevailing economic conditions have changed, and the composition of non-bypassable public policy charges within PG&E's rates, and the magnitude of those charges, have shifted. While counterintuitive, this is unfortunately inherent in applying a statutory valuation mechanism tied to the Petition date rather than closer in time to the Commission's decision in this proceeding or upon completion of a condemnation proceeding in Superior Court.

The Public Utilities Code contemplates an update proceeding to account for changes in just compensation between the valuation date and the condemnation date.[49] If CCSF's proposed taking comes to pass, that update will be critical to ensure that PG&E receives just compensation for any assets that CCSF actually condemns, and to prevent any costs that PG&E would incur in the intervening years from shifting to PG&E's remaining customers.

H. ESJ and Policy Considerations

The remainder of this Chapter discusses two important policy considerations: (i) the implications of this Petition on the Commission's Environmental and Social Justice ("ESJ") goals, and (ii) the long-term downsides of municipalization efforts like CCSF's.

1. Impact on Commission's ESJ Goals

The Assigned Commissioner's June 2022 Scoping Memo requires this proceeding to address the implications that CCSF's taking could have on the

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[48] Pub. Util. Code § 1411.

[49] *Id.* § 1417.

Commission's Environmental and Social Justice Action Plan.[50] The taking contemplated by the Petition would substantially impact those goals.

CCSF's proposed taking would not only carve a hole in PG&E's electric grid, but also in the Commission's jurisdiction. The municipal electric utility that CCSF proposes to form would not be subject to the Commission's ratemaking authority or such key policy priorities as clean energy, climate resiliency, energy reliability, consumer safety, and environmental protection. Consequently, CCSF taking PG&E's Assets will impede the Commission's ability to support ESJ communities and promote uniform State policies. The following are just a few prominent examples:

Goal 1: Commission Oversight. Because CCSF's proposed taking would remove San Francisco from the Commission's jurisdiction, it would deny San Francisco customers the benefit of the Commission's formalized, thoughtful consideration of ESJ issues throughout the regulatory process. The Commission has a track record of success implementing its ESJ goals.[51] CCSF's proposed taking would deny San Francisco customers the benefits of future Commission leadership on ESJ issues.

Goals 2 and 4: Climate Resiliency, Clean Energy, and Public Health. To further its second and fourth ESJ goals, the Commission has created policy program initiatives that support the State's energy policies to

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50 Scoping Memo and Ruling at 4 (June 24, 2022), citing CPUC, Environmental and Social Justice Action Plan (Version 2.0) ("ESJ Plan 2.0"), at 4–6 (Apr. 7, 2022), available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-v2jw.pdf.

The CPUC's ESJ Action Plan identifies the following ESJ goals: (1) Consistently integrate equity and access considerations throughout CPUC regulatory activities; (2) Increase investment in clean energy resources to benefit ESJ communities, especially to improve local air quality and public health; (3) Strive to improve access to high-quality water, communications, and transportation services for ESJ communities; (4) Increase climate resiliency in ESJ communities; (5) Enhance outreach and public participation opportunities for ESJ communities to meaningfully participate in the CPUC's decision-making process and benefit from CPUC programs; (6) Enhance enforcement to ensure safety and consumer protection for all, especially for ESJ communities; (7) Promote high road career paths and economic opportunity for residents of ESJ communities; (8) Improve training and staff development related to environmental and social justice issues within the CPUC's jurisdiction; and (9) Monitor the CPUC's environmental and social justice efforts to evaluate how they are achieving their objectives.

51 ESJ Plan 2.0, App. D: Select Case Studies of ESJ in CPUC Proceedings.

ensure that ESJ communities are able to receive clean, efficient, and affordable electric service. These programs include:

- financial incentives for more efficient use of energy in homes and businesses;
- direct installation of energy efficient measures for low-income customers;
- financial incentives for on-site clean generation and battery storage;
- rate options to encourage time-of-use consumption changes to better manage the cost-effective operation of the grid;
- financial incentives to support clean transportation, including electric vehicle charging infrastructure;
- rate discounts for low-income customers;
- customized payment plans for low-income customers;
- bill reduction benefits for customers with qualifying medical devices; and
- rate benefits for customers in disadvantaged communities that participate in community renewable programs.[52]

CCSF's planned acquisition would cause San Francisco customers to lose access to these Commission-created programs and other environmental benefits.

CCSF apparently intends to implement climate and energy programs of its own, as its purported purposes in taking the Subject Assets include to "combat global warming,"[53] and advance "climate action goals in several key areas, including transportation, energy, and construction."[54] But CCSF already provides approximately 85% of the energy consumed in San Francisco through its community choice aggregator (CleanPowerSF) and Hetch Hetchy power. And it is unlikely that CCSF could advance climate, clean energy, and public health goals as well as the Commission does—particularly considering that the Commission, unlike CCSF, can take

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52 For more details about these programs and the non-bypassable charges that fund them, *see* Chapter 8.

53 Ex. CCSF-001 – Prepared Direct Testimony of Dennis Herrera on Behalf of the City and County of San Francisco at 1 (Apr. 20, 2026) (errata May 21, 2026) ("Herrera Testimony").

54 CCSF's Petition at 8–9.

advantage of statewide economies of scale for its programs. As such, CCSF's proposed takeover does not offer significant environmental benefit, but, rather, significant additional costs, disruption, duplication, and negative environmental impacts.

Goal 6: Safety and Consumer Protection. Along similar lines, CCSF's takeover of PG&E's electric assets would deny San Francisco customers the benefits of the Commission's strong independent safety and consumer protection oversight. Each of the Commission's divisions maintains dedicated expert staff with extensive experience in their respective areas of responsibility, and other organizations within the Commission's purview perform critical customer-facing services. For example:

- The Commission's Safety Policy Division supports the Commission's policymaking and regulatory efforts to ensure safe and reliable electric delivery.
- The Safety and Enforcement Division conducts public safety audits and investigations and takes enforcement action as needed to protect consumers from violations of state statutes and the Commission's General Orders.
- The Public Advocates Office, an independent organization within the Commission created by statute, advocates on behalf of utility ratepayers.

CCSF's proposed municipalization would deprive San Francisco electric customers of these Commission resources without any guarantee that CCSF would provide similar resources, while undermining the Commission's ability to provide such resources uniformly across the state.

2. CCSF's Proposed Municipalization Could Incentivize Others to Municipalize, Further Undermining the Commission's ESJ Goals and State Energy Policy.

It is also important to consider CCSF's proposed municipalization in the context of California's statewide energy policy, rather than in isolation. Specifically, CCSF's proposed municipalization could lead to additional such efforts, because an increase in customer departures could leave fewer customers covering a disproportionate share of such statewide costs as

wildfire hardening. Indeed, a City of Chico Councilmember called this out explicitly in discussing municipalization:

> If San Francisco successfully departs from PG&E's system, PG&E's costs will be distributed among fewer customers, leading to higher rates, and prompting other cities to explore their own alternatives. If there is a "ratepayer rebellion" the people of Chico would benefit from our leadership in making us one of the first, not one of the last ones out.[55]

Such a trend could both burden remaining customers and reduce the Commission's ability to affect statewide policy. Over time, fewer and fewer customers could receive the benefit of CPUC jurisdiction and the Commission's ESJ efforts.

Notwithstanding claims of lower costs and improved service, departing customers commonly experience higher rates and lose benefits when they are no longer protected by the Commission. In practice, the actual rates that municipal utilities charge often far exceed the rates that they predicted before they completed their municipalizations, resulting in municipal electric rates that often far exceed IOUs' rates.[56]

Indeed, multiple municipalities have abandoned attempts to municipalize electric and other utilities after review of accurate estimates of fair market value, which often make municipalizations financially infeasible without significant rate increases.[57] In multiple cases, municipalization efforts have gone so poorly that those utilities have de-municipalized and returned to private ownership. Here in California, the Hercules Municipal Utility ultimately put its electric facilities up for sale after it became apparent that its optimistic predictions regarding financial benefits did not manifest. In fact, its rates were higher than those of PG&E, and the City faced significant financial challenges.[58] PG&E successfully bid on the assets when Hercules

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55 Letter from Councilmember Addison Winslow, City of Chico, District 4, available at https://chico-ca.granicus.com/MetaViewer.php?clip_id=1302&meta_id=102640&view_id=2.

56 Concentric Energy Advisors, *Electric Utility Privatization: An Analysis of Why Municipalization Efforts Fail* at 10–11, 13 (Oct. 2019) ("Concentric Report").

57 Toby Bishop, Ann Bulkley & Chris Wall, *Electric Utility Municipalization: Key Statistics and Risk Considerations* at 4, 7 n.2, 11–12 (Jan. 2025).

58 Concentric Report at 10.

put them up for sale. Outside of California, Elk City, Oklahoma municipalized a portion of its community in 2004, only to reprivatize those customers' service in 2010.[59] No one benefits from the waste of money and service disruptions that municipalization and later reprivatization triggers.

On the whole, municipalization efforts are often deeply contrary to the public interest. PG&E will not, as CCSF suggests, consent to "a negotiated transaction" to "facilitate" such an inequitable result.[60]

I. Testimony Roadmap

PG&E's testimony is organized as follows:

TABLE 1-4
PG&E TESTIMONY CHAPTERS AND SUBJECT MATTER

Chapter	Witness(es)	Subject Matter	Summary
1	Carla Peterman, PG&E	Policy & Summary	Overview of testimony; discussion of relevant policy issues.
2	Shay Bahramirad, Marcelo Romano, Aimee Crawford, Jadwindar Singh, PG&E	Overview of PG&E Electric System in San Francisco	Overview of PG&E assets subject to proceeding.
Valuation of the Subject Assets			
3	Matthew Thibodeau, Sargent & Lundy; Ned Allis, GFT	Overview of RCNLD Testimony	Provides overview of PG&E's RCNLD valuation testimony.
3.1	Matthew Thibodeau, Sargent & Lundy	RCN for Physical Assets	Replacement Cost New valuation of Subject Assets.
3.2	Ned Allis, GFT	Depreciation to RCNLD	Depreciation of RCN figure to RCNLD.
4	Walter Carney, Valbridge, and Michael Waldron, Waldron & Assocs.	Cost Approach, Real Estate	Determination of RCNLD value of PG&E's real estate interests.

59 *Id.* at 8.

60 Herrera Testimony at 2.

5	John A. Williams, EPS; Richard Gerger, Cornell/Gerger Consulting	Market Approach, Income Approach, Appraiser Weighting	Market approach; income approach; potential obsolescence adjustments to RCNLD; and weighting to determine fair market value.
6	Kerry Hegarty, PG&E; Bryon Winget, PG&E; Tim Wedlake, PG&E; Ned Allis, GFT	Net Book Value, Rate Base, and Forecast of Capital Expenditures	Calculation of net book value, rate base, and capital expenditure forecast underlying income approach; and criticism of CCSF approach.
7	David Rubin, PG&E (retired)	Public Purchasers	Government purchasers for Subject Assets.
Business Severance			
8	David Rubin, PG&E (retired)	Overview of Business Severance Damages	Overview of PG&E's Business Severance testimony.
8.1	David Rubin, PG&E (retired); Shaun Hoppes, PG&E; Tim Wedlake, PG&E; Marcus Keller, PG&E	Business Severance Damages	Quantification of Business Severance damages due to PG&E and analysis of tax issues impacting Business Severance damages.
8.2	Whitney Alary, HKA	Business Severance Damages: Avoided Cost Study	Discussion of costs that PG&E will avoid (and not avoid) following CCSF's taking.
8.3	Michael Delaney, PG&E	Business Severance Damages: Non-Tariff Products & Services	Discussion of non-tariff revenues that PG&E earns in San Francisco.
Physical Severance			
9	Stephen Teran, Danovo; Matthew Thibodeau, Sargent & Lundy; Dewey Day, PG&E; Marcelo Romano, PG&E; Tim Wedlake, PG&E	Overview of Physical Severance Analysis and Costs	Overview of PG&E's Physical Severance and costing testimony, including discussion of necessary remediations by PG&E following CCSF's proposed separation.
Allocation of Just Compensation Award and Analysis of Whole/Remainder			
10	Sienna Rogers, PG&E	Allocation of Just Compensation Award and Whole/Remainder Analysis	Regulatory accounting analysis of how to allocate damages paid to PG&E after taking, and analysis of the whole versus remainder, as required by the Interim Decision.

For convenience, PG&E also provides below a chart showing CCSF's testimony chapters and the relevant chapters of PG&E's testimony that respond to each.

TABLE 1-5
MAPPING OF CCSF TESTIMONY TO PG&E TESTIMONY

CCSF Chapter and Witness	PG&E Responding Chapter/Witness
Ch. 1, Dennis Herrera, Overview	Ch. 1, Carla Peterman, Policy and Summary
Ch. 2, Nelson Bacalao, RCNLD	Ch. 2, Shay Bahramirad, Marcelo Romano, Aimee Crawford, Jadwindar Singh, Overview of PG&E Assets Ch. 3.1, Matthew Thibodeau, RCN Valuation
Ch. 3, Timothy Runde, Real Estate RCNLD	Ch. 4, Walter Carney and Michael Waldron, Real Estate RCNLD
Ch. 4, Grant Rabon, Appraisal, Depreciation, Market Approach, Income Approach, Weighting	Ch. 3.2, Ned Allis, RCNLD Depreciation Ch. 5, John Williams, Appraisal, Market Approach, Income Approach, Weighting, Criticisms of Rabon (with supporting information in Ch. 6 and 7)
Ch. 5, Scott Beicke, Banker Testimony	N/A – Not an appraisal
Ch. 6, Mark Fulmer, Regulatory Accounting	Ch. 8, David Rubin, Business Severance Ch. 10, Sienna Rogers, Allocation; Whole/Remainder
Ch. 7, Manho Yeung and Ryan Wu, Physical Separation	Ch. 9, Stephen Teran, Physical Separation

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

OVERVIEW OF PG&E ELECTRIC SYSTEM IN SAN FRANCISCO

WITNESSES: SHAY BAHRAMIRAD, AIMEE CRAWFORD,

MARCELO ROMANO, AND JADWINDAR SINGH

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
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CHAPTER 2
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A. Introduction

My name is Shay Bahramirad, and I am the Vice President, Electric Engineering, Asset Management, and Risk and Compliance at Pacific Gas and Electric Company (PG&E). Unless otherwise stated, I sponsor this chapter of PG&E's testimony; Aimee Crawford, PG&E's Land Management Senior Director; Marcelo Romano, PG&E's Director of Corporate Real Estate Strategy and Services; and Jadwindar Singh, PG&E's Senior Director, Electric Asset Knowledge Management, sponsor sections of this chapter where explicitly stated. We submit this testimony in response to the City and County of San Francisco's (CCSF) Petition (CPUC Docket P.21-07-012).

PG&E's electric system within and serving San Francisco is a physically and operationally complex, interdependent network of physical electric transmission and delivery assets, control systems, communications infrastructure, property interests, and intangible assets that PG&E developed throughout its history of serving San Francisco. This system does not operate as a stand-alone grid that tracks to San Francisco's geographic boundaries; rather, PG&E's San Francisco system is an integral part of a much larger grid spanning 70,000 square miles. PG&E's system in San Francisco depends on resources located both inside and outside San Francisco, including assets that support PG&E's gas operations in San Francisco and beyond. Understanding the scale, interconnection, and operational interdependence of these assets is essential to evaluating the consequences of CCSF's proposed taking and the costly and substantial severance, replacement, and transition issues that CCSF's planned taking would create.[1]

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[1] PG&E generally refers to "San Francisco" when referring to the City's geographic location and "CCSF" when referring to the City as an entity.

To that end, this chapter provides an overview of PG&E's integrated electric system, serving as context for PG&E's valuation of its assets in and serving San Francisco (see Chapters 3, 4, and 5) and forecasted severance costs (see Chapters 8 and 9). This chapter proceeds by providing an overview of:

1) PG&E's electric operations throughout Northern and Central California, including an overview of how PG&E delivers electricity through its complex system of generation, transmission, substation, and distribution assets;
2) PG&E's electric operations and assets in San Francisco;
3) PG&E's extensive real estate holdings and property interests, on which PG&E relies to provide power to San Francisco; and
4) the interconnections between PG&E's electric system and gas system.

For purposes of this testimony, I focus on a snapshot of PG&E's system as of the July 2021 date of CCSF's petition in this proceeding. I note, however, that PG&E's system is dynamic rather than static. PG&E is constantly updating its system, implementing new technology, performing maintenance work, installing new assets, and so on. In the event CCSF proceeds with its proposed taking, the asset inventory and valuation will need to be updated.

B. PG&E's Northern and Central California Electric System

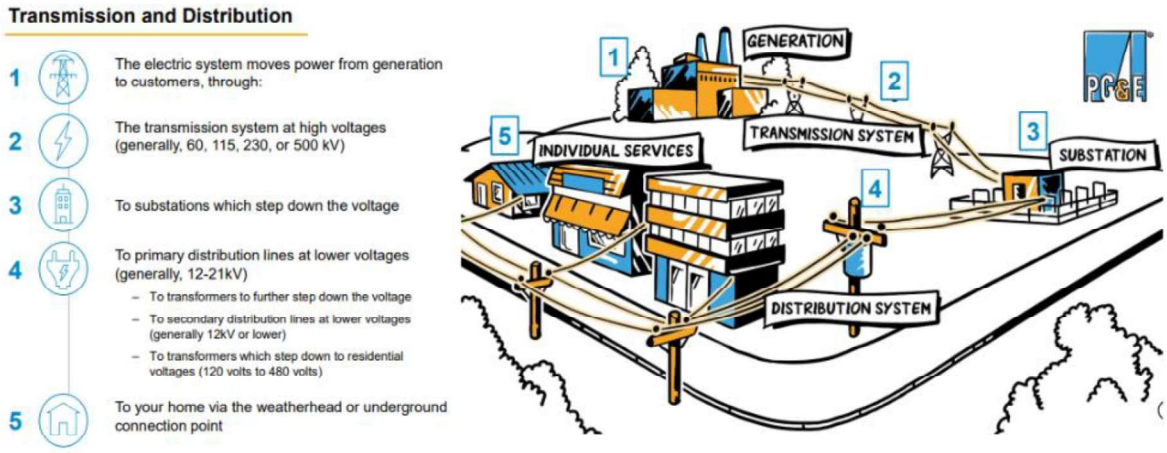
PG&E was incorporated in 1905, consolidating the businesses of California Gas and Electric Corporation and San Francisco Gas and Electric Company. The company went on to merge with many more businesses in an effort to consolidate power provision across Northern California. By 1952, PG&E represented the incorporation of over 500 companies.

PG&E currently provides electric service, gas service, or both to approximately 16 million people in California. PG&E provides service across a 70,000-square-mile service territory stretching from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean eastward to the Sierra Nevada mountains. As of 2021, PG&E had approximately 26,000 employees, approximately 5.5 million electric customer accounts, approximately 108,000 circuit miles of electric distribution lines, and approximately 18,000 circuit miles of interconnected transmission lines.

PG&E's electric system is an extremely complex, highly integrated network comprised of: (1) electric generation facilities (utility-owned or contracted facilities, as well as generating facilities that PG&E owns or contracts to

third-party energy suppliers), which produce energy from conventional and renewable sources for (2) transmission via high voltage electric transmission facilities, which transmit power to (3) substations, which step down the power voltage to (4) lower voltage distribution facilities, which then deliver the power to (5) distribution transformers, which step down the power for delivery through service drops and metered consumption by end use customers. PG&E's system also integrates generation facilities located directly on customer property (mostly solar photovoltaics) and storage facilities that deliver power directly to the point of consumption (mostly batteries). Figure 2-1 provides a high-level schematic of this electric system architecture.

FIGURE 2-1
ELECTRIC SYSTEM ARCHITECTURE



PG&E's system does not operate in isolation from the rest of California or the rest of the electric providers on the West Coast. At the state level, PG&E's system is part of a larger grid that the California Independent System Operator (CAISO) oversees. The CAISO manages the operation of the high voltage electric grid to ensure that supply and demand are carefully balanced at all times throughout the State. PG&E, as a Participating Transmission Owner, works with the CAISO to support the reliable delivery of energy to Californians. The CAISO manages the flow of electricity across the high-voltage, long-distance power lines serving 80% of California and a small portion of Nevada. Beyond the CAISO, PG&E's system is also part of the much larger Western Interconnection, for which the Western Electricity Coordinating Council serves as the Federal

Energy Regulatory Commission (FERC)-approved entity responsible for reliability planning, assessments, compliance monitoring, and enforcement.

C. PG&E's System Serving San Francisco

PG&E's electric system within and serving San Francisco is a large, complex, and highly urbanized network that, as of 2021, served approximately 420,000 customer accounts through an interconnected combination of transmission, substation, and distribution facilities. The system is uniquely dense and infrastructure-intensive, with a substantial underground footprint and a specialized downtown network designed to provide high reliability. Several aspects of PG&E's system in San Francisco make it particularly challenging to carve out of the remainder of PG&E's system.

First, PG&E's San Francisco system is heavily interconnected with surrounding communities. PG&E's system in and serving San Francisco receives transmission-voltage power [redacted] [2] [redacted]. At the distribution level, many of PG&E's distribution circuits cross the San Francisco-San Mateo county border; some of PG&E's distribution customers in southern San Francisco receive their electricity from PG&E's substations located in San Mateo County, and vice versa.

Second, PG&E's San Francisco system relies heavily on assets outside of San Francisco. As noted above, PG&E's system in San Francisco is highly reliant on the Martin Substation, which is located in San Mateo County. PG&E also monitors, manages, and operates its electric system (including the portions that serve San Francisco) through assets and equipment located elsewhere in its service area. [redacted]

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2 Generally, transmission voltages run from 60 kV and above, and distribution voltages from 34.5 kV and below.

Third, PG&E's San Francisco system is unique in its design and operational diversity. Much of PG&E's system serving downtown San Francisco is a spot and grid network system. Such grids—located primarily in urban areas containing many high-rise buildings—are known for their complexity, redundancy in design and operation, and reliability. Much of PG&E's system in San Francisco is also underground, in light of San Francisco's urban and space-constrained environment, and shares narrow underground corridors with water, sewer, telecom, and transit infrastructure. Relatedly, PG&E's San Francisco system is more difficult and costly to operate, maintain, and modernize than other areas of the grid. This results in substantial part from the dense, urban nature of San Francisco: work that may be comparatively straightforward in less-constrained areas—such as replacing cable or installing new equipment—can require extensive excavation, specialized underground construction, traffic management, and multi-agency permitting.

These factors collectively distinguish San Francisco from other parts of PG&E's territory and underscore why cutting a hole in PG&E's existing system would be both uniquely challenging and resource-intensive.

D. Assets Comprising PG&E's Electric System in and Serving San Francisco

PG&E's operations in San Francisco rely on a significant number of electric assets, communications and protection equipment, asset knowledge repositories, and other key infrastructure and resources. Many of these assets are discussed in Chapter 3.1, in which witness Matthew Thibodeau addresses the Replacement Cost New for PG&E's San Francisco system.

To provide context for that testimony, I provide an overview of the assets, resources, and infrastructure on which PG&E relies to provide power to San Francisco. These include: (1) generation assets, (2) transmission assets, (3) substations, (4) distribution assets, (5) metering systems, (6) streetlights, (7) protection and automation assets, (8) telecom assets, (9) communications assets, (10) control centers, (11) fleet assets, (12) spare parts, and (13) PG&E's extensive repository of operating records and asset information.

1. Generation

Power delivery to San Francisco customers starts with power generation. With limited exceptions, the electricity that San Francisco

residents consume comes mostly from sources outside of San Francisco. This includes power sourced by PG&E and by CCSF itself, through its ownership of the Hetch Hetchy hydroelectric generating facility, contracts with third-party-owned power supply facilities, and third-party Energy Service Providers. Generation facilities within San Francisco include three small PG&E-owned solar photovoltaic facilities,[3] as well as various customer-owned solar photovoltaic units.

2. Transmission

Power generated outside San Francisco initially enters San Francisco [redacted] which carry electric power to and from PG&E-owned substations in San Francisco. The image below provides an overview of PG&E's transmission system in and serving San Francisco:

[3] These facilities were put into service in 2007 and were approved as rate base additions in PG&E's 2014 General Rate Case.

CONFIDENTIAL FIGURE 2-2
PG&E TRANSMISSION SYSTEM

[redacted]

PG&E's transmission network in San Francisco consists of approximately 68 circuit miles of high-voltage lines, over 99% of which are underground. The underground transmission network is made up of three types of cables—pipe-type high-pressure gas-filled (HPGF) cables, pipe-type high-pressure fluid-filled (HPFF) cables, and solid dielectric cross-linked polyethylene (XLPE) cables. Pipe-type HPFF and HPGF cables were the technology of choice for underground transmission until the early 2000s and make up approximately two-thirds of the underground transmission cable system in San Francisco. PG&E now installs XLPE cable for newer underground transmission projects.

PG&E's electric underground transmission system in San Francisco also incorporates assets such as [redacted]

[redacted]. San Francisco also has electric transmission transition stations for hybrid lines (lines with overhead and underground components); these are fenced facilities that contain equipment that transitions a transmission line from overhead conductors to underground.

3. Substations

The power delivered to San Francisco via transmission lines next travels to substations—the facilities that step down the power delivery voltage from higher to lower levels. PG&E's substations are secured outdoor or indoor facilities. PG&E's outdoor substations are surrounded by security walls and multiple towers with security cameras, and its indoor substations are inside large, multi-story buildings, as shown in the example below.

FIGURE 2-3
IMAGE OF INDOOR SUBSTATION, SUBSTATION J

As of 2021, PG&E owned 32 active substations that serve San Francisco—31 located within city boundaries [redacted] and the Martin Substation in San Mateo County.[4] These substations operate at voltages ranging from [redacted] and contain varied equipment including transformers and circuit breakers. Of the 31 active substations located within city boundaries, [redacted]. Because there are many areas of San Francisco without transmission service, PG&E utilizes [redacted].

[redacted]

[4] PG&E also owns the "Substation I" property within San Francisco, but that substation was decommissioned long before 2021 and is no longer used to provide San Francisco customers with electric service.

[redacted]

CONFIDENTIAL FIGURE 2-4
MARTIN SITE

[redacted]

4. Distribution

After PG&E substations step down the power to distribution voltages, PG&E's distribution system carries the electricity either to individual customers directly or through service drops at customer premises.

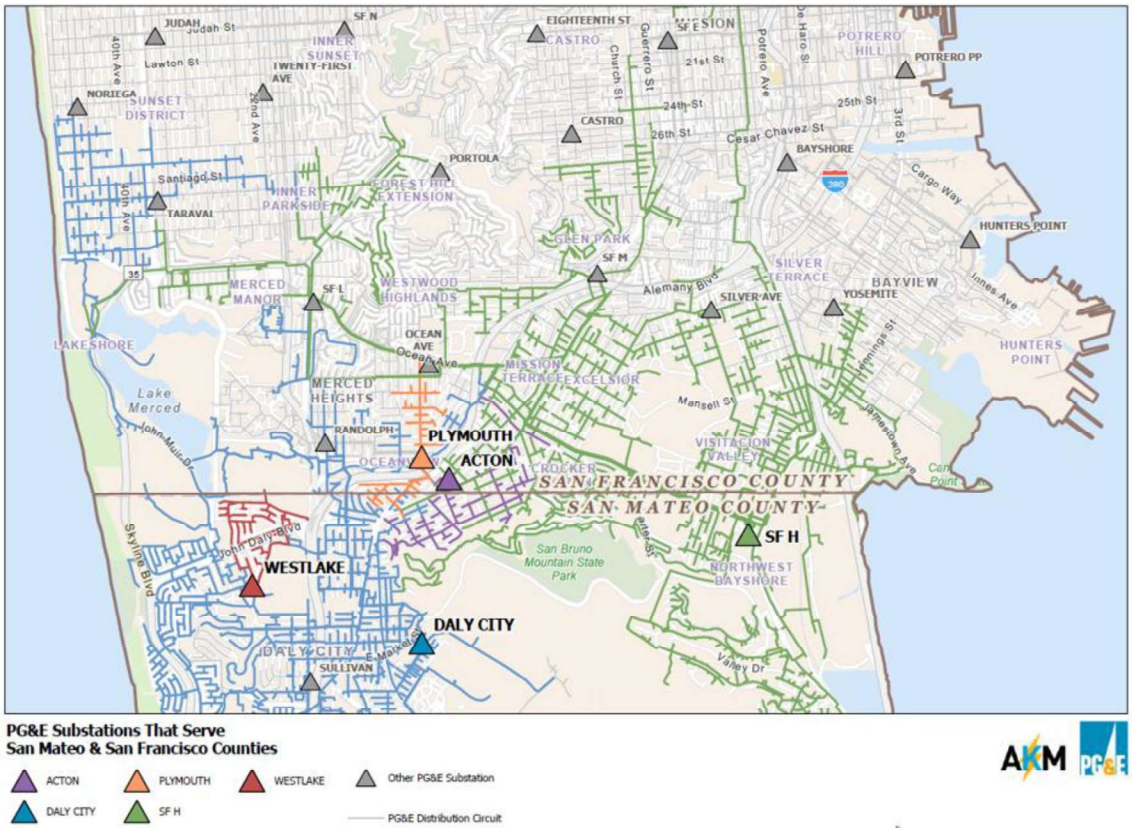
PG&E's electric distribution grid in San Francisco serves approximately 420,000 customer accounts within the city. PG&E's distribution system includes main or "primary" lines, which are generally 12- or 4-kV, and lower voltage "secondary" lines (both overhead and underground), which are generally 120-, 240-, or 480-V; distribution transformers, which lower voltage to usage levels; switching equipment to connect lines together in various combinations and patterns; and other assets, including capacitor banks and

protective devices. Approximately 65% of PG&E's distribution system in San Francisco is underground based on conductor length. The underground distribution conductors are housed within conduits in trenches and underground enclosures, mostly beneath streets and sidewalks (with some running through private property pursuant to easements that PG&E owns). Some of these trenches also contain co-located gas and other assets.

PG&E's downtown distribution network system is particularly complex. It serves commercial and residential customers in downtown San Francisco and adjacent areas. The system is built in a network configuration beneath downtown San Francisco's sidewalks and streets and in its high-rise buildings. PG&E designed the downtown system for redundancy to meet the higher reliability needs of such a dense urban area. In a network system, PG&E serves customers through multiple transformers so that the loss of a single line or transformer does not cause an interruption of power. The result is highly reliable service for PG&E customers.

PG&E's interconnected distribution system—and the assets that it relies on to provide power to San Francisco customers—exists beyond San Francisco's borders as well. Some of the primary distribution circuits that originate from substations within San Francisco also feed PG&E customers in San Mateo County. Conversely, some customers in San Francisco rely on substations outside of San Francisco (such as the Daly City and Martin Substations) for their power. The image below shows where distribution lines cross the border between San Francisco and neighboring communities.

FIGURE 2-5
DISTRIBUTION OVERLAP



5. Metering Systems

PG&E's electric assets are complemented by metering systems, which are integral to the operation of PG&E's system.

PG&E's Advanced Metering Infrastructure (AMI), also known as PG&E's SmartMeter™ system, is an integrated metering system that provides two-way communication between PG&E and its meters for purposes of measuring electric consumption, billing, outage management, and demand response.

Residential electric SmartMeters™ connect to [redacted]

PG&E's AMI consists of such field assets as residential, commercial, and industrial electric smart meters, [redacted]

[redacted]

[redacted].

The graphic below illustrates how the AMI system operates.

CONFIDENTIAL FIGURE 2-6
ADVANCED METERING INFRASTRUCTURE

[redacted]

6. Streetlights

PG&E also owns and maintains thousands of streetlights within San Francisco, located primarily in residential neighborhoods and on major thoroughfares. There are cobrahead-style lights mounted on standard wood distribution poles, which include the light fixture, bracket, photocell, and wiring. PG&E mounts other cobrahead streetlights on streetlight-only poles. PG&E converted its cobrahead streetlights from high-pressure sodium (HPS) to light-emitting diode (LED) between 2017 and 2019. PG&E also owns and maintains hundreds of decorative streetlights in an array of fixture styles. Over 25% have LED fixtures, and the rest contain HPS fixtures.

7. Protection Systems/Schemes and Automation Assets

PG&E's system in San Francisco also includes protection and automation systems to support the safe and reliable operation of the electric system.

a. SCADA System

An essential asset in this category is PG&E's Supervisory Control and Data Acquisition (SCADA) system. The SCADA system monitors

and controls PG&E's substations. SCADA supports operational improvements by providing real-time information about the condition of the system, enabling remote switching of substation equipment, and providing historical data to examine line-loading trends, forecast future loading, and perform outage investigations. SCADA also facilitates Smart Grid technologies (such as distributed energy resources management systems); microgrids; and fault location, isolation, and restoration. The SCADA system relies on a number of complex and interconnected assets to function, including data centers, Internet Protocol (IP) networks, and field devices, as discussed further below.

b. Protection Assets

PG&E also employs protection system assets to monitor its power grid, quickly identify faults and short circuits, and then trip protective circuit breakers to isolate any identified faults. This helps limit a fault's duration and maintain continuity of service to customers outside the faulted zone.

Protective relays are a key category of protective assets. Protective relays monitor information such as current, voltage, frequency, temperature, and oil pressure. They detect faults and quickly send signals to trip relevant circuit breakers, typically within less than a half a second. This minimizes the impact of a fault on other parts of PG&E's transmission system and safeguards PG&E equipment that might otherwise incur damage from prolonged exposure to fault currents. [redacted].

PG&E's protection system relies on a number of components, [redacted]. PG&E also uses a variety of other system monitoring assets, including [redacted].

c. Remedial Action Schemes

PG&E also relies on Remedial Action Schemes (RAS) as part of the transmission-level architecture that protects the reliability of its broader grid. A RAS is a scheme designed to detect predetermined system conditions and automatically take corrective actions, such as adjusting or tripping generation, tripping load, or reconfiguring system elements. [redacted]

8. Telecom Assets

PG&E's system in San Francisco also relies on a number of telemetry and teleprotection assets, which are essential to operating the metering, monitoring, and protection assets described above.

a. IT and Telecom Assets Supporting SCADA

PG&E's SCADA system relies on a suite of communications network components. These components work together to provide remote monitoring, management, and control of electric devices. PG&E's SCADA platform is a fully distributed architecture [redacted] [5] [redacted].

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[5] [redacted]

The SCADA IT and network assets on which PG&E relies to serve San Francisco also include [redacted]. These components work together to provide remote monitoring, management, and control of PG&E's gas, electric, and generation systems.

b. IT and Telecom Assets Supporting Electric Transmission

Transmission line protection systems also depend on IT and Telecom infrastructure to enable communication-assisted protection and allow fast fault clearing for 100% of the protected line while maintaining proper relay coordination and selectivity. PG&E's protection systems and RAS, for example, rely [redacted]

9. Communications Systems for Dispatch Applications

PG&E also employs a variety of assets to enable communications between the employees that maintain its system in San Francisco. [redacted] enabling essential communications to coordinate responses to trouble tickets and maintenance activities.

To facilitate these communications, PG&E uses [redacted], providing coverage to San Francisco, the Peninsula, and the

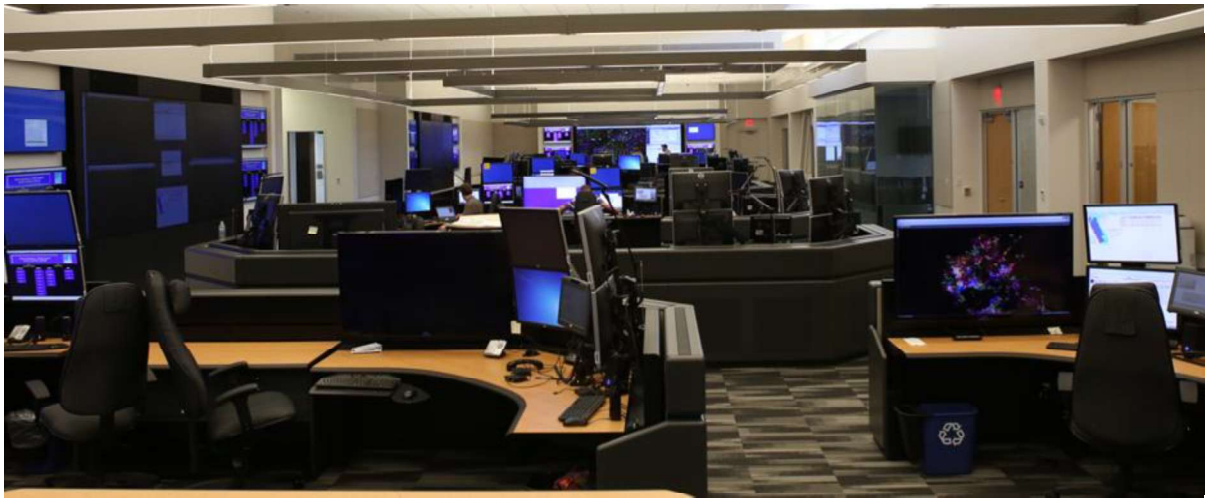
East Bay, and they support both PG&E's gas and electric lines of business in those areas.

10. Electric Transmission and Distribution Control Centers

PG&E also maintains [redacted] control centers to remotely monitor and control its electric assets [redacted]

Highly trained dispatchers and distribution operators at the control centers monitor and operate the grid in PG&E's service area, including San Francisco, 24 hours a day, seven days a week. Their responsibilities include: responding to emergencies, hazards, and outages; developing, checking, and directing all line switching activities for planned and unplanned maintenance and construction; and coordinating with other entities including generators, the CAISO, and other utilities. The control centers employ [redacted].

FIGURE 2-7
ONE OF PG&E'S CONTROL CENTERS



11. Fleet

PG&E also maintains a fleet of transportation assets in San Francisco that support operations and maintenance of PG&E's electric and natural gas systems, emergency response, service continuity for customers, and responding to customer service requests. PG&E's Transportation Services organization manages hundreds of vehicles and related equipment that the company uses across San Francisco, including passenger vehicles, flatbed and enclosed trailers, medium and heavy trucks (including bucket trucks, cable pullers, and flatbed and utility trucks for transport), compact and cargo vans, forklifts, and backup generators.[6]

12. Spare Parts

PG&E also maintains an inventory of spare materials to ensure that it has assets on hand to repair its system or replace assets, as necessary.

Transmission. PG&E stores spare materials for its electric transmission [redacted]

[6] It is PG&E's understanding that CCSF does not intend to acquire any of these assets, although some of them are specifically used to support unique requirements of serving San Francisco and would constitute stranded costs in the event of a taking.

Substations. PG&E also has spare parts for its substation system [redacted].

Distribution. PG&E houses spare parts for its distribution system at PG&E's [redacted]. The major equipment, including transformers, switches, and meters, is classified as rapid response stock for restoration-related work. The minor materials, such as nuts, bolts, and other pole line hardware, constitute as-needed working stock. [redacted] PG&E relies upon to serve San Francisco and the surrounding region.

13. PG&E Records, Asset Information, and Databases (Sponsored by Jadwindar Singh)

PG&E also maintains an extensive system of records, asset information, and databases to operate its system in San Francisco.[7]

a. PG&E Records and Asset Information

PG&E has developed and maintained, over time and at substantial expense, detailed records and asset information relating to its operations in San Francisco. These materials allow PG&E to operate more efficiently and to maintain, monitor, plan, and bill for the electric system in and serving San Francisco. These materials include reliability and outage records (e.g., outage-tracking data, restoration records, disturbance reports); safety records (e.g., incident reports, near-miss

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[7] CCSF's testimony confirms that it plans to take most of the records and asset information that PG&E uses to operate in San Francisco. Ex. CCSF-002C – Prepared Direct Testimony of Nelson Bacalao on Behalf of the City and County of San Francisco at 13:26–14:3 (Apr. 20, 2026) (Errata May 21, 2026) ("Bacalao Testimony") (confirming CCSF's intention to acquire "records (documents, diagrams, maps, plans, maintenance records, databases, models, etc.) that the City will need to safely own, operate and maintain the electric system it acquires from PG&E, plan and carry out repairs and upgrades, respond to equipment failures and emergencies, serve and bill customers, and perform other necessary functions").

reports, training and certification requirements, inspection logs); operating and maintenance records (e.g., preventive maintenance schedules, condition assessments, work histories, repair and replacement records); capital and planning records (e.g., plant-addition and retirement records, planned capital expenditures, planning studies, load forecasts, substation load-flow records); and customer, metering, and billing records (e.g., AMI equipment records, billing and payment histories, delinquency data). PG&E also maintains maps, drawings, standards, and engineering procedures related to its San Francisco assets including property-rights-related records such as deeds, licenses, and third-party attachment agreements.

These materials show how PG&E designed its assets, how they have performed over time, their maintenance history, whether they have non-standard features, what outages or disturbances have occurred, and how PG&E's assets interact with other parts of the company's broader grid. Historical outage data, condition scores, maintenance histories, and planning studies are particularly valuable because they reflect years of engineering judgment, field inspections, operating experience, and post-event learning. The body of technical and operational information that PG&E has developed and maintained over many decades, at substantial effort and expense, is essential to PG&E's (and any other entity's) ability to safely provide electric service in San Francisco.

b. PG&E Databases

PG&E also maintains detailed databases of its assets throughout its service territory, as described below. PG&E relies on these databases in the course of its day-to-day operations, and both PG&E and CCSF have relied on those databases in preparing their testimony.

GIS System. PG&E's Geographic Information System (GIS) is the system of record for most of its electric transmission and distribution asset inventory and includes such detail as spatial location and attribute data. [redacted]

[redacted]. The system of record for PG&E's substation assets is its [redacted] [8] [redacted] [9]

Other Asset Data. PG&E also maintains additional repositories of data for other assets, including:

- [redacted] is the system of record for PG&E's meters.
- IT and Telecom databases. PG&E maintains the data for IT applications and computer/storage infrastructure assets in its [redacted] databases. PG&E stores the data for its telecom network assets and circuit connectivity topology details in its [redacted], and its fiber-optic cable data in [redacted], as noted above.

E. PG&E Land and Real Estate Interests Involved in Serving San Francisco (Sponsored by Aimee Crawford and Marcelo Romano)

PG&E's provision of power to customers in San Francisco also relies on an extensive network of fee-property interests, easements, and other property

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8 PG&E also maintains single-line drawings of its substations, which serve to verify the assets at its substations and may be used to supplement or correct data [redacted].

9 PG&E tracks certain spare parts for Transmission and Substation Greater Bay Area Earthquake Restoration in PG&E's Earthquake Emergency Restoration Manual, Appendix E (Bill of Materials).

rights. The discussion below provides an overview of those property interests, which witnesses Walt Carney and Michael Waldron discuss in greater detail in Chapter 4.

1. PG&E Fee-Owned Property

PG&E owns and maintains many properties in or near San Francisco that it relies on to provide service. In its amended testimony, CCSF identified 33 fee-owned[10] properties that it wishes to take, which PG&E uses primarily for substations, switchyards, service centers, and laydown yards.[11] Thirty-two of those properties are located within San Francisco; the remaining property, Martin, is located in San Mateo County. All 33 properties are entitled, meaning that all requisite zoning requirements and land use requirements have been identified and approved (on a preliminary or final basis) by the applicable local and state authority.

These 33 properties are not the only PG&E-owned properties within or near San Francisco that are necessary for PG&E's provision of electric service to the City. Most notably, PG&E also owns the Harrison Service Center, which is PG&E's [redacted].

2. Enterprise Land Rights

PG&E's land rights are essential for the operation and maintenance of its electric facilities. PG&E owns private easements—over 2,400 within San Francisco—and other land rights necessary to cross private property and operate its electric distribution, transmission, and service facilities.[12] PG&E has approximately 135 miles of distribution easements on third-party properties, which permit PG&E to locate, maintain, and operate overhead

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[10] PG&E's fee-simple or fee-owned properties are properties that are wholly owned by PG&E.

[11] Ex. CCSF-003C – Prepared Direct Testimony of Timothy P. Runde on Behalf of the City and County of San Francisco at App'x II, Attachment A (Apr. 20, 2026) (Errata May 21, 2026) ("Runde Testimony").

[12] Pursuant to PG&E electric tariff Rule 16, PG&E owns and operates electric facilities on applicant's property for the sole purpose of providing electric service to the applicant's property. Easements or other land rights are generally not acquired when on and only serving the applicant's property and not crossing third-party property.

and/or underground distribution lines. PG&E also owns 2.16 miles of electric transmission easements on private property within San Francisco to locate, maintain, and operate underground transmission lines. The company acquired these land rights and easements throughout its operational history.

3. Buildings, Facilities, and Improvements

The properties that PG&E relies on to provide power in San Francisco also include buildings and other facilities and improvements. The 33 fee-owned properties that CCSF intends to acquire include 31 substation properties (including the decommissioned Substation I, but not including the two customer-dedicated substations, as PG&E does not own real property associated with those substations),[13] as well as two vacant lots. PG&E has improved 14 of the substation sites with one or more special-purpose industrial buildings. These structures typically consist of concrete, steel, or masonry, and frequently feature basements, mezzanines, fire sprinklers, and overhead cranes. The remaining substations generally contain outdoor-mounted transformers and equipment. The site improvements on these unenclosed properties primarily consist of perimeter security fencing, automatic gates, concrete masonry walls, and asphalt paving or crushed rock ground coverings. One parcel—the site for the future Egbert Switching Station—currently is a vacant lot improved with temporary construction fencing. The final parcel, Beeman Lane, is traversed by an underground transmission easement. All 33 properties are urban parcels with such standard off-site improvements as concrete curbs, gutters, sidewalks, and street lighting.

Additionally, as noted above, PG&E owns and operates its San Francisco Service Center, also called the Harrison Service Center, on five adjacent parcels comprising over 10 acres in the general area [redacted]

[13] PG&E does not own real property, buildings, or improvements associated with its two customer-dedicated substations in San Francisco.

[redacted]. These structures provide approximately 267,000 square feet of gross building area.

4. Martin Facilities

PG&E's provision of power to San Francisco also relies heavily on PG&E's Martin facilities, which are on an approximately 50-acre property comprised of six parcels within Brisbane and Daly City and described in Section D.3, above.

The Martin Substation supplies power [redacted].

The Martin Service Center includes [redacted]. These buildings comprise approximately 120,000 square feet of gross building area, not including the Martin Substation.

Finally, the Martin site also [redacted].

In addition to providing electric service, the Martin Substation also includes [redacted].

Martin relies on numerous easements, franchise agreements, and other land use agreements. In particular, [redacted] property that CCSF proposes to take, property that PG&E would retain after the proposed taking, and public rights-of-way.

F. Overlap of PG&E's Electric and Gas Operations

PG&E provides both electric and gas service to San Francisco customers. PG&E serves nearly 300,000 gas customers in San Francisco. PG&E's gas and

electric operations are deeply interlinked, with both physical and operational overlaps in San Francisco that enable customers to benefit from economies of scale and scope.[14]

As to physical overlap, PG&E's gas and electric facilities often utilize t[redacted]. Some PG&E gas-related equipment[redacted]. PG&E's gas metering system also [redacted].

PG&E's electric and gas operational and business functions also overlap significantly. Several of PG&E's gas operations rely on electricity and communications tools from PG&E's electric operations to function. For example, certain gas assets [redacted].

Shared operational facilities and personnel are especially important. PG&E currently supports its San Francisco gas and electric operations from common service centers, storage locations, and operational workspaces—including, most notably, [redacted]. PG&E's workforce and field operations also have substantial gas/electric overlap. PG&E's San Francisco-based field crews, construction personnel, dispatch personnel, emergency responders, and customer operations staff support both gas and electric operations. Similarly, PG&E's customer-facing and back-office functions, including IT, customer care, telecom, procurement, and corporate support, support both gas and electric service.

Finally, as an integrated utility, PG&E can coordinate gas and electric work in the same street or corridor, allowing a single excavation, restoration, and

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14 As noted in Chapter 8.1, PG&E does not quantify the financial impact of the loss of these economies of scale and scope in this testimony but reserves the right to do so in the future as appropriate and permitted by the Commission.

project mobilization effort to support work on both systems where appropriate. This allows PG&E to minimize construction and maintenance disruption and supports safer operations. As PG&E owns and maintains detailed records about the locations of both electric and gas assets, its crews and contractors working on one system (electric or gas) can readily reduce the risk of dig-ins and damage to the other, without coordinating with third parties.

G. Conclusion

PG&E's San Francisco grid is part of a much larger, integrated system that encompasses a complex, interdependent network of physical electric transmission and delivery assets, control systems, communications infrastructure, and property interests—many of which support both PG&E's electric and gas businesses. Understanding these assets is critical to determining the just compensation PG&E would be owed for these assets and to forecasting PG&E's business and physical severance damages.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

REPLACEMENT COST NEW LESS DEPRECIATION VALUATION OF CERTAIN PG&E ELECTRIC UTILITY ASSETS IN SAN FRANCISCO

WITNESSES: MATTHEW THIBODEAU AND NED W. ALLIS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
REPLACEMENT COST NEW LESS DEPRECIATION VALUATION OF CERTAIN PG&E ELECTRIC UTILITY ASSETS IN SAN FRANCISCO
WITNESSES: MATTHEW THIBODEAU AND NED W. ALLIS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
REPLACEMENT COST NEW LESS DEPRECIATION VALUATION OF CERTAIN PG&E ELECTRIC UTILITY ASSETS IN SAN FRANCISCO

A. Introduction and Purpose

Our names are Matthew R. Thibodeau of Sargent & Lundy and Ned W. Allis of GFT Infrastructure, Inc. ("GFT"). Our testimony in this chapter summarizes Pacific Gas and Electric Company's ("PG&E") Replacement Cost New Less Depreciation ("RCNLD") valuation of the assets that the City and County of San Francisco ("CCSF") asks the Commission to value in this proceeding other than PG&E's real property and intangible assets (for purposes of this Chapter, the "Subject Assets"). Unless otherwise stated, we jointly sponsor the testimony in this chapter.

The RCNLD method is one of three valuation approaches that the Commission's Interim Decision requires the parties to apply in determining just compensation for the Subject Assets.[1] The RCNLD method values the Subject Assets by first determining what it would cost to replace them with comparable assets—referred to as Replacement Cost New ("RCN")—and then subtracting depreciation (meaning accrued physical depreciation, not book depreciation) to reflect that the existing assets are not new and have already consumed a portion of their service lives.

Our joint testimony provides an overview of Chapters 3.1 and 3.2 of PG&E's testimony, which support PG&E's RCNLD valuation:

- In Chapter 3.1, Mr. Thibodeau presents PG&E's RCN analysis and concludes, based on fourth quarter 2022 costs, that the RCN of the Subject Assets (other than real estate and intangible assets) is $16,001,136,000 (*i.e.*, replacing the Subject Assets in fourth quarter 2022 would have cost approximately $16 billion).
- In Chapter 3.2, Mr. Allis presents PG&E's depreciation analysis. He first de-escalates Mr. Thibodeau's 2022 RCN valuation to 2021 dollars, bringing that

[1] Decision Establishing Methods and Standards for Just Compensation and Valuation, D.25-10-039 at 33–35 (Oct. 30, 2025) ("Interim Decision").

figure to approximately $13.0 billion. He then concludes that accrued depreciation of approximately $2.8 billion should be subtracted from RCN, based on an overall "Percent Good" factor of approximately 79% for the Subject Assets (*i.e.*, the Subject Assets have, as a whole, approximately 79% of their useful value remaining).

Based on these analyses, PG&E's RCNLD for the tangible, non-real-estate assets at issue in this proceeding is approximately $10.2 billion. This valuation is as of July 27, 2021, the date of CCSF's petition in this proceeding (the "Valuation Date").

By comparison, CCSF calculates an RCNLD of approximately $4.68 billion for this same set of assets (before reduction for economic obsolescence).[2] As summarized below, this gap largely results from:

1) CCSF's understating RCN, principally by underestimating how expensive it would be to rebuild a heavily underground grid like PG&E's in a dense urban environment like San Francisco; and
2) CCSF's overstating depreciation, by applying accounting rather than valuation depreciation methodologies and ignoring that unique aspects of the Subject Assets, such as the fact that much of PG&E's San Francisco grid is underground, will enable the Subject Assets to have longer useful lives.

B. Summary of Replacement Cost New Analysis (Sponsored by Matthew Thibodeau)

My testimony in Chapter 3.1 provides PG&E's RCN analysis. The analysis values the Subject Assets based on what it would cost to replace them with comparable assets using contemporary materials and modern construction practices. PG&E and CCSF stipulated to the assets at issue, so differences in the parties' RCN calculations result from differing unit cost assumptions rather than different asset quantities.

Sargent & Lundy's RCN analysis relied on multiple data sources, including PG&E's GIS and SAP databases, RSMeans cost publications, Sargent & Lundy's cost databases, site visits, and discussions with PG&E employees. We

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[2] Ex. CCSF-004C – Prepared Direct Testimony of Grant Rabon, ASA on Behalf of the City and County of San Francisco at Table 4 (Apr. 20, 2026) (errata May 21, 2026) ("Rabon Testimony").

used cost data as of fourth quarter 2022 since this was the date nearest to when electric asset information was extracted from PG&E databases; CCSF's witness, Mr. Bacalao, used a similar approach.[3]

The total RCN for the Subject Assets (which for purposes of this Chapter does not include PG&E's real estate and intangible assets) is $16,001,136,000, broken down as follows:

TABLE 3-1
SUMMARY OF RCN (2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

Line No.	Major Asset Category	Replacement Cost New
1	Transmission Assets	$1,822,735,000
2	Distribution Assets	$12,212,257,000
3	Substation Assets (excl. Martin)	$1,400,398,000
4	Martin Substation and Related Assets	$456,403,000
5	Other Asset Categories	$109,343,000
6	Total	$16,001,136,000

Distribution assets constitute the largest share of RCN and are dominated by the costs of the underground conduit system ($4.24 billion) and subsurface structures ($3.16 billion), which together account for approximately $7.4 billion of RCN. These values reflect the cost and complexity of constructing an underground electric network in one of the most densely populated urban environments in the United States.

C. Summary of Depreciation Analysis (Sponsored by Ned Allis)

My testimony in Chapter 3.2 first converts Sargent & Lundy's RCN analysis, which used costing data from 2022, into 2021 dollars. The result of that calculation is an RCN of approximately $13.0 billion as of 2021 for PG&E's tangible, non-real-estate assets.

My testimony next applies physical depreciation to that 2021 RCN to calculate RCNLD for PG&E's tangible, non-real-estate assets. Consistent with the Commission's directive that the parties base RCNLD on "accrued depreciation (not book depreciation)," GFT employed a valuation-based

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3 Ex. CCSF-002C – Prepared Direct Testimony of Nelson Bacalao on Behalf of the City and County of San Francisco at 18:12-26 (Apr. 20, 2026) (errata May 21, 2026) ("Bacalao Testimony").

approach to depreciation (*i.e.*, one focused on the current, actual value of the Subject Assets and their ability to continue providing service) rather than the cost-allocation approach used in utility ratemaking (which focuses instead on accounting principles and depreciating an asset steadily over time regardless of its actual physical condition).[4]

Specifically, GFT used the present worth method, under which a Percent Good factor is calculated for each vintage of assets based on (in simplified terms) the ratio of the asset's remaining service life to the total service life of a new asset. This method—which is commonly used for cost-based property valuation in California—incorporates the expected remaining useful life of each surviving vintage of assets, as derived from Iowa-type survivor curves.[5]

To apply this method, GFT conducted an Asset Vintage and Service Life Study that:

- Determined the installation dates (vintages) of the Subject Assets using PG&E databases, historical accounting records, site visits, and discussions with PG&E experts;
- Estimated service lives for each asset category using Iowa-type survivor curves, incorporating San Francisco-specific information regarding underground construction, indoor substations, and the network distribution system—characteristics that support longer service lives than PG&E's system as a whole; and
- Calculated remaining life, probable life, and Percent Good factors at the vintage level for each asset category.

Based on this analysis, GFT concludes that the Subject Assets are approximately 79% good overall, meaning that approximately 21% of their replacement cost has been consumed through physical deterioration—resulting in accrued depreciation of approximately $2.8 billion and an RCNLD of approximately $10.2 billion as of the Valuation Date.[6]

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4 Interim Decision at 35.

5 *See California State Board of Equalization, Assessors' Handbook Section 582, The Explanation of the Derivation of Equipment Percent Good Factors.*

6 Chapter 5 of PG&E's testimony provides PG&E's ultimate RCNLD valuation by (1) adding together (i) the $10.2 billion in RCNLD for PG&E's tangible, non-real-estate assets; (ii) the value of PG&E's real estate assets, calculated in Chapter 4; and (iii) the value of PG&E's intangible assets; and then (2) analyzing economic obsolescence.

D. Key Differences Between PG&E's and CCSF's Approaches

The following table summarizes and compares PG&E's and CCSF's RCNLD calculations[7] for PG&E's tangible, non-real-estate assets:

TABLE 3-2
COMPARISON OF PG&E AND CCSF RCNLD

Line No.		PG&E	CCSF
1	Replacement Cost New (2022$)	$16,001,136,000	$10,924,709,000
2	Percent Good (physical depreciation)	~79%	~49%
3	RCNLD (before economic obsolescence) (2021$)	~$10.24 billion	~$4.68 billion
4	Difference		~$5.56 billion

As explained further below and in Chapters 3.1 and 3.2 of PG&E's testimony, the approximately $5.56 billion gap between PG&E's and CCSF's RCNLD calculations results from two compounding sources of error in CCSF's analysis: (1) CCSF understates the cost to replace the Subject Assets (the RCN component), and (2) CCSF overstates how much those assets have depreciated (the "Less Depreciation" component).

1. Key Differences on Replacement Cost New (Sponsored by Matthew Thibodeau)

The approximately $5.1 billion difference in 2022 RCN between PG&E and CCSF is driven overwhelmingly—nearly 90%—by the calculated RCN for two asset categories, both of which relate to PG&E's underground distribution grid: PG&E's conduit system and its subsurface structures. The conduit system consists of the underground ducts and pipes—typically PVC or rigid steel—that PG&E installed in trenches below San Francisco streets and sidewalks and through which it has routed electric distribution conductors. Subsurface structures are the concrete enclosures that PG&E installed below ground to house critical equipment such as transformers, network protectors, and other distribution devices. The following table summarizes the differences between PG&E's and CCSF's RCN values for conduit systems and subsurface structures:

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7 *See* Rabon Testimony at Table 4; Bacalao Testimony at 18:27–19:3.

TABLE 3-3
COMPARISON OF CONDUIT SYSTEM AND SUBSURFACE STRUCTURES
(2022 DOLLARS, ROUNDED TO NEAREST MILLION)

Line No.		PG&E	CCSF[8]	Difference
1	Conduit System	$4,245,000,000	$1,820,000,000	$2,425,000,000
2	Subsurface Structures	$3,163,000,000	$1,036,000,000	$2,127,000,000

The parties have reached agreement on the quantity of underground assets, *i.e.*, the length of conduit and the number of subsurface structures in San Francisco. The difference in the respective RCN values results from contrasting unit cost assumptions—that is, how much it would actually cost to install replacement conduit and subsurface structures in San Francisco.

PG&E/Sargent & Lundy developed detailed, bottom-up engineering cost models specifically tailored to underground construction in San Francisco. These models capture the complete construction sequence—including pavement removal and restoration, excavation (often by hand in confined spaces), navigation around existing underground infrastructure, traffic control, shoring, material handling, installation, and the site-specific constraints of working in a dense urban environment with significant regulatory restrictions on work hours and street closures. These models are necessary to accurately calculate RCN for conduit and subsurface structures in light of the unique complexity of installing conduit and subsurface structures in San Francisco.

CCSF, by contrast, based its RCN estimates for conduits and subsurface structures primarily on cost codes from RSMeans (an industry resource that provides pricing data) and then applied a 35% "Job Conditions Adjustment" factor to account for the complexities of working in San Francisco. RSMeans is a widely accepted and appropriate starting point for construction cost estimation, and Sargent & Lundy does not dispute its use for certain asset categories. However, RSMeans itself notes that cost adjustments may be required to be added to its underlying cost and labor data, depending on the specific work location, project, and conditions. CCSF

8 CCSF's RCN values consider the adjustments applied by CCSF in their workpapers, including owner's cost and contingency. These adjustments are also included in the PG&E RCN numbers in the comparison table.

attempted to address these complexities by using a "Job Conditions Adjustment" factor. Given the uniqueness and challenges associated with work in San Francisco, accurately defining the "Job Conditions Adjustment" factor is foundational to accurately calculating RCN for complex assets. The selection of a 35% adjustment factor by CCSF underestimates the complexity and cost of constructing underground assets in San Francisco, and CCSF also fails to provide sufficient basis justifying the selection of this factor.

PG&E's average unit cost for the underground distribution system (the conduit system, subsurface structures, and underground conductor costs combined) is $1,153/ft—well within the Commission's own stated range for the analogous work of undergrounding distribution lines in California ($420/ft to $1,380/ft in 2022 dollars, inclusive of rural, suburban, and dense, urban environments) and consistent with actual undergrounding costs in San Francisco's own 1996–2006 undergrounding program ($1,000/ft in 2022 dollars). CCSF's average of $543/ft (combining CCSF's conduit system, subsurface structures, and underground conductor costs, inclusive of owner's cost and contingency adjustments) falls below actual undergrounding costs observed in comparable dense urban environments nationwide.

2. Key Differences on Depreciation (Sponsored by Ned Allis)

CCSF also made multiple fundamental errors in connection with its depreciation analysis, which further contribute to its substantial understatement of the RCNLD value of the Subject Assets.

1) **CCSF's depreciation approach relies on an inapplicable accounting methodology.** PG&E applies valuation-based depreciation using the present worth/Percent Good method, which measures the remaining value of each vintage of assets relative to a new asset. This methodology is consistent with the purpose of RCNLD analysis—it analyzes, on an asset-by-asset level, the expected remaining useful life of the asset. CCSF, by contrast, applies straight-line depreciation based on inapplicable ratemaking concepts—an accounting methodology designed to allocate cost recovery over time rather than to measure current asset value. This is fundamentally inconsistent with the Interim

Decision's guidance to subtract "accrued depreciation" rather than "book depreciation" as part of the RCNLD analysis. More broadly, it is inconsistent with the purpose of an RCNLD analysis, which is to determine, based on the assets themselves as they existed on the Valuation Date, the actual value of those assets based on their actual physical condition, rather than an accounting-based value that applies depreciation without regard to the actual physical condition of the assets.

2) **CCSF's reliance on broad, imprecise assumptions is inaccurate.** PG&E calculates depreciation at the vintage level, preserving the different ages, remaining lives, and Percent Good factors of the different asset vintages within each category. This approach enabled PG&E to more accurately apply depreciation based on the specific assets at issue. In contrast, CCSF took a broad-brush approach, calculating depreciation at the FERC account level using average-age assumptions, which distorted its depreciation analysis—particularly for accounts containing a mix of older and newer assets.

3) **CCSF's use of systemwide rather than San Francisco-specific data creates further inaccuracy.** PG&E's service life estimates incorporate San Francisco-specific data, reflecting that the City's largely underground, duct-installed, network-configured system has longer expected service lives than PG&E's system as a whole. In contrast, CCSF relies on system-wide service life parameters from PG&E's 2020 General Rate Case without adjusting for San Francisco's unique characteristics.

These differences produce dramatically different results. PG&E's analysis concludes that the Subject Assets are approximately 79% good, meaning approximately 21% depreciated; CCSF's concludes they are only approximately 49% good, meaning approximately 51% depreciated (and effectively only 30% good after CCSF's economic obsolescence adjustment). Accordingly, before economic obsolescence, CCSF applies a depreciation rate approximately 30 percentage points higher than PG&E's—more than twice PG&E's estimated depreciation rate. CCSF's approach is unreasonable and inaccurate, as illustrated by CCSF's methodology finding

that PG&E's distribution poles are only 6% good—a result so extreme that it implies a negative value for poles that are observably in service and in good condition. As described further in my detailed testimony, these errors result in CCSF significantly over-depreciating the Subject Assets and understating RCNLD.

E. Conclusion

For the reasons set forth in our more detailed testimonies, PG&E's RCNLD for PG&E's assets other than real estate and intangible assets is approximately $10.2 billion as of the Valuation Date. This figure reflects a rigorous, asset-by-asset replacement cost analysis supported by detailed analysis and (for certain complex assets) by detailed engineering models. It also reflects a valuation-based depreciation methodology that measures the remaining service potential of the Subject Assets based on detailed analysis of the assets themselves and San Francisco-specific data relating to how similar assets have survived over time. CCSF's RCNLD of approximately $4.7 billion for PG&E's non-real-estate assets (before economic obsolescence) understates the value of the essential electric infrastructure serving San Francisco—both by underestimating how much it would cost to replace that infrastructure and by overstating how much of its useful life has been consumed.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.1

REPLACEMENT COST NEW ANALYSIS OF CERTAIN PG&E ELECTRIC UTILITY ASSETS IN SAN FRANCISCO

WITNESS: MATTHEW THIBODEAU

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3.1
REPLACEMENT COST NEW ANALYSIS OF CERTAIN PG&E ELECTRIC UTILITY ASSETS IN SAN FRANCISCO
WITNESS: MATTHEW THIBODEAU

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3.1
REPLACEMENT COST NEW ANALYSIS OF CERTAIN PG&E ELECTRIC UTILITY ASSETS IN SAN FRANCISCO
WITNESS: MATTHEW THIBODEAU

A. Introduction and Summary

My name is Matthew Thibodeau, and my testimony in this chapter provides the Replacement Cost New (RCN) analysis for Pacific Gas and Electric Company's (PG&E) electric assets serving San Francisco. The RCN methodology is one of the three methods that the Interim Decision requires PG&E to use to value PG&E's San Francisco assets.[1] At a high level, the RCN methodology values a set of assets based on what it would cost to replace them. As set forth below, it is my opinion that the RCN of the PG&E electric utility assets that the City and County of San Francisco (CCSF) seeks to take[2] in this proceeding (the "Subject Assets") is $16,001,136,000. My testimony provides support for this number and explains why it differs from the RCN developed by CCSF's expert. My testimony proceeds as follows:

- *Overview of Inventory and Methodology.* I begin by providing an overview of PG&E's electric system in and serving San Francisco and describing the electric system assets that were considered in the RCN analysis.
- *Overview of RCN Methodology.* I then describe the RCN methodology my team and I employed, including the sources of data relied upon and the categories of costs captured within the RCN. As explained further below, my analysis valued PG&E's electric assets by applying cost data from various sources, including RSMeans (a well-known and generally reliable resource for the cost of electric assets), Sargent & Lundy's internal project cost information, and other sources—with appropriate adjustments based on unique concerns specific to San Francisco. For certain assets in the City,

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1 *See* Decision Establishing Methods and Standards for Just Compensation and Valuation, D.25-10-039 at 35 (Oct. 30, 2025) ("Interim Decision").

2 My testimony focuses on the RCN value of PG&E's tangible, non-real-estate assets. PG&E's real-estate assets are valued in Chapter 4. PG&E's intangible assets are valued in Chapter 5.

such as underground conduits and subsurface structures, my analysis also relies on detailed models developed by my team and on extensive analysis to determine unit costs for installing such assets.

- *Summary of the RCN Results.* I then provide an overview of the results of my RCN analysis, which concludes that the RCN for PG&E's assets at issue is approximately $16 billion. This result is broken down by major asset categories and supported by detailed workpapers.
- *Comparison with CCSF Results.* Finally, I provide a comparison of my RCN result to CCSF's RCN result. CCSF's total RCN of $10,924,709,000 (in 2022 dollars) is approximately $5.1 billion lower than mine. The majority of this difference (approximately 89%) results from differing unit cost assumptions relating to PG&E's underground conduit system and subsurface structures. For the conduit system, CCSF assigns an RCN of $1,820,188,000, whereas I assign an RCN of $4,244,543,000. Likewise, for subsurface structures, CCSF assigns an RCN of $1,036,442,000, whereas I assign an RCN of $3,162,968,000.[3] PG&E and CCSF agree on the length of conduit and the number of subsurface structures, but CCSF understates their RCN value by applying unrealistic assumptions regarding construction costs—assumptions that do not reflect how much it would cost to replace an underground electric network like PG&E's in San Francisco, one of the most densely populated urban centers in the United States. CCSF's estimates are also inconsistent with data regarding how much similar underground construction efforts have actually cost in San Francisco. A more detailed discussion of these differences in RCN between PG&E and CCSF is provided in Section F.

For the reasons explained below, it is my opinion that $16,001,136,000 represents a reasonable and well-supported estimate of the RCN of the assets at issue, and that CCSF's lower figure understates the RCN.

B. Witness Background and Qualifications

I am a Senior Vice President and Senior Project Director with Sargent & Lundy. My primary duties include serving as the director of consulting engagements and providing subject matter expertise on matters in the energy

[3] Note that both the PG&E and CCSF RCN values are on the same basis as they are both inclusive of contingency and owner's costs adjustments.

and utilities sectors. As the director of consulting engagements, I provide executive support to project teams working under my direction and guidance. The practice areas I lead for Sargent & Lundy include utility planning, cost and performance studies, power supply planning, power procurement, electric grid infrastructure planning, generation resource planning, power plant project development and financing, renewable energy integration, and battery energy storage projects.

I earned a Bachelor of Science in Mechanical Engineering degree from Worcester Polytechnic Institute in Worcester, Massachusetts in 1994. I earned an MBA from the University of Michigan in Ann Arbor, Michigan in 2003. I am a licensed Professional Engineer in Indiana, Illinois, Michigan, and Puerto Rico.

For purposes of this RCN analysis, I served as the Project Director and one of the lead consultants for the Sargent & Lundy team. I oversaw the work of the Sargent & Lundy team, performed in close coordination with the various PG&E subject matter experts, and performed site visits and visual inspections of portions of the PG&E electric utility assets in San Francisco.

C. Overview of San Francisco Electric System

The Subject Assets consist primarily of transmission, distribution, and substation equipment. Chapter 2 of PG&E's Testimony provides additional details regarding its utility assets and its electric system in the City more broadly. I provide below a brief overview of PG&E's system as relevant background for my RCN analysis—focusing most heavily on aspects of PG&E's system relevant to the RCN analysis.

1. Transmission System

Bulk electric power for PG&E customers is delivered to San Francisco [redacted] [4] [redacted]

Electricity is then transmitted throughout San Francisco via transmission lines [redacted]

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[4] The Trans Bay Cable is independently owned by NextEra Energy and provides [redacted] in San Francisco.

[redacted]. These lines interconnect with several transmission and distribution substations, which are described below. The transmission system also includes [redacted]. The electric transmission system also includes other assets, such as transmission manholes and vaults.

2. Distribution System

The San Francisco electric system also includes approximately [redacted] of overhead and underground distribution lines (not including service conductors[5]). Approximately 65% of PG&E's distribution system in San Francisco is underground, based on conductor span length. Many of the underground distribution conductors are inside of conduits and in trenches throughout the city, mostly below streets and sidewalks. The materials used for the underground distribution conduit system include tile, steel, soapstone, fiber, and others; the different materials are an indication of the range of vintages of the underground distribution system. More recent underground distribution installations use PVC conduit or rigid steel conduits.

The underground electric distribution system is built in a *network* configuration in most of the downtown area of San Francisco and a *radial* configuration in the remainder of the city. The purpose of the network configuration design is to provide higher reliability and redundancy. In a network configuration, electricity is delivered through a highly integrated and complex system of transformers, network protectors, switches, and underground cables, which are connected and operate in parallel. In such a system the outage of a single line or transformer does not cause an interruption of power for customers, given the significant redundancy that exists. The increased reliability and redundancy provided by a network configuration also come at increased cost, given the additional assets required.

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5 Service conductors—conductors that carry electricity from a distribution transformer to an individual customer premise—are addressed separately, in Section E.3.f.6.

3. Conduit System and Subsurface Structures

As noted above, many of PG&E's electric assets in San Francisco are in underground trenches, conduits, and subsurface structures. Conduits are protective ducts or pipes—typically PVC or rigid steel—that are installed in underground trenches below streets and sidewalks and that serve as the pathway through which electric distribution and transmission conductors are routed. The conduit system in San Francisco encompasses approximately [redacted] of underground infrastructure.

Subsurface structures are concrete enclosures, often referred to as manholes or utility vaults, that are installed below ground and provide access to the underground electric system. They house [redacted]. These structures range in size from small streetlight boxes and duct junctions to large equipment and transformer vaults that can be the size of a room. PG&E's electric system in San Francisco includes nearly [redacted] subsurface structures of varying types and sizes.

CONFIDENTIAL FIGURE 3.1-1

[redacted]

[redacted]

Most of the conduits contain conductors that transmit electricity (live conductors); some conduits carry a combination of live conductors with fiber cables. Additionally, as part of the underground distribution system, some conduits are left as spare and ready to be used in case additional conductor needs to be added. As discussed below, the underground nature of PG&E's system in San Francisco substantially increases RCN—a function of the significant complexities of constructing underground trenches and structures within the City.

4. Substations

In San Francisco, there are [redacted]. The substations are secured facilities surrounded by security walls or security fences and multiple towers with surveillance and security cameras. The indoor, transmission-to-distribution substations are inside large, multi-story buildings. The Sargent & Lundy RCN analysis includes electric assets inside substation buildings but does not otherwise include land, buildings, or land improvements. As noted, separate appraisal of the real estate is included in Chapter 4.

The Martin Substation, which is in Brisbane just south of San Francisco,[6] is an outdoor transmission-to-distribution substation that functions [redacted].[7] [redacted]

[6] The substation itself is located in Brisbane. The larger Martin site, including the adjacent Martin Service Center, straddles Brisbane and Daly City, San Mateo County.

[7] [redacted]

CONFIDENTIAL FIGURE 3.1-2

[redacted]

[redacted]

FIGURE 3.1-3
SAN FRAN H (MARTIN) SUBSTATION AREA

CCSF has indicated it intends to acquire the entire Martin Substation, so this RCN analysis includes all assets at Martin Substation. There are also several assets between Martin Substation and the San Francisco boundary that CCSF intends to acquire for reliable system operation. Because of this, S&L separately included in the RCN analysis several electric utility assets that are related to the operation of the Martin Substation, but that are outside of the CCSF boundary.

5. Other Assets in San Francisco

In addition to electric transmission, distribution, and substation equipment, Sargent & Lundy's RCN analysis includes the following other asset categories:

- Fiber optic assets
- Spare parts[8]
- Direct current (DC) assets

D. Overview of RCN Methodology

1. General Principles Applied in RCN Analysis

I applied a replacement cost new methodology to value the assets that CCSF seeks to take from PG&E. Under this methodology, the objective is to value the subject assets by comparing them to assets that could functionally replace them—thereby determining what it would cost to "replace" the assets. The replacement asset would be the most economical new asset that could replace the service provided by the subject asset.[9] The RCN analysis performed by Sargent & Lundy considered contemporary

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8 Spare parts include equipment and materials located at several PG&E warehouses. [redacted]

9 It is important to understand the difference between *replacement cost new* and *reproduction cost new*. The Fourth Edition of "*Valuing Machinery and Equipment. The Fundamentals of Appraising Machinery and Technical Assets*" defines "Replacement Cost" as the current cost of a similar new property having the nearest equivalent utility as the property being appraised. It defines "Reproduction Cost" as the current cost of producing a new replica of the property being appraised using the same, or closely similar, materials. This analysis uses a Replacement Cost approach.

materials, standards, designs, and modern construction practices.[10]

While CCSF's petition in this proceeding dates to July 2021, asset inventory data gathering was performed and completed during 2022. Therefore, PG&E provided Sargent & Lundy asset information that reflected the configuration, layout, and quantification of its San Francisco electric utility assets as of the third quarter of 2022. The RCN analysis is nonetheless generally limited to the state of PG&E's system as close to the July 2021 petition date as possible, with asset inventory dates of the third quarter of 2022. This is the same general approach taken by CCSF's expert addressing RCN.

2. Sources of Data for Developing RCN Inventory

I based my RCN analysis on a variety of data sources relating to the Subject Assets. PG&E provided Sargent & Lundy with information from its Geographic Information System (GIS) database for its transmission and distribution electric utility assets. PG&E also provided information from its SAP database for the electrical assets that are part of the 32 substations mentioned above. PG&E also provided electrical single line diagrams (SLD) for the 32 substations and general arrangement drawings for the outdoor substations.[11]

PG&E provided additional data for streetlight assets, meters and metering infrastructure (including advanced metering infrastructure), communications equipment (including fiber optic network assets) and spare parts and equipment (including materials stored in San Francisco for use in San Francisco), that was compiled from other PG&E databases different from the GIS database.

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10 For example, for the transmission line RCN, data provided by PG&E shows that most of the San Francisco transmission line conductors are High Pressure Gas Filled (HPGF) pipe-type with paper insulation. In recent transmission line work performed in San Francisco, PG&E uses an extruded dielectric type with a cross-linked polyethylene insulation (XLPE) type conductor, which is consistent with general industry trends. Since the XLPE type conductor is a modern replacement for the HPGF conductor, the RCN analysis utilizes XLPE type conductors.

11 In some instances, the databases included assets that customers or third parties owned. S&L filtered out the customer-owned and third-party owned assets and did not include them in the RCN analysis. Similarly, S&L filtered out any assets that were identified as proposed to be installed.

PG&E and CCSF also engaged in extensive discussions in the form of presentations and workshops, during which all major categories of the electric asset inventory in San Francisco were discussed. As a result of these workshops, PG&E and CCSF reached agreements related to asset inventory counts and descriptions. My testimony calculates the RCN value of the Subject Assets based on those agreed inventory counts and descriptions. Those agreed counts and descriptions are reflected in exhibits to the asset stipulation agreed to by the parties.[12]

3. Site Visits Conducted in Connection with RCN Analysis

S&L also conducted site visits to several PG&E locations that CCSF has asked the Commission to value in this proceeding. In June 2023, part of my team and I, together with personnel from PG&E, performed a number of site visits. Those site visits included the following six PG&E substations:

TABLE 3.1-1
LIST OF SITE VISIT SUBSTATIONS

Line No.	Substation
[redacted]	

We were able to examine a range of different equipment and substation configurations, which provided us with additional insights to be applied into the RCN cost estimating process. The substations were all in good working condition, consistent with their age, and were operating as designed. We also performed site visits to other transmission and distribution facilities throughout the city, including observations on transmission manholes related to the types of cable and configuration used as well as cable splicing conditions and observations of distribution manholes and padmounted equipment. Overall, the assets and equipment observed during the site

[12] Ex. CCSF-002C - Prepared Direct Testimony of Nelson Bacalao on Behalf of the City and County of San Francisco at Appendix IV (Apr. 20, 2026) (errata May 21, 2026) ("Bacalao Testimony").

visits were in good condition.

4. Costs Included in RCN Analysis

To develop the RCN for the Subject Assets, I accounted for a number of different types of costs, including material and equipment costs, labor costs associated with the work required to install such materials and equipment, and other categories of costs that would be incurred in replacing PG&E's system in San Francisco.

For material costs, we used data from several sources, including: (1) RSMeans, and (2) Sargent & Lundy's internal project and cost information.

[redacted]. The RCN analysis developed by Sargent & Lundy assumes that an independent contractor will be hired to perform the installation of the electric assets. Therefore, costs have been added to cover social security, workmen's compensation, and federal and state unemployment insurance. The labor rate is based on the various crafts and crews needed to complete the work and includes general conditions. General conditions reflect the proportion of other RCN costs associated with the contractor labor, such as construction management, labor supervision, overtime, show-up time, general and administration expenses on labor, contractor profit on labor, and other related items.

Labor costs also take into account the specific amount of labor that will be required to install particular assets in light of the challenges of performing construction in the densely populated San Francisco city/urban environment. To more reliably determine such costs, for several major asset categories, S&L developed conceptual engineering models to represent typical configurations found in PG&E's system and used the models as the basis to develop RCN. These models were specifically applicable to asset classes with complex construction requirements, such as the distribution conduit system, distribution subsurface structures, and underground transmission system. S&L used these models to define the complete scope of construction for a typical project—including pavement removal and

replacement, excavation, material handling, equipment, installation, and the site-specific constraints inherent to performing work in the densely developed urban environment of San Francisco. S&L's models capture the construction sequence in an integrated framework, yielding a more accurate and internally consistent cost estimate.

For example, for the underground distribution conduit system, S&L developed [redacted] models based on PG&E design standards—[redacted] These models were discussed with PG&E subject matter experts, who confirmed that they are representative of the vast majority of different underground distribution trench sizes and configurations in San Francisco. Similarly, for subsurface structures, S&L developed [redacted] models corresponding to the various structure types in PG&E's GIS database, [redacted]. S&L then used these models to better estimate unit costs (including labor costs).

For most assets, other factors were included to account for costs related to sales tax in San Francisco on materials and purchased equipment,[13] engineering costs, as well as owner's costs,[14] and construction contingency. These factors are discussed in detail in Section E.7.

Finally, there were a few asset types for which these allowances were not all included because of the nature of how the material costs were defined, such as spares.

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13 For purposes of this valuation, I uniformly apply San Francisco tax rates regardless of whether the materials and equipment would be in San Francisco or San Mateo Counties.

14 Owner's costs are project costs that an owner must pay to complete a project that are beyond the contract price paid to the contractor. These include costs incurred during different project stages, such as development and studies, permitting, legal and regulatory costs, and owner's engineering and project management, among other areas.

5. Conservative Estimates and Approach

Throughout the course of my analysis, I endeavored to make conservative estimates regarding costs (i.e., estimates that would understate rather than overstate the potential replacement cost of PG&E's relevant assets). [redacted] [15] [redacted] [16] [redacted]

The possibility that my analysis understates the actual replacement cost associated with this project is further supported by comments made by Pamela M. Husing on behalf of CCSF in written testimony submitted before FERC (Exhibit SF-0001), dated September 9, 2022, related to the City receiving electric service from PG&E under PG&E's Wholesale Distribution Tariff (WDT). In that testimony, Ms. Husing discussed the possibility of the City undertaking a relatively small (by comparison) project—constructing new electric distribution facilities that "would, in essence, duplicate the existing PG&E-owned secondary facilities throughout the City that have been used to deliver electricity to the City's unmetered loads for decades."[17] Ms. Husing then stated that the costs to do so "could roughly range between

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15 Bacalao Testimony at 10, 26.

16 CCSF Response to PG&E Data Request Set 17, No. 1 (June 4, 2026).

17 *Prepared Written Testimony of Pamela M. Husing on Behalf of the City and County of San Francisco*, Docket Nos. ER22-619-001, ER22-620-001, ER20-2878-015 (consolidated), Exhibit SF-0001, Page 28 of 35, September 9, 2022.

$3 billion and $30 billion."[18] This significant range of costs, for a relatively small portion of the overall PG&E electric system within San Francisco, underscores the potential magnitude and sizeable range of outcomes associated with significant construction efforts like this one.

E. Summary of RCN Results for PG&E Electric System Assets

1. RCN Summary Results

The RCN for the Subject Assets is $16,001,136,000, as of the fourth quarter of 2022.[19] A breakdown of the RCN by Major Asset Category is provided in Table 2, showing results categorized according to transmission, distribution, substation, and "other" assets.

TABLE 3.1-2
EXECUTIVE SUMMARY – REPLACEMENT COST NEW
(2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

Line No.	Major Asset Category	Replacement Cost New
1	Transmission Assets	$1,822,735,000
2	Distribution Assets	12,212,257,000
3	Substation Assets (excluding Martin Substation)	1,400,398,000
4	Martin Substation and Martin Related Assets	456,403,000
5	Other Asset Categories	109,343,000
6	Total	$16,001,136,000

2. Transmission Assets RCN

This section provides a breakdown of the RCN determined for transmission electrical assets.

The transmission assets included in the RCN analysis include overhead, underground, and submarine transmission lines, at 230 kV and 115 kV voltage levels. The table below shows a summary of the transmission assets RCN.

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18 *Id.*

19 Note that the electric asset databases used to develop the RCN reflect inventory as of the third quarter of 2022. Therefore, the RCN was developed considering equipment and labor costs as of the fourth quarter of 2022.

TABLE 3.1-3
SUMMARY OF THE TRANSMISSION ASSETS
(2022 DOLLARS, ROUNDED TO NEAREST thousand)

Line No.	Transmission Assets	Replacement Cost New
1	115kV Transmission Lines	$1,326,769,000
2	230kV Transmission Lines	495,966,000
3	Total	$1,822,735,000

a. Transmission Lines and Assets Considered in RCN Analysis

Table 4 below shows a summary of the transmission lines considered in the RCN analysis.

TABLE 3.1-4
TRANSMISSION LINES INCLUDED IN RCN ANALYSIS

Line No.	T-Line Name	From Substation	To Substation	Nominal Voltage
1	[redacted]			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				

I provide additional information relevant to the RCN analysis below.

Underground Transmission Assets. Underground transmission includes two 230 kV transmission lines, [redacted] This analysis also includes [redacted] of 115 kV underground transmission lines. The underground transmission assets also include [redacted] transmission manholes located throughout the city.

Overhead Transmission Assets. Small sections of overhead transmission lines are included in the analysis. Specifically, [redacted].

Submarine Transmission Line. [redacted] The recent construction of this transmission line, which was completed during the third quarter of 2016, involved specialized construction methods and a higher construction complexity than other transmission lines in the city. S&L developed the RCN for this transmission line using information contained in PG&E's [redacted] transmission line detailed estimate.[20]

b. Specific Issues Relating to RCN of Underground Transmission Assets

To determine the RCN for underground transmission assets—and in particular, to determine an appropriate unit cost for installation of such assets—[redacted] engineering models were developed. [redacted]

[20] A.12-12-004, Application of Pacific Gas and Electric Company for a Certificate of Public Convenience and Necessity Authorizing the Construction of the Embarcadero-Potrero 230 kV Transmission Project (Dec. 11, 2012).

[redacted] discussed earlier, models were developed in order to estimate more accurate unit costs, in this case for transmission duct banks and transmission vaults.

The RCN analysis also accounted for underground transmission line crossings (also called special crossings). A review of the relevant transmission line drawings identified [redacted] underground transmission line crossings with other transmission lines, rail or subway crossings, highways, and other utilities, among others. Construction of several of these underground transmission line crossings would require special construction equipment and/or methods to minimize surface disruption. This adds additional construction complexity and costs because the construction methods required for special crossings rely on highly technical and specialized equipment and require specialized work crews, increasing mobilization and investment costs.

3. Distribution Assets RCN

The RCN for distribution assets includes several categories, such as distribution conductors, subsurface structures, the distribution underground conduit system, and other electric distribution equipment.

Table 5 provides a breakdown of the RCN by each category identified above. Additional information is provided in the subsections below.

TABLE 3.1-5
SUMMARY OF THE DISTRIBUTION ASSETS
(2022 DOLLARS, ROUNDED TO NEAREST thousand)

Line No.	Distribution Assets	Replacement Cost New
1	Conductors	$1,325,694,000
2	Support Structures	476,924,000
3	Conduit System	4,244,543,000
4	Subsurface Structures	3,162,968,000
5	Distribution Transformers	623,419,000
6	Other Distribution Equipment	1,172,312,000
7	Services	532,598,000
8	Streetlights	24,987,000
9	Metering Infrastructure	648,812,000
10	Total	$12,212,257,000

a. Distribution Conductors

Distribution conductors are the distribution power lines that deliver power to PG&E customers. The RCN for distribution conductors includes overhead and underground conductors for both primary and secondary voltages. For overhead distribution, approximately [redacted] of conductor spans[21] are located throughout San Francisco. For underground distribution, approximately [redacted] of conductor spans are located within San Francisco. PG&E confirmed that out of this total underground distribution conductor span length, approximately [redacted] are for the network distribution system (as opposed to the radial system) in San Francisco.

[redacted]

The total length considered as part of the conductor RCN is shown in Table 6.[22]

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21 Service conductors are not included here and are instead discussed separately in Section E.3.f below.

22 Distribution conductor length shown in this table excludes conductors listed in PG&E's database as customer-owned.

TABLE 3.1-6
LENGTH OF DISTRIBUTION CONDUCTORS IN SAN FRANCISCO

Line No.	Distribution Conductor Type	Length (miles)
1	Primary Overhead	[redacted]
2	Secondary Overhead	
3	Primary Underground	
4	Secondary Underground	
5	Total	

To determine the RCN for distribution conductors, Sargent & Lundy considered the data fields from PG&E's GIS database with information related to the type of conductor, such as copper or aluminum, and the measured length. [redacted]

b. Support Structures

Support structures, broadly, are poles and other equipment that support PG&E's distribution overhead lines and other above-ground distribution assets. Support structures included in the RCN analysis include several assets such as poles, guy stubs, pole stubs, electroliers, and other additional equipment. PG&E's GIS database provides information on these support structures, including the height and class of the support structure, where applicable. The database also provides information on whether the structure is fully owned by PG&E or jointly owned by PG&E and others. To determine the RCN for support structures, Sargent & Lundy excluded assets listed in the database as customer-owned and proposed to be installed. Based on this, the RCN analysis considers a total of [redacted] support structures.

The RCN analysis considers [redacted][23] assets identified as poles in the support structures database. Distribution poles in PG&E's database are categorized by height and class. Sargent & Lundy developed conceptual framework cost estimates for the work associated with the installation of distribution poles, which were used to determine the RCN.

Sargent & Lundy also developed unit costs for the remaining [redacted] support structures considered in the RCN, which based on the database are identified as guy stubs, other structures, and electroliers and are categorized by height and class. S&L developed conceptual cost estimates for these remaining units, particularly noting that electroliers are steel support structures dedicated to supporting streetlights only.

Of the [redacted] support structures considered in the RCN, 1.7% did not contain information related to height or class. Where information on height or class of the support structure was not available, as applicable, Sargent & Lundy [redacted].

An important aspect to consider in the support structure RCN development is that approximately 4.9% of support structure assets are installed in backyard or rear easements or other harder-to-access areas. The installation of these assets would therefore require special equipment and additional labor. Sargent & Lundy developed a specific framework cost estimate that considered these characteristics when developing the RCN for support structures located in hard-to-access areas.

As part of the RCN analysis, Sargent & Lundy developed two scenarios related to the support structure ownership. In the first scenario, Sargent & Lundy assumed that the distribution support structures listed in the database were fully owned by PG&E. The RCN for distribution support structures considering this assumption is $700,721,000. In the second scenario, Sargent & Lundy further

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23 Note that assets within the database identified as "poles" account for [redacted] structures. However, for RCN purposes, S&L included [redacted] asset identified as a "tower" in the "pole" category.

evaluated jointly owned poles and performed an additional analysis to determine the portion of the RCN associated with PG&E's ownership interest. The additional analysis that we performed followed the relevant methodology of the Northern California Joint Pole Association (NCJPA). Using average ownership interest factors from the NCJPA, we determined that the RCN for PG&E's ownership interest portion of the distribution support structures is $476,924,000, as shown in Table 5.[24]

c. Conduit System

The conduit system refers to the underground infrastructure used to house and protect PG&E's underground distribution cables. PG&E uses a number of different types of conduit and trench configurations within the San Francisco area. PG&E's database for underground conduit is divided into three categories: (1) CIC, defined as cable-in-conduit, (2) conduit, and (3) duct bank. A summary of the length identified in the database for each category is shown in the table below:

TABLE 3.1-7
LENGTH OF CONDUIT SYSTEM

Line No.	Conduit System Category	Length (miles)
1	CIC	[redacted]
2	Conduit	
3	Duct Bank	
4	Total	

The installation of new conduit/trenching is complex and requires careful planning and engineering. Installation must be performed so as not to impact or interfere with other subsurface utilities (e.g., water pipes, sewer pipes) and often requires that the sidewalk or street above the site of the new conduit be demolished to allow for the installation and then be replaced. Any cost determined for the installation of underground conduit must also consider time constraints that may apply to the construction area and any adjustments to labor cost that these

[24] For purposes of Sargent & Lundy's RCN calculation, Sargent & Lundy uses the $476,924,000 figure.

requirements cause. In addition to the crew performing the work, other personnel must be involved to control traffic and maintain/monitor safety protocols.

The complexity and unit cost for underground conduit and trenching are highly dependent on the specifics of the type of work being performed. Accordingly, in order to capture all the construction activities in an integrated framework and allow for more accurate cost estimation in connection with the underground conduit system, Sargent & Lundy developed engineering models to support its cost estimates. For the underground conduit system, Sargent & Lundy developed [redacted] conceptual engineering models to represent PG&E's underground distribution system in San Francisco, [redacted]

TABLE 3.1-8

[redacted]

[redacted]

1 [redacted]

2 [redacted]

3 [redacted]

4 [redacted]

CONFIDENTIAL FIGURE 3.1-4

[redacted]

[redacted]

CONFIDENTIAL FIGURE 3.1-5

[redacted]

[redacted]

To determine the RCN for the distribution underground conduit system, Sargent & Lundy also used information provided by PG&E from their GIS system—specifically system type (radial versus network), length, conduit size, and conduit count—to aggregate the appropriate length of the system [redacted]

TABLE 3.1-9
SUMMARY OF RCN FOR DISTRIBUTION CONDUIT SYSTEM
(2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

[redacted]		
12	Total	$4,244,543,000

d. Subsurface Structures

Subsurface structures are underground structures or electrical enclosures that are located below streets, sidewalks, on private property and/or rear easements, and can be accessed by access panels or manholes. There is a wide range of sizes of distribution subsurface structures in San Francisco that contain electric system components and equipment. Some of the larger subsurface structures (referred to as vaults) are the size of a large room and contain multiple transformers and other electrical equipment required for the operation of the electric grid. Some subsurface structures are prefabricated enclosures while others may be built using concrete poured in place.

As with the conduit system, the installation of a new subsurface structure (even a small one) is a complex project that requires careful planning and engineering. Again, work on subsurface structures (i) must be performed with care to avoid impact on other subsurface infrastructure; (ii) often requires demolishing and then replacing portions of street or sidewalk; and (iii) must be performed under potential time constraints (to avoid, for example, closing major thoroughfares during rush hour) and with large teams of personnel (to ensure safety and traffic control).

As with the conduit system, to more accurately determine the RCN of the distribution subsurface structures and capture all the construction activities in an integrated framework, Sargent & Lundy developed [redacted] models that represent the various types of structures listed in PG&E's GIS database. [redacted]

TABLE 3.1-10
RCN FOR DISTRIBUTION SUBSURFACE STRUCTURES
(2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

Line No.			
1	[redacted]		
2			
3			
4			
5			
6			
7			
8			
9	Total	[redacted]	$3,162,968,000

e. Distribution Transformers and Other Distribution Equipment

Distribution transformers step down higher distribution-level voltage to the lower voltage used by end-use customers. PG&E's distribution system also relies on other assets (both overhead and underground) to deliver power and operate, monitor, and protect PG&E's electric assets. Table 11 shows the count of distribution transformers and other distribution assets considered in the RCN analysis with their associated

RCN. Material unit prices were developed using: (1) RSMeans, and (2) Sargent & Lundy's internal project databases.

TABLE 3.1-11
RCN FOR DISTRIBUTION TRANSFORMERS AND OTHER DISTRIBUTION EQUIPMENT
(2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

Line No.	Distribution Asset Type	[redacted]	Replacement Cost New
1	Transformers		$623,419,000
2	Capacitor Bank		15,752,000
3	Fuses		32,118,000
4	Network Protector		122,619,000
5	Padmount Structure		6,468,000
6	Primary Riser		18,659,000
7	Recloser Interrupter		75,207,000
8	Secondary Riser		36,396,000
9	Smart Meter Network Devices		2,158,000
10	Switches		862,096,000
11	Voltage Regulators		839,000
12	Total		$1,795,731,000

f. Services

Service assets are the infrastructure between a distribution transformer and a customer premise through which electric service is provided to a customer. Services are defined by both *service locations* and *service points*. *Service locations* refer to the unique locations where PG&E provides services (*i.e.*, buildings, homes, etc.), whereas *service points* refer to each individual customer that receives electric service. There may be multiple *service points* within a single *service location.* PG&E provides electric service to approximately [redacted] San Francisco customer accounts (service points) at [redacted] service locations.[25] To determine the RCN for services, S&L calculated that PG&E uses approximately [redacted] of overhead service conductors and [redacted] of underground service conductors to provide services to the

[25] GIS data regarding the specific number of overhead service locations vs. underground service locations from the third quarter of 2022 was not available, so S&L used PG&E records for 2025 to perform a statistical analysis to determine the number of overhead and underground service locations during the third quarter of 2022 for purposes of its RCN calculations. PG&E indicated that the difference in services between 2022 and 2025 is not significant.

city of San Francisco. The RCN for services is shown in the table below.

TABLE 3.1-12
SUMMARY OF SERVICES RCN
(2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

Line No.	Asset Type	[redacted]	Replacement Cost New
1	Overhead Service		$343,395,000
2	Underground Service		189,203,000
3	Total		$532,598,000

g. Streetlights

In addition to its assets dedicated to providing power to San Francisco customers, PG&E also owns thousands of streetlights in San Francisco. To determine the RCN for streetlights, we considered [redacted] streetlights of different types and sizes that are owned by PG&E. Table 13 provides the results of our RCN analysis for this asset category. The RCN associated with streetlight conductor, both overhead and underground, and associated poles or conduits used for streetlight purposes is included in the respective RCN for those separate asset categories.

TABLE 3.1-13
RCN FOR STREETLIGHTS
(2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

Line No.	Asset Type	[redacted]	Replacement Cost New
1	Streetlight Lamps		$24,987,000
2	Total		$24,987,000

h. Metering Infrastructure

PG&E's system in San Francisco also relies on an extensive metering infrastructure that allows PG&E to accurately monitor customer usage and bill customers accordingly. The development of the RCN for metering infrastructure includes assets related to primary metering as

well as customer meters and includes advanced metering infrastructure assets that are in place in San Francisco. Primary metering is used for larger customers, at different voltage levels from 2.4 kV to 34.5 kV. Primary metering equipment includes the meter itself, as well as current transformers (CT) and potential transformers (PT) that are used since current or voltage conversion is required to perform metering functions. Customer meters are used for residential or smaller commercial customers and for the most part do not require additional metering infrastructure in the form of CTs or PTs. Note that some customer meters do require CTs and PTs—these are listed separately in the RCN table below. Table 14 provides the results of our RCN analysis as to metering infrastructure.

TABLE 3.1-14
RCN FOR METERING INFRASTRUCTURE
(2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

Line No.	Asset Type	[redacted]	Replacement Cost New
1	Primary Meters		$8,429,000
2	Customer Meters		572,540,000
3	CTs and PTs for Metering		67,843,000
4	Total		$648,812,000

4. Substation Assets RCN

A substation is a facility in the electric power grid that transforms voltage levels—stepping electricity up for long-distance transmission or stepping it down for local distribution to homes and businesses. It also houses protective equipment such as circuit breakers, switches, and relays that monitor, control, and safeguard the flow of electricity through the grid.

The RCN developed for substation assets considers 32 substations as detailed in Table 15 below. Note that the RCN for assets within the San Fran H (Martin) Substation is shown in a separate section of this testimony.

TABLE 3.1-15
LIST OF SUBSTATIONS INCLUDED IN RCN ANALYSIS[26]

Line No.	Substation	Location	Type
1	[redacted]		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
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31			
32			

PG&E's SAP database provides lists of assets present at PG&E substations. Assets included were [redacted]

[26] San Fran H (Martin) Substation is listed in this table for completeness. However, the RCN developed for Martin is shown in Table 18.

[redacted]. We compared the asset data from the SAP database against the single-line diagrams for each substation to confirm the quantity of substation assets.

As with the RCN developed for the other electric system assets in San Francisco, substation RCN estimates include the engineering, local sales tax on materials or purchased equipment, owner's cost, and contingency adjustments. [redacted] The table below shows the RCN determined for each substation.

TABLE 3.1-16
SUMMARY RCN FOR SUBSTATIONS
(2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

Line No.	Substation Name	Type	Replacement Cost New
1	[redacted]		$1,831,000
2			1,372,000
3			1,520,000
4			1,812,000
5			2,160,000
6			2,034,000
7			1,630,000
8			2,348,000
9			2,088,000
10			1,079,000
11			2,080,000
12			3,171,000
13			466,537,000
14			32,254,000
15			13,742,000
16			16,609,000
17			16,594,000
18			44,427,000
19			11,260,000
20			10,266,000
21			12,174,000
22			81,526,000
23			31,533,000
24			261,682,000
25			85,844,000
26			279,587,000
27			985,000
28			3,410,000
29			3,066,000
30			2,861,000
31			2,916,000
32	Total		$1,400,398,000

Costs associated with buildings and real estate are not included in the substation RCN shown above; these costs are included in Chapter 4.

5. Martin Substation and Martin Related Assets

Sargent & Lundy developed an RCN for the Martin Substation, also known as San Fran H. The RCN for Martin considers all the assets at the substation and is consistent with CCSF's intended taking of Martin in its entirety. The RCN for the Martin Substation was determined using a consistent methodology and assumptions with those used for the other substations within the San Francisco boundary.

CCSF has also proposed to take additional electric utility assets related to the Martin substation that run from Martin (in San Mateo County) to the San Francisco boundary. These additional assets, located in what is referred to as the "Martin Triangle," [redacted]. Assets within the Martin Triangle consist of primary overhead and underground conductors, support structures, associated underground conduit, primary risers, switches, and subsurface structures. Table 17 below shows the inventory for these additional Martin assets.

TABLE 3.1-17
MARTIN RELATED ASSETS INVENTORY

Line No.	Asset Type	Length (mi)	Count
1	Conduit	[redacted]	
2	Primary OH Conductor		
3	Primary UG Conductor		
4	Primary Riser		
5	Subsurface Structures		
6	Support Structures		
7	Switches		

The inventory of assets within the Martin Triangle was submitted by CCSF as part of its testimony and associated workpapers.[27] CCSF developed that inventory utilizing information provided in the GIS database and by making adjustments to several underground feeder lengths that CCSF believed had segments missing.[28] For purposes of developing the RCN for the additional Martin assets (as throughout), Sargent & Lundy used the asset counts and characteristics CCSF included as part of the exhibits to the asset stipulation.

The RCN of these assets was determined using a consistent methodology and set of assumptions as were used for similar types of

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27 Bacalao Testimony at Appendix II, Volume II, Attachment O, Martin-Feeders-RCN-(Triangle)_APR-2026.xlsx. *See also id.* at Appendix IV, Proposed Stipulation Exhibit E - Distribution Radial Assets- Martin-Border_Detail_CONF FINAL.xlsx.

28 *Id*.

assets in the city; however, Sargent & Lundy has listed the RCN for the specific assets associated with Martin separately below.

TABLE 3.1-18
MARTIN SUBSTATION AND MARTIN-RELATED ASSETS RCN
(2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

Line No.	Type	Replacement Cost New
1	Martin Substation	$401,500,000
2	Martin-Related Assets	–
3	Conduit	39,471,000
4	Primary OH Conductor	436,000
5	Primary UG Conductor	7,042,000
6	Primary Riser	22,000
7	Subsurface Structures	6,711,000
8	Support Structures	686,000
9	Switches	535,000
10	Total	$456,403,000

6. Other Asset Categories

Under the Other Assets Category, we included several electric system assets in San Francisco that are owned by PG&E but that are not specifically included with the main transmission, distribution, and substation assets.

Fiber Optic Assets. PG&E provided asset details from the GIS database related to the fiber optic network in the San Francisco area. The length of the fiber optic network used for the RCN was [redacted]. This amount excludes specific fiber optic cables that CCSF indicated it would not acquire. [redacted]

Spare Assets. CCSF provided the spares inventory it intends to take as part of their testimony, focusing on network transformers, network protectors, and distribution transformers.[29] The RCN of these assets was determined using a consistent methodology to the similar types of assets in the city. [redacted]

[29] Bacalao Testimony at Appendix IV, Proposed Stipulation Exhibit F - Spare Materials and Equipment-CONF FINAL.xlsx.

[redacted]

DC Assets. A small portion of PG&E's electric grid in San Francisco utilizes direct current (DC) equipment to provide service to customers. Equipment under the DC assets inventory includes overhead and underground rectifiers, overhead and underground secondary and service conductor, distribution boxes, and risers. The RCN for DC assets is shown in the table below.

TABLE 3.1-19
OTHER ASSETS RCN
(2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

Line No.	Other Asset Categories	Replacement Cost New
1	Fiber optic assets	$11,754,000
2	Spares	46,017,000
3	DC Assets	51,572,000
4	Total	$109,343,000

Communications Equipment. Costs related to communications equipment are generally included as part of other asset categories (*i.e.*, within substation and distribution assets). As such, a separate RCN for the communication equipment identified in Exhibit J of the stipulation was not developed.

7. Cost Adjustment Factors

The RCN analysis considered various cost adjustment factors to account for San Francisco-specific considerations and project-specific cost adjustments. I address some of those items below.

Owner's Costs. The RCN analysis includes an owner's cost allowance applied to most asset categories. Owner's costs are the project costs that an owner must incur to complete a project beyond the contract price paid to the construction contractor. For a project of the nature contemplated here—

building the electric utility assets serving San Francisco—these costs would necessarily include items such as project management, construction management and inspection, permitting and regulatory compliance, environmental compliance, legal/transactional costs, commissioning and acceptance testing, insurance, and similar items. These are real and unavoidable costs that any owner replacing this system would bear. Excluding them would understate the true replacement cost of an asset of equivalent utility, which is the measure the cost approach is intended to capture.

[redacted]

Adjustments for Engineering. In addition to the Owner's cost, the RCN for substation, transmission, and distribution assets includes a [redacted]

Taxes/Allowances. The RCN for substation, transmission, and distribution assets includes an adjustment for sales tax on equipment and materials equal to 8.625%, consistent with the state / local sales tax rate for San Francisco (2022). Note that this tax allowance is the same used by CCSF's RCN witness Bacalao.

Contingency. Contingency is a cost allowance included in project construction estimates to account for unforeseen conditions, uncertainties, and risk events that cannot be fully anticipated at the time of estimation. Contingency covers risks common to all large-scale utility construction projects, such as the potential need for design modifications due to conditions discovered during construction, material price escalation, labor availability constraints, and other similar items. In the context of construction work in San Francisco, contingency is particularly warranted given the city's densely developed urban environment and the fact that a significant portion of the city's electrical system is located underground.

[redacted]

CONFIDENTIAL FIGURE 3.1-6

[redacted]

[redacted]

1 [redacted]
2 [redacted]
3 [redacted]
4 [redacted]
5 [redacted]
6 [redacted]
7 [redacted]
8 [redacted]
9 [redacted]
10 [redacted]
11 [redacted]
12 [redacted]
13 [redacted]
14 [redacted]
15 [redacted]
16 [redacted]

CWIP (Construction Work in Progress). It is also worth noting that our RCN figure does *not* account for any subsequent projects or improvements made to San Francisco's electric system, including construction work in progress (CWIP) by PG&E. Because CCSF has not included CWIP in its stipulated asset lists, it is instead addressed in Chapter 8.

F. Comparison of PG&E RCN Results to CCSF RCN Results

As part of preparing and refining my RCN analysis, I also analyzed CCSF's RCN testimony from Nelson Bacalao and worked to understand the differences between our RCN results and CCSF's RCN results and the reasons for those differences.

It is worth noting at the outset that there is agreement between PG&E and CCSF regarding asset counts. PG&E and CCSF had a series of seven workshops in 2025 to align on asset count inventories. The result of these workshops was an overall alignment on asset counts, which was memorialized in the parties' asset stipulation. Accordingly, any differences in calculated RCN between S&L and CCSF are unrelated to asset counts. It is also worth noting, as discussed further below, that as to the vast majority of asset categories, PG&E's and CCSF's RCN analyses are fairly similar, with just a few asset categories driving the vast majority of divergence.

The table below shows a comparison of the RCN results between Sargent & Lundy and CCSF, considering CCSF's revised RCN values.[30] Note that for comparison purposes, the RCN for each asset category includes all adjustments applied by each respective party, such as owner's cost and contingency.[31] Rounding has been applied to the nearest thousand.

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30 RCN values for CCSF were gathered from the April 20, 2026, version of Nelson Bacalao's Direct Testimony and accompanying workpapers and attachments and the *errata* version provided on May 21, 2026.

31 CCSF's RCN values consider the adjustments applied by CCSF in their workpapers, such as applying 20% owner's cost for distribution assets, 25% owner's cost for transmission assets, and 10% contingency for all assets. Note that in the case of spare assets, CCSF did not apply an owner's cost adjustment; it only applied the 10% contingency adjustment.

TABLE 3.1-20
REPLACEMENT COST NEW COMPARISON
(2022 DOLLARS, ROUNDED TO NEAREST THOUSAND)

Line No.	Asset Categories	S&L RCN	CCSF RCN	Difference
1	115kV Transmission Lines	$1,326,769,000	$996,117,000	$330,652,000
2	230kV Transmission Lines	495,966,000	444,923,000	51,043,000
3	Subtotal Transmission	$1,822,735,000	$1,441,040,000	$381,695,000
4	Conductors	$1,325,694,000	$1,411,387,000	$(85,693,000)
5	Support Structures	476,924,000	453,750,000	23,174,000
6	Conduit System	4,244,543,000	1,820,188,000	2,424,355,000
7	Subsurface Structures	3,162,968,000	1,036,442,000	2,126,526,000
8	Distribution Transformers	623,419,000	837,070,000	(213,651,000)
9	Other Distribution Equipment	1,172,312,000	1,018,442,000	153,870,000
10	Services	532,598,000	477,724,000	54,874,000
11	Streetlights	24,987,000	20,144,000	4,843,000
12	Metering Infrastructure	648,812,000	565,450,000	83,362,000
13	Subtotal Distribution	$12,212,257,000	$7,640,597,000	$4,571,660,000
14	Substations (31, in CCSF)	$1,400,398,000	$1,301,119,000	$99,279,000
15	Martin Substation	$401,500,000	$370,315,000	$31,185,000
16	Martin Related Assets	54,903,000	40,546,000	14,357,000
17	Subtotal Martin	$456,403,000	$410,861,000	$45,542,000
18	Fiber optic assets	$11,754,000	$10,597,000	$1,157,000
19	Spares	46,017,000	42,470,000	3,547,000
20	DC Assets	51,572,000	78,025,000	(26,453,000)
21	Subtotal Other Assets	$109,343,000	$131,092,000	$(21,749,000)
22	Total RCN	$16,001,136,000	$10,924,709,000	$5,076,427,000

The comparison between CCSF's RCN and Sargent & Lundy's RCN for the electrical assets considered in this process shows that CCSF's RCN is lower than Sargent & Lundy's, by approximately $5,076,427,000. I include below a summary of some of the more significant differences between Sargent & Lundy's and CCSF's RCN values, starting with areas for which Sargent & Lundy developed lower RCN values than CCSF and then addressing areas for which Sargent & Lundy developed higher RCN values than CCSF.

1. Discussion on Lower S&L Results than CCSF's

When comparing the RCN differences for specific assets, we note that for some categories of assets, such as distribution transformers and network

protectors, Sargent & Lundy's RCN figures are lower than CCSF's. A discussion of the reasons why is provided below.

a. Distribution Transformers

For distribution transformers, CCSF's RCN value is $837,070,000, while Sargent & Lundy's RCN value is $623,419,000. The delta does not result from any difference in core methodology. Both Sargent & Lundy and CCSF extracted material costs from RSMeans for available transformers that were similar to the ones listed in PG&E's database for this asset category. Then, both Sargent & Lundy and CCSF applied a trendline approach to calculate material costs for any additional transformers that were not explicitly available in RSMeans.

The driver for the difference between both parties' RCN is the year (or year quarter) used as the basis for the extraction of historical material costs from RSMeans. As mentioned, Sargent & Lundy based the RCN analysis on costs for the fourth quarter of 2022. CCSF based their RCN analysis on year 2023 costs. While this may not represent a significant time difference, it results in a significant cost difference for the material costs used as the basis for the RCN due to the fact that transformer costs were increasing sharply in this time period. An example of how RSMeans material costs differ for the transformers used as the basis to determine the RCN between the fourth quarter of 2022 and year 2023 is shown in the table below.

TABLE 3.1-21

[redacted]

[redacted]

Higher transformer costs in 2023 relative to 2022 were primarily driven by the continued escalation of supply-chain and manufacturing constraints that had emerged earlier during the COVID-19 pandemic, combined with sustained increases in key input costs and stronger demand.

b. Network Protectors

Network protectors are another asset category in which Sargent & Lundy's RCN is lower than CCSF's. The RCN determined by Sargent & Lundy is $122,619,000, while CCSF's RCN is $352,723,000.[32] The main difference between both figures is the material cost used as the basis to determine the RCN. While CCSF has a base cost of [redacted] for a [redacted], the base cost used by Sargent & Lundy is lower. [redacted]

2. Discussion on Higher S&L Results than CCSF's

For other asset categories, the RCN developed by Sargent & Lundy is higher than the one developed by CCSF. The vast majority, approximately 89%, of the $5,076,427,000 difference between CCSF's and Sargent & Lundy's RCN figures is from two asset categories: Conduit System and Subsurface Structures. For conduits there is a $2,424,355,000 difference and for subsurface structures there is a $2,126,526,000 difference. These differences are explained in further detail below, and the basis for Sargent & Lundy's position is substantiated.

a. Conduit System

As part of the workshop process, there were extensive discussions between the parties regarding the underground distribution system, including the length of the major categories in San Francisco's conduit system: (1) "CIC" (cable in plastic conduit using direct burial), (2) "Conduit" (cable in conduit normally using backfill material), and

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32 [redacted]

(3) “Duct Bank” (normally encased in concrete). During the workshop process, the parties reached agreement on the length of each of these categories included in the conduit system database.

Since there is agreement on the lengths, the main driver of cost difference in this category therefore is not how *much* conduit is in San Francisco, but the unit cost difference for each of the construction units—that is, how much it would cost to actually build replacement for that length of conduit. The unit costs determined by CCSF are lower than those determined by Sargent & Lundy and are not fully reflective of the complexity of installing underground conduit in the city of San Francisco. The table below shows an RCN comparison between the construction units developed by Sargent & Lundy and equivalent construction units developed by CCSF.[33]

TABLE 3.1-22
CONDUIT SYSTEM CONSTRUCTION UNIT COST COMPARISON (2022 DOLLARS)

[redacted]

[redacted]

[33] [redacted]

[redacted]

Sargent & Lundy's Approach. For complex asset classes with multiple workstreams—such as the conduit system—Sargent & Lundy developed bottom-up engineering cost models tailored to doing work in San Francisco. These cost estimates, as discussed above, were based on conceptual engineering models to represent PG&E's underground distribution system in San Francisco, which allowed Sargent & Lundy to estimate the cost of installing the conduit system in San Francisco with more specificity.

Sargent & Lundy took this approach for a few reasons. First, work related to undergrounding utility facilities is inherently capital-intensive due to its complexity since it extends well beyond the placement of primary or secondary electric conductors below grade. In addition to trench excavation and conduit installation, undergrounding projects typically require extensive planning and design, cabling, safe navigation around other underground utility interfaces, traffic control, pavement, and surface restoration, among other task. The decision to build bottom-up cost models ultimately results in Sargent & Lundy calculating an RCN that is a more accurate representation of costs to install the assets in the city.

Second, Sargent & Lundy noted that work to install conduit in San Francisco is particularly complex. Available studies[34] indicate that undergrounding facilities, such as the electrical distribution system, is more expensive in San Francisco than in other jurisdictions due to a combination of physical, operational, and regulatory constraints. Furthermore, local constraints increase costs and reduce productivity, including (i) the need to trench both sides of many streets, (ii) restrictions limiting open trench length, (iii) higher permit and traffic control costs, (iv) work-hour and lane-closure restrictions that often

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34 Policy Analysis Report Re: Utility Wire Undergrounding Costs, City and County of San Francisco Board of Supervisors, Budget, and Legislative Analyst (Mar. 2, 2015. *See also* Utility Undergrounding Program, Master Workplan Study (July 15, 2020).

require overnight work for large projects,[35] (v) material staging limits, (vi) higher street restoration costs (including the need to repave all impacted lanes for the entire length of the street for trenches that are more than 25% of the length of the street[36]), (vii) numerous subsurface and streetside obstructions / utility interfaces, (viii) major overhead feeder conflicts, and (ix) the added difficulty and expense of trenching across municipal rail trackways. San Francisco's high urban density also requires underground utility infrastructure to be placed near the public right-of-way or on private property through easements, which can further lengthen and complicate construction. These considerations are not adequately captured in CCSF's RCN for the conduit system, as is discussed further below.

CCSF's Approach. CCSF, by contrast, developed their estimate using RSMeans codes and multiplying their determined base RSMeans costs by a "Job Conditions Adjustment" factor. RSMeans is a widely accepted and appropriate starting point for construction cost estimation, and Sargent & Lundy does not dispute its use. In fact, Sargent & Lundy utilizes RSMeans as part of the process to determine the RCN for many assets in San Francisco. However, RSMeans itself[37] notes that cost adjustments may be required to be added to its underlying cost and labor data, depending on the specific work location, project, and conditions. As one example, RSMeans explicitly states, "The productivity, daily output and labor-hour figures for each line item are based on working an eight-hour day in daylight hours in moderate temperatures. For work that extends beyond normal work hours or is performed under adverse conditions, productivity may decrease."[38] It further states: "We have made no allowance for overtime. If you

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35 San Francisco Municipal Transportation Agency (SFMTA) Regulations For Working In San Francisco Streets, https://www.sfmta.com/media/34435/download?inline=.

36 San Francisco Public Works DPW Order No: 187005, Regulations for Excavating and Restoring Streets in San Francisco, Section 12.3-C, Part 2, https://sfpublicworks.org/sites/default/files/PW-Order-187005-Signed.pdf.

37 *See* Understanding RSMeans Data's Construction Costs and Using Them to Estimate (May 23, 2025) https://www.rsmeans.com/resources/what-is-construction-estimating.

38 *Id.*

anticipate premium time or work beyond normal working hours, be sure to make an appropriate adjustment to your labor costs."[39] Considering many undergrounding projects in San Francisco have to be performed at night due to SFMTA daytime street closure limitations, an adjustment to the appropriate RSMeans costs would be thus warranted for determining RCN in San Francisco. Further considerations specific to San Francisco detailed above, such as the high probability of encountering/having to navigate around existing infrastructure when digging in the city, frequent mobilization/demobilization due to work hour limitations, navigating around the rail/subway network, unique restoration and permitting requirements, etc., all require adjustments on the base RSMeans costs.

CCSF attempted to address these complexities by using a "Job Conditions Adjustment" factor. Given the uniqueness and challenges of work in San Francisco, accurately defining the "Job Conditions Adjustment" factor is foundational to obtaining an RCN value that accurately represents the cost of the work. CCSF sets their Job Conditions Adjustment equal to 35%; however, a value of 35% for the "Job Conditions Adjustment" factor is too low and not sufficiently supported, as is described further below.

To understand the basis for CCSF's 35% value for the "Job Conditions Adjustment" factor, PG&E asked CCSF a series of questions about this factor as part of discovery. CCSF's response was the following: "The Consulting Team compared the RCN calculation to the average unit cost information that PG&E provided for underground cables in the document titled Workpaper Table 17-27 (PGE000082653) [the General Rate Case unit costs table]. The comparisons showed that for assets that require underground construction, the 5% adjustment resulted in costs that were lower than the PG&E unit costs for San Francisco in Table 17-27. However, when a 35% adjustment factor is applied to underground job conditions, rather than 5%, the unit cost is essentially the same as the PG&E underground construction unit cost as

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39 *Id.*

illustrated in the table below. This analysis shows that the 35% factor is reasonable."[40] CCSF's response then includes the following table, illustrating an approach that is intended to justify the "Job Conditions Adjustment" factor:

TABLE 3.1-23
CCSF RESPONSE EXPLAINING THEIR 35% JOB CONDITIONS ADJUSTMENT FACTOR

Line No.	PG&E Item	PG&E Costs	Unit cost based on RSMEANS San Francisco Location with:	5%	35%
1	Primary UG Cable w/trench 200' SF BAY AREA	156,000	15 kV UG 3x 500 kcmil AL	26,419	33,396
2	(Note: 1) $780 / Ft (Row 53)		2 Conduit 6" diameter	51,600	65,226
3			Splicing Box * 4	38,005	48,041
4	Total with 10% Contingency			127,626	161,329
				(18)%	3%

Note 1: PG&E Cost according to PGE000082653.PDF (Workpaper Table 17-27)

This table (and CCSF's response more broadly) provides insufficient basis for CCSF's selected Job Conditions Adjustment factor. The table indicates that CCSF derived its Job Conditions Adjustment factor from PG&E's estimate for underground trenching in San Francisco prepared in connection with PG&E's 2023 GRC—which was $780/ft (shown on the left side of CCSF's table). That figure is both out-of-date (it is based on projects performed prior to 2022, the year as of which all the costs in this chapter were calculated) and reflects the *average* cost of new underground trench construction in San Francisco.[41] Notwithstanding, a key issue with CCSF's analysis. s that if one takes the GRC average trenching cost value—even the out of date, $780/ft value—and

[40] CCSF Response to PG&E Data Request Set 3, No. 7 (May 23, 2023).

[41] For example, the $780/ft value in the table is from the 2023 GRC, defined as the "UG New w/trench – SF Only," and is intended to represent the average cost of underground trenching in San Francisco. It is also important to note that the GRC trenching unit cost value of $780/ft was developed using projects performed prior to 2022—meaning inflation adjustments need to be added for the unit cost value to be in a comparable timeframe with the RCN calculations.

multiplies it by the total length of trench in the city ([redacted]), the cost results in over $5.7 billion—$1.7 billion more than the RCN value the CCSF team calculated for the underground assets in the city (conduit system, underground conductor, and subsurface structures combined). CCSF's table therefore does not provide a reasonable basis for CCSF's application of a 35% Job Conditions Adjustment factor—noting also that CCSF has pointed to no other support for such a factor—and the factor underestimates the RCN of the conduit system in San Francisco. As such, Sargent & Lundy considers CCSF's 35% "Job Conditions Adjustment" factor to lack sufficient support and to be lower than what is realistic.

b. Subsurface Structures

For subsurface structures, workshop discussions also resulted in agreements for asset inventory categories and subsurface structure dimensions. Therefore, the difference between the calculated RCN of the parties is once again related to the costs considered for each construction unit. To determine the cost associated with replacing these structures, the following items need to be considered as part of the scope, at minimum: (i) removal or demolition of pavement/street/sidewalk, (ii) disposal of removed or demolished material, (iii) materials (including the subsurface structure), (iv) equipment used for construction, (v) installation of the structure, and (vi) repair of the sidewalk/street. Additional aspects of performing construction in San Francisco need to be considered in the unit cost as well. As described earlier, San Francisco is one of the densest cities in the United States—meaning that any underground construction must navigate and avoid damaging the complicated underground network of existing water, sewer, gas, communications, and other utility facilities. Navigating each interface requires careful coordination, which adds complexity, time, and labor to underground construction projects. Furthermore, allowances for traffic control personnel and logistics, such as specific windows of time a construction crew is permitted to work, safety personnel, etc., should be included in any cost estimate of this type.

Below is a comparison of the parties' construction unit RCN.

TABLE 3.1-24

[redacted]

The difference results from fundamental issues in CCSF's methodology. As discussed in the section above, the use of RSMeans for an asset class with a complex, multi-discipline construction process, such as subsurface structures, requires appropriate adjustments in order to capture the unique complexities of the asset installation, as well as associated costs of construction in San Francisco. The adjustments CCSF makes fall short of accurately capturing the costs of these construction complexities. CCSF's methodology results in three fundamental issues with the unit costs they develop: (1) the unit costs include a limited scope of work that does not capture all the intricacies of building underground distribution systems in San Francisco, (2) the labor cost portion of CCSF's unit costs is too low and thus does not reflect the true complexity of the work, and (3) the same unrealistically low 35% "Job Conditions Adjustment" factor as used with the conduit system is also used with subsurface structures.

Scope of Work. As to the limited scope of work covered by CCSF's unit costs, CCSF's unit costs do not include the following costs: (a) traffic control, (b) costs for disposal of excavated materials, (c) costs for use of / installing additional construction equipment needed to perform safe constructions in large excavations, such as the installation of shoring walls, and (d) costs for electrically grounding the structure. These are important and significant costs that should be included.

Labor Costs. As to the labor costs portion of CCSF's subsurface structure unit costs, as noted, those costs are unrealistically low for work of this nature. The following table presents CCSF's total labor costs for the various construction units, derived from CCSF's relevant workpaper.

TABLE 3.1-25

[redacted]

The majority of the subsurface structure types require, at a minimum, a medium to large team of people from multiple disciplines (crews) to perform the installation, in addition to the closure of sections of / the entire street. The larger structures may require construction schedules that span a week or more due to the complexity of excavating in San Francisco and of safely navigating the complicated network of other existing underground utility interfaces.

As an example, considering an assumed fully loaded labor rate (which includes costs to cover social security, workmen's compensation, and federal and state unemployment insurance) of [redacted] and using CCSF's total labor costs, [redacted]. This would include mobilization and transporting equipment to the site, removing the pavement/sidewalk, digging (potentially a large part by hand) while avoiding other utility interfaces, installing any necessary wall shoring or other equipment for worker safety, installing the concrete primary enclosure, installing any necessary electrical grounding on the structure, remediating/restoring the area, and performing final demobilization activities—all while also safely managing any automobile and/or pedestrian traffic over the duration of the project, which would potentially need to be completed overnight due to SFMTA street closure

restrictions during peak hours. A total of [redacted] equates to a team of four workers starting and finishing this entire project in a [redacted]. In Sargent & Lundy's opinion, this is an underestimation of the work required. The excavation alone, considering the complexity required to navigate the other underground utility interfaces in the city, would take at least a day or more, depending on the specific location of the project. In Sargent & Lundy's opinion, the total project is likely to take a team at least a week. Sargent & Lundy considers a more accurate labor hour assumption to be closer to [redacted] hours for this type of structure, which considers the various technical disciplines and teams of people needed to install this structure, and includes the important cost considerations, such as traffic control, shoring, material disposal, etc., excluded by the CCSF team. CCSF's low labor cost assumptions to install subsurface structures in San Francisco extend to each of the different types of subsurface structures and ultimately are a key driver of why CCSF calculates a lower RCN than one that accurately reflects the complexity of the work required.

Job Conditions Adjustment. Finally, similar to the conduit RCN, CCSF's underground structure RCN relies on a 35% Job Conditions Adjustment factor applied to RSMeans. As discussed above, CCSF does not provide a sufficiently-supported basis for the adjustment and applying the adjustment results in an unduly low estimate of RCN for subsurface structure construction in San Francisco.

c. Project Contingency – Underground Assets

CCSF's RCN figure is also understated because CCSF relies on an unrealistic project contingency figure in connection with PG&E's underground assets in San Francisco. Sargent & Lundy includes a project contingency [redacted] for underground assets, whereas CCSF includes a project contingency figure of just 10%.

Project contingency is a reserved amount of dollars added to a baseline project cost estimate to cover project unknowns—specific project risks, design gaps, price changes, and similar items. Mr. Bacalao applied a 10% project contingency to each asset category

in his RCN analysis, including underground assets. The basis for the value of 10% that Mr. Bacalao uses rests on his characterization of the RCN as the equivalent of an AACE International Class 1 estimate, which he noted in CCSF's response to PG&E's discovery request question related to the basis of his contingency assumptions for the entire system RCN,[42] stating:

> Moreover, the RCN is based on replacing existing equipment that has been identified and inventoried with a high degree of specificity, rather than estimating a new project with uncertain routing, design, permitting, or constructability conditions. For these reasons, I consider the RCN estimate to be similar to a Class 1 estimate, as that term is used in the AACE International estimate classification framework. AACE defines Class 1 estimates as estimates prepared when project definition is substantially complete, generally in the range of 65% to 100%, with typical accuracy ranges of approximately -3% to -10% on the low side and +3% to +15% on the high side. I therefore selected a 10% contingency, which is consistent with the AACE Class 1 range and is appropriate given the high level of inventory detail available.

The use of a contingency factor based on an AACE Class 1 estimate is unrealistic given the nature of this project. For reference, AACE reserves Class 1 estimates for projects whose engineering and project definition is substantially complete. The following table provides a summary of the different AACE estimate classification levels.[43] As can be seen, a Class 1 estimate has the tightest accuracy range of all the different levels. [redacted]

[42] CCSF Response to PG&E Data Request Set 17, No. 1 at 4 (June 4, 2026).

[43] *See* 96R-18, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Power Transmission Line Infrastructure Industries.

TABLE 3.1-26

[redacted]

[redacted]

Mr. Bacalao's classification that his RCN estimate is "similar to a Class 1 estimate" exaggerates his cost estimate's accuracy—especially for underground construction, as is described in more detail below. The PG&E database files used by Mr. Bacalao to calculate the RCN estimates are designed for asset/inventory-management purposes—primarily to define what assets exist, where they are located, how many there are, and list any key characteristics. The database files do not include the fully engineered configuration and constructability details that drive replacement cost for these complex asset types and are required for a Class 1 estimate.

As noted, the question of the accuracy of Mr. Bacalao's estimate is particularly relevant for the underground assets in San Francisco, which dominate the overall RCN. Roughly two-thirds of San Francisco's

primary distribution system is underground, and the conduit system is the single largest line item in the systemwide estimate. For these underground assets, items such as the trench geometry, existing buried infrastructure interfaces, and subsurface soil and groundwater conditions—which are essential to fully understand for each project in order to develop an AACE Class 1 estimate—need to be considered.

Mr. Bacalao's own discussion of underground assets also makes clear that he is not actually developing an AACE Class 1 estimate as to those assets. Instead, Mr. Bacalao employs a parametric approach and a number of significant key assumptions, which is more consistent with an AACE Class 4 or 5 estimate, to estimate the RCN. For the conduit system specifically, he states [redacted] [44] [redacted] [45] [redacted] [46] [redacted] [47] [redacted] These are Mr. Bacalao's descriptions of his methodology. Each of these assumptions helps drive estimated RCN for the respective asset categories, and each is a hallmark of a parametric estimate—assumed dimensions, proxy counts, interpolated unit costs, and standardized configurations—rather than the

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44 Bacalao Testimony, Vol. II, Attachment A, § A.5.1, Geodatabase Attribute Gaps.

45 Bacalao Testimony, Vol. II, Attachment A, § A.5.1, Geodatabase Attribute Gaps.

46 Bacalao Testimony, Vol. II, § 3.28.2, Underground Duct Banks at 101–102.

47 Bacalao Testimony, Vol. III, § 3.2, Transmission Cable Inventory at 17.

substantially complete engineering and project definition that a Class 1 estimate requires.

Sargent & Lundy notes that there are certain aspects of Mr. Bacalao's RCN analysis that resemble close to an AACE Class 1 estimate. For example, there are aspects of RCN that are genuinely inventory count-dependent and construction is straightforward—such as installation of equipment such as transformers, capacitors, regulators, fuses, etc. But for portions of RCN where construction is subject to more uncertainty—including installation of the underground portions of this project—application of project contingency percentages consistent with an AACE Class 1 estimate effectively underrepresents the fair RCN of the underground assets and thus the system as a whole.

In light of the substantial uncertainty that would be associated with underground portions of this project, the Sargent & Lundy team considers a [redacted] contingency allotment for assets where large amounts of ground excavation are required, including the underground distribution conduit system, distribution subsurface structures, and underground transmission system. Based on our experience, we consider this a more appropriate—albeit still very conservatively low—contingency value. [redacted]

d. Underground Asset Cost Comparison – CCSF and Sargent & Lundy

Given that the vast majority of the difference in calculated RCN between CCSF and Sargent & Lundy relates to the underground assets (both conduit system and subsurface structures), Sargent & Lundy compared CCSF's average underground asset costs against several benchmarks. This benchmarking effort underscores that CCSF's unit cost materially understates the cost of installing underground electrical distribution facilities in San Francisco:

CPUC Benchmarks. Sargent & Lundy examined costs that the Commission has estimated for undergrounding distribution lines in California—work that is largely similar in nature to conduit system and

subsurface structure installation work. The CPUC's stated range for undergrounding distribution lines in California (in 2019 dollars) is $350/ft to $1,150/ft, with an average of $3.8 million per circuit mile.[48] Converting these to 2022 dollars,[49] the costs range from approximately $420/ft to $1,380/ft and average $4.6 million per circuit mile ($870/ft). Sargent & Lundy notes that the undergrounding costs listed by the CPUC also include certain costs that are not related to conduit construction, such as costs associated with removing overhead lines before they are relocated underground; however, overhead line removal costs are a very small portion of the project when compared to the costs associated with trenching/ground excavation, conduit installation, subsurface structure installation, and ground/pavement remediation. Accordingly, the CPUC's stated range offers a useful datapoint for comparison to the calculated RCN values for the conduit system installation.

To perform a direct comparison to the CPUC stated range, RCN costs associated with the conduit system, underground conductors (primary and secondary), and subsurface structures were combined and normalized by the total conduit system length [redacted]

CCSF's average cost equates to $543/ft and falls below the average of the three California investor-owned utilities, by a significant margin, and completely under the lowest stated costs for both PG&E and SDG&E. This is especially noteworthy considering the CPUC stated

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48 California Public Utilities Commission, CPUC Undergrounding Programs Description, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/electric-reliability/undergrounding-program-description.

49 [redacted]

cost ranges span from rural areas, where it is relatively inexpensive to underground electrical assets, to dense urban areas, like San Francisco, where it is much more expensive. In contrast, Sargent & Lundy's total unit costs are $1,153 and both fall within the Commission's accepted ranges and reflect the complexities and added costs of installing an underground electrical system in San Francisco, one of the densest major cities in the United States.

San Francisco Undergrounding Program. Sargent & Lundy also examined information from San Francisco's undergrounding program, which took place between 1996 and 2006. The scope of the program was to underground 45.8 miles of overhead utility lines. Similar to the CPUC stated undergrounding range comparison above, this undergrounding project offers a reasonable datapoint for performing a high-level assessment of the calculated conduit system RCN costs, given the broad similarity of the type of work such efforts require. The program was completed at a total cost of $173,167,804, an average of $3.8 million per mile or approximately $720/ft. Considering this figure to be year 2006 dollars and escalating to year 2022 dollars, it results in an average of approximately $1,000/ft costs for undergrounding utility lines—nearly two times larger than the average unit cost calculated by CCSF in their RCN.

Additional Cities Similar to San Francisco. Cost data on undergrounding electric distribution lines from other major U.S. cities that are similar to San Francisco further corroborates that CCSF's calculated RCN for underground assets in San Francisco is understated. In New York City, a 2013 study prepared by the City of New York Office of the Mayor[50] presents costs for undergrounding overhead distribution lines in the Bronx/Westchester service area at $1,570/ft (presented as $8.29 million/mile), and in Staten Island $1,480/ft (presented as $7.81 million/mile), both in 2013 dollars. Escalating these to 2022 dollars, these costs equate to approximately $2,100/ft and $1,980/ft,

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50 Utilization of Underground and Overhead Power Lines in the City of New York, Office of Long-Term Planning and Sustainability, Office of the Mayor, City of New York (Dec. 2013), www.nyc.gov/html/planyc2030/downloads/pdf/power_lines_study_2013.pdf.

respectively. Notably, cost estimates to underground assets in the densest (and thus most expensive) part of New York City—Manhattan—are not in the report due to the fact that Manhattan already has all of its electrical infrastructure located underground. Separately, the main utility in Massachusetts, Eversource Energy, which includes the city of Boston, published[51] underground cable installation costs ranging from approximately $360 to $1,800/ft (in 2022 dollars, presented as $1.9 million/mile to $9.5 million/mile). This cost range spans across Eversource Energy's service territory—including both less dense areas and also dense urban areas. In Washington, D.C., the Executive Office of the Mayor[52] published a cost range of between approximately $380 to $950/ft in 2013 dollars (presented as $2 million/mile to $5 million/mile), equivalent to approximately $510 to $1,260/ft in 2022 dollars. Finally, in Connecticut, Eversource Energy's response to a data request from the Connecticut Office of the Attorney General in PURA Docket No. 20-08-03[53] states that the cost to replace an overhead distribution line with an underground line ranges from $1 million/mile in a rural, single-phase, lateral area to $14 million/mile in a densely populated downtown backbone area (in 2020 dollars); escalated to 2022 dollars and expressed on a per-foot basis, this range equates to approximately $220 to $3,130/ft.

Each of these independently sourced, publicly available cost benchmarks are higher than CCSF's calculated average cost of $543/ft for the underground asset RCN in San Francisco. The consistency of these independently derived benchmarks, obtained from a diverse set of

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51 Eversource, Distributed Energy Resources (DER) Project Costs (July 2022), https://www.eversource.com/residential/about/doing-business-with-us/interconnections/massachusetts/distributed-energy-resources-project-costs.

52 Mayor's Power Line Undergrounding Task Force – Findings & Recommendations, Government of the District of Columbia, Executive Office of the Mayor (Oct. 2013), https://oca.dc.gov/sites/default/files/dc/sites/oca/page_content/attachments/Power%20Line%20Undergrounding%20-%20Task%20Force%20Report.pdf.

53 Eversource Energy's response to a data request from the Connecticut Office of the Attorney General in PURA Docket No. 20-08-03 (Sep. 14, 2020), https://www.dpuc.state.ct.us/dockhistpost2000.nsf/8e6fc37a54110e3e852576190052b64d/70d21f84f88f416785258db70054eba9?OpenDocument&Highlight=0,undergrounding,cost,%2414,million.

utilities and regulatory jurisdictions with no relationship to this proceeding, provides strong corroborating evidence that CCSF's RCN materially understates the true cost of the underground electric assets serving San Francisco, and further confirms that Sargent & Lundy's calculated average cost of $1,153/ft is well within the range of undergrounding costs observed nationally.

A comparison figure and associated table illustrating the different benchmarks are both provided below.

FIGURE 3.1-7
UNDERGROUNDING COST DATAPOINT COMPARISONS (2022 DOLLARS)

TABLE 3.1-27
UNDERGROUNDING COSTS DATAPOINT COMPARISONS

Line No.	Datapoint Description	Cost ($/foot) (2022 Dollars - Converted)
1	CPUC Stated Undergrounding Cost Range – PG&E	$780 to $1,380
2	CPUC Stated Undergrounding Cost Range – SCE	$420 to $1,190
3	CPUC Stated Undergrounding Cost Range – SDG&E	$600 to $840
4	New York City (Staten Island) - Office of the Mayor	$1,980
5	New York City (Bronx/Westchester) - Office of the Mayor	$2,100
6	Massachusetts (Entire State) – Eversource Energy	$360 to $1,800
7	Washington DC – Office of the Mayor	$510 to $1,260
8	Connecticut (Entire State) – Eversource Energy	$220 to $3,130
9	1996-2006 Undergrounding Program (Adjusted to 2022)	$1,000
10	S&L Calculated Underground Assets RCN	$1,153
11	CCSF Calculated Underground Assets RCN	$543

G. Conclusion

The purpose of my testimony has been to describe the inventory of PG&E electric system assets in San Francisco considered in the RCN analysis, explain the methodology and data sources used to develop the RCN, summarize the results, and compare those results with the RCN developed by CCSF's consultant. Based on the analysis performed by the Sargent & Lundy team under my direction, it is my opinion that the RCN of the PG&E electric utility assets in San Francisco, as of the fourth quarter of 2022, is $16,001,136,000. This figure reflects a thorough, asset-by-asset evaluation across the four major asset categories—transmission, distribution, substation, and other assets—developed in close coordination with PG&E subject matter experts.

By comparison, CCSF's RCN for the same assets is $10,924,709,000, approximately $5.1 billion lower than Sargent & Lundy's result. As discussed above, the asset counts underlying both analyses were substantially aligned through the parties' 2025 workshops, so this difference is not attributable to inventory; rather, it is driven principally by differences in unit cost assumptions and scope, most notably for the conduit system and subsurface structures, where CCSF's costs do not fully capture the complexity of performing underground construction in San Francisco. For these reasons, it is my opinion that Sargent & Lundy's RCN represents a reasonable and well-supported estimate of the replacement cost new of the assets at issue, and that CCSF's lower figure understates that cost.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.2

PHYSICAL DEPRECIATION OF RCN FOR ELECTRIC SYSTEM IN SAN FRANCISCO

WITNESS: NED W. ALLIS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3.2
PHYSICAL DEPRECIATION OF RCN FOR ELECTRIC SYSTEM
IN SAN FRANCISCO
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3.2
PHYSICAL DEPRECIATION OF RCN FOR ELECTRIC SYSTEM IN SAN FRANCISCO
WITNESS: NED W. ALLIS

A. Introduction

My name is Ned W. Allis, and this chapter of my testimony supports Pacific Gas and Electric Company's ("PG&E") valuation under the Replacement Cost New Less Depreciation method ("RCNLD") of the electrical assets that the City and County of San Francisco ("CCSF")[1] seeks to take.[2] Specifically, this testimony calculates the deduction for depreciation to be applied to the RCN calculated by Sargent & Lundy to determine RCNLD, based on analyses of the vintages, remaining lives and percent good of the relevant assets. The goal of this analysis is to determine the value of the relevant assets based on the percentage of their useful life that remains (*i.e.*, how much longer they can be expected to provide service). Importantly, depreciation for purposes of RCNLD should be based on valuation concepts as part of an assessment of the overall value of the Subject Assets. As I discuss, CCSF's approach to depreciation for purposes of its RCNLD analysis incorporates several methodologies that are appropriate for purposes of regulatory accounting rather than in determining depreciation of the fair market value of the Subject Assets, resulting in CCSF over-depreciating the Subject Assets (and thereby improperly decreasing CCSF's RCNLD valuation).

This testimony[3] proceeds in five parts:

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1 For clarity and to avoid confusion, I generally refer to the governmental entity that is seeking to take PG&E's assets as "CCSF" and the geographic area in which those assets are located as "San Francisco."

2 The assets analyzed in this chapter are referred to as the "Subject Assets" and include, for purposes of this chapter, PG&E's electric assets that CCSF seeks to take other than PG&E's real estate and non-tangible assets, which are addressed in Chapter 4 (real estate) and Chapter 5 (intangible assets).

3 In addition to my testimony in this chapter, I also testify in Chapter 6 about the flaws in CCSF's testimony regarding the net book value of the subject assets.

First, I provide a summary of my overall conclusion regarding RCNLD. The RCN used in the RCNLD calculation was developed by Sargent & Lundy. Sargent & Lundy estimates approximately $16.0 billion of RCN as of the fourth quarter of 2022 for PG&E's electric assets excluding real estate and intangible assets. I use the Handy-Whitman Index to adjust the cost level of the Sargent & Lundy RCN to the July 27, 2021 valuation date, resulting in approximately $13.0 billion of RCN for those assets. I then conclude that the $13.0 billion RCN figure should be reduced by approximately $2.8 billion of physical depreciation to a $10.2 billion RCNLD figure for PG&E's tangible, non-real-estate assets.[4] The resulting overall Percent Good factor is approximately 79%, which reflects the remaining value of the Subject Assets. CCSF's approach results in a Percent Good factor of only 49%, which is further reduced to 30% based on CCSF's application of economic obsolescence. Based on my analysis, CCSF's estimates of Percent Good significantly understate the remaining value of the Subject Assets, which results in large part from CCSF's application of regulatory cost recovery concepts that do not readily apply to a valuation exercise.

Second, I provide background regarding the valuation principles underlying my analysis, focusing on: (i) the ways in which depreciation for valuation purposes differs from depreciation for accounting purposes; (ii) the methodology by which I analyze present worth depreciation, including by calculating Percent Good and remaining life for the relevant assets; and (iii) my exclusion of net salvage from my depreciation analysis and my reasons for doing so—in short, because deducting it is inconsistent with the underlying purpose of calculating depreciation in connection with RCNLD.

Third, I provide specific estimates of remaining and probable lives of the relevant PG&E assets, based on my analysis of the specific assets at issue and my preparation of an Asset Vintage and Service Life study for the relevant assets. Based on my understanding of PG&E's system in San Francisco and its system as a whole, as obtained through site visits, discussions with PG&E subject-matter experts, and analyses of service lives over the past two decades,

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4 The calculation of depreciation set forth herein is based on physical depreciation and does not incorporate functional or economic obsolescence. PG&E did not develop RCN estimates for assets that are functionally obsolete and, as a result, these are excluded from the RCNLD. Chapter 5 addresses economic obsolescence.

I conclude that CCSF's analysis understates the remaining lives of the Subject Assets. The combination of the extent of underground assets in San Francisco as well as the type of construction in San Francisco means that the probable remaining lives for the Subject Assets are longer than the probable remaining lives for PG&E's system as a whole. My recommendations appropriately consider the characteristics and remaining period over which the San Francisco assets will provide value.

Fourth, based on my analysis of remaining and probable lives, I calculate Percent Good and depreciation for the relevant assets. I conclude that the relevant assets are, as a whole, 79% good and have an approximate $2.8 billion of accrued physical depreciation, which is 21% of the RCN for these assets.

Fifth, I conclude that NewGen understates the RCNLD for the assets valued by S&L (even before applying its economic obsolescence adjustment) by approximately $5.5 billion. This difference results from differences in RCN, depreciation methodology, and estimates of vintages and remaining lives of the relevant assets. Among other flaws, NewGen: (1) improperly applies regulatory cost allocation depreciation concepts (such as the inclusion of net salvage using straight line depreciation) rather than valuation depreciation concepts; (2) unreasonably estimates remaining lives of the relevant assets (often vastly understating the remaining useful lives and remaining value of PG&E's San Francisco assets); and (3) improperly reduces RCNLD value based on net salvage, which is inappropriate in the valuation context.

As Mr. Thibodeau explains in his testimony, CCSF's RCN for PG&E's tangible, non-real-estate assets significantly understates how much it would cost to replace PG&E's San Francisco electric system. But even accepting CCSF's unduly low starting point, CCSF's flawed application of depreciation principles results in CCSF understating RCNLD by an additional $2.78 billion,[5] and CCSF further reduces RCNLD by another $1.86 billion for economic obsolescence.

The Subject Assets comprise a large network of electric infrastructure that provides electricity to one of the largest cities in the United States, with an overall average vintage of 1991 and a remaining life of 34 years. CCSF's cost

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5 Calculated as CCSF's $9.5 billion RCN times the 30% difference in Percent Good (79% for PG&E versus 49% for CCSF).

approach would reduce the value of these assets, based on RCN, by 51% as a result of depreciation. In consideration of the condition of the assets, the necessity of the service they provide, and the remaining period of time the Subject Assets will provide this service, CCSF determines too significant a reduction in value for depreciation. Instead, starting from PG&E's calculation of RCN at approximately $13.0 billion in 2021 dollars, and applying depreciation appropriately, the RCNLD value of the PG&E assets that CCSF seeks to take is $10.2 billion, excluding PG&E's real estate and intangible assets.

B. Experience and Qualifications

My name is Ned W. Allis, and my business address is 300 Sterling Parkway, Mechanicsburg, PA 17050. I am Senior Vice President of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming"), part of GFT Infrastructure, Inc. ("GFT").

At GFT, my primary duties include conducting and overseeing a variety of services to clients in the electric, natural gas, water, and railroad industries. These services include depreciation studies, valuation studies, capital planning, and advising clients on industry trends and emerging issues in the utility industry. I have presented this work before state and federal regulatory agencies and have testified in more than twenty US and Canadian regulatory jurisdictions. I am also responsible for developing and maintaining GFT's proprietary depreciation software, training depreciation staff, and developing solutions for technical issues related to depreciation. GFT has more than two decades of experience working with PG&E (referred to herein as "PG&E" or the "Company") on projects involving the estimation of depreciation, service lives, net salvage and the vintages of Company assets. As part of the depreciation studies filed with PG&E's General Rate Cases ("GRCs") and Transmission Owner rate cases ("TOs"), GFT has performed several service life studies of PG&E's transmission and distribution property, including analyses of asset vintages for particular portions of PG&E's service area and for particular time periods during its history. The first such study performed by GFT dates to PG&E's 2003 GRC, and the most recent was filed for PG&E's 2027 GRC. My involvement in these studies began with PG&E's 2011 GRC.

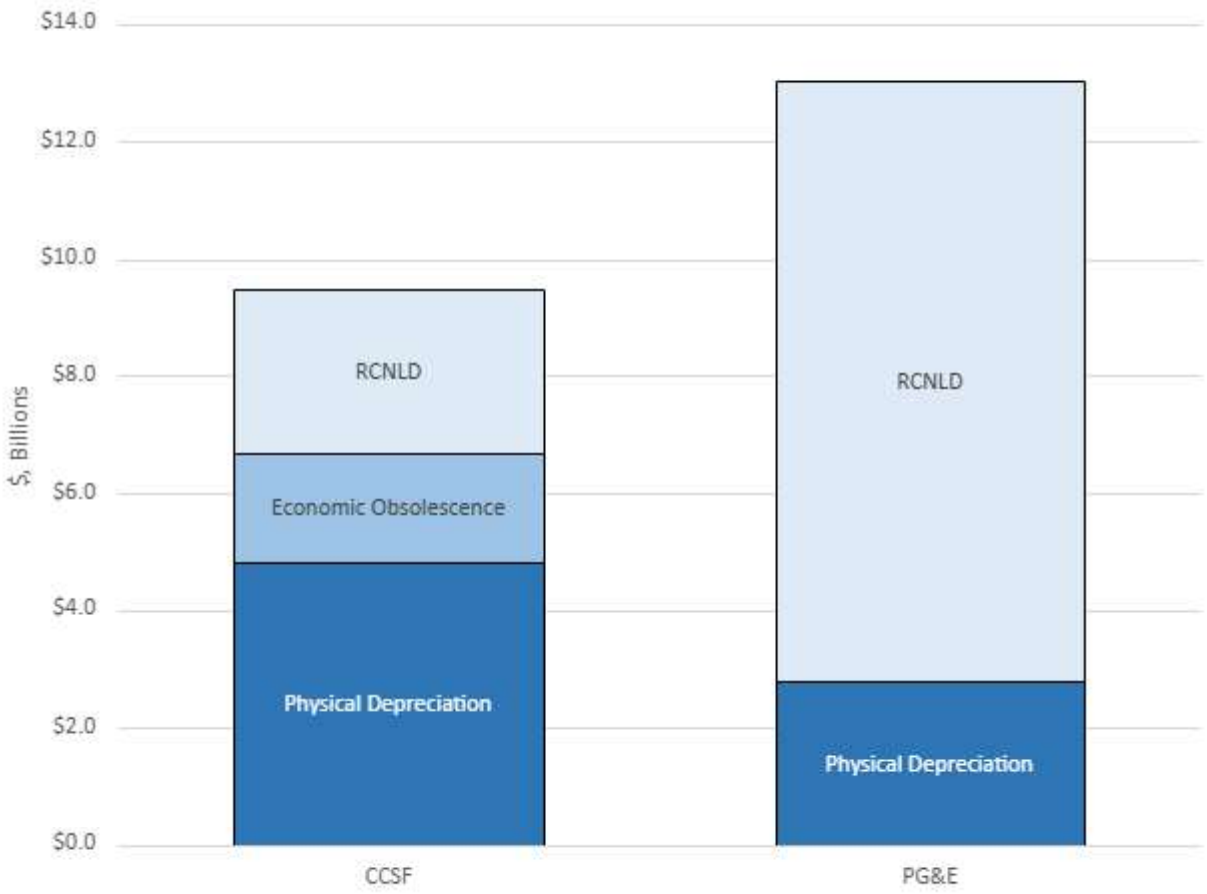
I hold a Bachelor of Science in Mathematics from Lafayette College in Easton, PA and am a Certified Depreciation Professional. Appendix 1 includes additional information regarding my relevant experience and qualifications.

For purposes of this proceeding, I led the GFT team responsible for applying depreciation and percent good concepts to translate the RCN number provided by Sargent & Lundy into an RCNLD figure for the Subject Assets at issue.

C. Summary of RCNLD

I include below a graphic summarizing the RCN, accrued depreciation, and RCNLD for the Subject Assets as calculated by CCSF/NewGen and by PG&E/GFT. In total, CCSF/NewGen calculates RCNLD of PG&E's tangible, non-real-estate assets (before adjusting for economic obsolescence) of approximately $4.68 billion, compared with PG&E/GFT's RCNLD of approximately $10.2 billion for the same assets. Please refer to the attached RCNLD, Asset Vintage and Service Life Study (Study) for a more detailed comparison of PG&E and CCSF's RCNLD and Percent Good Factors by FERC account.

FIGURE 3.2-1
COMPARISON OF CCSF AND PG&E RCNLD ANALYSIS



As noted above, the difference in PG&E's and CCSF's RCNLD values reflects both the higher RCN calculated by PG&E for these assets—$13.0 billion for PG&E in 2021 dollars versus $9.5 billion for CCSF—and the higher amount of depreciation applied by CCSF—with CCSF's calculation implying that the Subject Assets are only 49% good, while PG&E's indicates that the assets are 79% good.

The differences are especially pronounced for the transmission and distribution assets that make up the majority of the Subject Assets. For transmission plant, PG&E/GFT calculates RCNLD of approximately $1.57 billion, compared with CCSF/NewGen's $1.15 billion, and PG&E/GFT's overall Percent Good factor is 72% compared with CCSF/NewGen's 55%. For distribution plant, PG&E/GFT calculates RCNLD of approximately $8.63 billion, compared with CCSF/NewGen's $3.48 billion, with an overall Percent Good factor of 80% for PG&E compared with CCSF's 47%. These differences result from both the replacement-cost inputs and the depreciation methodology.

As discussed in the remainder of my testimony, PG&E/GFT's analysis reflects the age, service life, remaining life, and survivor characteristics of the Subject Assets based on their actual vintage and based on San Francisco-specific data regarding similar assets, while CCSF/NewGen's approach improperly relies more heavily on ratemaking rather than valuation depreciation concepts,[6] account-level calculations, and inputs that understate the remaining service potential of PG&E's San Francisco electric assets. The result is that CCSF over-depreciates PG&E's assets for purposes of CCSF's RCNLD calculation. CCSF's analysis estimates that accrued depreciation would reduce the value of its RCN by approximately half, even before accounting for its estimate of economic obsolescence. Once economic obsolescence is included, CCSF estimates that less than a third of the value of the Subject Assets remains. Based on the age, condition and utilization of the Subject Assets, this is far too low an estimate of value.

D. Background Regarding Depreciation Approach

In general terms, depreciation is the recognition that a long-lived asset loses value or usefulness over time due to use, age, wear and tear, obsolescence, or other factors. Particularly for long-lived assets, quantifying depreciation requires estimates of factors such as useful lives and remaining value. The appropriate methods and considerations when making these quantifications depend on both the characteristics of the property as well as the purpose of the quantification. Below, I discuss key depreciation principles underlying my testimony and analysis. Specifically, I provide: (1) a brief overview of the RCNLD approach to valuation; (2) a discussion of the difference between depreciation in the valuation and accounting contexts; (3) background regarding "present worth" depreciation and the percent good approach, which is the approach I use for depreciation here; (4) a summary of how Percent Good—the key input for the present-worth approach—is calculated; (5) an explanation for how Percent Good

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[6] While my testimony does not address economic obsolescence, I note that CCSF's cost approach result is identical to its income approach result, once CCSF's adjustment for economic obsolescence is considered. For both approaches, the resultant value is based on ratemaking assumptions. Dr. Williams addresses economic obsolescence in Chapter 5 and provides PG&E's ultimate RCNLD valuation.

is translated into remaining life for an asset; and (6) a discussion of the proper treatment of net salvage in calculating RCNLD.

1. The Cost Approach

The cost approach is a recognized appraisal methodology used to estimate the value of property based on the principle of substitution. Under this principle, a prudent purchaser would not pay more for an existing asset than the cost to acquire or construct a substitute asset providing equivalent utility and functionality.[7] Consistent with this principle, the cost approach begins with an estimate of the Replacement Cost New ("RCN") of the property and then deducts accrued depreciation to reflect the fact that the existing assets are not new and therefore do not possess the full service life or utility of newly constructed assets. The resulting measure, Replacement Cost New Less Depreciation ("RCNLD"), is a standard valuation metric used under the cost approach and represents the remaining value embodied in the existing assets.[8]

Importantly, the electric property in San Francisco provides an essential service. San Francisco cannot function without electric transmission and distribution infrastructure. Homes, businesses, hospitals, transit systems, government facilities, and other critical services require electric service. CCSF's depreciation methodology places substantial emphasis on concepts developed for utility regulation and cost recovery. However, the cost approach seeks to measure the value of the physical assets and their remaining service potential. The essential nature of the electric system

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[7] CCSF Witness Rabon similarly defines the cost approach as "based on the premise that an informed buyer would pay no more than the cost of producing a substitute property with the same function or utility as the Subject Property." Ex. CCSF-004C – Prepared Direct Testimony of Grant Rabon, ASA on Behalf of the City and County of San Francisco at 7:22–24 (Apr. 20, 2026) (errata May 21, 2026) ("Rabon Testimony").

[8] Decision Establishing Methods and Standards for Just Compensation and Valuation, D. 25-10-039 at 10 (Oct. 30, 2025) ("Interim Decision") provides a definition of the cost approach, including the terms RCN and RCNLD: "This approach is most relevant for unique properties. The approach involves estimating the replacement cost new (RCN) of the property and deducting all forms of accrued depreciation (RCN less depreciation or RCNLD). The Staff Proposal states that the cost approach is applicable to this proceeding in estimating the value of the part taken. However, RCNLD alone will not include business severance damages. Thus, if RCNLD is used for the whole and the remaining PG&E system after the taking, then business severance damages would need to be calculated separately."

does not depend on whether the owner is an investor-owned utility, municipal utility, or other entity. Any purchaser would require an electric system capable of providing service and would otherwise have to incur the cost of constructing such a system. Accordingly, for the cost approach, the appropriate starting point is the replacement cost of an equivalent system, adjusted for depreciation that reflects the consumed portion of the assets' service lives and remaining utility.

2. Valuation Depreciation and Cost Allocation Depreciation

The methodology used for the estimation and calculation of depreciation is a function of the purpose and context in which depreciation is calculated. In practice, there are two distinct "concepts" of depreciation that are most often measured and applied—the valuation concept and the cost-allocation (accounting) concept.

Under a cost allocation concept, depreciation is determined by allocating the cost of an asset over an adopted period in which the asset provides service. This approach is used in accounting and ratemaking, where the objective is to match the recovery of capital investment with the periods in which customers receive the benefit of that investment. Depreciation under this concept reflects the allocation or recovery of cost over a selected time period rather than a direct measure of an asset's value or remaining useful life at a particular point in time. Because the goal with an allocation concept is to account for (or recover) costs over time, depreciation is often applied in "straight line" fashion, with an asset depreciated a set amount per year regardless of its physical condition or actual remaining useful life relative to a new asset.

By contrast, under a valuation concept, depreciation measures the reduction in an asset's value relative to a new asset, based on the asset's physical condition and its actual remaining useful life. Depreciation under a valuation concept calculates the reduction in the asset's remaining service potential or the value of the future benefits that the asset is expected to provide. This approach to depreciation is therefore based on the asset's current condition and its expected future usefulness rather than on the allocation of historical cost over a pre-determined period and often does not proceed in linear fashion. This is particularly true for long-lived assets that

provide similar service each year, for which the loss in value is minimal for many years into an asset's life. For example, electrical conductor that is five years of age might in an allocation context be subject to significant depreciation, but in a valuation context might have similar value to new conductor because it is expected to remain in service over a long period of 40 years or more.

The distinction between these two concepts is important and informs the method by which depreciation is estimated and calculated. In a valuation setting, depreciation is intended to measure the loss in value from a new asset. In a ratemaking setting, depreciation is intended to allocate the recovery of investment over time. While estimation of depreciation for both may use similar inputs—such as age, service life, and expected retirement patterns—they are designed to measure different things. Cost allocation methods are appropriate when the objective is to determine depreciation expense or accumulated depreciation for purposes of rate recovery. Valuation based methods are appropriate when the objective is to estimate the current value of an asset, as is the case when performing a cost-based valuation using Replacement Cost New Less Depreciation.

The Commission's Interim Decision on valuation reflects this distinction between an allocation versus valuation approach to depreciation. The Interim Decision requires PG&E's assets to be valued under the RCNLD approach and directs that RCNLD be calculated using "accrued depreciation (not book depreciation)."[9] Book depreciation is derived from accounting conventions designed to recover cost over time. Accrued depreciation, by contrast, is intended to reflect the actual decline in value of the asset. By referencing accrued depreciation, the Commission made clear that depreciation for purposes of RCNLD should be approached using valuation rather than allocation principles.

The Commission's broader valuation framework also reinforces that depreciation is based on a valuation concept in the context of this proceeding. The decision adopts a fair market value standard, defined as the price that a willing buyer would pay a willing seller, and emphasizes that

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9 Interim Decision at 33–34.

compensation should be measured by what the property owner has lost.[10] The decision also highlights the need to consider the earning power of the property in determining value.[11] These are valuation principles that focus on the assets' current condition and ability to generate future benefits, rather than on the recovery of historical cost. A valuation approach to depreciation is most consistent with these objectives.

In light of the above, in this analysis, I apply the valuation concept of depreciation, which is consistent with measuring the remaining value of the Subject Assets rather than the recovery of historical cost. As discussed further below, NewGen applies a cost allocation concept, rather than a valuation concept, including use of straight line-based depreciation more appropriate for ratemaking purposes. This fundamental flaw renders NewGen's depreciation calculations untethered to the valuation-based depreciation approach appropriate for RCNLD.[12]

3. Present Worth Depreciation and Percent Good

To best reflect a valuation concept of depreciation, PG&E calculates depreciation by applying a Percent Good to the RCN (rather than, for example, straight line depreciation)—where the Percent Good is the percentage of an asset's replacement cost new that remains after adjusting

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10 *Id.* at 26–27.

11 *Id.* at 24.

12 NewGen then further adjusts its RCNLD for economic obsolescence to match the result of CCSF's income approach, which effectively renders CCSF's cost approach results meaningless.

for accrued depreciation. This approach is referred to as a present worth approach (also referred to as a "sinking-fund" method).[13]

Under the present worth approach, depreciation is calculated based on a Percent Good factor that represents the ratio of the present worth of the remaining service of an existing asset to the present worth of the total service of a new asset. In effect, the method compares the future benefits expected from an existing asset to the benefits expected of a new asset, with appropriate recognition of the time value of money.

The present worth method is appropriate in the valuation context because it focuses on the reduction in value or remaining service potential of an asset relative to a new asset and reflects the value of the future service that the asset is expected to provide. For this reason, Percent Good depreciation approaches derived from present worth concepts are commonly used in California for cost-based property valuation. The California Board of Equalization ("BOE") uses present worth calculations to determine the Percent Good, and the method is used for the cost approach for valuations of property in that context.

The present worth method reflects several key characteristics of utility assets, not all of which are captured by Age-Life methods or straight line depreciation:

- First, it recognizes the time value of money, such that future service provided many years from now is worth less than near term service.
- Second, it explicitly incorporates remaining life expectancy, rather than relying solely on original service life assumptions.

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[13] I note here that another method, the Age-Life Method, has also been used to determine Percent Good. This method is simpler in that the Percent Good is equal to 1 less the ratio of the age and the total life of an asset. If the chronological age is used, then the Age-Life Method is effectively the same as straight line depreciation. However, the age may be adjusted to represent the effective age of property, which can result in a higher Percent Good than would occur from a formulaic application of the Age-Life Method. The complexity of PG&E's system, the wide range and volume of assets, and the long lives of utility property present challenges in accurately applying the Age-Life method based on the condition of PG&E's property and, as discussed below, CCSF's attempt to use a modification of this method produces results that diverge significantly from the condition and remaining utility of different asset classes. The calculation of Percent Good factors using Present Worth Depreciation and statistical survivor curves better determines the remaining value of PG&E's assets.

- Third, it reflects the fact that utility assets retire over a range of ages, as represented by survivor curves, rather than at a single deterministic life.
- Finally, it reflects that, because electric assets such as poles, wires and substation equipment have long lives, relatively new assets would have a similar value to brand new assets because both will provide many decades of essentially the same utilization.

These features are particularly important for determining the value of long lived electric utility assets, such as transmission and distribution infrastructure, where assets may remain in service for decades beyond their average service life and continue to provide reliable service.

Accordingly, in this analysis, accumulated depreciation for purposes of calculating RCNLD is based on the present worth (Percent Good) method.

4. Calculation of Percent Good Factors

The present worth method requires determining the Percent Good Factor for the relevant assets and depreciating them based on that figure. The Percent Good Factor represents the percentage of remaining value of an asset after adjusting for depreciation. The Percent Good is equal to the following:[14]

$$\boldsymbol{Percent\ Good} = \frac{(\mathbf{1}+\boldsymbol{r})^{\boldsymbol{PL}} - (\mathbf{1}+\boldsymbol{r})^{\boldsymbol{a}}}{(\mathbf{1}+\boldsymbol{r})^{\boldsymbol{PL}} - \mathbf{1}}$$

Where a is the Age, PL is the Probable Life (also referred to as Total Life) at age a, and r is the discount rate. GFT uses a discount rate of r = 4.25%, which is the published rate of return for Percent Good calculations for the Board of Equalization.

A related value, the Present Worth Depreciation Factor (PWD), is equal to:

$$1 - Percent\ Good$$

[14] These formulas, along with additional discussion of their derivation, are discussed in detail in the BOE's California Assessors' Handbook Section 582.

The RCNLD of a particular asset can be calculated using the following equivalent formulas:[15]

$$\boldsymbol{RCNLD = C \times Percent\ Good}$$

$$RCNLD = C \times (1 - PWD)$$

Where C is the cost of a new asset or group of assets.

To illustrate, assume that a vintage of distribution conductor has RCN of $100,000, a probable life of 50 years at the valuation date, and an age of 10 years. Using a 4.25% discount rate, the Percent Good factor is 92.6%.

Percent Good = [(1.0425)^50 - (1.0425)^10] / [(1.0425)^50 - 1] = 92.6 percent

RCNLD is then calculated by multiplying RCN by Percent Good: $100,000 x 92.6% = approximately $92,639. The corresponding accrued depreciation is approximately $7,361.

5. Determination of Remaining Life and Probable Life Using Iowa Curves

As discussed above, one of the key inputs for the present worth method (and in particular, the Percent Good factor) is the "probable life" of a particular asset. An asset's probable life (i.e., its total expected useful life) equals the asset's remaining life plus the current age of the asset.

Probable Life at Age a = Age a + Remaining Life at Age a

Determining an asset's probable life therefore requires two steps—first, determining the asset's "remaining life" at a particular age and then adding that remaining life figure to the asset's current age to calculate the asset's probable life.

Depending on the type of assets studied, there are different methods of calculating an asset's remaining life. Both NewGen and I have used Iowa type survivor curves[16] to apply to groups of property such as poles, wires,

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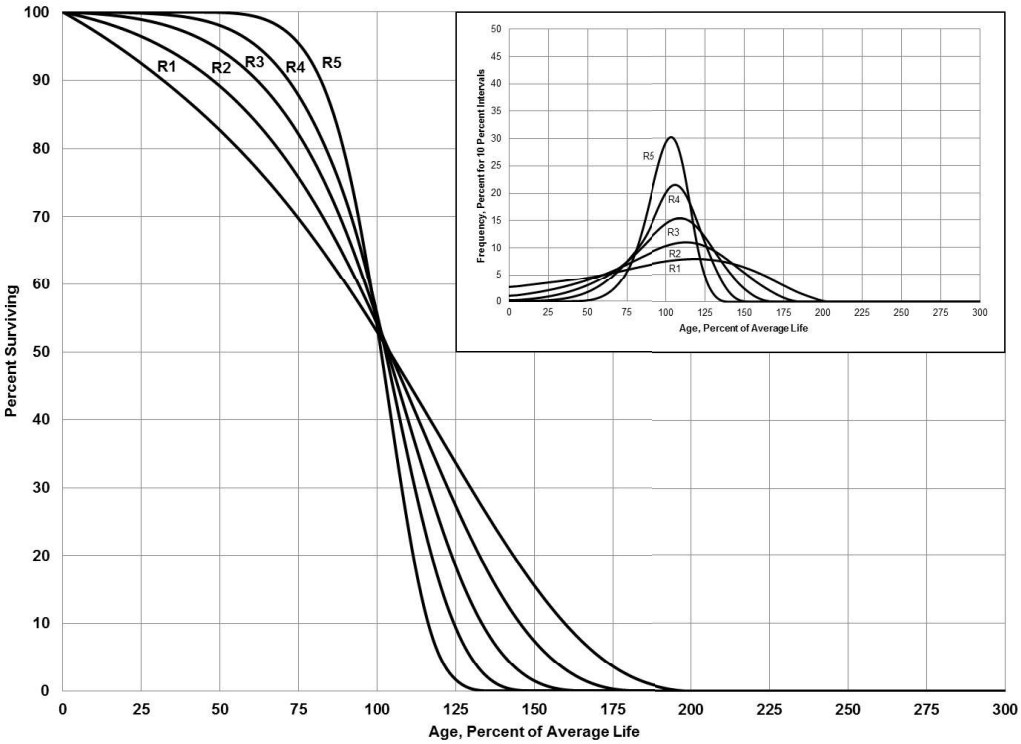
15 For reasons discussed further below, net salvage is not normally used to calculate value for the Cost approach. Net salvage factors must be appropriately applied, particularly if estimated based on Original (or Historical) Cost rather than Replacement Cost.

16 These curves are named for the school, Iowa State College (n.k.a. Iowa State University), where the original research was conducted in the 1930s.

and substation assets. Iowa type survivor curves are widely used in utility depreciation analysis. They provide a means by which to estimate the range of lives for groups of property that experience a range, or dispersion, of service lives and can therefore be used to reasonably estimate remaining lives and probable lives. For Iowa type survivor curves to be accurate, they must appropriately consider the assets studied and the application for which they are used.

Iowa survivor curves are developed by analyzing historical retirement experience for groups of similar utility assets, plotting the percentage of original assets that remain in service at each age, and selecting the standardized Iowa curve whose shape and average service life best fit that observed survivor pattern. An Iowa curve thus represents the probability distribution of asset retirements over time for a given asset group. Rather than assuming that all assets retire at a single age, the Iowa curve reflects that assets are retired over a range of ages, with some assets retiring earlier and others remaining in service well beyond the average service life. This distributional approach provides a more realistic representation of how utility assets behave in service and provides a direct linkage between asset age, survival characteristics, and remaining service potential, tying the value of an asset to the expected pattern and timing of its future service. I include below an example of the R-type Iowa curves, with the x-axis representing asset age and the y-axis representing percentage of the asset surviving at each age interval.

FIGURE 3.2-2
EXAMPLE OF IOWA CURVE



For a given asset group, the selected Iowa curve provides an original average service life, based on the mean of the full retirement distribution.

Iowa curves can also provide the expected remaining life of assets that have reached a given age—*i.e.*, the expected *future* service period of the assets conditional on those assets having survived to their current age—which is the relevant measure for purposes of estimating depreciation in a valuation context. This value is derived directly from the portion of the Iowa survivor curve beyond the current age of the assets being analyzed and is equal to the area under the survivor curve from that age to the maximum life of such assets, divided by the percent surviving at that age. That calculation is shown below:

Remaining Life at Age a = (area under the survivor curve after age a) / (proportion of the asset group surviving at age a)

Conceptually, the remaining life value represents the average of the future service periods reflected in the survivor curve, weighted by the probability of survival at each future age.[17]

Once remaining life has been calculated using survivor curves, as discussed above, probable life of an asset is calculated as the sum of the current age of an asset and the asset's remaining life. This measure represents the expected total service life of assets that have survived to the valuation date. Because it is conditioned on survival to the current age, the probable life of a given asset at a particular age may differ from the original average service life of the asset group, particularly for older vintages that have already demonstrated survival beyond the average service life. Put simply, assets that have already survived for a long period of time can often reliably be expected to continue operating beyond the average service life of such assets.

6. Determination of Asset Age

The other key input for the present worth method of depreciation is the present age of an asset. The age of an asset both underlies the remaining life calculation (because it informs the inputs to the survivor curves) and the probable life calculation (because it is added to remaining life to determine an asset's probable life). Age can be determined in a variety of ways, such as based on installation records, site visits, or statistical methodologies based on available data. All of the methodologies endeavor to determine the date that an asset went into service, so that it can be determined how long it has been in service (if it remains in service) or how long it remained in service (for retired assets). As discussed below, GFT conducted an extensive asset vintage study focused on the assets at issue in this proceeding to determine the present age of the relevant assets.

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17 The application of Iowa survivor curves to the calculation of RCNLD assumes the Subject Assets are in-service and contributing to the delivery of electric service. To the extent certain assets are functionally obsolete (*e.g.*, legacy underground segments abandoned in place, bypassed, or otherwise no longer providing utility), these assets were not included in the vintage analysis or the RCNLD calculations.

7. Treatment of Net Salvage in RCNLD

My approach to depreciation for purposes of RCNLD does not include net salvage in the calculation of accumulated depreciation. Doing so provides a more appropriate measure of RCNLD in this analysis and allows the resulting depreciation to better reflect the current condition and remaining service potential of the Subject Assets, consistent with the purpose of the cost approach in estimating fair market value.

The net salvage that will be experienced by the Subject Assets is not relevant in the RCNLD context. As discussed above, depreciation in an RCNLD context is intended to reflect the loss in value associated with physical deterioration, functional obsolescence, and economic obsolescence. These forms of depreciation arise from changes in the condition, usefulness, or economic environment of the assets. Net salvage, by contrast, represents the expected cost or proceeds associated with the retirement of an asset at the end of its service life, including costs of removal and any associated salvage value. Accordingly, net salvage is not a measure of the current condition or service capability of the asset, but rather a future cost obligation associated with its eventual disposition. Moreover, cost of removal and salvage value for most of the studied assets will occur as replacement projects, rather than decommissioning projects. Future replacement costs are not included in a measure of current value. Instead, they are part of the future operation of a utility that will remain a going concern.

This treatment of net salvage is consistent with the purpose of an RCNLD analysis, which is to estimate the current value of existing assets based on their remaining service potential, rather than to measure the full life cycle cost of owning and retiring those assets. Because net salvage does not reflect a reduction in current service potential, its inclusion in accrued depreciation would not be consistent with the objective of measuring the remaining value of the asset in its current state. Instead, including net salvage in depreciation effectively adjusts the RCNLD result for costs that are expected to be incurred in the future associated with continued operation as a going concern, in many cases decades after the

valuation date, and costs that do not directly affect the asset's present ability to provide service.

This treatment is also supported by the Percent Good depreciation framework described in the California Assessors' Handbook and applied here.[18] Under that framework, RCNLD is generally calculated by applying a Percent Good factor to RCN, where the Percent Good factor reflects the remaining service value of the asset. In this formulation, net salvage is not a required component of the calculation, and the exclusion of net salvage is consistent with the application of Percent Good factors to estimate value based on remaining service potential.

The exclusion of net salvage from RCNLD is also consistent with the distinction between valuation and depreciation accounting. In depreciation studies prepared for ratemaking purposes, net salvage is typically incorporated into depreciation rates to ensure recovery of total life cycle costs over time. However, depreciation studies are based on a cost allocation objective, not a valuation objective. In a valuation context, the relevant question is not the total cost that will ultimately be incurred over the life of the asset, but rather the value of the remaining service that the asset is expected to provide as of the valuation date. Including net salvage in an RCNLD calculation would therefore mix these two distinct concepts by incorporating a future cost recovery element into what is intended to be a measure of current value. This would tend to overstate accumulated depreciation and understate the value of assets, particularly for long lived electric assets for which removal costs are incurred far in the future and subject to significant uncertainty.

For these reasons, I have excluded net salvage from my depreciation calculation.

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18 California State Board of Equalization, *Assessors' Handbook Sections 502 (Advanced Appraisal), 582 (The Explanation of the Derivation of Equipment Percent Good Factors*), https://www.boe.ca.gov/proptaxes/pdf/ah502.pdf, https://www.boe.ca.gov/proptaxes/pdf/ah582.pdf

E. Estimation of Remaining Lives, Asset Ages, and Probable Lives for the Subject Assets

1. Introduction

As discussed above, the calculation of present worth depreciation is based on the age, remaining life, and probable life of assets included in the valuation. GFT performed a study—the RCNLD, Asset Vintage and Service Life Study—to determine these inputs for the calculation of present worth depreciation. The Study developed both (i) the vintage years (and therefore age) of the Subject Assets; and (ii) the service lives of the Subject Assets. Based on the study, GFT determined the age, remaining life, and probable life for all of the Subject Assets. The Study is attached hereto and incorporated into my testimony by reference.

GFT conducted its study by grouping the assets into homogeneous asset categories and vintages (a.k.a., installation years). As described in detail below, GFT determined vintage years for relevant asset categories based on PG&E records and other relevant data and information, and then prepared estimated survivor curves applicable to each relevant asset category, based on City-specific information relating to those assets and other factors that will affect the remaining physical life of the assets.

I provide an overview of the study and its results below, by (1) cataloging certain key aspects of the Subject Assets relevant to the Asset Vintage and Service Life Study; (2) discussing the methodology and data sources used for purposes of the study; and (3) summarizing the results of the study.

2. Overview of the Subject Assets

The Subject Assets consist of the PG&E electric transmission and distribution equipment in and serving San Francisco as well as assets in or connected with the Martin Substation in San Mateo County. Chapter 2 of PG&E's testimony provides additional detail regarding the Subject Assets. I provide below a brief discussion of the Subject Assets, focusing on aspects of PG&E's system particularly relevant to my analysis.

- The Subject Assets include approximately 67 circuit miles of 115 kV or 230 kV transmission lines, over 95% of which are underground.

- The Subject Assets include 32 substations, 28 of which are indoors or partially indoors, and three of which have been upgraded with gas-insulated switchgear to enhance safety, decrease equipment deterioration over time, and save space in San Francisco's dense urban environment.[19]
- The Subject Assets include PG&E's San Francisco electric distribution system; measured by conductor length, approximately 65.48% of PG&E's San Francisco distribution system is underground.
- The underground distribution system serving downtown—originally built in the 1920s and 1930s and upgraded over time—employs some radial assets but consists largely of a network system with built-in redundancy to meet the higher reliability needs in this densely populated area. PG&E's radial assets use more varied types of construction and materials than PG&E's network system, with much of the radial system installed more recently than the network system.
- Most overhead distribution assets in San Francisco are on wood poles, but several of the forces of retirement that affect poles and other overhead assets in PG&E's broader service area—such as moisture, snow, and wildfires—are not as pronounced for PG&E's San Francisco assets.

The asset records show a wide range of cost-weighted vintages. For example, GFT's weighted-average installation years are 1972 for transmission underground conduit, 1976 for transmission underground conductors, 1992 for distribution underground conduit, and 2000 for distribution underground conductors.

3. Asset Vintage and Service Life Study

This section describes GFT's data and methodology for estimating asset vintage and service life and summarizes the results of the Study, which is attached to and incorporated by reference into my testimony. GFT's Study has two key components related to the age and expected lives of the Subject Assets—an asset vintage study that estimated the installation dates

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[19] Of PG&E's 32 substations, 31 reside within San Francisco, and one—Martin Substation—resides in San Mateo County.

of the Subject Assets, and a service life study that estimated the service lives for each property group.

a. Data Sources

GFT analyzed multiple sources of data and information pertaining to the Subject Assets serving San Francisco as well as PG&E's system as a whole to determine the most reasonable approach for the estimation of vintage and service life as to each category of assets. In undertaking that analysis, GFT leveraged its two decades of experience working with PG&E on projects involving estimation of the vintages and service lives of Company assets, including several depreciation studies prepared in connection with GRCs and TO filings, and GFT also considered the differences in construction of electric systems in San Francisco and electric systems in suburban or rural areas. For San Francisco's downtown network system, for instance, conductor is installed in ducts, and 98% of transformers and network protectors are installed in vaults. These characteristics support a longer service life for the San Francisco located assets than for PG&E's system as a whole, which has a higher percentage of underground conductor that is direct buried or installed with PVC conduit.

The specific data sources and methodologies used in GFT's evaluation of asset vintage and service life included extensive examination of, among other data sources, the following:

1. PG&E's Geographic Information System database ("GIS") and substation asset registry database ("SAP") as of August 2022. These databases track the inventory and conditions of PG&E's electric system assets.
2. Historical accounting records from PG&E's balances for assets serving San Francisco.
3. Site visits, including those from the Asset Vintage and Service Life Study and from prior depreciation studies, as well as additional discussions with PG&E subject matter experts.
4. Historical accounting records and depreciation study data for PG&E's system as a whole.

5. San Francisco-specific actuarial analyses of available retirement and surviving-plant data, supplemented by the City's asset records and operational information.
6. Industry-standard Iowa type survivor curves used to classify the ages at which utility and industrial property have been retired.
7. Broader industry data regarding company practices and service life estimates for electric utilities in the United States.
8. GFT's decades of experience estimating service lives for depreciation studies.

More detailed explanations of the data sources relied upon can be found in the Study.

The extent and type of data available from each source varied as a function of historical record-keeping and accounting practices. As an example, PG&E, like other California utilities, historically did not maintain the vintage years of retirements in its accounting records used for depreciation studies. Instead, for many years, service life analyses for California depreciation studies were based on the Simulated Plant Record method of analysis, which does not use vintage years of retirements.[20] Due to such historical practices, it is common in the industry for vintage years to differ between GIS and SAP databases, historical accounting records, and other engineering or operational systems.

GFT factored these variations between data sources into its estimates of both vintages and service lives for the Subject Assets. Generally, for the purpose of the RCNLD calculations, the GIS data were given the most consideration for the asset vintage study, and other data sources were used to supplement the GIS data when vintage years were unavailable. When, for certain types of assets, available information from the GIS data on vintage year was limited, GFT estimated vintage based on other data sources, such as PG&E's known historical capital additions or conversations with subject matter experts.

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20 The Simulated Plant Record (SPR) method is used when vintage year data is not available and allows for fitting of survivor curves to unaged data for which vintage years are not known.

With respect to its service life estimates, GFT also considered prior PG&E service life studies conducted for GRCs as a useful reference for its analysis. Because PG&E's service life studies have historically been performed for its service area as a whole, rather than by city or county, GFT also conducted additional actuarial analyses on available data that was specific to PG&E's assets in and serving San Francisco.

b. Asset Vintage Methodology

GFT then applied a rigorous methodology to confirm and, as needed, estimate the installation dates of the Subject Assets. GFT's approach combined statistical methodologies, various data sources, site visits, information from PG&E's subject matter experts, and GFT's knowledge of electric transmission and distribution assets obtained through depreciation and valuation studies performed for PG&E and utilities across the country.

The following summarizes the methodology used to determine reasonable vintages for the Subject Assets:

1. Installation dates that were known and available from PG&E's GIS and SAP databases remain unchanged for the present study. Conversations with Company subject matter experts, site visits, and our overall experience and knowledge of PG&E's system confirmed the reasonableness of these known vintages. Overall, the GIS and SAP data as of August 2022 included vintage information for approximately 39% of the asset quantity records.
2. In cases where the GIS and SAP data as of August 2022 provided a substantial proportion of known vintages for a specific asset class, such as for distribution poles, GFT used the data from GIS and SAP as the primary basis to estimate the vintages of the unknown assets. The known vintages served as reliable proxies to be used to estimate vintages for the unknown assets, which were determined in proportion to the vintage distribution of known assets.

3. For assets with unknown vintages in categories where the GIS and SAP data did not provide a sufficient proxy for the vintages of assets, one of the following approaches was employed:
    a. Ages were estimated in proportion to a reasonable proxy (*e.g.*, unknown overhead services were allocated in proportion to San Francisco's distribution of known meter installations, based on the reasonable assumption that services tend to be installed at the same time as meters);
    b. Vintages were statistically assigned in proportion to the known PG&E San Francisco electric system's surviving plant balances by vintage as of July 27, 2021;
    c. Vintages were statistically assigned in proportion to the known PG&E historic capital additions; or
    d. Vintages were assigned consistent with information obtained from site visits and/or conversations with Company subject matter experts.

The specific approach varied for each type of asset. A more detailed description of the process and considerations for each asset class can be found in Parts V, VI and VII of the attached Study.

c. Service Life Methodology

GFT also estimated service lives of the relevant asset categories at issue. An asset's service life is the total amount of time that the asset will remain functional before it fails or deteriorates beyond use. Put another way, an asset's service life in the context of an RCNLD is the theoretical maximum lifespan of the equipment, assuming no external factors force its removal.

To estimate service life expectations for the Subject Assets, GFT evaluated (i) the currently authorized service life estimates for

ratemaking in the Commission's 2020 GRC decision;[21] (ii) the results of the asset vintage study; (iii) statistical analyses of PG&E's historical accounting records; (iv) PG&E management's plans, policies, and outlook; (v) general knowledge of the property studied; and (vi) general knowledge of the electric utility industry, including service life estimates from GFT's studies of electric systems comparable to PG&E's San Francisco system.[22] We also took into account historical replacement and retirement behavior for similar assets where records were available, engineering and operating considerations that drive replacement timing, the reasons for past retirements, the expected causes of future retirements, and San Francisco-specific conditions observed during site visits and discussed with PG&E subject matter experts, which provided insight into the function of the Subject Assets.

PG&E filed its 2023 GRC on June 30, 2021, approximately one month prior to the valuation date. The 2023 GRC included a depreciation study I conducted, with service life estimates based on the most recent data available at that time. While the estimates from the 2023 GRC had not yet been evaluated by the CPUC at the time of the valuation date, the service life estimates in the 2023 GRC depreciation study and supporting analysis for that study are reasonable considerations when estimating the service lives of the Subject Assets.

Based on these service life expectations, GFT estimated survivor curves for each asset class—depictions of service life which provide the percentage of each vintage expected to survive at successive ages.

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21 At the time of the valuation date, the service lives adopted in the 2020 GRC were in effect and the 2023 GRC depreciation study had been recently filed. Subsequent to the valuation date, the Commission extended service lives for a number of accounts from those in the 2023 GRC study and those adopted in the 2020 GRC. Because the service lives used for the RCNLD are developed to be applicable as of the Petition date, the 2023 Decision and PG&E's proposed service lives in the 2027 GRC were not considered when estimating service lives for the Subject Assets. However, if consideration were given to subsequent depreciation studies and Commission decisions, the result would be to reduce depreciation and increase the RCNLD.

22 Based on GFT's experience, two of the more comparable electric systems to PG&E's urban radial and network configuration are those employed by Consolidated Edison Company of New York and Commonwealth Edison. GFT has conducted depreciation studies for both companies. However, it is important to note that no two systems are identical.

GFT did so by analyzing historical data for PG&E's assets through the use of widely-accepted techniques, such as the retirement rate method of analysis;[23] incorporating information from PG&E depreciation studies, meetings with subject matter experts, site visits and knowledge of service life characteristics for similar assets across the industry; and forecasting the survivor characteristics for each depreciable asset group on the basis of interpretations of the historical data analyses and the probable future expectations. This combination of historical data and estimated future expectations yielded industry-standard Iowa type survivor curves, which encompass the range of survivor characteristics usually experienced by utility and industrial properties. The survivor curve estimates were then used to derive average service lives, remaining lives, and probable lives for certain asset classes among the Subject Assets.

d. Results

The above analyses resulted in two outputs—asset vintages for the relevant asset categories and service life estimates for those asset categories. The results as to both asset vintages and service lives are described briefly below and more fully in the attached Study.

1) Asset Vintage Study Results

Overall, 39% of asset vintages were known. Asset classes for which most vintages were not available in the GIS and SAP databases were primarily underground assets or overhead wire. Most vintages were also unavailable in these databases for smart meter devices, street lighting, and transmission substation structures. Overall, the RCN weighted average vintage from PG&E's analysis is 1991, which is four years newer than the same weighted average age calculated for CCSF's analysis (i.e., under PG&E's analysis, assets are on a weighted-average basis four years newer than CCSF determined). A comparison of the weighted

[23] The retirement rate method (also known as the annual rate method) is an actuarial method of deriving survivor curves based on the average rates at which property within a particular asset class is retired during a period of observation within historical data. This method is described in further detail in the attached Study.

average vintage for each FERC Account is shown in the table below.

TABLE 3.2-1
ASSET VINTAGE RESULTS

Line No.	Account	Asset Description	NewGen	PG&E
1	**TRANSMISSION**			
2	352.00	Structures and Improvements	n/a	1955
3	353.00	Station Equipment	2009	2006
4	354.00	Towers and Fixtures	n/a	1948
5	357.00	Underground Conduit	1981	1972
6	358.00	Underground Conductors and Devices	1988	1976
7				
8	**DISTRIBUTION**			
9	361.00	Structures and Improvements	n/a	2004
10	362.00	Station Equipment	2001	1997
11	364.00	Poles and Fixtures	1964	1979
12	365.00	Overhead Conductors and Devices	1985	1986
13	366.00	Underground Conduit	1994	1992
14	367.00	Underground Conductors and Devices	1999	2000
15	368.01	Line Transformers – Overhead	2001	2004
16	368.02	Line Transformers – Underground	1998	1999
17	369.01	Services – Overhead	2003	1974
18	369.02	Services – Underground	1995	1974
19	370.00	Meters	2012	1997
20	370.01	Meters – AMI	n/a	2012
21	373.03	Street Lighting and Signal Systems	2018	2017
22				
23	**GENERAL**			
24	397.08	Communication Equipment	2000	2000

2) Service Life Results

The table below provides a comparison of GFT's service life estimates for the Subject Assets, categorized by asset type, to those from the 2020 GRC that are applicable to PG&E's system as a whole. Additional details are provided in the Asset Vintage and Service Life Study.

TABLE 3.2-2
SERVICE LIFE RESULTS

Line No.	Account	Asset Description	NewGen	PG&E
1				
2	**TRANSMISSION**			
3	352.00	Structures and Improvements	n/a	75-R2
4	353.00	Station Equipment	46-R2	47-R2
5	354.00	Towers and Fixtures	75-R4	75-R4
6	357.00	Underground Conduit	65-R4	70-S1
7	358.00	Underground Conductors and Devices	55-R3	55-R1
8				
9	**DISTRIBUTION**			
10	361.00	Structures and Improvements	n/a	70-R3
11	362.00	Station Equipment	46-R1.5	50-R1
12	364.00	Poles and Fixtures	44-R2	50-S1.5
13	365.00	Overhead Conductors and Devices	46-R2	50-S1.5
14	366.00	Underground Conduit	65-R4	70-R3
15	367.00	Underground Conductors and Devices	50-R3	55-S0.5
16	368.01	Line Transformers – Overhead	32-R2.5	32-R2.5
17	368.02	Line Transformers – Underground	33-R2.5	34-R2.5
18	369.01	Services – Overhead	55-R2.5	55-R2.5
19	369.02	Services – Underground	50-R4	55-R2.5
20	370.00	Meters	20-R2	30-R1.5
21	370.01	Meters – AMI	n/a	20-R2
22	373.03	Street Lighting and Signal Systems	25-L0	25-L0
23				
24	**GENERAL**			
25	397.08	Communication Equipment	20-SQ	15-SQ

For many asset classes, the service lives for PG&E's San Francisco system are expected to be similar to PG&E's system as a whole. However, for some asset classes such as underground conductor, different service lives are estimated. For example, a higher percentage of underground assets in San Francisco are network assets with duct and manhole construction than in the system as a whole and, therefore, the assets in this asset class in San Francisco will have different service life characteristics than the system as a whole. Substations have different construction configurations in the city and poles are less impacted by factors such as wildfires. Due to the differences, as well as consideration of

the ages of the assets studied, for some asset classes the survivor curves for the Subject Assets differ from those for PG&E's system as a whole. Each estimate is discussed in more detail in the Study.

F. Calculation of Percent Good and Depreciation

1. Application of Age, Remaining Life and Probable Life to Percent Good

Using the results of the asset vintage and service life studies as inputs, GFT then calculated depreciation under the present-worth depreciation method. Based on my review of the available data, condition of assets, and general knowledge of the system, the application of survivor curves provides a reasonable basis to determine the Percent Good for the Subject Assets. The Subject Assets comprise a large number of individual assets that are part of a larger system, which lends itself to the use of statistical techniques to determine remaining and probable lives for each asset class. However, the survivor curves used to determine probable lives need to align with the ages and current expectations of the Subject Assets.

The process of applying the present-worth depreciation method involved six steps.

First, GFT adjusted the RCN to the valuation date. Sargent & Lundy developed its RCN estimates at fourth-quarter 2022 cost levels. GFT adjusted those estimates to the July 27, 2021 valuation date using the applicable Handy Whitman Index for each utility plant category.[24]

Second, GFT determined remaining lives for each vintage of assets in the relevant asset categories. GFT did so based on the estimated Iowa survivor curves for each vintage of assets and applying the estimated survivor pattern for that asset group to estimate the expected remaining life of assets that have survived to that age.[25] GFT performed the calculation of

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24 CCSF followed the same general process, adjusting its end-of-2022 RCN estimates to July 27, 2021 using Handy Whitman. Accordingly, there is no material disagreement regarding the need to state RCN at valuation date cost levels or the general use of account-specific escalation indexes.

25 Specifically, remaining life was calculated as the area under the applicable survivor curve after age a, divided by the percentage of the original vintage surviving at age a. The resulting value represents the average future service period indicated by the survivor curve for assets that have remained in service through the valuation date. This differs from the average service life of the original asset group, which reflects the full distribution of retirements beginning at age zero.

RCNLD at the vintage level because the age, remaining life, probable life, and Percent Good factor differ by vintage.

Third, after determining remaining life, GFT determined the probable life for each vintage within each asset category by adding together the age of the vintage and its remaining life. "Probable life at age" therefore represents the expected total service life of assets that have survived to their current age. Depending on the selected Iowa curve and the age of the vintage, probable life at age may differ from the asset category's original average service life. For some older surviving vintages, the conditional probable life may exceed that original average life because the calculation reflects the vintage's survival beyond its life expectancy at age zero.

Fourth, GFT used each vintage's age and probable life to calculate its Percent Good factor under the present-worth formula used in this analysis:

$$Percent\ Good = \frac{(1+r)^{PL} - (1+r)^{a}}{(1+r)^{PL} - 1}$$

The Percent Good factor expresses the present worth of the vintage's remaining service relative to the present worth of the service associated with a new asset having the same probable life assumption. In practical terms, the factor identifies the portion of replacement cost associated with the vintage's remaining service potential under the selected present-worth method. The complementary factor, one minus Percent Good, represents the depreciation indicated by that method.

Fifth, GFT applied the Percent Good factor to the RCN assigned to each vintage:

$$Vintage\ RCNLD = Vintage\ RCN \times Vintage\ Percent\ Good$$

GFT performed this calculation for each vintage within each asset category and then summed the resulting vintage-level RCNLD amounts to determine the category total. For vintages for which the Percent Good was calculated to be less than 10%, GFT applied a floor of 10% to the specific

vintage. This recognizes that assets currently in service have a minimum remaining service value.[26]

Sixth, after GFT calculated and summed the vintage-level RCNLD values for each asset category, the category-level RCNLD values were aggregated to determine the total RCNLD for the Subject Assets.

The resultant RCNLD incorporates the impact of physical depreciation and represents value prior to accounting for any functional or economic obsolescence.

2. RCNLD for San Francisco Assets

Table 3 summarizes the RCNLD calculations for the Subject Assets, which is, in total, $10.24 billion. This amount is calculated using S&L's RCN and the ages and survivor curves discussed in Section E.

TABLE 3.2-3
SUMMARY TABLE OF PG&E RCNLD ($, MILLIONS)

Line No.	FUNCTION	RCN (2021$)	DEPR.	RCNLD	PERCENT GOOD FACTOR
1	TRANSMISSION	2,170.7	598.1	1,572.6	72%
2	DISTRIBUTION	10,815.4	2,183.7	8,631.7	80%
3	GENERAL	8.6	7.8	0.9	10%
4	SPARES	34.1	0.0	34.1	100%
5	**TOTAL PG&E**	**13,028.9**	**2,789.6**	**10,239.3**	**79%**

G. Key Differences With CCSF's Analysis

In addition to developing estimates of asset vintages, service lives, and accumulated depreciation, GFT reviewed similar work product produced by CCSF. GFT provides below a comparison of its results to CCSF's and analysis of various flaws in CCSF's analysis.

PG&E's RCNLD for PG&E's electric assets valued by S&L, of $10.2 billion, is $7.4 billion higher than CCSF's RCNLD of $2.8 billion for the same set of

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26 CCSF also applied a floor of 10% in calculations of depreciation, although it did so at the asset class level rather than the vintage level. As discussed further below, application of a floor at the vintage level is more appropriate and reasonable than CCSF's application at the asset class level.

assets. $1.9 billion of this is due to CCSF's estimate of economic obsolescence. There are several additional key differences:

- PG&E's RCN of $13.0 billion for PG&E's non-real-estate assets is $3.5 billion higher than CCSF's RCN of $9.5 billion for those same assets.
- PG&E's RCNLD does not include a deduction for future net salvage.
- PG&E's RCNLD uses Present Worth rather than Straight Line Depreciation.
- PG&E's estimated remaining and probable lives are better aligned with the Subject Assets, both due to better estimates of vintage years and more reasonable estimates of survivor curves that better represent the Subject Assets.

I provide additional detail on some of the key differences between PG&E's and CCSF's analyses below. To begin, I provide below a comparison of the results of GFT's and CCSF's asset vintage and service life studies. The vintage years and survivor curve estimates are inputs into both PG&E's and CCSF's calculations of depreciation. For the reasons discussed below, PG&E's estimates of both vintages and service lives are more reasonable than those of CCSF. At a high level, for certain asset classes, CCSF applies vintages that are older than the data support (claiming assets are older than they are and thereby unduly depreciating them) and uses in its analysis service lives that are unduly short (particularly for assets like those in San Francisco that are operating in an urban environment and often underground).

I then discuss methodological differences between PG&E's and CCSF's calculations of physical depreciation. Differences in the methods of calculating Percent Good factors and the inclusion of net salvage account for further differences between PG&E's and CCSF's cost approach results, with CCSF's methods producing too high of depreciation.[27]

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[27] Neither PG&E nor CCSF estimate material functional obsolescence that would be separate from physical depreciation. CCSF's estimate of economic obsolescence is addressed in more detail by Dr. John Williams of EPS in Chapter 5.

1. Comparison with the Vintage and Service Life Estimates Prepared by CCSF

a. Asset Vintage Comparison

Table 3-1, above, provides a comparison of average ages for NewGen and PG&E. For some asset classes, such as distribution station equipment, underground conduit, and underground conductors and devices, the average vintage year developed by GFT is the same or relatively similar to the vintage developed by NewGen. For other asset classes, such as distribution overhead conductors and devices and transmission underground conduit, GFT's estimated vintage years are older than those estimated by NewGen. Finally, for a number of asset categories, NewGen's vintage estimates are significantly older than GFT's vintages, such as distribution poles, towers, and fixtures.

One of the categories with the most pronounced difference in the vintage estimated by GFT as compared to NewGen is Account 364, distribution "Poles, Towers, and Fixtures." NewGen's analysis includes an average vintage year of 1964, meaning NewGen's calculations assume that, on average, poles were 57 years old in 2021. GFT's analysis, by contrast, results in a dollar-weighted average vintage year of 1979 and thus an average age of 42 years old.

GFT's estimation is more reasonable than NewGen's, particularly when considered in context of NewGen's estimated average service life for this account. NewGen's 44-year average service life for this account is significantly lower than NewGen's estimated average age for these assets—57 years old in 2021. NewGen's calculations are thus based on an average service life that is 15 years shorter than its estimated average age for the account. As a result, under NewGen's calculations, many distribution poles have significantly exceeded their expected useful service lives. Generally speaking, with the exception of accounts that encompass asset types being phased out-of-service (which has not been true of PG&E's poles historically), it would be unusual for the average age of assets in an account to be significantly older than the average service life for the assets in that account. This occurs because most assets in service have not reached the end of their useful life.

NewGen's approach results in an unusually high reserve ratio for the account and is far less reasonable than GFT's recommendations, which include both an average age that is 15 years younger and an average service life of 50 years. NewGen then compounds its over-depreciation of this account by incorporating a high net salvage ratio. GFT's recommendations do not have the same mismatch and they produce a more reasonable Percent Good for the account. Similar flaws exist across a number of significant accounts.

b. Service Life Comparison

There are also differences between GFT's and NewGen's service life estimates. These differences result from the fact that NewGen based its service lives on those approved by the Commission in PG&E's 2020 GRC that are applicable to PG&E's system as a whole. While the system-wide 2020 GRC result was one consideration that informed my recommendations, I have incorporated additional information and considerations—in particular, San Francisco-specific information relating to the Subject Assets—which results in more accurate service life estimates. Consideration of San-Francisco specific data is important because, while system-wide survivor curve estimates provide important information that may be applicable to a subset of the Subject Assets, certain San Francisco assets have different characteristics than PG&E's system as a whole, which support a longer service life for these San Francisco located assets. I provide below a few key examples of how PG&E's assets in San Francisco differ from PG&E's systemwide assets in ways that impact the service life analysis:

- Many of PG&E's retirements in its transmission system as a whole are due to wildfire hardening or other environmental impacts. San Francisco has about half a mile of overhead transmission that is in a coastal region, with the remaining transmission underground due to the density of the city. The assets in the system as a whole are, therefore, not representative of those in San Francisco.
- A large portion of San Francisco's distribution system is an underground network system built in ducts, which is different from most of PG&E's radial systems outside the city. The underground

network assets—which are primarily replaced due to capacity and have been upgraded over time—typically have longer average lives than PG&E's entire system. In addition, where San Francisco radial underground assets use conduit, concrete-encased duct banks, and vault access similar to the network system, the cable is shielded from direct soil contact, surface weather, and some mechanical disturbance and can often be replaced within the protected civil pathway. Those construction features support longer service lives than direct-buried underground construction.

- PG&E's substations in San Francisco also have differences from the rest of the system, some of which are also supportive of a longer service life. For example, more equipment is indoors due to congestion in the city, substation buildings use a different construction, and several substations have been upgraded with gas-insulated switchgear.

As a result, for at least some accounts, longer service life estimates are more reasonable to apply. As discussed in greater detail in the attached Study, differences in the construction, use, and other factors pertaining to PG&E's San Francisco distribution poles, overhead conductors, underground conduit, conductor, and services support longer service lives for these assets, on average, than PG&E's system as a whole.

Importantly, both the inputs for CCSF's calculations (discussed above) and CCSF's methodology have flaws, which combine to produce results that do not withstand scrutiny. I discuss methodological issues with CCSF's approach in the next section.

2. Methodological Issues with CCSF's Calculation of Depreciation

Beyond the differences in vintage and service life calculations discussed in the previous section, NewGen also makes additional methodological errors that result in NewGen over-depreciating the Subject Assets.

a. CCSF Uses an Allocation Rather than Valuation Approach to Depreciation

The first flaw in NewGen's method of determining depreciation for its RCNLD is that NewGen applies depreciation concepts developed for accounting and ratemaking when developing NewGen's depreciation calculation, rather than depreciation concepts more appropriate for valuation purposes that focus on the remaining value or service potential of the Subject Assets. As discussed in Section D.2, NewGen uses straight line depreciation and includes an adjustment for future net salvage, which is appropriate in the accounting context but not the valuation context. NewGen's workpapers and testimony confirm that NewGen's depreciation calculation is based on the current CPUC-approved depreciation parameters for PG&E in the ratemaking context, including average service lives, survivor curves, and net salvage rates, assigned by FERC account.[28]

But inputs from the utility ratemaking context do not establish the market value of the assets in a valuation context. The question in this proceeding is not how PG&E's investment should be recovered from customers over time, but what remaining value should be attributed to the Subject Assets as of the valuation date. As discussed in detail in Section D of this testimony, PG&E's methodology is better aligned with the purpose of determining value based on the cost approach.

b. CCSF Applies Depreciation at the FERC Account Rather than Vintage Level

NewGen's approach also fails to account for the different value of different vintages of assets within a single asset category. NewGen's depreciation calculation applies depreciation at the FERC account level through reserve ratios developed from average age, average service life, and survivor-curve inputs.[29] That approach does not preserve the vintage-level differences that are significant when calculating remaining life and probable life under an Iowa survivor curve framework. As

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28 Rabon Testimony at 19:13–16, 21:3–11 & Appendix 2, at 2-4 ¶¶ 29, 30.

29 *Id.* at 21:14–19, 23:10–12; Attachment A, Tables A-4/A-5.

explained above, the remaining life of a surviving vintage is conditional on survival to its current age, and the probable life at age is equal to age plus remaining life. Those values vary by vintage. Collapsing the calculation to an account-level average age therefore obscures the distribution of asset ages within the account and can materially distort (and overstate) the resulting depreciation estimate.

This limitation is particularly important for accounts that include a broad range of vintages or a mix of older and newer assets. An Iowa curve is not a linear depreciation formula. The remaining life for a surviving asset is not simply the average service life less the asset's age, and the appropriate probable life for older surviving vintages may differ substantially from the original average service life of the account. The reason is that assets that have already survived to a certain age are often likely to continue surviving beyond the average service life of assets in a particular category. A calculation based on a single average age and account-level reserve ratio therefore does not measure the remaining service potential of the assets actually included in the valuation.

c. CCSF Deducts Net Salvage as Part of Its Depreciation Analysis

NewGen further reduces RCNLD by incorporating net salvage or cost of removal through the same depreciation-accounting framework. NewGen's testimony describes net salvage as gross salvage less cost of removal, and NewGen's workpapers apply approved net salvage rates by FERC account.[30] That treatment is once again consistent with depreciation studies prepared for ratemaking, where net salvage is included so that customers recover the total life-cycle cost of utility plant over time. It is not, however, a measure of the current physical condition or remaining service potential of the assets. As discussed in more detail in Section D.7, net salvage should not be included in the determination of RCNLD, particularly because future net salvage in the ratemaking context for PG&E is primarily related to replacement activity for current assets to continue operating the system in the future.

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30 *Id.* at 21: 7–10, 22: 3–10, 23: 3–11.

d. CCSF's Use of a Minimum Value Floor Reveals the Flaws in Its Analysis

NewGen's use of a maximum accumulated depreciation of 90%, or stated differently a minimum remaining value of 10%,[31] confirms that NewGen's methodology can produce results that are not reasonable without an overriding adjustment. A minimum value floor may be appropriate in some circumstances when applied carefully to reflect the fact that operating assets retain service potential. Indeed, as discussed in Section F.1, when determining the RCNLD at the vintage level, I agree it is appropriate to use a 10% floor to recognize that vintages in service have a remaining value. But when the floor is needed at the account level because the underlying depreciation calculation would otherwise drive the value of in-service utility assets to zero or near-zero, it indicates that the underlying calculation is not reliably measuring remaining value. This is especially true where the low value is caused by the combined effect of account-level average age assumptions, cost allocation depreciation concepts, and the inclusion of future net salvage. The fact that NewGen needed to adopt a minimum value floor for an entire asset category reveals that NewGen's approach is flawed.

e. NewGen's Approach Produces Unreasonable Results

The flawed nature of NewGen's approach is also underscored by the unreasonable results it produces. For example, for Account 364, Poles, Towers and Fixtures, NewGen calculates an RCNLD of $27.7 million for $430.1 million of RCN, meaning that the RCNLD is only 6% of RCN. Having seen many of PG&E's poles across the city, this result is not consistent with the observed condition and continued operation of PG&E's San Francisco poles. NewGen comes to this RCNLD result for several reasons, the most consequential being that NewGen assumes the average age of poles in the City is older than its estimated average service life. NewGen's use of straight line depreciation and net salvage further exacerbates the issue. Moreover, NewGen's additional reduction for economic obsolescence likely means

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31 *Id.* at 25:1–4, 56:29–30.

NewGen assumes the poles in San Francisco have a negative value. Finally, for determining rate base, NewGen limits the percent good to no less than 10% of the original cost. However, NewGen uses no such floor for the RCNLD at the account level. This inconsistency, too, underscores the flawed nature of NewGen's depreciation approach.

H. Conclusion

My testimony supports PG&E's calculation of RCNLD for the Subject Assets by applying a valuation-based depreciation method that reflects the remaining service potential of the Subject Assets. GFT developed asset vintages and service life estimates using available PG&E records, San Francisco-specific asset information, engineering and operational input, and GFT's experience preparing depreciation and valuation studies for PG&E and other electric utilities. Those inputs were then applied at the vintage level to calculate remaining life, probable life, Percent Good factors, and RCNLD. Based on that analysis, PG&E/GFT calculates total RCNLD of approximately $10.2 billion, with an overall Percent Good factor of approximately 79%.

CCSF's depreciation analysis does not provide a reasonable measure of RCNLD because it relies on ratemaking and depreciation-accounting concepts that are not designed to measure current value. In particular, CCSF applies system-wide depreciation inputs and account-level straight-line reserve concepts, includes future net salvage costs as a reduction to current value, and in several instances produces results that are inconsistent with the continued service and observed condition of the Subject Assets. Those errors overstate accrued depreciation and understate the RCNLD of the Subject Assets.

For these reasons, PG&E's RCNLD calculation provides the more appropriate measure of depreciation for the cost approach. Accordingly, CCSF's RCNLD should be rejected and PG&E's RCNLD should be used for the cost approach valuation.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3.2

ATTACHMENT A

RCNLD, ASSET VINTAGE AND SERVICE LIFE STUDY

PACIFIC GAS AND ELECTRIC COMPANY

OAKLAND, CALIFORNIA

RCNLD, ASSET VINTAGE AND SERVICE LIFE STUDY

PACIFIC GAS AND ELECTRIC COMPANY'S
CITY AND COUNTY OF SAN FRANCISCO
ELECTRIC PLANT
AS OF JULY 27, 2021

Prepared by:

GFT

PACIFIC GAS AND ELECTRIC COMPANY

OAKLAND, CALIFORNIA

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ELECTRIC PLANT
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October 20, 2026

Pacific Gas and Electric Company
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Ladies and Gentlemen:

Pursuant to your request, we have conducted an RCNLD, Asset Vintage and Service Life Study related to Pacific Gas and Electric Company's electric transmission and distribution plant in and serving the City and County of San Francisco. The attached report presents a description of the methods used in the estimation of asset vintages and service lives and includes support for each estimate.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

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PACIFIC GAS AND ELECTRIC COMPANY

RCNLD, ASSET VINTAGE AND SERVICE LIFE STUDY

EXECUTIVE SUMMARY

Pursuant to Pacific Gas and Electric Company's ("PG&E" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming" or "GFT") performed analyses to support the cost-based valuation of PG&E's non-real estate and tangible electric assets serving the City and County of San Francisco ("the Subject Assets") as of July 27, 2021. This work supports the overall estimation of the Replacement Cost New Less Depreciation ("RCNLD") for the Subject Assets and includes the estimation of asset vintages and service lives used to determine remaining lives, as well as the calculation of accrued physical depreciation used to convert Replacement Cost New ("RCN") to RCNLD to determine the remaining value under the cost approach.

The RCN used in GFT's RCNLD calculation was developed by Sargent & Lundy. Sargent & Lundy estimated approximately $16.0 billion of RCN as of the fourth quarter of 2022 for the transmission, distribution and general ("TDG") plant included in its analysis, excluding real property and certain other separately valued assets. GFT used the Handy-Whitman Index to adjust the cost level of the Sargent & Lundy RCN to the July 27, 2021 valuation date, resulting in approximately $13.0 billion of RCN for those assets. GFT then calculated approximately $2.8 billion of accrued physical depreciation for the TDG plant using a present-worth Percent Good method, resulting in approximately $10.2 billion of RCNLD for those assets, which corresponds to a Percent Good factor of approximately 79 percent. The calculated depreciation represents an estimate of accrued physical depreciation. No separate deduction for functional obsolescence was applied in GFT's calculation, and economic obsolescence is outside the scope of GFT's analysis.

GFT has analyzed the service lives and asset vintages of PG&E transmission and distribution property and estimated depreciation in studies for PG&E general rate cases and Transmission Owner rate cases spanning the 2003 through 2023 GRCs. Those prior studies generally analyzed PG&E's system as a whole. Because the Subject Assets differ in configuration, construction, operating environment, asset ages, and forces of retirement, GFT considered PG&E's systemwide experience together with San Francisco-specific data and information in developing the asset vintage and service life estimates used in this study.

The asset vintage estimates were developed using available PG&E GIS and SAP data, plant accounting records, site visits, and information obtained from Company subject matter experts. The service life estimates were informed by the asset vintage analysis, available retirement data and actuarial analyses, prior PG&E depreciation studies, site observations, information obtained from Company subject matter experts, and experience with reasonably comparable electric utility property. Based on these considerations, GFT recommends San Francisco-specific survivor curves for several transmission and distribution plant accounts rather than mechanically applying the service life estimates for PG&E's system as a whole. The resultant vintages and service life estimates provide a reasonable basis to determine the estimated remaining lives for the Subject Assets.

The RCNLD results by account are summarized in Table 1 of this Study. The composite asset vintages by asset type are summarized in Table 2. The service life estimates recommended in this study are summarized in Table 3.

GFT's analysis does not include the value of PG&E's real property assets and certain other assets addressed by other witnesses; it instead focuses on the assets valued by S&L. Assets that are functionally obsolete were not included in S&L's RCN.

GFT also does not analyze the application of economic obsolescence; that issue is addressed by a separate witness.

PART I. INTRODUCTION

PACIFIC GAS AND ELECTRIC COMPANY
CITY AND COUNTY OF SAN FRANCISCO
RCNLD, ASSET VINTAGE AND SERVICE LIFE STUDY

PART I. INTRODUCTION

SCOPE

This Study sets forth the results of the RCNLD, Asset Vintage and Service Life Study for Pacific Gas and Electric Company ("PG&E" or "Company"), as applied to PG&E's non-real estate and tangible electric plant in service serving the City and County of San Francisco ("the Subject Assets"). The RCNLD analysis uses the RCN developed by Sargent & Lundy and calculates accrued physical depreciation based on the asset vintages and service life characteristics developed by GFT. GFT did not apply a separate functional-obsolescence deduction, as functionally obsolete assets were excluded from the RCN, and did not evaluate economic obsolescence.

The asset vintage estimates resulting from the study were based on factors which included Geographic Information System ("GIS") data provided by PG&E, plant accounting records related to PG&E's SF Electric System, site visits, and conversations with Company subject matter experts. The service life estimates resulting from the study were developed through informed judgment that considers factors such as the analyses of historical plant retirement data as recorded through 2022; a review of Company practice and outlook relating to changes in technology, plant operation and retirement; and consideration of current practice in the electric industry including service life estimates used for other electric companies, as well as for PG&E's system as a whole.

PLAN OF STUDY

Part I, Introduction, describes the scope, plan and analytical basis of the Study. Part II, PG&E's San Francisco Electric System, presents an overview of the transmission and distribution system serving San Francisco. Part III, Replacement Cost New Less

Depreciation, describes the present-worth Percent Good method, the adjustment of Sargent & Lundy's RCN to the valuation date, and the calculation of accrued physical depreciation and RCNLD. Part IV, Estimation of Survivor Curves, describes the survivor curve concepts and methods used in the service life analysis. Part V, Estimation of Vintages of Assets, describes the methods used to determine known and estimated installation vintages. Part VI, Service Life Considerations, presents the factors considered in the service life analysis and the recommended survivor curves. Part VII, Service Life and Vintage Estimation, provides an explanation of the estimates for each asset category.

BASIS OF THE STUDY

Valuation

This study supports the cost approach used to estimate the value of the Subject Assets. Under the cost approach, Sargent & Lundy developed the Replacement Cost New ("RCN") of the Subject Assets, and GFT developed the deduction from RCN for accrued physical depreciation. GFT calculated accrued physical depreciation and Replacement Cost New Less Depreciation ("RCNLD") using a present-worth Percent Good methodology based on the asset vintages and service-life estimates developed in this study. A summary of these results is included in Table 1 in Part III of the Study. Part III describes the present-worth Percent Good methodology and its application to Sargent & Lundy's RCN in greater detail.

Estimates of Vintage

GFT developed installation vintages using available PG&E Geographic Information System ("GIS") and SAP data, plant accounting records, site observations, information obtained from Company subject matter experts, relationships among associated assets, and statistical allocation methods. Known installation dates were retained where reliable. Where installation dates were unavailable or incomplete, GFT

estimated vintages using methods appropriate to the available information for each asset category. The resulting database identifies the applicable depreciable group, asset quantity, and known or estimated vintage for the transmission and distribution assets included in the analysis. These vintages provide the asset ages used in the RCNLD calculation. Table 2, provided in Part V of the Study, summarizes the composite vintages and principal estimation method by asset category.

Service Life Estimates

GFT developed the service life estimates through informed judgment considering available retirement data and actuarial analyses, prior PG&E depreciation studies, the asset-vintage analysis, the characteristics and operating environment of the Subject Assets, site observations, information obtained from Company subject matter experts, and experience with reasonably comparable electric utility property. Iowa type survivor curves, described in Part IV of this Study, were used to depict the estimated survivor curves for the plant accounts.

The procedure for estimating service lives is described in more detail in Parts IV and VI of this Study and consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future expectations. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived. The results of the estimates of asset vintage study were also incorporated into the estimation of service lives. The results of the service life study by account are provided in Table 3 in Part VI of this Study.

SITE VISITS

To be familiar with the operation of the Company and observe representative portions of the plant, site visits were conducted. Site visits provided an understanding of the age, condition and function of the Subject Assets and an understanding of the causes of depreciation. The site visits informed estimates of asset ages, remaining lives and remaining value for the Subject Assets.

Gannett Fleming conducted site visits specific to this study:

June 20, 2023

Martin Substation
Hunters Point Substation
Potrero Substation
Mission Substation
Embarcadero Substation

In addition to these most recent site visits, Gannett Fleming has conducted several other site visits across PG&E's service territory during my career. These include site visits for the 2014, 2017 and 2020 General Rate Cases ("GRCs") and several transmission depreciation studies, which included site visits to representative facilities such as combined cycle generation plants, hydro generation plants, electric distribution and transmission lines and substations, gas mains and services, gas regulating stations, and PG&E owned structures and fleet operations.

In addition to viewing these facilities, meetings were held with Company Subject Matter Experts ("SMEs") to further discuss and understand PG&E's SF Electric System.

QUALIFICATIONS AND LIMITATIONS OF ESTIMATES

The asset vintage, service life and RCNLD results presented in this Study are estimates developed from the data and information available for the study. Certain installation vintages were unavailable or incomplete and were estimated using the

methods described in Parts V and VII. The selected survivor curves and service lives also reflect informed judgment concerning the future retirement characteristics of the Subject Assets. Accordingly, the results are subject to the assumptions and limitations inherent in the available data and estimation methods.

GFT relied on GIS and SAP data, plant accounting records, information provided by PG&E subject matter experts, site observations, Sargent & Lundy's RCN estimates and other information identified in this Study. GFT reviewed these sources for reasonableness and consistency but did not independently audit or verify every underlying record. Where the available sources were incomplete or conflicting, such as when manufacturing and installation dates differed or GIS and plant accounting records indicated different installation dates, GFT evaluated the available evidence and applied professional judgment to develop reasonable estimates.

Although the available data required the use of estimates and professional judgment, GFT believes the resulting asset vintages, service lives and RCNLD are reasonable and appropriate for this study. Accordingly, GFT recommends the RCNLD presented in Table 1 for use in the cost-based valuation of the Subject Assets as of July 27, 2021.

PART II. PG&E'S SAN FRANCISCO ELECTRIC SYSTEM

PART II. PG&E'S SAN FRANCISCO ELECTRIC SYSTEM

OVERVIEW

PG&E's San Francisco Electric System is comprised of both high voltage transmission and lower voltage distribution equipment. The transmission system within San Francisco is 115 kV or 230 kV and is primarily underground. Most of the larger substations are indoor or partially indoor. Three of these stations have already been upgraded to gas insulated substations with plans for additional upgrades or the implementation of new technologies that can similarly address space constraints in the urban environment.

PG&E's San Francisco distribution system includes both underground and overhead construction. Downtown San Francisco is served by both network and radial distribution systems. Portions of the underground network system date to the 1930s and have been upgraded over time. Radial distribution systems are also used throughout San Francisco and include construction of varying types and vintages.

TRANSMISSION SYSTEM

PG&E's San Francisco transmission system was originally constructed around sources of power within the city and in consideration of the need to transmit power to densely populated downtown areas. The hilly terrain, geographical constraints of the San Francisco Peninsula and other environmental conditions also inform siting and construction of transmission lines and substations.

PG&E has seven substations in the San Francisco area with transmission voltages, including the Martin station located outside of the city and county borders. The high-voltage substations in San Francisco are those which contain equipment that can

support and transmit 115 kV or higher, and either convert one transmission voltage to another transmission voltage (e.g., [redacted]) or convert transmission voltage to distribution voltage (e.g., [redacted]

Some of the oldest currently surviving major transmission assets are located at Hunters Point and Potrero and date to the 1940s and 1960s, respectively. Originally these assets were part of the switchyards at Hunters Point and Potrero power plants, which were divested by PG&E in the 1990s and eventually retired in 2006 and 2011. These power plants and switchyards were designed as part of an overall network to transmit power from these and other generating sources throughout the city. Over time, substations at these locations have been repurposed as part of a network that delivers power from beyond the city, county and (often) state to residences, schools, hospitals, nonprofits, industry, government buildings and businesses throughout San Francisco.

PG&E has made major upgrades to its San Francisco transmission system over the past two decades, driven by both growth and external factors in deregulated electricity markets. For example, major portions of the Potrero, Embarcadero and Mission substations have been rebuilt, including construction of gas insulated substation equipment at each of these stations. Work is planned at other stations in the coming years as well. Additions for capacity and system changes also have been made over the past several decades, including the addition of 230 kV and 115 kV lines to the transmission system. The most significant upgrade has been the [redacted]

The project included major substation upgrades, including gas insulated substation equipment, at both the [redacted].

DISTRIBUTION SYSTEM

Similar to the transmission system, PG&E's San Francisco distribution system has evolved over time and includes different types of construction. Underground network distribution assets were constructed to provide power to densely populated areas and commercial districts and some assets in network systems date to the 1930s. Underground radial distribution also serves customers and varies in construction over the decades. Overhead distribution assets also serve customers throughout portions of San Francisco.

The [redacted] network system in downtown San Francisco dates to the 1930s. Conductor is installed in ducts constructed of materials such [redacted] The original cable in the network system is [redacted] While the Company has targeted replacements of PILC for several years and has replaced most of these assets, [redacted] had a relatively long service life and is, on average, older than underground cable throughout PG&E's system as a whole. Network transformers were proactively replaced in the 1980s and the Company has begun replacing the 1980s vintage transformers over the past decade. There is also a [redacted], which is also over 40 years old.

The radial system also dates to a similar time period as the network system and some assets had [redacted] similar to the network system.[1] However, other types of underground assets have also been used over the decades with similar construction to those assets added throughout PG&E's system at similar time periods. Thus, PG&E's San Francisco distribution system includes direct buried, cable-in-conduit ("CIC") and cable installed in rigid (typically PVC) conduit. Overall, the radial system has

[1] A radial configuration is structured in a hierarchical manner, with electricity flowing in one direction from the source (e.g., substation) to the load (e.g., consumers) without looping back. A network distribution system forms a grid-like structure where multiple interconnected paths exist between substations, feeders, and consumers. Electricity can flow in multiple directions, allowing for redundancy and flexibility.

more varied types of construction with much of the system installed more recently than the network system.

PG&E's overhead distribution also has had similar construction as PG&E's system as a whole. Poles have been installed with different sizes, class and pole treatments over time but, on average, are older than those in PG&E's system as a whole. Conductors, transformers and other overhead assets are also similar to PG&E's system as a whole, with wire ranging from copper to various aluminum and steel composites depending on vintage and location. Like poles, some of these other overhead assets are, on average, older than PG&E's system as a whole. Some of the forces of retirement that affect poles and other overhead assets are not as prominent for PG&E's assets serving San Francisco as compared to the system as a whole. For example, risks due to moisture, snow and wind loading, and wildfire are lower for assets in the City and County.

Overall, PG&E's electric system serving San Francisco differs from the Company's broader system in several respects relevant to this study. These differences include the greater prevalence of underground construction, the concentration of network distribution facilities in downtown San Francisco, differences in the construction and configuration of substations, the age of portions of the existing system, and differences in the forces that result in asset retirement and replacement. GFT considered these characteristics, together with PG&E's systemwide experience, in developing the RCNLD, asset vintage and service life estimates described later in this Study.

PART III. REPLACEMENT COST NEW LESS DEPRECIATION

PART III. REPLACEMENT COST NEW LESS DEPRECIATION

PURPOSE AND BASIS OF RCNLD CALCULATIONS

RCNLD is a cost-based measure of value that begins with the cost to replace existing property with new property and deducts accrued physical depreciation applicable to the existing property. For the assets addressed in this Study, Sargent & Lundy developed the RCN used as the starting value, and GFT calculated accrued physical depreciation and RCNLD.

GFT calculated accrued physical depreciation using a present-worth Percent Good method. The principal inputs are RCN, asset age as of the valuation date, the applicable Iowa survivor curve, remaining life, probable life, and the discount rate. Asset age is determined from the installation vintage developed in the asset vintage analysis. The asset vintage and service life analyses described in Parts V through VII provide the age and survivor curve inputs used in the RCNLD calculation.

REPLACEMENT COST NEW COST

Sargent & Lundy developed the Replacement Cost New ("RCN") estimates for the Subject Assets at fourth quarter 2022 cost levels. GFT adjusted the Sargent & Lundy RCN estimate of approximately $16.0 billion to place those costs on a basis consistent with the valuation date of July 27, 2021. GFT adjusted the RCN estimates using the applicable Handy-Whitman Index of Public Utility Construction Costs for the relevant utility plant categories, resulting in approximately $13.0 billion of RCN at July 27, 2021, excluding real property and certain separately valued assets.

The Handy-Whitman adjustment reflects the change in construction cost levels between the cost basis of the Sargent & Lundy estimates and the valuation date. This

adjustment is separate from the deduction for accrued depreciation. The resulting July 27, 2021 RCN amounts represent the estimated replacement cost of the Subject Assets included in Sargent & Lundy's analysis stated at valuation-date cost levels and serve as the basis for GFT's RCNLD calculations.

GFT then applied the Percent Good factors developed from the asset vintage and service life analyses described in this Study to the valuation-date RCN amounts. As described in the following section, those Percent Good factors reflect the accrued physical depreciation applicable to the existing assets. The application of Percent Good to the adjusted RCN produces the estimated RCNLD for the Subject Assets as of July 27, 2021.

PRESENT WORTH DEPRECIATION AND PERCENT GOOD

RCNLD is calculated by applying a Percent Good factor to RCN. The Percent Good factor represents the percentage of replacement cost new that remains after recognizing accrued physical depreciation. Under the present-worth approach used in this analysis, Percent Good is based on the present worth of the remaining service expected from existing property relative to the present worth of the service expected from equivalent new property.

The present-worth method recognizes the timing of future service, the remaining life of property that has survived to its current age, and the range of retirement ages represented by the applicable survivor curve. These characteristics are relevant to utility property because assets within a property group retire over a distribution of ages and surviving assets may remain in service beyond the original average service life of the group.

Calculation of Percent Good Factors

The Percent Good factor is calculated from asset age, probable life, and the discount rate. The formula used in this analysis is:

$$Percent\ Good = [((1 + r)^{PL} - (1 + r)^{a}) / ((1 + r)^{PL} - 1)]$$

where a is the asset age, PL is the probable life at age a, and r is the discount rate. GFT used a discount rate of 4.25 percent in the RCNLD calculation.

The complementary Present Worth Depreciation factor ("PWD") is equal to one minus Percent Good:

$$PWD = 1 - Percent\ Good = [((1 + r)^{a} - 1) / ((1 + r)^{PL} - 1)]$$

$$RCNLD = RCN\ x\ Percent\ Good$$

$$Accrued\ Physical\ Depreciation = RCN\ x\ PWD = RCN - RCNLD$$

For example, assume that a vintage of distribution conductor has RCN of $100,000, a probable life of 50 years at the valuation date, and an age of 10 years. Using a 4.25 percent discount rate, the Percent Good factor is approximately 92.6 percent. The resulting RCNLD is approximately $92,639 and the corresponding accrued physical depreciation is approximately $7,361.

Determination of Remaining Life and Probable Life Using Iowa Curves

Probable life at a given age equals the current age of the property plus its expected remaining life at that age. The selected Iowa survivor curve provides the information needed to determine the remaining life of property that has survived to its current age.

$$Probable\ Life\ at\ Age\ a = Age\ a + Remaining\ Life\ at\ Age\ a$$

An Iowa survivor curve represents the expected distribution of retirements for a property group. The original average service life is based on the full retirement distribution

from age zero through the maximum life of the survivor curve. For property that has already survived to age a, the relevant remaining life is conditional on survival to that age. It is calculated from the portion of the survivor curve after age a by dividing the area under the curve after age a by the proportion of the original property group surviving at age a.

$$\textit{Remaining Life at Age a} = \textit{Area Under Survivor Curve After Age a} \,/\, \textit{Proportion Surviving at Age a}$$

The probable life will differ from the original average service life of the property group for ages greater than zero. Older vintages that have already survived for a substantial period may have a probable life that extends beyond the original average service life because their expected remaining life reflects the fact that the property has already survived to its current age.

Determination of Asset Age

Asset age is determined from the installation vintage developed in this Study. A vintage consists of property installed in a particular calendar year. For purposes of the RCNLD calculation, asset age was measured as of July 27, 2021 using a half-year convention, so that a 2021 vintage is assigned an age of 0.5 years, a 2020 vintage is assigned an age of 1.5 years, and so forth. Where an individual installation date was unavailable, the calculation uses the estimated vintage developed under the methods described in Part V and the account-level analyses in Part VII.

TREATMENT OF NET SALVAGE IN RCNLD

Net salvage is the gross salvage value expected at retirement less the cost of removing the property. GFT does not include net salvage in the calculation of accrued physical depreciation for RCNLD. Net salvage represents costs or proceeds associated

with the future retirement and disposition of property rather than the loss in value attributable to accrued physical depreciation as of the valuation date.

Net salvage is commonly included in depreciation rates prepared for financial and ratemaking purposes so that the full life-cycle cost of utility property is recovered over its service life. The RCNLD calculation has a different purpose. It measures the remaining value of existing property as of the valuation date based on the service that the property is expected to provide. Accordingly, GFT did not include net salvage in the accrued physical depreciation deduction used to determine RCNLD.

CALCULATION OF PERCENT GOOD AND DEPRECIATION

GFT calculated RCNLD at the vintage level using the asset vintage and service life results developed in this Study. Performing the calculation at the vintage level recognizes differences in age, remaining life, probable life, and Percent Good among vintages within the same asset category.

Application of Age, Remaining Life and Probable Life to Percent Good

For each vintage within an asset category, GFT first determined the age as of July 27, 2021. GFT then applied the selected Iowa survivor curve to determine the expected remaining life of property that had survived to that age. Probable life was calculated by adding the vintage age to its remaining life. The resulting age and probable life values were used in the present-worth formula to determine the vintage Percent Good factor.

The Percent Good factor was applied to the RCN assigned to each vintage. GFT then summed the vintage-level RCNLD amounts to determine the RCNLD for each asset category and aggregated the category results to determine the total RCNLD.

Land was not subject to physical depreciation and the value for real property is addressed separately in an appraisal provided by Valbridge Property Advisors and

Waldron & Associates, Inc. The appraised value is used for the cost approach and no separate RCN or depreciation were determined for real property. There is no physical depreciation assumed for spares which are included in the overall cost valuation at RCN at the valuation date.

RCNLD for San Francisco Assets

Sargent & Lundy's RCN for the transmission, distribution and general plant included in its analysis, adjusted to July 27, 2021 cost levels, was approximately $13.0 billion. GFT applied the vintage-level Percent Good factors described above to this RCN to calculate approximately $2.8 billion of accrued physical depreciation and approximately $10.2 billion of RCNLD. The resulting Percent Good factor for these assets is approximately 79 percent. A summary of the RCNLD results is included in Table 1.

PACIFIC GAS AND ELECTRIC COMPANY

CITY AND COUNTY OF SAN FRANCISCO ASSETS

TABLE 1. SUMMARY OF REPLACEMENT COST NEW LESS DEPRECIATION BY FERC ACCOUNT

ACCT	DESC	SURVIVOR CURVE	REPLACEMENT COST NEW	ACCUMULATED DEPRECIATION	REPLACEMENT COST NEW LESS DEPRECIATION	PERCENT GOOD FACTOR	WEIGHTED AVERAGE INSTALL YEAR
	TRANSMISSION						
352.00	STRUCTURES AND IMPROVEMENTS	75-R2	267,193,554	89,676,325	177,517,229	66%	1955
353.00	STATION EQUIPMENT	47-R2	610,341,849	91,086,155	519,255,694	85%	2006
354.00	TOWERS AND FIXTURES	75-R4	2,394,553	1,431,067	963,485	40%	1948
357.00	UNDERGROUND CONDUIT	70-S1	27,352,152	6,565,285	20,786,867	76%	1972
358.00	UNDERGROUND CONDUCTORS AND DEVICES	55-R1	1,263,440,966	409,353,940	854,087,026	68%	1976
	TOTAL TRANSMISSION		***2,170,723,073***	***598,112,771***	***1,572,610,301***	***72%***	**1982**
	DISTRIBUTION						
361.00	STRUCTURES AND IMPROVEMENTS	70-R3	64,069,622	4,541,135	59,528,487	93%	2004
362.00	STATION EQUIPMENT	50-R1	623,567,390	123,931,764	499,635,626	80%	1997
364.00	POLES AND FIXTURES	50-S1.5	442,878,189	189,435,174	253,443,015	57%	1979
365.00	OVERHEAD CONDUCTORS AND DEVICES	50-S1.5	257,019,992	89,430,500	167,589,492	65%	1986
366.00	UNDERGROUND CONDUIT	70-R3	6,478,993,952	1,044,138,337	5,434,855,616	84%	1992
367.00	UNDERGROUND CONDUCTORS AND DEVICES	55-S0.5	1,627,027,963	231,560,591	1,395,467,372	86%	2000
368.01	LINE TRANSFORMERS - OVERHEAD	32-R2.5	134,285,171	44,211,952	90,073,219	67%	2004
368.02	LINE TRANSFORMERS - UNDERGROUND	34-R2.5	276,416,595	109,481,639	166,934,955	60%	1999
369.01	SERVICES - OVERHEAD	55-R2.5	270,828,598	120,386,462	150,442,137	56%	1974
369.02	SERVICES - UNDERGROUND	55-R2.5	146,077,690	64,928,791	81,148,899	56%	1974
370.00	METERS	30-R1.5	66,077,409	29,043,613	37,033,796	56%	1997
370.01	METERS - AMI	20-R2	407,141,883	130,526,841	276,615,042	68%	2012
	TOTAL METERS		***473,219,291***	***159,570,453***	***313,648,838***	***66%***	**2010**
373.03	STREET LIGHTING AND SIGNAL SYSTEMS	25-L0	21,061,637	2,101,202	18,960,435	90%	2017
	TOTAL DISTRIBUTION		***10,815,446,089***	***2,183,717,998***	***8,631,728,091***	***80%***	**1993**
	GENERAL						
397.08	COMMUNICATION EQUIPMENT	15-SQ	8,627,720	7,764,948	862,772	10%	2000
	TOTAL GENERAL		***8,627,720***	***7,764,948***	***862,772***	***10%***	**2000**
	TOTAL TD&G		***12,994,796,882***	***2,789,595,718***	***10,205,201,164***	***79%***	**1991**

PACIFIC GAS AND ELECTRIC COMPANY

CITY AND COUNTY OF SAN FRANCISCO ASSETS

TABLE 1. SUMMARY OF REPLACEMENT COST NEW LESS DEPRECIATION BY FERC ACCOUNT

ACCT	DESC	SURVIVOR CURVE	REPLACEMENT COST NEW	ACCUMULATED DEPRECIATION	REPLACEMENT COST NEW LESS DEPRECIATION	PERCENT GOOD FACTOR	WEIGHTED AVERAGE INSTALL YEAR
	SPARES						
353.00	STATION EQUIPMENT - SPARES	47-R2	6,228,475	-	6,228,475	100%	2021
358.00	UNDERGROUND CONDUCTORS AND DEVICES - SPARES	55-R1	3,055,383	-	3,055,383	100%	2021
368.01	LINE TRANSFORMERS - OVERHEAD SPARES	32-R2.5	20,240,975	-	20,240,975	100%	2021
368.02	LINE TRANSFORMERS - UNDERGROUND SPARES	34-R2.5	4,550,785	-	4,550,785	100%	2021
	TOTAL SPARES		***34,075,618***	***-***	***34,075,618***	***100%***	**2021**
	TOTAL PG&E		***13,028,872,500***	***2,789,595,718***	***10,239,276,783***	***79%***	**1991**

PART IV. ESTIMATION OF SURVIVOR CURVES

PART IV. ESTIMATION OF SURVIVOR CURVES

The RCNLD calculation described in Part III requires estimates of the remaining service lives of the Subject Assets as of the valuation date. GFT developed those estimates using survivor curves that describe the expected retirement pattern of a group of property over its service life. For property of a given age, the applicable survivor curve is used to determine expected remaining life and probable life, which are inputs to the Percent Good calculation used to estimate accrued physical depreciation. This Part describes survivor curves, Iowa type curves, and the retirement rate analyses considered in selecting the survivor curves used in this study.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. The average life can be derived from the separate lives of each of the units or a survivor curve that plots the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of a group of assets. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the

probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

For valuation purposes, the remaining life characteristic of the survivor curve is particularly important because the Subject Assets are existing property of varying vintages. The relevant question is therefore not only the average service life of new property, but the expected remaining life of property that has already survived to its age as of the valuation date.

Iowa curves for PG&E's system as a whole have been developed using informed judgment that incorporates the retirement rate analysis of historical retirement history. For the Subject Assets, the results of these analyses provided a consideration when determining survivor curves and related remaining lives. A discussion and illustrative example of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero.

The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

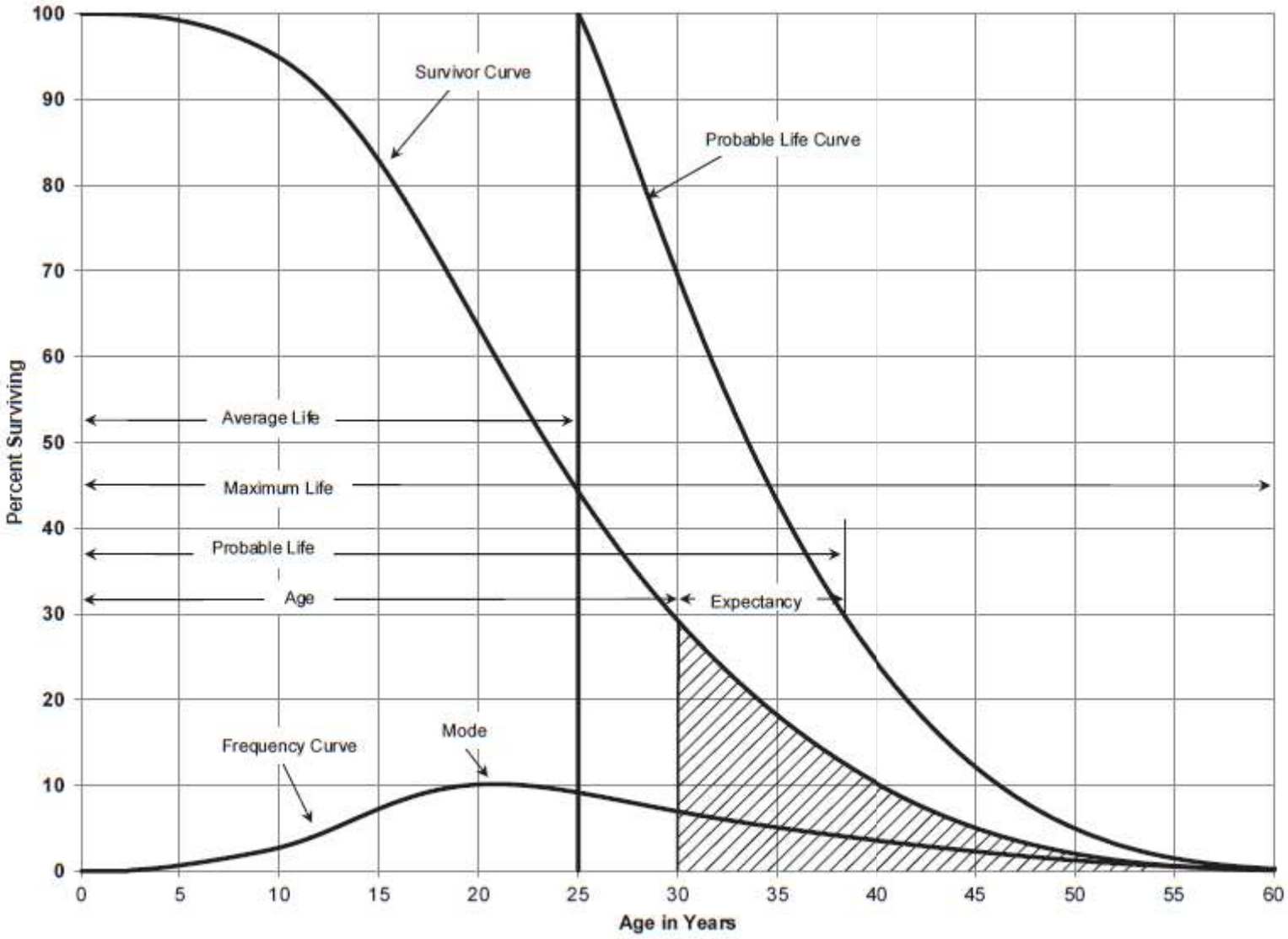


FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

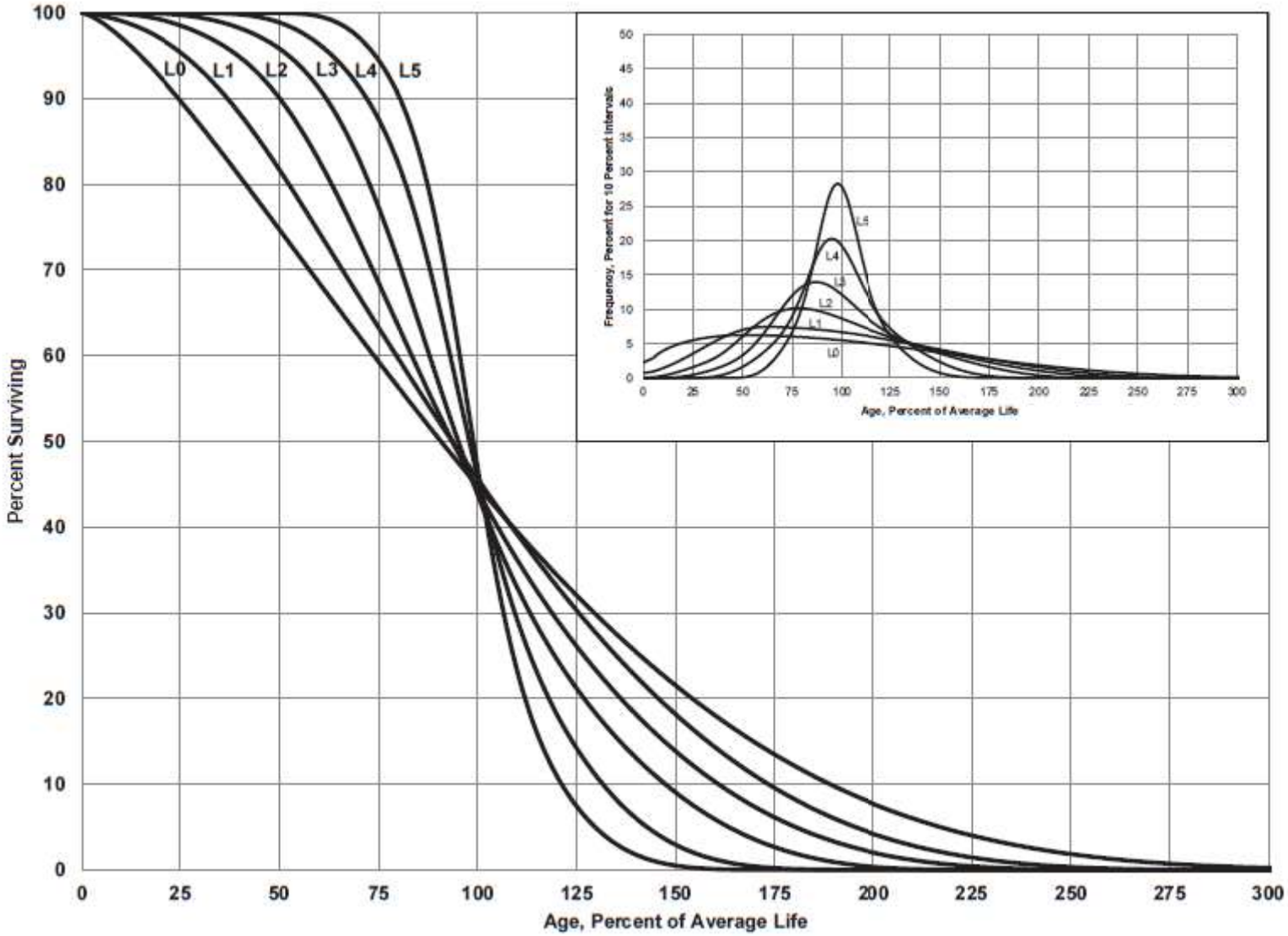


FIGURE 2. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

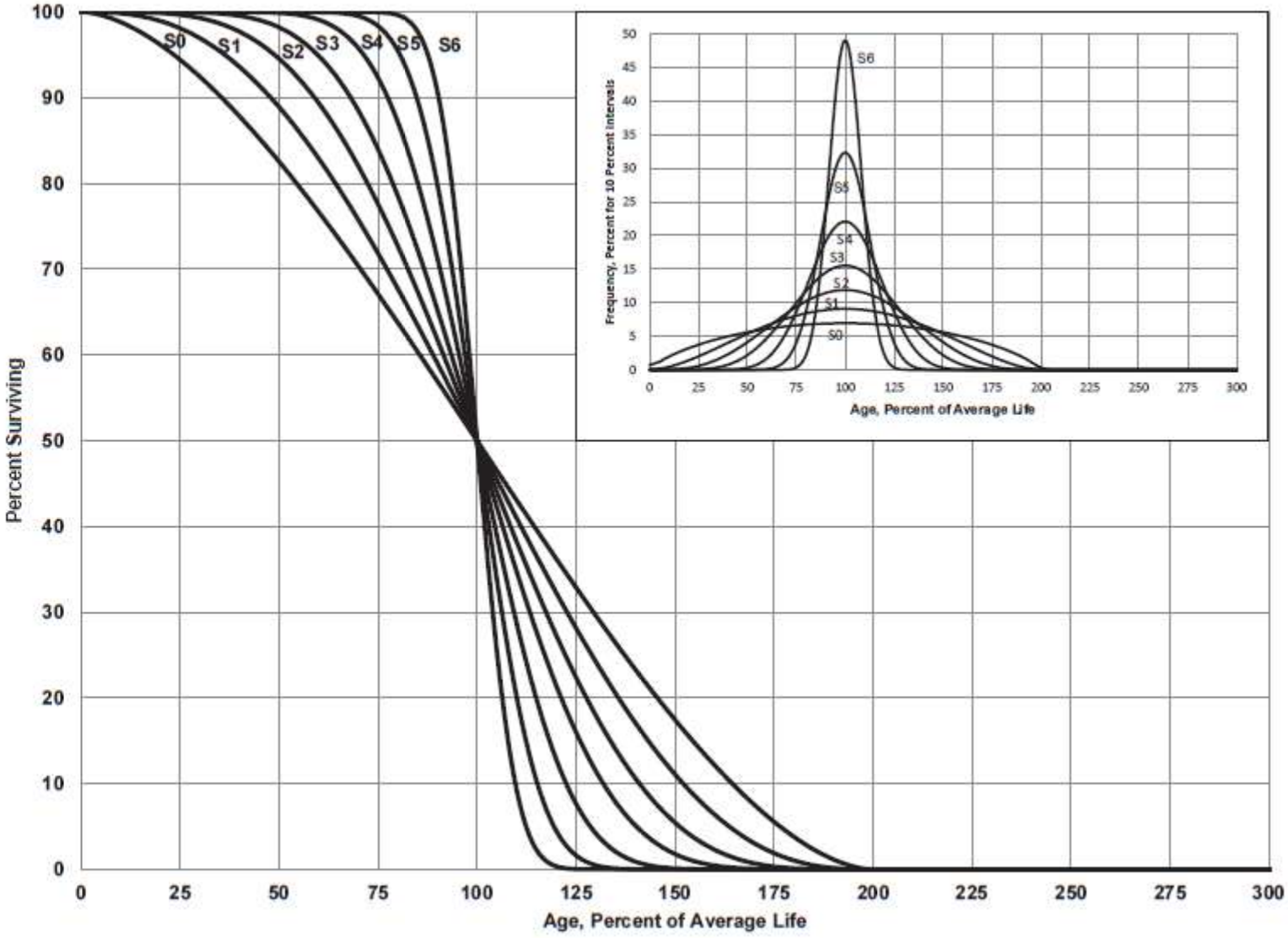


FIGURE 3. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

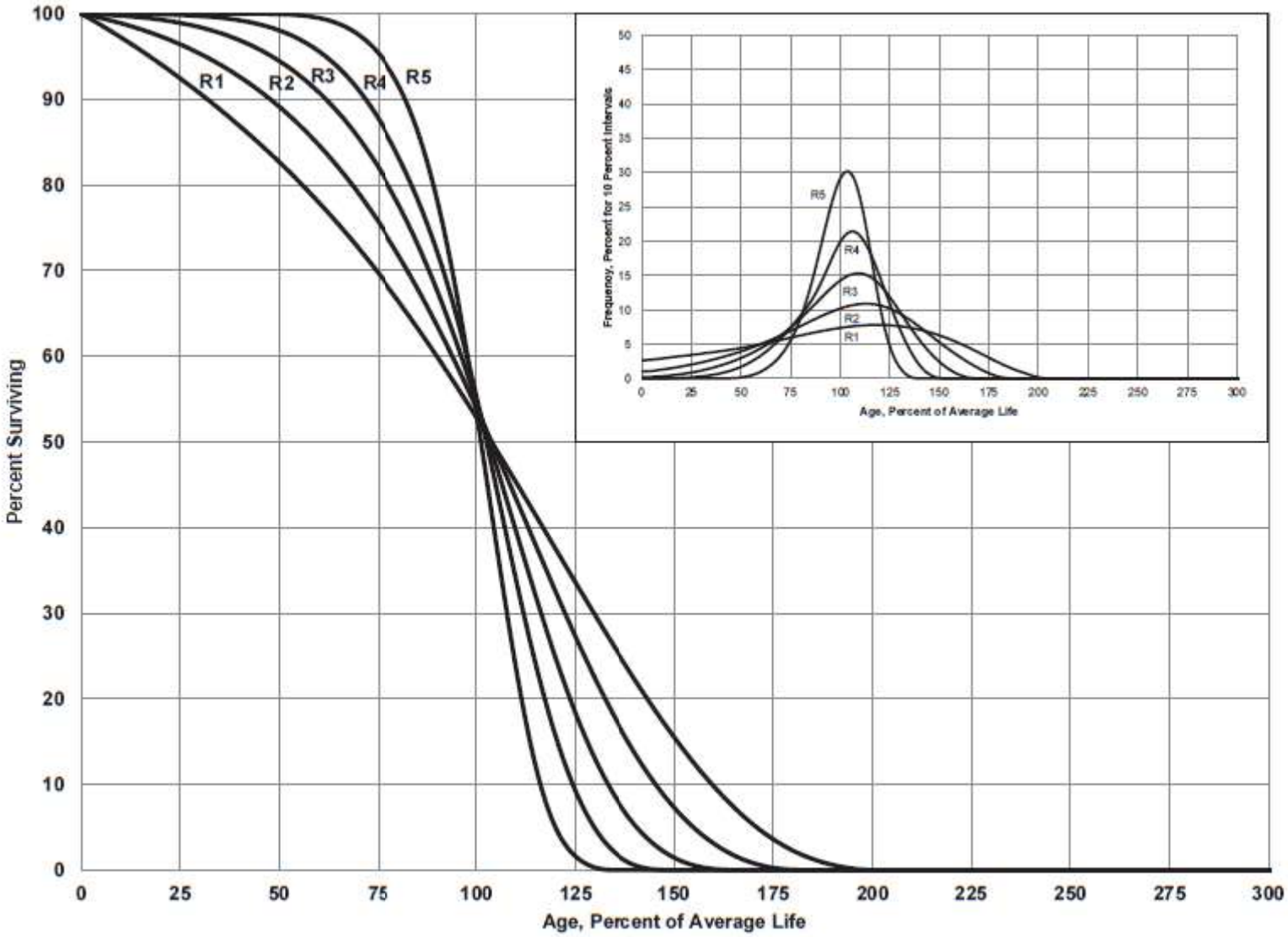


FIGURE 4. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

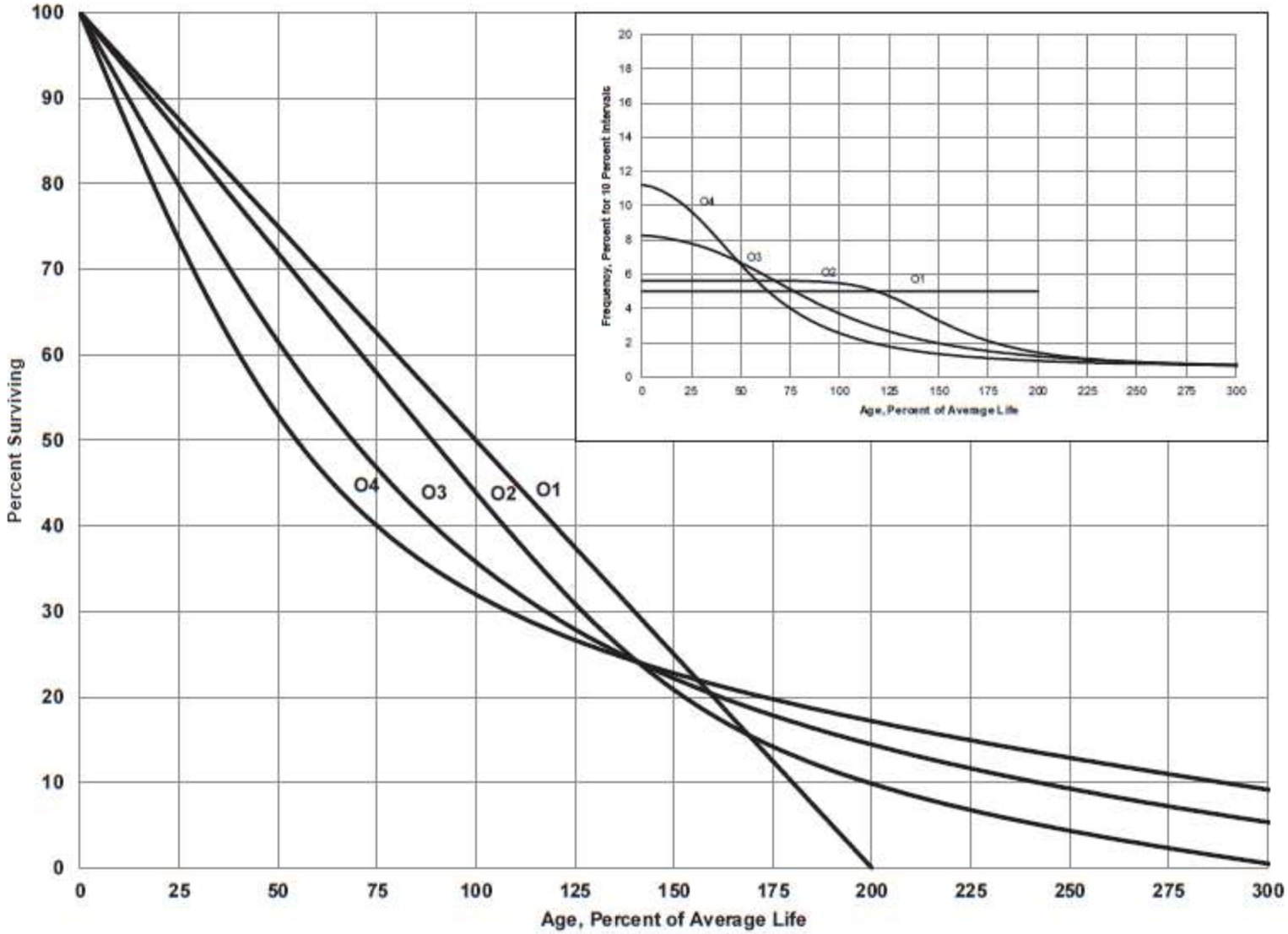


FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[2] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves. In addition to this entire set of R, S, L and O curves, half-mode curves (e.g., R1.5) are also widely used. The half mode curves were developed by averaging two adjacent whole-mode curves. For example, the R1.5 curve is the average of the R1 and R2 curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method used to analyze the historical retirement experience of utility property and develop observed survivor characteristics. The method compares the amount of property retired at each age with the amount of property exposed to retirement at that age. The resulting retirement ratios are used to develop the proportion of the original property group surviving at successive ages and, in turn, an observed survivor curve.

The method (also known as the annual rate method) is illustrated through the use of an example in the following text and is also explained in several publications including "Statistical Analyses of Industrial Property Retirements,"[3] "Engineering Valuation and Depreciation,"[4] and "Depreciation Systems."[5] Historical experience is analyzed over an experience band, which identifies the years during which retirements and other plant transactions are observed, and a placement band, which identifies the installation years of the property exposed to retirement during the experience band. Property additions, retirements, transfers and other transactions are organized by installation year and transaction year so that retirements and exposures can be associated with the

[2]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[3]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[4]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.

[5]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

appropriate age intervals.

For each age interval, the retirement ratio is calculated by dividing retirements during the interval by the property exposed to retirement at the beginning of the interval. The corresponding survivor ratio is one minus the retirement ratio. Beginning with 100 percent surviving at age zero, successive survivor ratios are applied to determine the percentage of the original property group surviving to each age. The resulting percentages form the original survivor curve. Because historical records generally do not encompass the entire potential life of the property group, the observed curve commonly terminates before reaching zero percent surviving and is therefore referred to as a stub survivor curve.

Smoothing the Original Survivor Curve

The original survivor curve provides an indication of the historical retirement characteristics of the property group but does not, by itself, establish the complete expected retirement pattern over the property's service life. GFT compares the observed survivor curve with established Iowa type curves using visual and mathematical fitting. This process smooths irregularities in the historical experience and provides a basis for extending the observed retirement pattern through the expected life of the property group.

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to

determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

'RATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

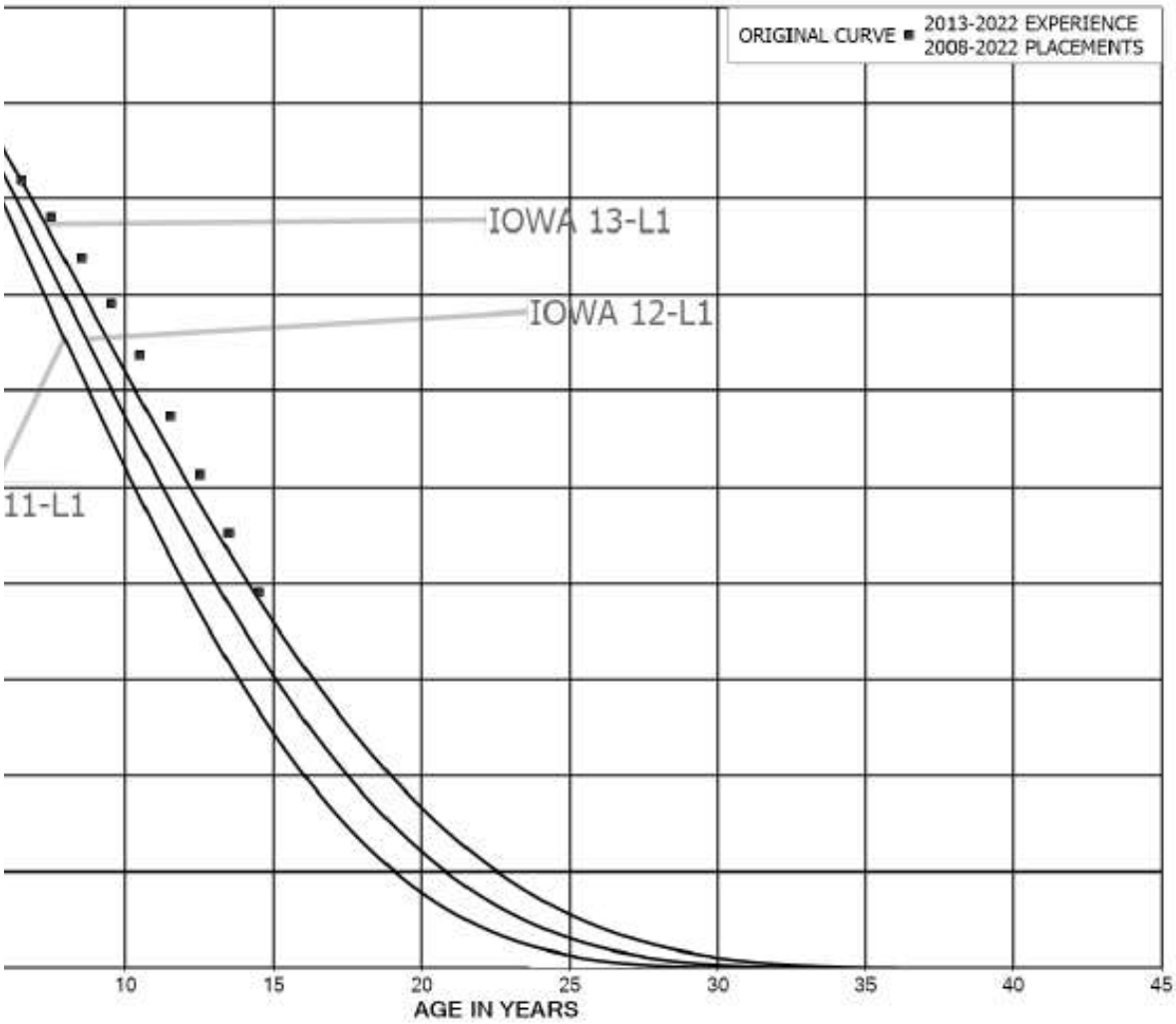
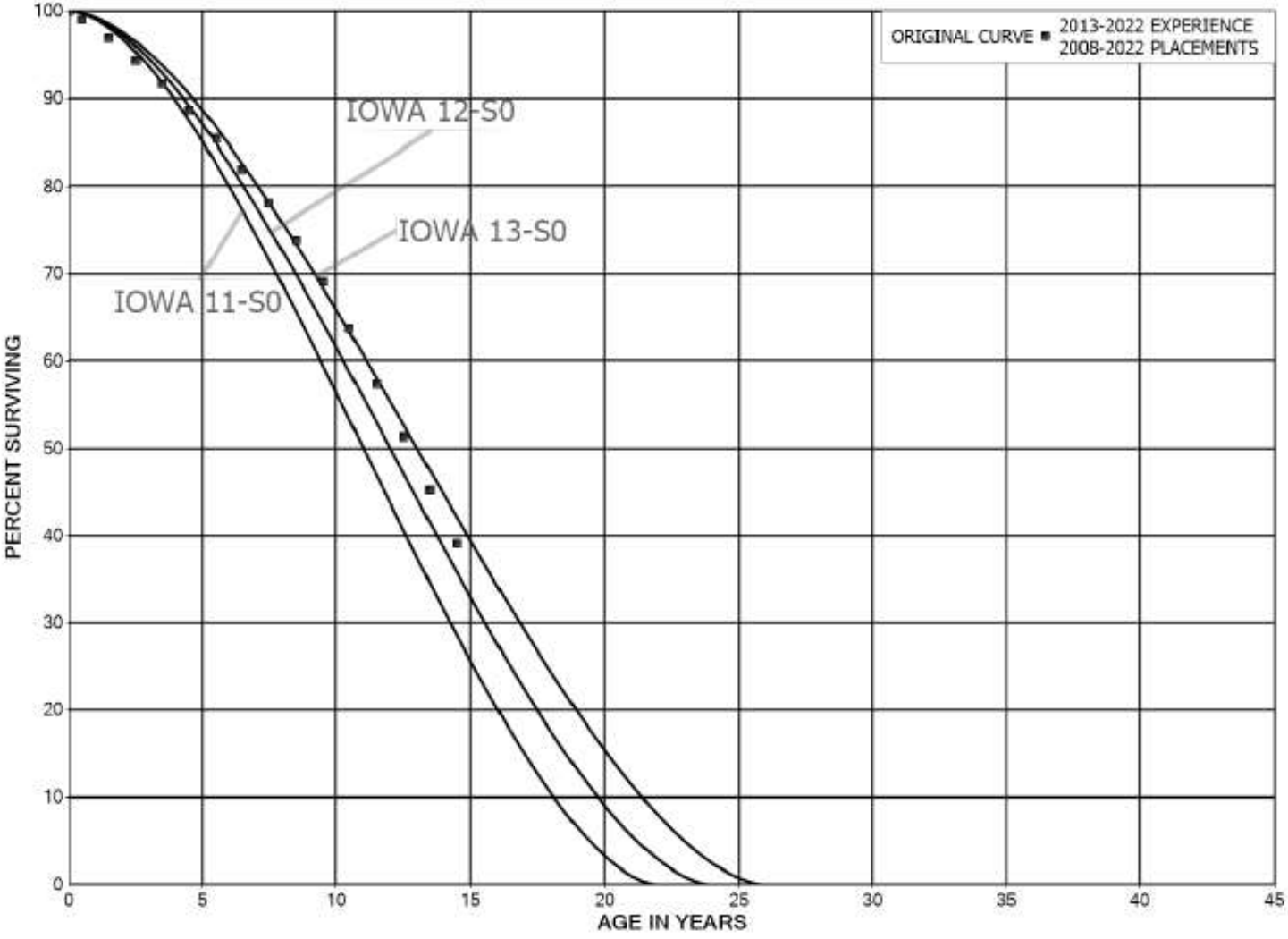
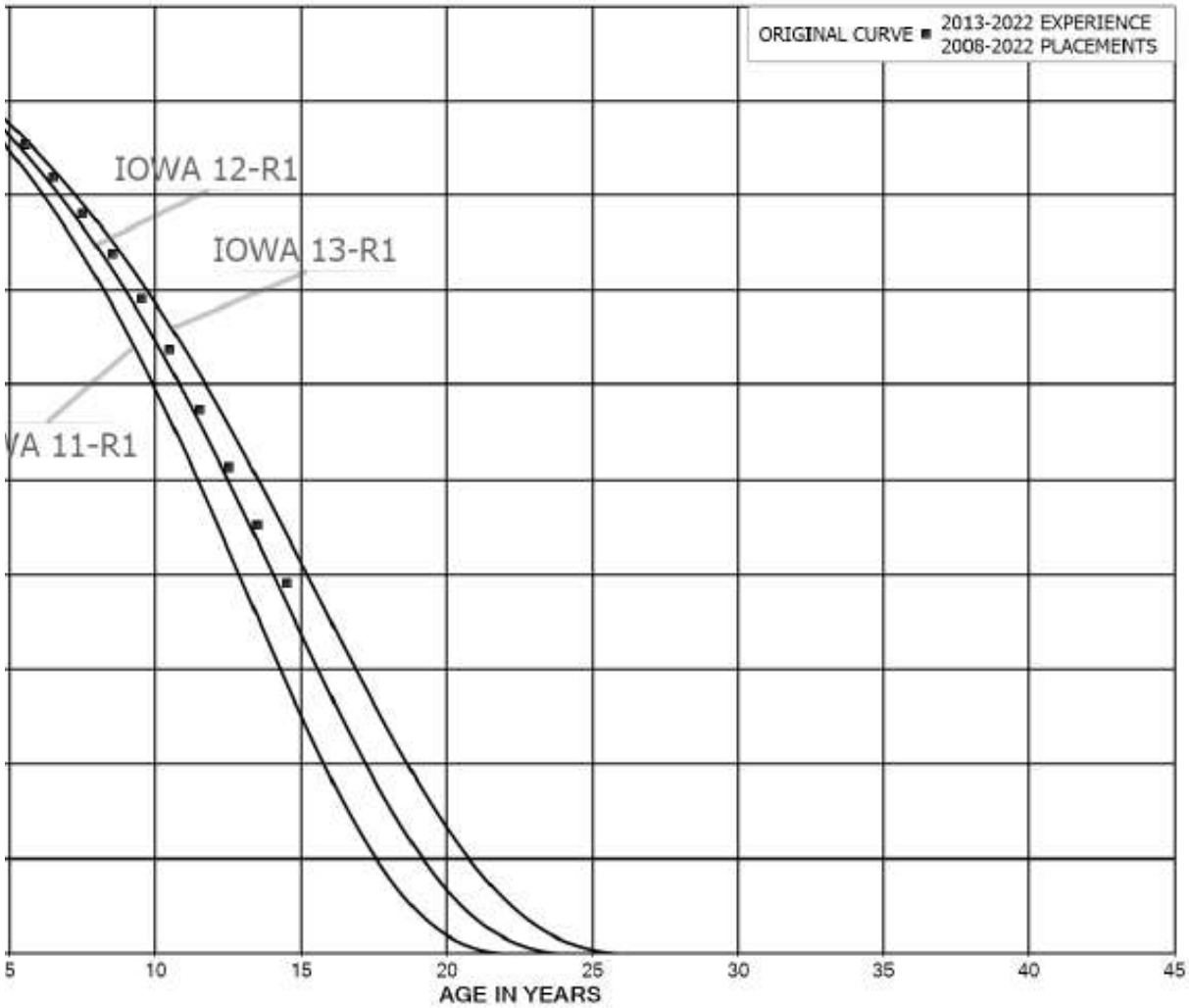


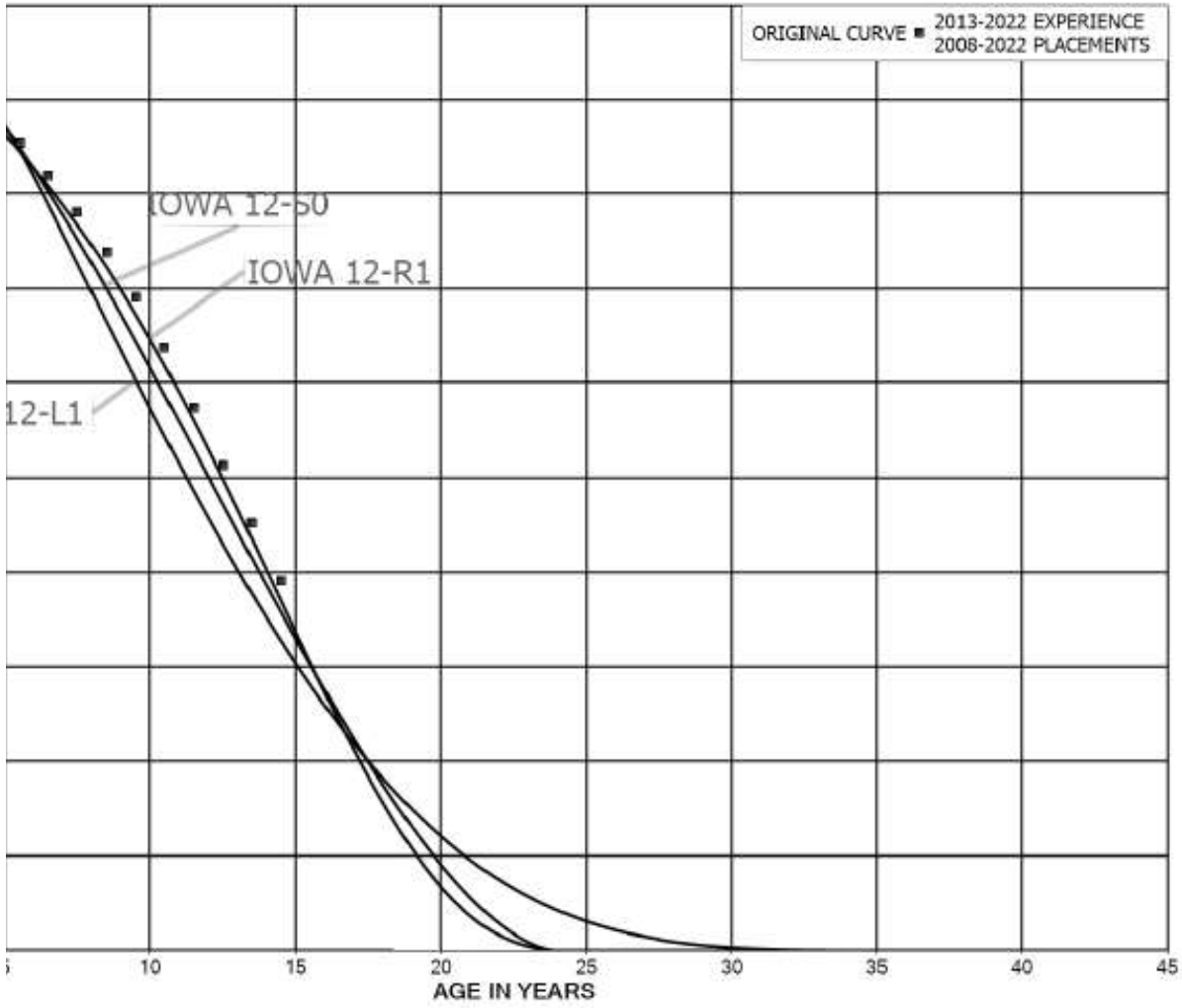
FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



ISTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



ION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



The statistical analysis of historical retirement experience is one consideration in selecting a survivor curve. As discussed in Part VI, GFT also considers other relevant information, including PG&E's systemwide depreciation studies and retirement experience, the characteristics of the Subject Assets, available San Francisco-specific information, site observations, information obtained from Company subject matter experts, and experience with reasonably comparable electric utility property.

The selected survivor curves are applied to the ages of the Subject Assets to estimate their remaining lives and probable lives. As described in Part III, those estimates are used in determining the Percent Good factors and accrued physical depreciation for the RCNLD calculation.

PART V. ESTIMATION OF VINTAGES OF ASSETS

PART V. ESTIMATION OF VINTAGES OF ASSETS

OVERVIEW

The primary objective of the study of asset vintages was to determine the installation dates of distribution and transmission assets within PG&E's SF Electric System as part of an effort to determine the value of those assets. While available records provided vintages for many assets, a portion of the assets had unknown installation dates, necessitating the use of statistical methods and informed assumptions to establish reasonable estimates of these assets' vintages.

The study employed a comprehensive approach that combined statistical methodologies, various data sources, site visits, information from PG&E's SMEs, and Gannett Fleming's knowledge of electric transmission and distribution assets obtained through depreciation and valuation studies performed for PG&E and utilities across the country. Data sources available and used to perform this study include:

1. Data from PG&E's GIS and from SAP. These data were provided at the retirement unit level and serve as the initial source for known transmission and distribution asset vintages in San Francisco.
2. Historical accounting records from PG&E's balances for assets that serve San Francisco.
3. Historical accounting records and depreciation study data for PG&E's system as a whole.
4. Standard Iowa survivor curves and our experience estimating service lives for depreciation studies.
5. Estimates used for similar assets for electric utilities in the United States.

The following process was employed to determine reasonable vintages for assets with unknown installation dates:

1. Installation dates that were known and available from GIS remain unchanged for the present study. Conversations with Company SMEs confirmed the reasonableness of these known vintages.

2. In cases where the GIS data provided a substantial proportion of known vintages, such as for distribution poles, Gannett Fleming used the data sources listed above as well as other available information to estimate the vintages of unknown assets. The known vintages served as reliable proxies, and vintages for the unknown assets were determined in proportion to the vintage distribution of known assets.
3. In instances where the GIS data provided an insufficient distribution for the vintages of assets, one of the following approaches was employed:
    a. Ages were estimated in proportion to a reasonable proxy (e.g., unknown overhead services were allocated in proportion to San Francisco's distribution of known meter installations);
    b. Statistically assigned vintages in proportion to the known PG&E San Francisco surviving plant balances by vintage as of July 27, 2021;
    c. Statistically assigned vintages in proportion to known PG&E historic capital additions; or
    d. Assigned vintages consistent with information obtained from the site visit and/or conversations with Company SMEs.

TRANSMISSION

There are far fewer quantities of transmission assets in PG&E's GIS database than the distribution data. Therefore, for non-substation transmission assets, vintages could be determined for each record at the line-item level and relied on information obtained from the site visit and meetings with Company personnel. For substation assets that serve transmission, the approach to assigning vintages was identical to the approach used for substation assets that serve distribution, as described later in this Study. For an account-by-account discussion on how vintages were estimated for transmission assets, please refer to Part VII of this Study.

DISTRIBUTION

The aging process for distribution assets varied by asset class. In several instances PG&E's GIS database on distribution data had mostly complete vintage information (e.g., distribution poles). To determine the estimate for unaged assets, a

variety of methods were employed. For an account-by-account discussion on how a vintage was estimated for distribution assets, please refer to Part VII of this Study.

SUBSTATIONS

The process of estimating vintages for substation assets varied by type of asset. These are discussed in more detail in Part VII of this Study.

RECOMMENDATIONS

A summary of the estimated vintages and approach used for each asset class is included in Table 2.

PACIFIC GAS AND ELECTRIC COMPANY

CITY AND COUNTY OF SAN FRANCISCO ELECTRIC SYSTEM

TABLE 2. SUMMARY OF AVERAGE AGE BY ASSET TYPE AS OF JULY 27, 2021

ASSET CLASS	QUANTITY	PCT AGE KNOWN	AVG VINTAGE	AVG AGE	OLDEST VINTAGE	NEWEST VINTAGE
(1)	(2)	(3)	(4)	(5)	(6)	(7)
TRANSMISSION						
352.00 STRUCTURES AND IMPROVEMENTS						
Structures | Lattice Steel | 115+ kV	187	0%	1951.6	69.4	1948	1972
Structures | Low Profile | 115+ kV	248	0%	1953.7	67.4	1948	1972
Structures | Tube Steel | 115+ kV	274	0%	1957.3	63.8	1948	1972
Structures | Tubular Pole | 115+ kV	55	0%	1963.0	58.1	1963	1963
Structures | Tubular Steel Pole | 115+ kV	139	0%	1948.0	73.1	1948	1948
Structures | Unknown | 115+ kV	17	0%	1948.0	73.1	1948	1948
Structures | Welded Anchorage | 115+ kV	18	0%	1963.0	58.1	1963	1963
Structures | Westinghouse | 115+ kV	3	0%	1948.0	73.1	1948	1948
353.00 STATION EQUIPMENT						
3rd Party Equipment | AIR SW	1	0%	2003.0	18.1	2003	2003
3rd Party Equipment | CIR BRKRS	1	0%	2003.0	18.1	2003	2003
Batteries | VLA	627	100%	2000.2	20.9	1955	2016
Batteries | VRLA	8	100%	2015.5	5.6	2014	2017
Battery Charger	20	80%	2004.9	16.2	1955	2016
Breaker | AIR	4	100%	2000.0	21.1	2000	2000
Breaker | OIL	6	100%	1975.5	45.6	1964	1981
Breaker | SF6	121	100%	2009.6	11.5	1988	2021
Breaker | VAC	12	100%	2016.1	5.0	2014	2019
Circuit Switch	11	91%	2001.8	19.2	1985	2006
Disc Switch	292	63%	2006.1	14.9	1949	2021
EER (Spares)	376,587	100%	2021.0	0.1	2021	2021
Motor Operated Switches	255	76%	2014.2	6.8	2005	2021
Series Reactor | Phase Series	3	100%	1997.0	24.1	1997	1997
Series Reactor | Rush	15	0%	2008.0	13.1	2008	2008
Series Reactor | Series	3	0%	2008.0	13.1	2008	2008
Series Reactor | Unknown	27	0%	2005.0	16.1	2005	2005
SF Protect Relay | EMR	678	92%	1977.4	43.7	1949	2020
SF Protect Relay | MR	1,356	98%	2012.1	8.9	1983	2021
SF Protect Relay | SSR	92	93%	1989.1	32.0	1947	2017
SF Protect Relay | Unknown	9	0%	2003.1	18.0	1994	2016
Shunt Cap	7	100%	2000.6	20.5	1999	2004
Shunt Reactor | IR	3	0%	2010.0	11.1	2010	2010

	ASSET CLASS	QUANTITY	PCT AGE KNOWN	AVG VINTAGE	AVG AGE	OLDEST VINTAGE	NEWEST VINTAGE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Shunt Reactor | OR	3	0%	2016.0	5.1	2016	2016
	Shunt Reactor | SH	19	68%	2010.8	10.3	1974	2021
	Static Var Comp | Static Var	1	100%	2004.0	17.1	2004	2004
	Transformer | 3 Phase	32	88%	2002.3	18.8	1946	2021
	Transformer | CCVT	149	47%	2006.6	14.4	1949	2021
	Transformer | CT	645	28%	2006.3	14.8	1949	2021
	Transformer | PT	77	51%	2005.7	15.4	1949	2021
	Transformer | Single Phase	4	100%	2004.0	17.1	2004	2004
354.00	**TOWERS AND FIXTURES**						
	HP-3 Towers | 115 KV	1	0%	1948.0	73.1	1948	1948
	PX-2 Towers | 115 KV	1	0%	1948.0	73.1	1948	1948
357.00	**UNDERGROUND CONDUIT**						
	HV Manholes	168	0%	1972.3	48.7	1948	2008
358.00	**UNDERGROUND CONDUCTORS AND DEVICES**						
	Martin Service Center Spares	2	100%	2021.0	0.1	2021	2021
	Stockton Service Center Spares	2	100%	2021.0	0.1	2021	2021
	Underground Line Segment | 115 KV	50	90%	1973.6	47.5	1948	2008
	Underground Line Segment | 230 KV	17	80%	1982.6	38.4	1974	2018
DISTRIBUTION							
361.00	**STRUCTURES AND IMPROVEMENTS**						
	Structures | Lattice Steel | <115 kV	44	0%	2005.2	15.9	1949	2021
	Structures | Low Profile | <115 kV	129	0%	2002.4	18.6	1973	2021
	Structures | Tube Steel | <115 kV	145	0%	2004.7	16.3	1973	2021
	Structures | Tubular Pole | <115 kV	18	0%	2005.0	16.1	1988	2021
	Structures | Tubular Steel Pole | <115 kV	49	0%	1986.1	34.9	1973	2018
	Structures | Unknown | <115 kV	4	0%	2011.0	10.1	2006	2018
	Structures | Welded Anchorage | <115 kV	1	0%	2003.0	18.1	2003	2003
362.00	**STATION EQUIPMENT**						
	3rd Party Equipment | CIR BRKRS	2	50%	2003.0	18.1	2003	2003
	Batteries | VLA	538	100%	2011.6	9.5	1992	2021
	Battery Charger	15	80%	2004.8	16.3	1960	2021
	Breaker | AIR	170	98%	1970.0	51.1	1945	2015
	Breaker | OIL	10	100%	1948.3	72.8	1928	1975
	Breaker | SF6	6	100%	1991.3	29.7	1986	2009
	Breaker | VAC	752	99%	2005.9	15.2	1965	2021

ASSET CLASS	QUANTITY	PCT AGE KNOWN	AVG VINTAGE	AVG AGE	OLDEST VINTAGE	NEWEST VINTAGE
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Disc Switch	786	4%	1993.5	27.6	1928	2021
Motor Operated Switches	10	60%	1980.4	40.7	1940	2007
Regulator | Single Phase Regulator	69	96%	1990.0	31.0	1963	2018
Series Reactor | Phase	66	14%	2019.7	1.3	2017	2020
Series Reactor | Phase Series	156	8%	2005.0	16.1	2005	2005
Series Reactor | Series	27	0%	2005.0	16.1	2005	2005
Series Reactor | Unknown	225	1%	2006.6	14.5	2005	2018
SF Protect Relay | EMR	301	99%	1961.1	59.9	1928	2020
SF Protect Relay | MR	506	98%	2011.6	9.5	1992	2020
SF Protect Relay | SSR	65	88%	1995.3	25.8	1946	2014
SF Protect Relay | Unknown	9	0%	2003.8	17.3	1990	2016
Shunt Cap	20	70%	1978.5	42.6	1959	1991
Shunt Reactor | GR	7	0%	1970.0	51.1	1962	1990
Shunt Reactor | IR	8	0%	2015.3	5.8	2010	2016
Shunt Reactor | NG	9	0%	1985.3	35.7	1971	2014
Shunt Reactor | SH	7	29%	2003.3	17.8	1991	2016
Shunt Reactor | Unknown	3	0%	1991.0	30.1	1991	1991
Transformer | 3 Phase	54	96%	1977.9	43.2	1946	2020
Transformer | CCVT	13	92%	2001.6	19.5	1949	2006
Transformer | CT	5,688	0%	2001.2	19.8	1928	2021
Transformer | PT	819	11%	1997.6	23.5	1928	2021
Transformer | Single Phase	7	100%	1967.0	54.1	1967	1967
Transformer | Station Service	110	2%	1991.7	29.4	1945	2020
Voltage Regulator | Pad Mounted	1	100%	2017.0	4.1	2017	2017
Voltage Regulator | Underground	1	0%	2017.0	4.1	2017	2017
364.00 POLES AND FIXTURES						
Electrolier	6,445	5%	2001.8	19.2	1940	2021
Guy Stub	292	87%	1985.1	35.9	1939	2021
Other Structure	430	73%	1971.4	49.7	1928	2013
Pole | Aluminum	1	100%	2000.0	21.1	2000	2000
Pole | Concrete	5	40%	1972.0	49.1	1953	2009
Pole | Fiberglass	5	100%	2005.8	15.3	2000	2019
Pole | Other	4	100%	1998.3	22.8	1969	2021
Pole | Steel	159	42%	1977.5	43.6	1942	2021
Pole | Throughbore	3,304	99%	1999.4	21.7	1925	2021
Pole | Unknown	2	100%	1967.0	54.1	1964	1970
Pole | Wood	27,417	99%	1972.1	48.9	1917	2021

ASSET CLASS	QUANTITY	PCT AGE KNOWN	AVG VINTAGE	AVG AGE	OLDEST VINTAGE	NEWEST VINTAGE
(1)	(2)	(3)	(4)	(5)	(6)	(7)
365.00 OVERHEAD CONDUCTORS AND DEVICES						
Capacitor Bank | Overhead	93	98%	1989.2	31.8	1981	2015
Fuse | Overhead	1,800	98%	2002.8	18.3	1941	2021
Interrupter | Overhead	4	100%	2016.8	4.3	2016	2019
OH DC Secondary Conductor	5	0%	1993.0	28.1	1993	1993
OH DC Service Conductor	1	0%	1974.0	47.1	1974	1974
Primary OH Conductor	6,004	57%	1988.9	32.2	1961	2012
Primary OH Conductor | Single	2,044	17%	1975.7	45.3	1925	2021
Primary OH Conductor | Three	15,548	19%	1978.9	42.1	1923	2021
Primary OH Conductor | Two	2,244	24%	1977.5	43.6	1925	2021
Recloser | Overhead	178	92%	2014.2	6.8	1998	2021
Secondary OH Conductor	45,747	25%	1982.5	38.6	1922	2021
Switch | Overhead	2,542	91%	1998.6	22.5	1919	2021
Switches | Overhead	5	80%	2010.8	10.3	2003	2019
366.00 UNDERGROUND CONDUIT						
CIC	29,155	43%	1984.7	36.4	1914	2021
Conduit	4,170,572	20%	1993.5	27.6	1910	2021
Duct Bank	3,051,268	29%	1990.0	31.0	1910	2021
Duct Junction	4,990	7%	1992.0	29.1	1920	2021
MV Manholes	42	0%	1978.2	42.9	1974	2018
Primary And Secondary Enclosure	96	5%	1995.1	26.0	1967	2021
Primary Enclosure	8,041	7%	1992.1	29.0	1920	2021
Secondary Enclosure	28,687	7%	1994.1	27.0	1964	2021
Subsurface Structures | Duct Junction	22	59%	2018.0	3.0	2018	2019
Subsurface Structures | Primary Enclosure	8	75%	2017.8	3.3	2015	2019
Subsurface Structures | Secondary Enclosu	1	100%	2015.0	6.1	2015	2015
Subsurface Structures | Vault	26	0%	1948.0	73.1	1948	1948
Vault	6,595	7%	1992.0	29.1	1910	2021
367.00 UNDERGROUND CONDUCTORS AND DEVICES						
Capacitor Bank | Pad Mounted	163	98%	1998.0	23.1	1981	2021
CIC	19,434	43%	1984.7	36.4	1920	2021
DC Fuses / Distribution Box	28	0%	2003.0	18.1	2003	2003
DC Risers	138	0%	2017.0	4.1	2017	2017
Fuse | Pad Mounted	8	75%	1993.9	27.2	1979	2015
Fuse | Subsurface	351	99%	2002.7	18.4	1975	2021
Fuse | Underground	4	50%	2005.3	15.8	2000	2021
Interrupter | Pad Mounted	10	50%	2013.4	7.7	2009	2019
Interrupter | Subsurface	484	87%	2015.3	5.8	1987	2021
Interrupter | Underground	79	97%	2010.8	10.2	2004	2020

	ASSET CLASS	QUANTITY	PCT AGE KNOWN	AVG VINTAGE	AVG AGE	OLDEST VINTAGE	NEWEST VINTAGE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Primary Riser	3	0%	2005.0	16.1	1985	2018
	Primary UG Conductor	23,663	70%	1996.7	24.4	1921	2021
	Primary UG Conductor & Conduit	34,285	19%	1990.3	30.8	1962	2021
	Risers | Primary	2,452	15%	2017.5	3.5	1974	2021
	Risers | Secondary	5,533	12%	2015.9	5.2	1962	2021
	Secondary UG Conductor	64,456	28%	1992.5	28.5	1914	2021
	Streetlight Box	455	10%	1994.0	27.1	1925	2021
	Switch | Pad Mounted	638	97%	2008.3	12.7	1971	2021
	Switch | Subsurface	7,944	87%	2005.5	15.6	1967	2021
	Switch | Underground	1,386	46%	2007.2	13.9	1948	2021
	Switches | Subsurface	5	40%	2015.0	6.1	2015	2015
	UG DC Secondary Conductor	41	0%	1983.0	38.1	1983	1983
	UG DC Service Conductor	5	0%	1974.0	47.1	1974	1974
368.01	**LINE TRANSFORMERS - OVERHEAD**						
	Distribution Transformers (Spares)	772	100%	2021.0	0.1	2021	2021
	OH DC Rectifier	16	94%	1996.1	25.0	1990	2011
	Transformer | Distribution Overhead	6,635	98%	2003.6	17.4	1930	2021
	Transformer | Street Light	28	39%	2003.2	17.9	1958	2021
368.02	**LINE TRANSFORMERS - UNDERGROUND**						
	Network Protector	1,144	24%	1996.3	24.8	1922	2021
	Network Protectors (Spares)	66	100%	2021.0	0.1	2021	2021
	Network Transformers (Spares)	29	100%	2021.0	0.1	2021	2021
	Padmount Structure | Pad	1,372	17%	2004.4	16.6	1949	2021
	Padmount Structure | Pedestal	50	28%	2009.2	11.8	1985	2021
	Transformer | Distribution Padmount	1,376	98%	2002.3	18.8	1949	2021
	Transformer | Distribution Subsurface	3,767	99%	2000.0	21.0	1938	2021
	Transformer | Equipment	7	100%	1986.3	34.8	1971	2005
	Transformer | Network	1,184	86%	1995.3	25.8	1964	2021
	Transformer | Secondary	3	0%	2015.7	5.4	2006	2021
	UG DC Rectifier	158	89%	2004.3	16.7	1990	2015
369.01	**SERVICES - OVERHEAD**						
	Service Location | Overhead	130,854	4%	1974.1	46.9	1921	2021
369.02	**SERVICES - UNDERGROUND**						
	Service Location | Underground	83,660	4%	1974.1	46.9	1921	2021
370.00	**METERS**						
	Current Transformer	23,468	100%	2000.0	21.1	1928	2021

	ASSET CLASS	QUANTITY	PCT AGE KNOWN	AVG VINTAGE	AVG AGE	OLDEST VINTAGE	NEWEST VINTAGE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Customer Meter | Legacy	10,188	100%	1980.3	40.8	1921	2021
	Potential Transformer | Low Voltage	32	100%	1992.3	28.8	1974	2017
	Potential Transformer | Medium Voltage	561	100%	2006.5	14.6	1952	2021
	Primary Meter | Not Populated	16	81%	1995.1	25.9	1977	2015
	Primary Meter | Overhead	174	92%	2000.2	20.8	1941	2021
	Primary Meter | Underground	2	100%	2014.5	6.6	2014	2015
370.01	**METERS - AMI**						
	Customer Meter | AMI	407,422	100%	2012.2	8.9	2001	2021
	Smart Meter | Access Point	74	0%	2011.4	9.7	2009	2019
	Smart Meter | Relay	132	0%	2012.6	8.4	2009	2021
373.03	**STREETLIGHTING AND SIGNAL SYSTEMS**						
	Streetlights	17,969	90%	2016.6	4.5	1921	2021
GENERAL							
397.08	**COMMUNICATION EQUIPMENT**						
	Fiber | Distribution | Underground	59	0%	2000.0	21.1	2000	2000
	Fiber | Telecom | Underground	26	0%	2000.0	21.1	2000	2000
	Fiber | Transmission | Overhead	1	0%	2000.0	21.1	2000	2000
	Fiber | Transmission | Underground	20	0%	2000.0	21.1	2000	2000

PART VI. SERVICE LIFE CONSIDERATIONS

PART VI. SERVICE LIFE CONSIDERATIONS

The service life estimates were based on judgment that considered several factors. The primary factors were the currently authorized estimates for PG&E; statistical analyses of PG&E data; current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric utility companies. For the transmission and distribution plant accounts in this study, survivor curves were estimated using the retirement rate method. However, due to the relatively limited historical data available for PG&E's assets serving San Francisco, other factors were given more consideration, including analyses performed for depreciation studies of PG&E's entire system.

For PG&E's system as a whole, the most recent depreciation study conducted for the 2023 GRC, which was filed prior to the valuation date on June 30, 2021, is more reflective of current operations than those from the 2020 GRC due to the availability of more contemporary data and information at the time of the 2023 GRC. For most transmission and distribution asset classes, the service life estimates recommended in the 2023 GRC have similar or longer service lives than those authorized in the 2020 GRC. While issued subsequent to the valuation date and not considered as an input to the survivor curves used for the RCNLD calculation, the Commission's Final Decision further extended service lives of some of these accounts. The service lives recommended in the 2023 GRC were considered when estimating service lives for PG&E's SF electric system assets. Had the 2023 GRC Decision been given more weight in the analysis, the result would be longer lives than we have recommended and a higher RCNLD.

Further, the results of this study are applicable to PG&E's SF Electric system as opposed to PG&E as a whole. There are several differences between assets located in

the San Francisco area and the rest of PG&E's system that support a longer service life for said San Francisco located assets. Many of PG&E's retirements in its transmission system as a whole are due to wildfire hardening or other environmental impacts. San Francisco has about half a mile of overhead transmission that is in a coastal region with the remaining transmission underground due to the density of the city.

Similarly, a larger portion of San Francisco's distribution system is an underground network system built in duct, which is different from most of PG&E's radial systems outside the city. The underground network is primarily replaced due to capacity and has been upgraded over time as the systems grow and has typically had longer average lives than PG&E's entire system. Due to different forces of retirement, some overhead assets such as poles have also experienced longer lives, on average, than those in PG&E's system as a whole.

PG&E's substations in San Francisco also have differences. More equipment is indoors with different configurations due to congestion in the city. Substation buildings are also different construction. Additionally, the Company has several Gas-Insulated Substations in San Francisco.

RECOMMENDATIONS

Several data sources were used for Gannett Fleming's analyses of San Francisco service lives. These included available historical data, for both San Francisco and PG&E's entire system, that could be used for statistical life analyses; information from site visits for this study and previous studies; information from SMEs for this study and previous depreciation studies; and information and estimates from studies of electric systems that were as comparable as possible to PG&E's, such as those that contained or were primarily in large urban environments with mild or temperate climates. Consideration for

each of these data sources was given based on the extensiveness and reliability of data and comparability to PG&E's assets.

A list of accounts for which a survivor curve was estimated in the service life study is included in the table below. A narrative description supporting each estimate is included in Part VII of this Study.

Table 3.
Summary of Service Life Estimates

	Account	2020 GRC Authorized	2023 GRC PG&E Proposed	2023 GRC PG&E Authorized	PG&E SF Electric System Proposed
	Transmission				
352.00	Structures and Improvements	70-R3	70-R3	70-R3	75-R2
353.00	Station Equipment	46-R2	47-R2	47-R2	47-R2
354.00	Towers and Fixtures	75-R4	75-R4	75-R4	75-R4
357.00	Underground Conduit	65-R4	65-R4	65-R4	70-S1
358.00	Underground Conductors and Devices	55-R3	55-R3	55-R3	55-R1
	Distribution				
361.00	Structures and Improvements	70-R3	70-R3	70-R3	70-R3
362.00	Station Equipment	46-R1.5	50-R1	53-R1	50-R1
364.00	Poles and Fixtures	44-R2	44-R2	47-R1.5	50-S1.5
365.00	Overhead Conductors and Devices	46-R2	44-R1.5	48-R1.5	50-S1.5
366.00	Underground Conduit	65-R4	70-R4	70-R4	70-R3
367.00	Underground Conductors and Devices	50-R3	52-R3	55-R3	55-S0.5
368.01	Line Transformers – Overhead	32-R2.5	32-R2.5	37-R2.5	32-R2.5
368.02	Line Transformers – Underground	33-R2.5	34-R2.5	34-R2.5	34-R2.5
369.01	Services – Overhead	55-R2.5	55-R2.5	64-R2	55-R2.5
369.02	Services – Underground	50-R4	50-R4	58-R3	55-R2.5
370.00	Meters	20-R2	15-R3	15-R3	30-R1.5
370.01	Meters - AMI	20-R2	15-R3	15-R3	20-R2
373.03	Street Lighting and Signal System – Lamps and Equipment	25-L0	25-L0	25-L0	25-L0

	Account	2020 GRC Authorized	2023 GRC PG&E Proposed	2023 GRC PG&E Authorized	PG&E SF Electric System Proposed
	General				
397.08	Communication Equipment	20-SQ	15-SQ	15-SQ	15-SQ

PART VII. SERVICE LIFE AND VINTAGE ESTIMATION BY ACCOUNT

PART VII. SERVICE LIFE AND VINTAGE ESTIMATION BY ACCOUNT

TRANSMISSION

OVERHEAD

PG&E's transmission system in San Francisco is primarily an underground system. Due to the limited amount of assets in San Francisco, overhead transmission assets in Accounts 355 Poles and Fixtures and 359 Roads and Trails are not included in this study.

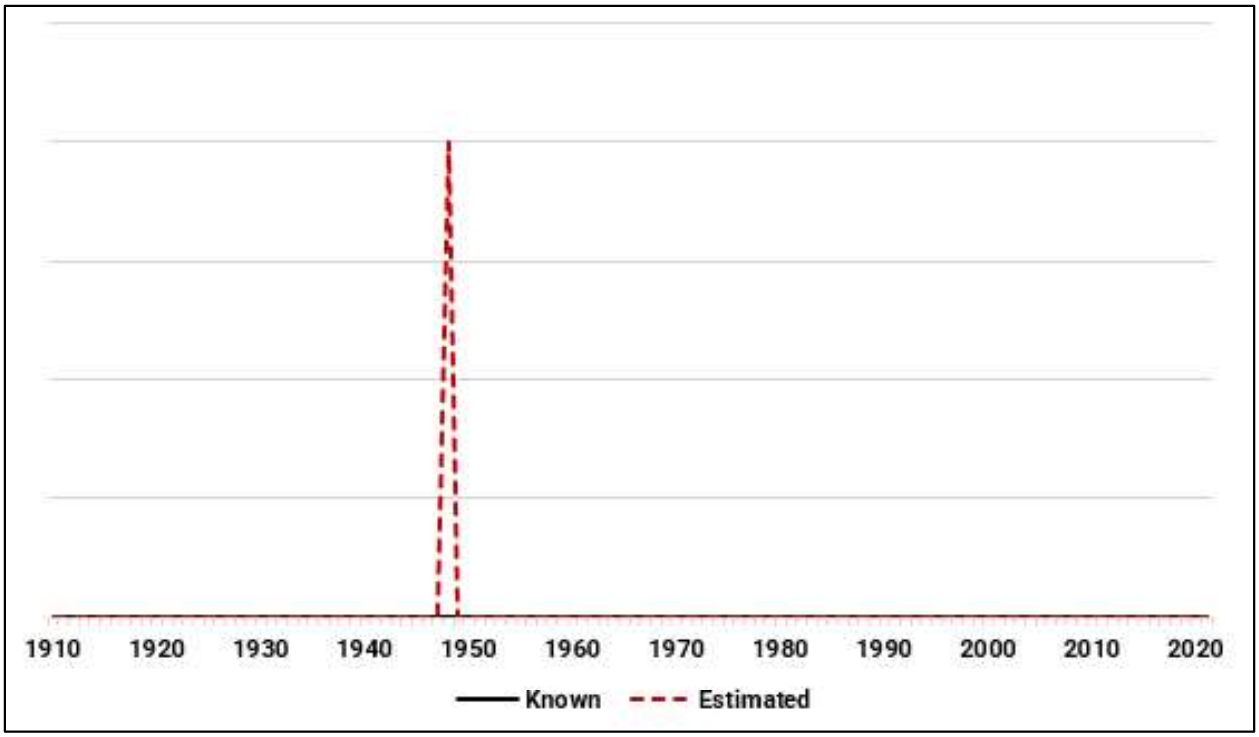
Account 354 Towers and Fixtures

This account encompasses the costs associated with transmission towers and their associated fixtures. PG&E utilizes steel lattice towers for its transmission infrastructure in San Francisco. Assets in the overhead system are limited primarily to the transmission line that runs between the Hunters Point and Mission substations.

ASSET AGE ANALYSIS

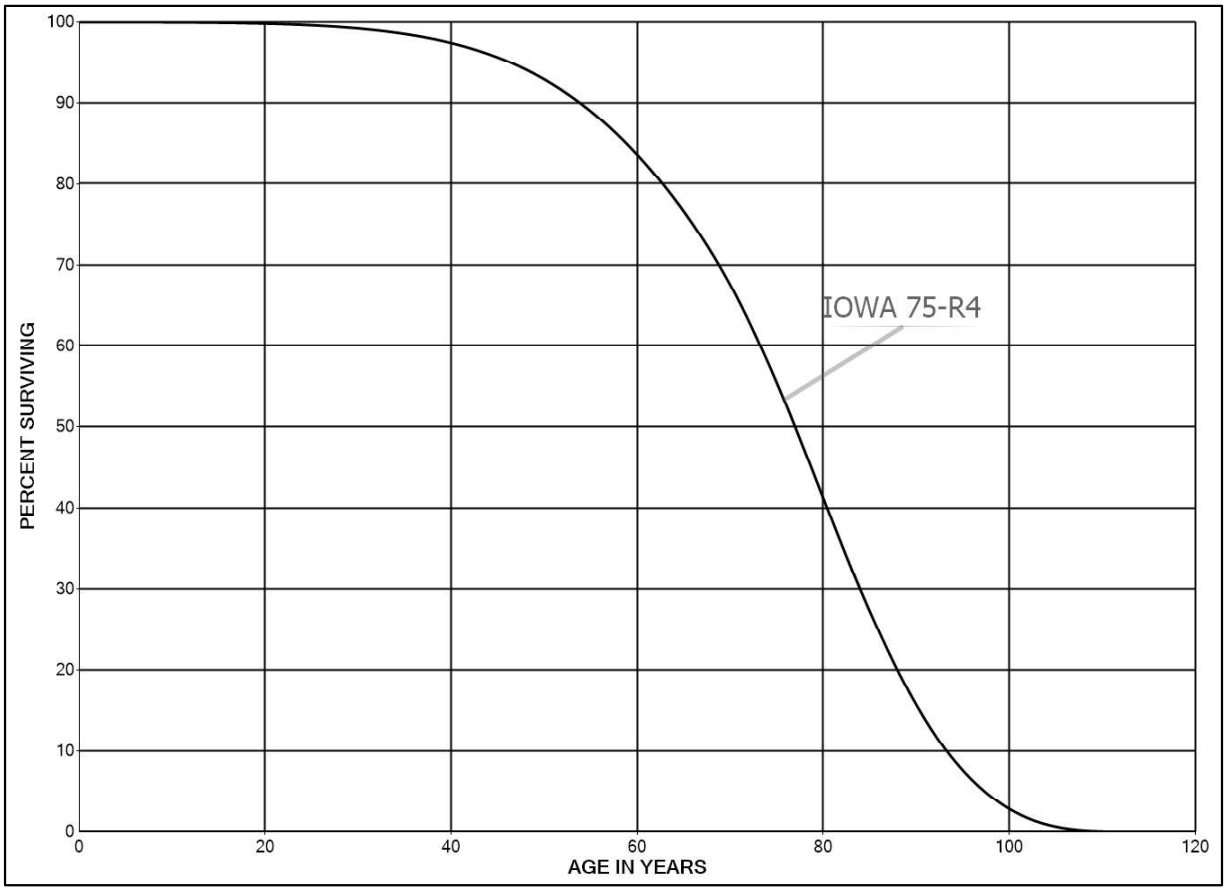
Information about the Company's overhead transmission towers was obtained from available GIS records, meetings with PG&E SMEs, and site visits. The assets in this account include two 115 kV tower assets, consisting of one HP-3 tower and one PX-2 tower. Installation years were not available in the source records for these assets. Vintages for the structures in this account were aligned with proximate substation installation dates. Both tower assets were assigned a 1948 vintage.

See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

The 75-R4 survivor curve for PG&E's electric system as a whole was authorized in the 2020 GRC and proposed in the 2023 GRC. Based on a review of PG&E's assets serving San Francisco, their ages and available data, the same survivor curve is recommended in this case. The 75-R4 survivor curve is recommended and is shown in the chart below.


IOWA 75-R4
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120

UNDERGROUND

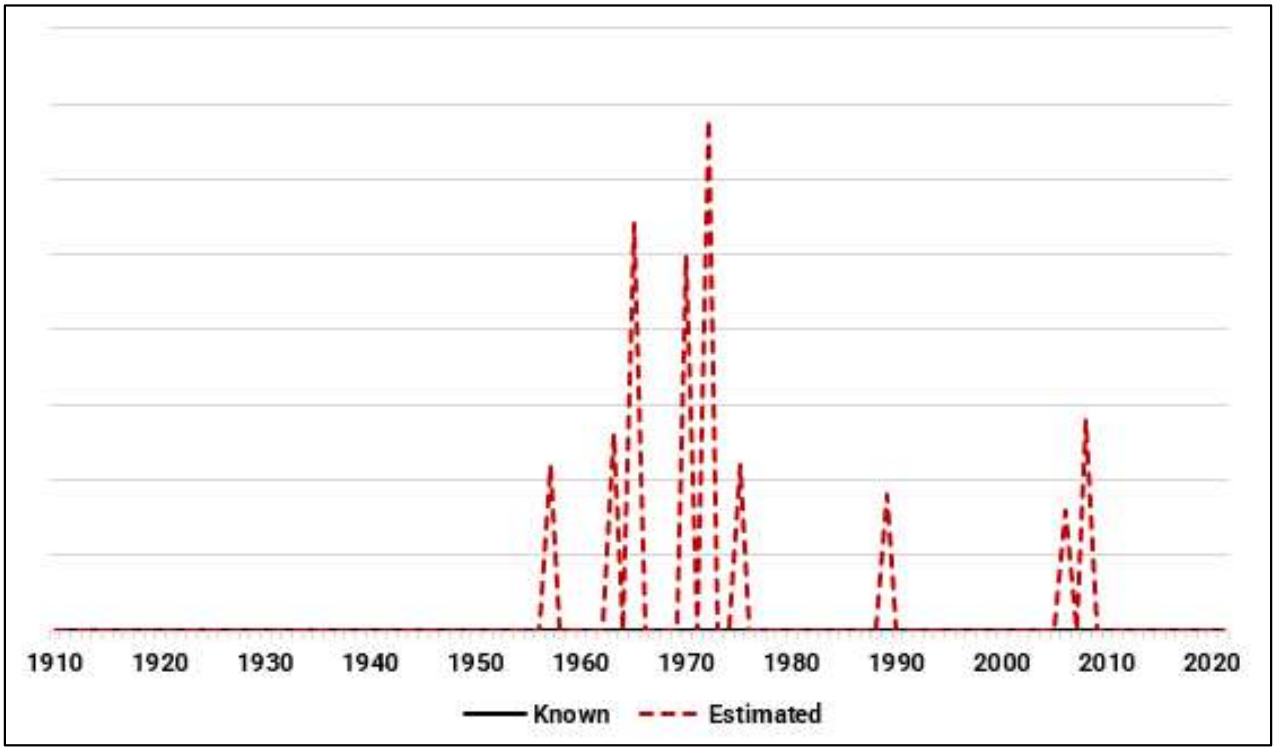
Account 357 Underground Conduit

This account includes the cost of underground conduit and tunnels for housing transmission cables and wires. PG&E has 115 kV and 230 kV underground transmission lines of various vintages and construction serving San Francisco. The Company has two types of conduit that have been installed in different periods of time. The 115 kV and 230 kV pipe type cable underground conduits are cathodically protected steel. Conduits with 230 kV contain cable oil, and cables for lower voltages have pressurized nitrogen. The 115 kV lines have been in service for around 40 to 60 years, and the 230 kV lines have been in service for around 40 years. The other type of conduit is for 115 kV and 230 kV XLPE cables, which are installed in PVC conduits encased in concrete and have been in service for approximately 25 years or less.

ASSET AGE ANALYSIS

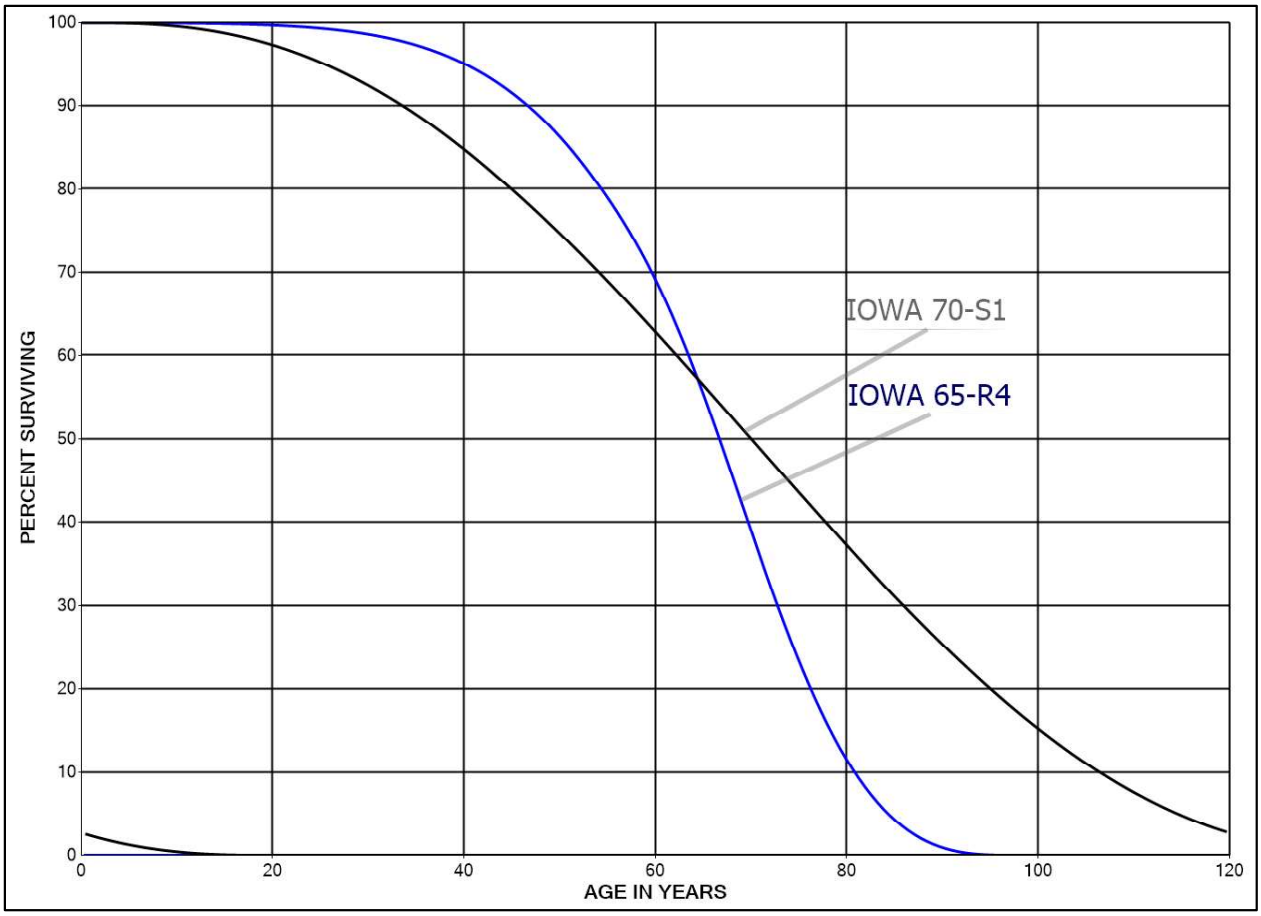
Information about the Company's underground transmission conduit was obtained from available GIS records, meetings with PG&E SMEs, and site visits. The assets aged in this account include 168 high-voltage manholes. Installation years were not available in the source records for these manholes, and vintages were aligned with proximate substation installation dates.

See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

The 65-R4 survivor curve for PG&E's electric system as a whole was authorized in the 2020 GRC and proposed in the 2023 GRC. The San Francisco data, however, shows few retirements of underground conduit compared to the Company as a whole. Based on a review of PG&E's assets serving San Francisco, their ages and available data, a somewhat longer and lower-mode survivor curve is recommended. The 70-S1 is recommended and is shown along with the 65-R4 survivor curve in the chart below.


PERCENT SURVIVING
AGE IN YEARS
IOWA 70-S1
IOWA 65-R4
0
10
20
30
40
50
60
70
80
90
100
0
20
40
60
80
100
120

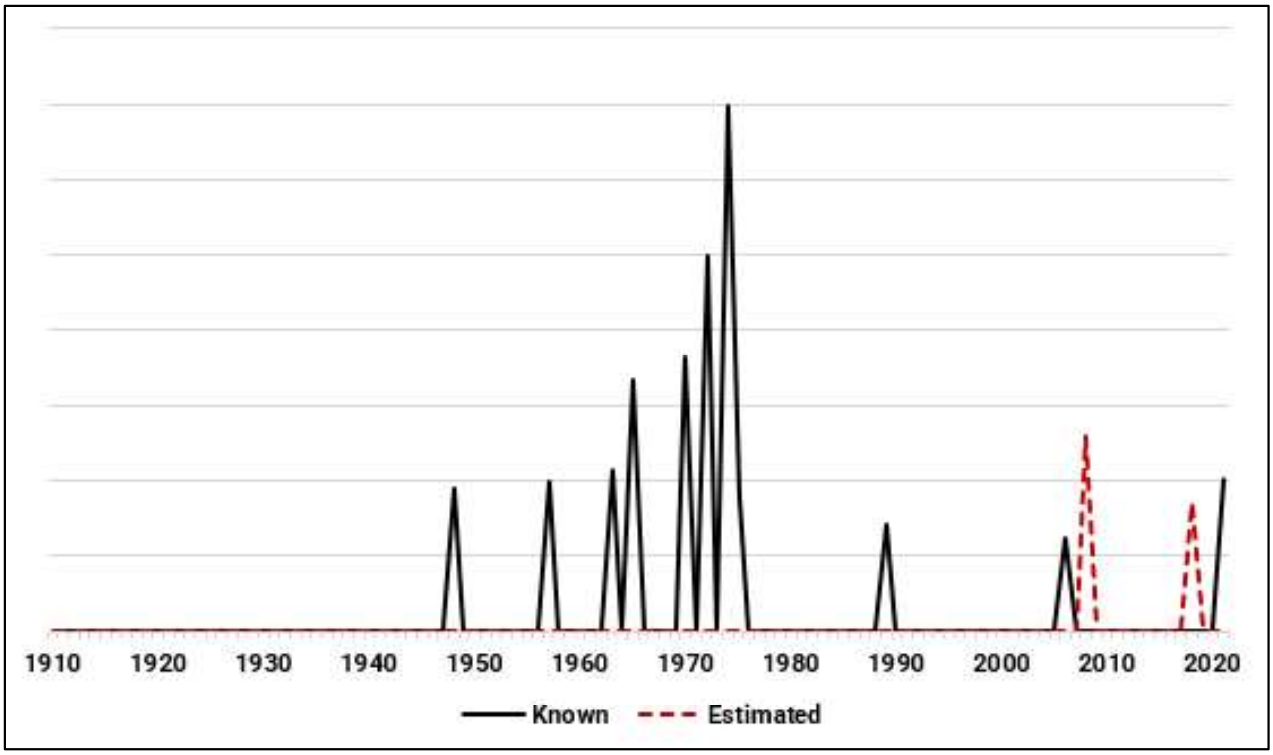
Account 358 Underground Conductors and Devices

This account includes the cost of underground conductors and devices for electric transmission. Similar to Account 357, there are different types of construction depending on age, voltage and location. Some cable is in oil- or high-pressure gas-filled pipe, while newer cable is more commonly XLPE. The newer 230 kV line from Potrero to Embarcadero is a submersible cable that runs under the San Francisco Bay.

ASSET AGE ANALYSIS

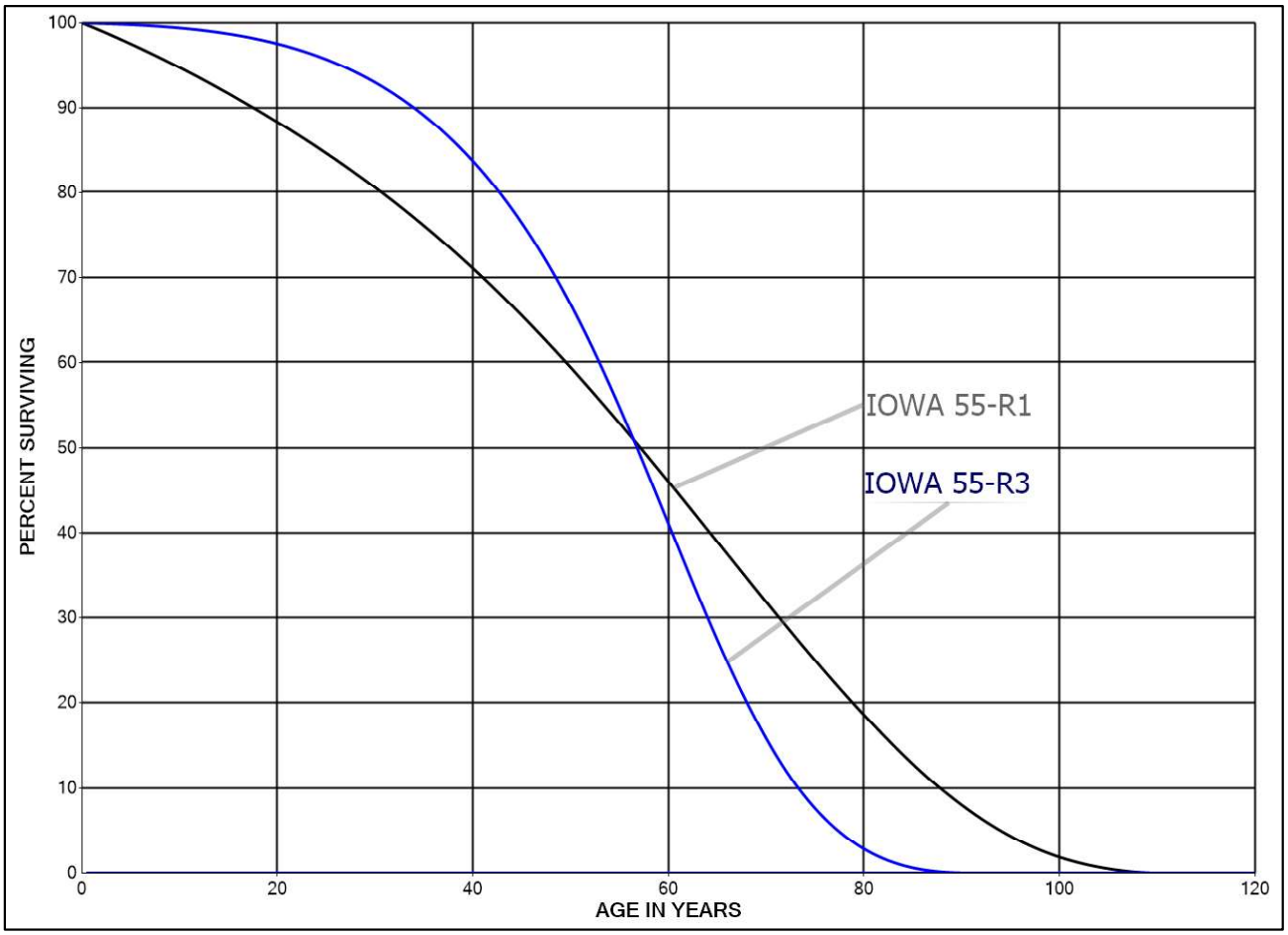
As with Account 357, most ages were available in the Company's records. For those for which vintage information was not available, vintages were determined using the ages of other PG&E transmission assets. Each was reviewed in relationship to PG&E's installation years of high-voltage substations that serve transmission to assign vintages to each asset, as underground transmission assets were, generally, installed at a similar time to the construction of these substations. The assets aged in this account include two Martin Service Center spares, two Stockton Service Center spares, 50 underground 115 kV line segments and 17 underground 230 kV line segments.

See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

Underground conductor is most commonly replaced due to capacity upgrades, as well as damage and other physical factors. The 55-R3 was authorized in the 2020 GRC and proposed in the 2023 GRC. Similar to Account 357, based on a review of the vintages of assets in the system and other Company information, an estimate with a lower mode is recommended. The recommended 55-R1 and the 55-R3 survivor curves are shown in the graph below.



SUBSTATIONS

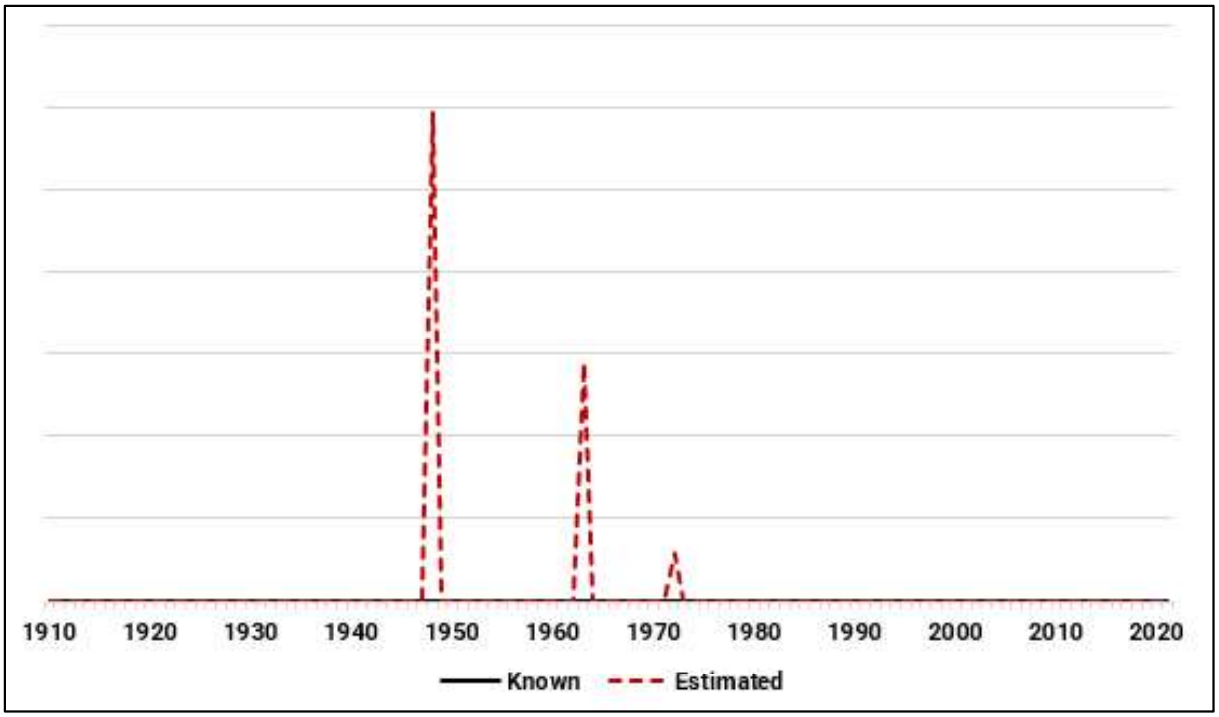
Account 352 Structures and Improvements

This account includes the cost of structures and improvements for electric transmission operations. Real estate is not included in the Study and, as a result, the assets included in this account are structural components of the substations. Unlike PG&E's system as a whole, a majority of San Francisco's substations (including Martin) that serve transmission (four out of these seven stations) are indoor or partially indoor facilities.

ASSET AGE ANALYSIS

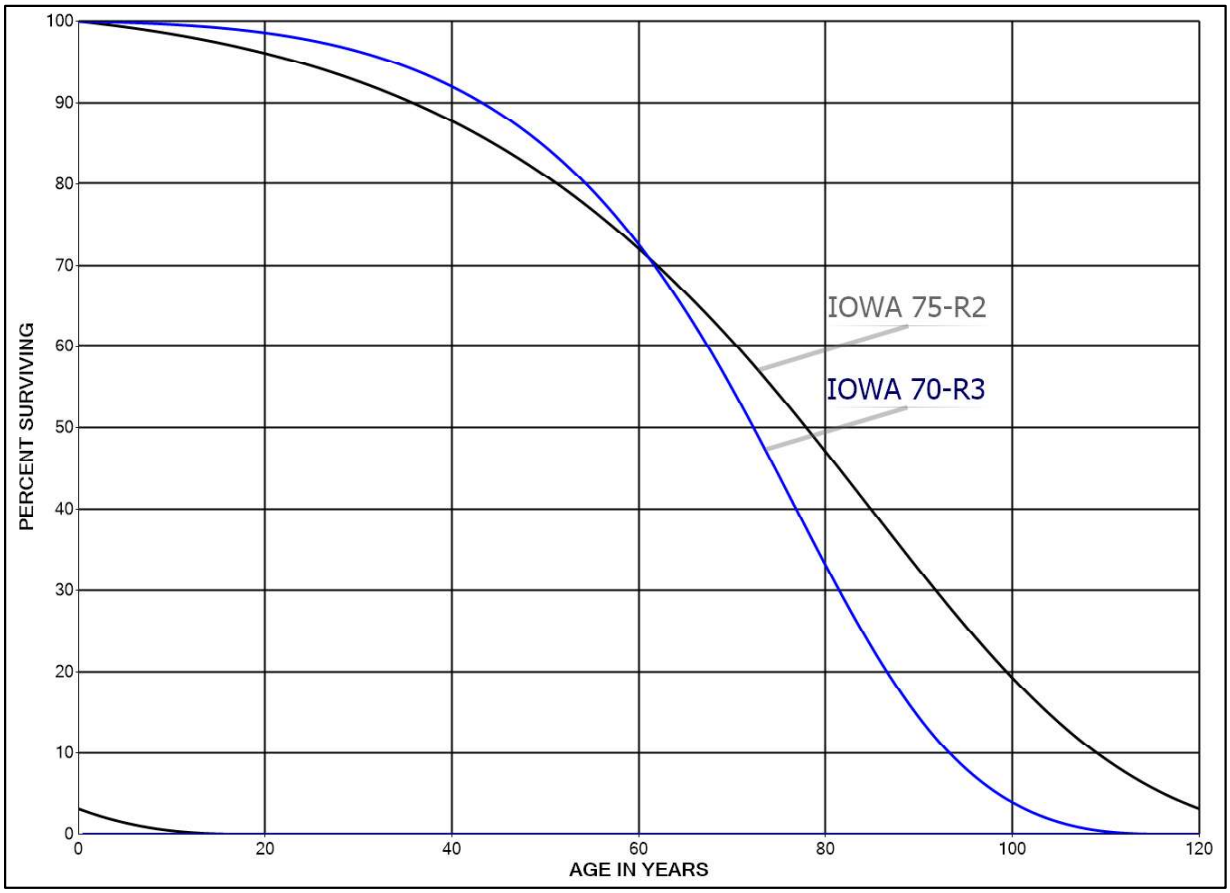
The assets vintaged in this account include PG&E's transmission substation facilities and their accompanying structures and buildings within the site. Information about the installation dates of facilities and buildings was obtained during the site visits to the substations that serve transmission. For the structures within the substations, higher voltage assets, defined as 115 kV or greater, were assigned a vintage that matched the original install year of the facility. The assets aged in this account include 187 lattice steel structures, 248 low profile structures, 274 tube steel structures, 55 tubular pole structures, 139 tubular steel pole structures, 17 unknown structure records, 18 welded anchorage structures and three Westinghouse structures, for a total of 941 structure records.

See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

The structures in this account consist primarily of control buildings at substations. The buildings are constructed of brick, block and metal. Retirements are generally the result of deterioration or deficiency according to current design standards. In the 2023 GRC, Gannett Fleming recommended the 70-R3 survivor curve. Given that many of the structures within San Francisco are located at indoor facilities, these assets are expected to be less susceptible to environmental deterioration and to experience longer lives than the 70 years authorized for PG&E. Given the location and types of construction of the facilities, a somewhat longer life for San Francisco assets is expected than for the system as a whole, and the 75-R2 is recommended. This estimate, along with the 70-R3 survivor curve, is shown in the chart below.


PERCENT SURVIVING
AGE IN YEARS
IOWA 75-R2
IOWA 70-R3
0
10
20
30
40
50
60
70
80
90
100
0
20
40
60
80
100
120

Account 353 Station Equipment

This account includes the cost of station equipment for electric transmission, specifically transforming, conversion and switching equipment used for the purpose of changing the characteristics of electricity in connection with transmission or for controlling transmission circuits. Unlike most substations within PG&E's service area, the majority of San Francisco substations are indoor or partially indoor facilities. The Company has also installed gas insulated substation equipment at substations in recent years.

ASSET AGE ANALYSIS

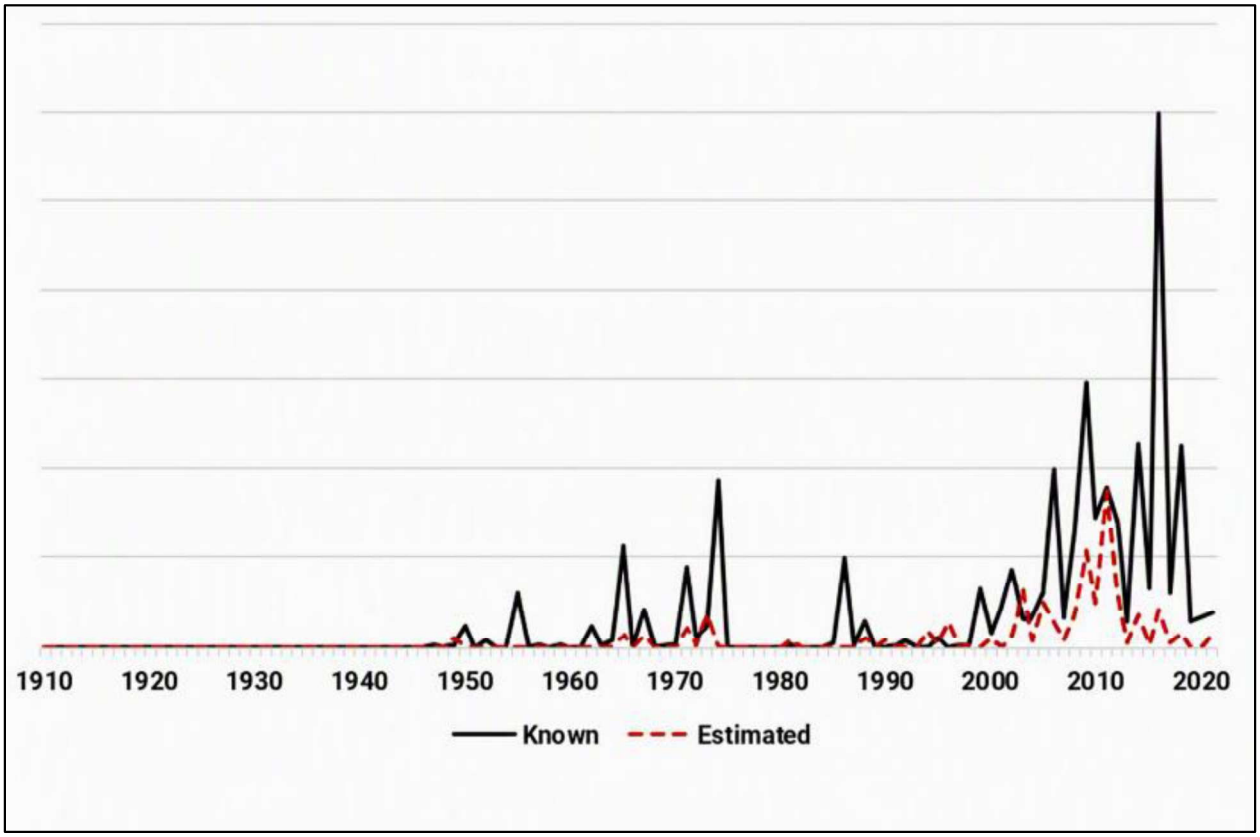
The following list provides all station equipment assets included in the present study. For any instance where there were some unknown installation years, the sources of information and/or methods used to estimate vintages are described:

- **3rd Party Equipment:** The assets aged in this group include one air switch and one circuit breaker. Installation years were not available in the source records for these assets, and the assets were aligned with a 2003 vintage.
- **Batteries:** The assets aged in this group include 627 VLA batteries and eight VRLA batteries. There were no unknown installation years for battery assets.
- **Battery Chargers:** The assets aged in this group include 20 battery chargers. Ages for most battery charger assets were known. Ages for assets with unknown installation years were manually estimated after reviewing the known installation years of batteries.
- **Breakers:** The assets aged in this group include four air breakers, six oil breakers, 121 SF6 breakers and 12 vacuum breakers. There were no unknown installation years for most circuit breaker assets.
- **Circuit Switches:** The assets aged in this group include 11 circuit switches. Ages for most circuit switch assets were known. For assets with unknown installation years, vintages were aligned with known circuit-switch vintages.
- **Disconnect Switches:** The assets aged in this group include 292 disconnect switches. Assets with an unknown installation year were assigned a vintage in

proportion to the age of known circuit breakers within a given station, which provided the most comprehensive database of known vintages.

- **EER Spares:** The assets aged in this group include 376,587 EER spares. There were no unknown installation years for EER spares.
- **Motor Operated Switches:** The assets aged in this group include 255 motor operated switches. Ages for most motor operated switch assets were known. For assets with unknown installation years, vintages were aligned with known motor-switch vintages.
- **Series Reactors:** The assets aged in this group include three phase series reactors, 15 rush reactors, three series reactors and 27 reactors with unknown subtype. Assets with an unknown installation year were assigned a vintage aligned with the installation year of the related substation.
- **Protection Relays:** The assets aged in this group include 678 EMR protection relays, 1,356 MR protection relays, 92 SSR protection relays and nine protection relays with unknown subtype. Assets with an unknown installation year were assigned a vintage in proportion to known protection relay ages.
- **Shunt Capacitor:** The assets aged in this group include seven shunt capacitors. There were no unknown installation years for shunt capacitor assets.
- **Shunt Reactors:** The assets aged in this group include three IR shunt reactors, three OR shunt reactors and 19 SH shunt reactors. Assets with an unknown installation year were aligned with known shunt-reactor vintages or assigned to a fixed vintage where appropriate.
- **Static VAR Compensation Equipment:** The assets aged in this group include one static VAR compensator. There were no unknown installation years for static VAR compensation equipment.
- **Transformers:** The assets aged in this group include 32 three-phase transformers, 149 CCVTs, 645 current transformers, 77 potential transformers and four single-phase transformers. Ages for most transformer assets were known. Certain transformer installation dates were manually aged using information obtained during the site visit.

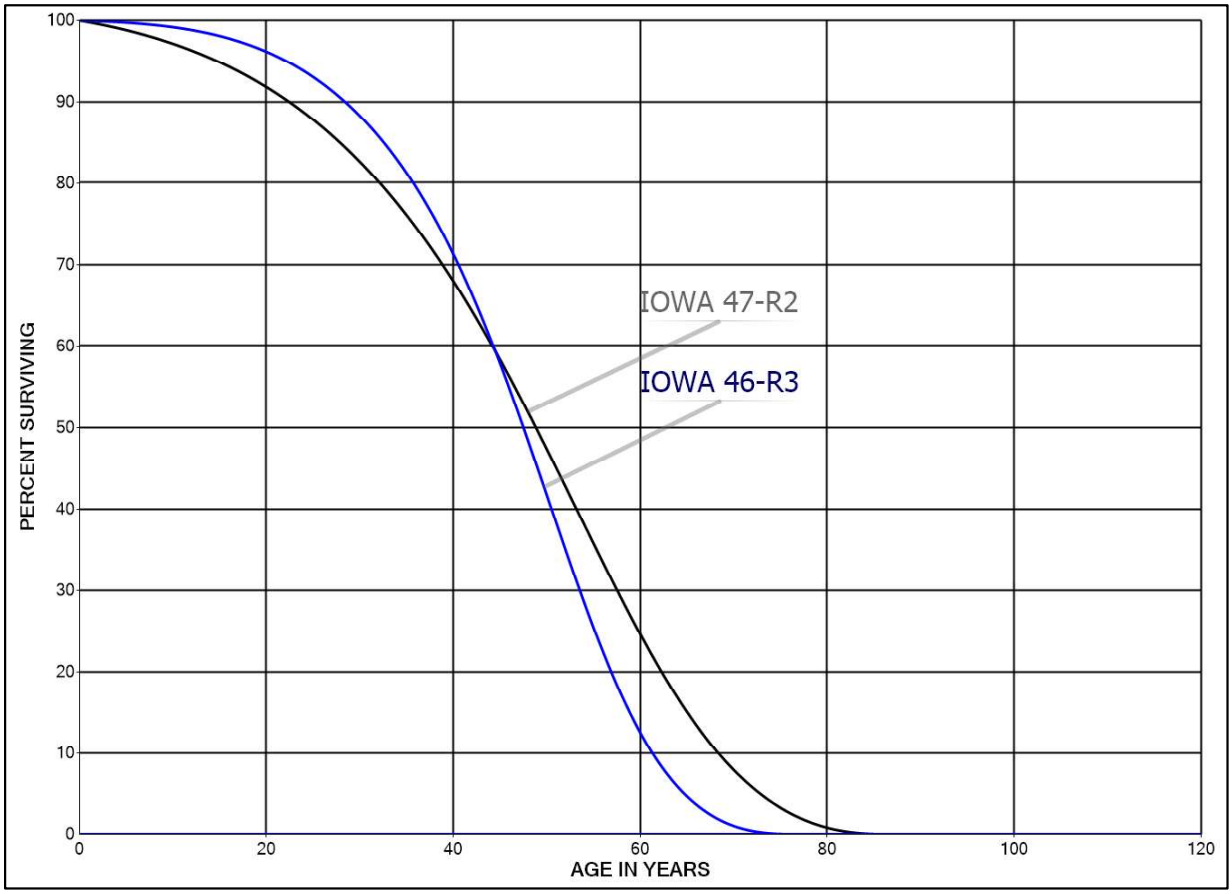
See the figure below for the asset quantities (known and estimated) by vintage for this account (excluding spares, which were all vintage 2021):



SERVICE LIFE ANALYSIS

Two of the largest groups of assets in this account are transformers and circuit breakers. Based on discussions with management, the industry expects physical lives of transformers to be around 50 years and the physical lives of circuit breakers to be around 40 years. However, this expectation of physical life of these assets does not include the impact of other forces of retirements such as capacity. The results of actuarial life analysis for all PG&E assets indicate average service lives of around 45 years or somewhat longer. Low and mid-mode R curves are most common for this type of equipment. In the 2023 GRC, the 47-R2 survivor curve was proposed. While there are factors that could impact service lives of substation assets in different ways for PG&E's assets serving San Francisco than the system, overall Gannett Fleming expects relatively similar service life experience for PG&E's assets serving San Francisco, and the 47-R2 is recommended.

This estimate, along with the 46-R2 survivor curve authorized in the 2020 GRC, is shown in the chart below.



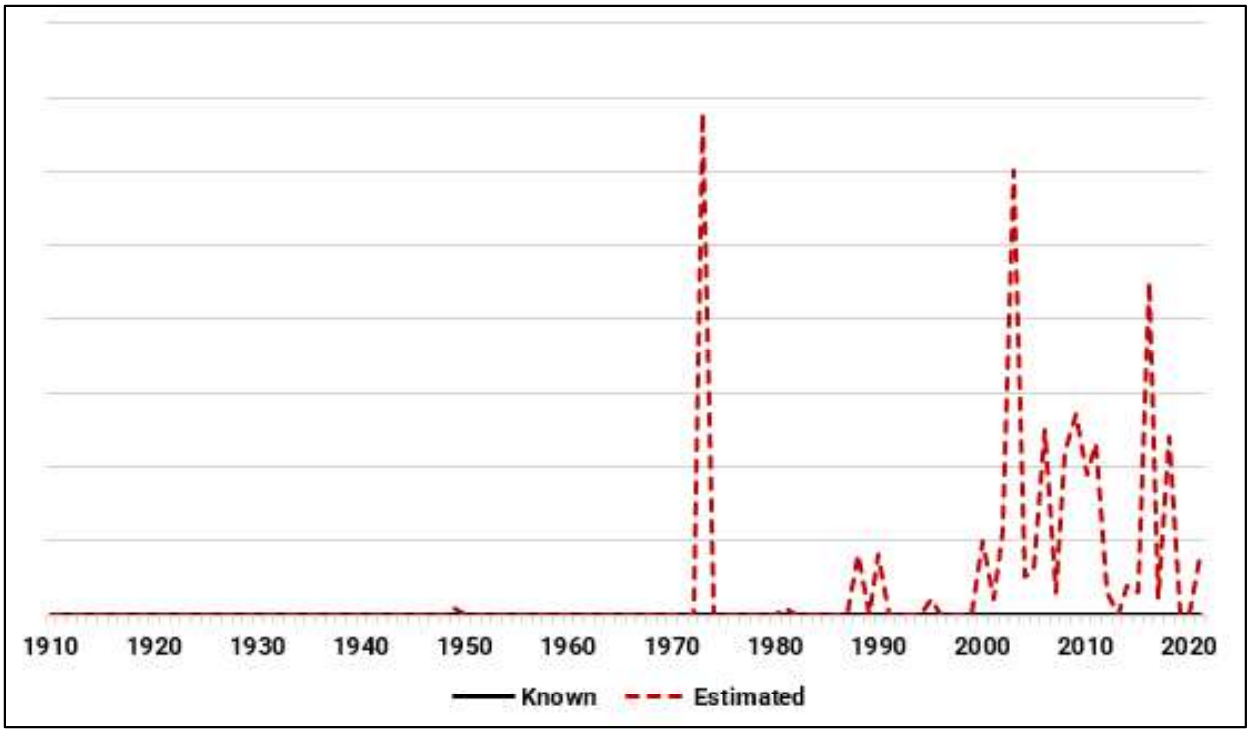
Account 361 Structures and Improvements

This account includes the cost of structures and improvements used in connection with electric distribution substations. Real estate is not included in the Study and, as a result, the assets included in this account are structural components of the substations. Like transmission substations, more assets are indoors in San Francisco than PG&E's system as a whole.

ASSET AGE ANALYSIS

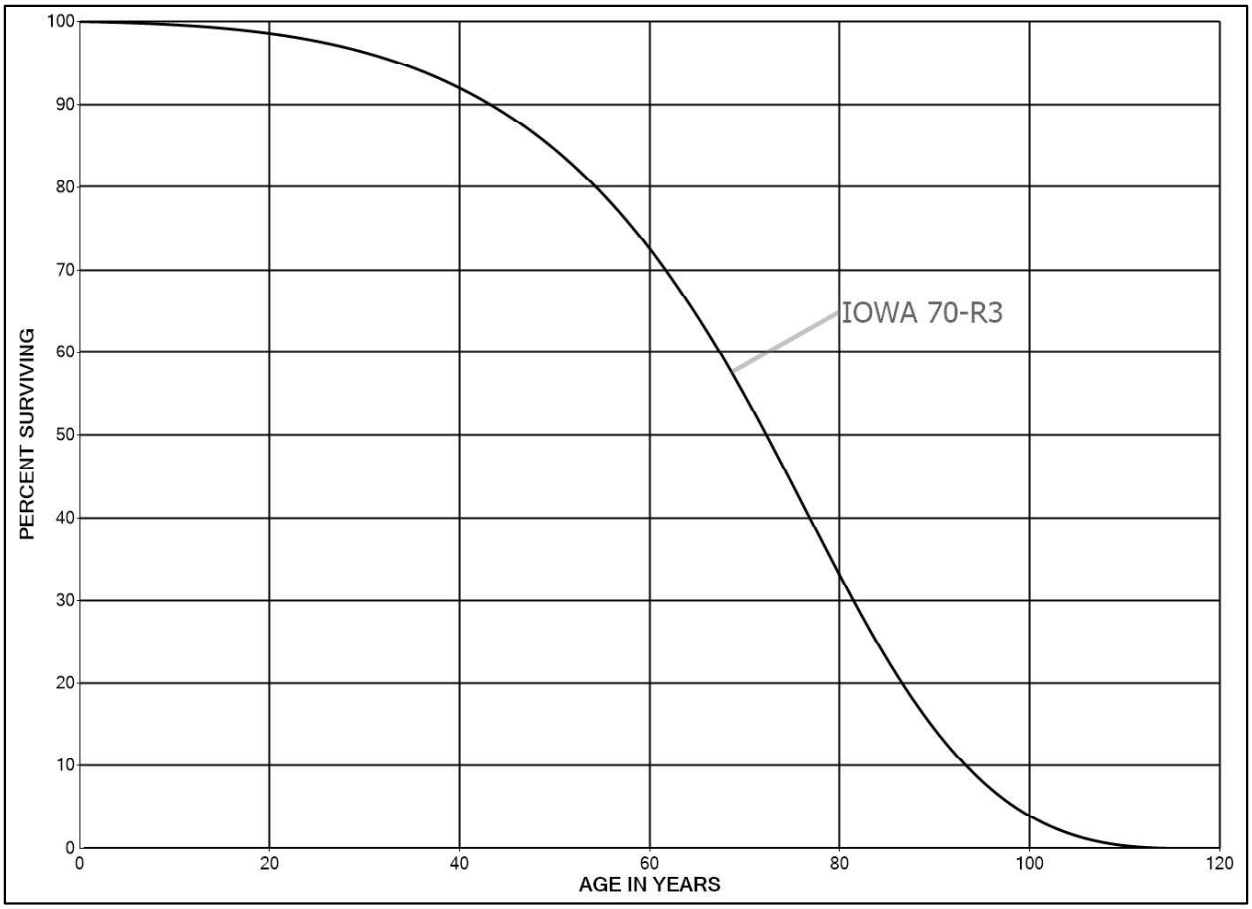
The assets aged in this account include PG&E's distribution substation facilities and their accompanying buildings within the site. Information about the installation dates of facilities and buildings was obtained during the site visit. For the structures within the substations, lower voltage assets, defined as less than 115 kV, were assigned a vintage in proportion to the age of circuit breakers at a given station. The assets aged in this account include 44 lattice steel structures, 129 low profile structures, 145 tube steel structures, 18 tubular pole structures, 49 tubular steel pole structures, four unknown structure records and one welded anchorage structure, for a total of 390 structure records. Vintages for these assets range from 1949 to 2021, with a weighted average install year of 2004.

See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

The 70-R3 survivor curve was authorized in the 2020 GRC and proposed in the 2023 GRC. The actuarial analysis for all of PG&E indicates an average service life of around 70 years or more with a mid- or higher- mode survivor curve. For this account, the same 70-R3 survivor curve is reasonable for PG&E's assets serving San Francisco and is shown in the chart below.


100
90
80
70
60
50
40
30
20
10
0
PERCENT SURVIVING
IOWA 70-R3
0
20
40
60
80
100
120
AGE IN YEARS

Account 362 Station Equipment

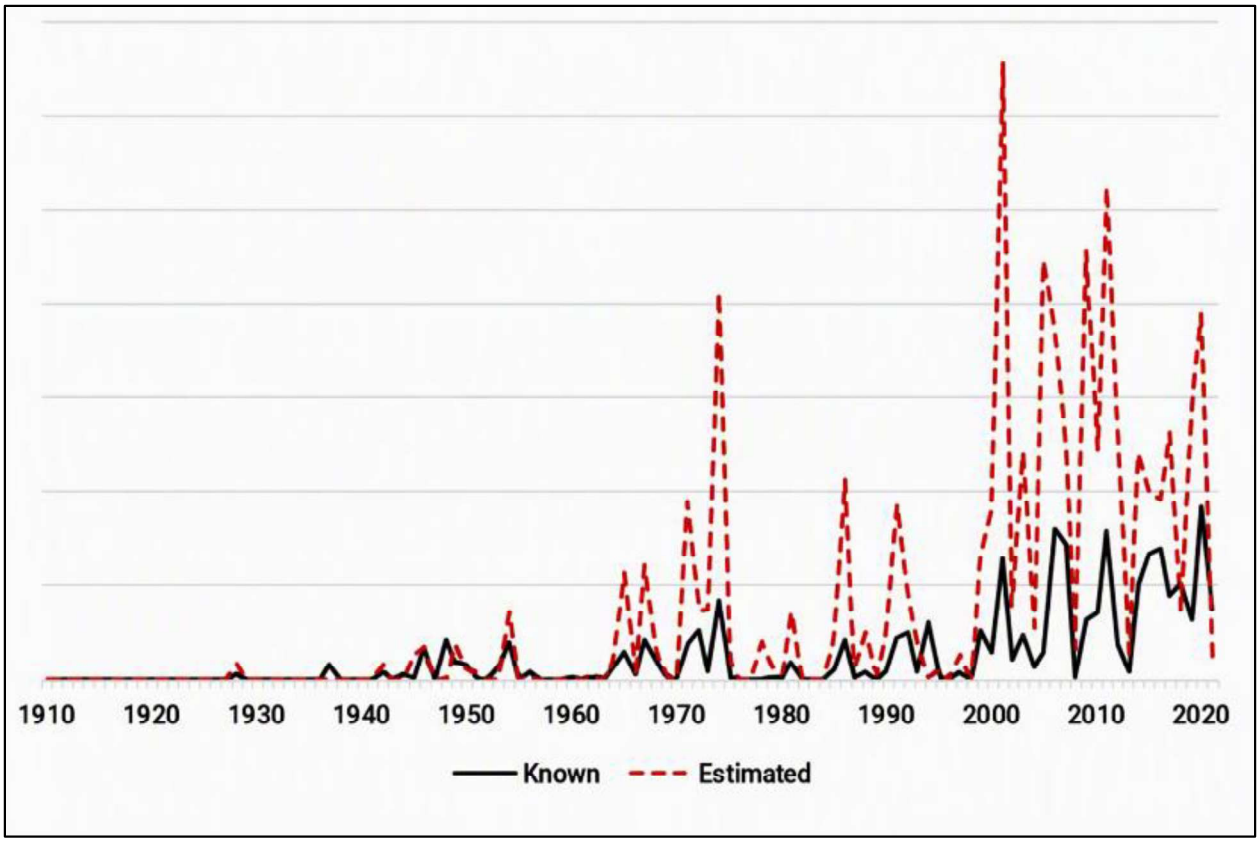
This account includes the cost of station equipment, including transformer banks, used for the purpose of changing the characteristics of electricity with its distribution operations. Similar to transmission substations, more assets are located indoors than for PG&E's overall system.

ASSET AGE ANALYSIS

Assets in distribution station equipment were vintaged according to the same general methodology as for transmission station equipment assets. Please refer to the discussion for Account 353 Station Equipment for a further discussion of the process. The assets aged in this account include distribution station equipment such as batteries, battery chargers, breakers, disconnect switches, motor operated switches, regulators, series reactors, protection relays, shunt capacitors, shunt reactors, transformers and voltage regulators.

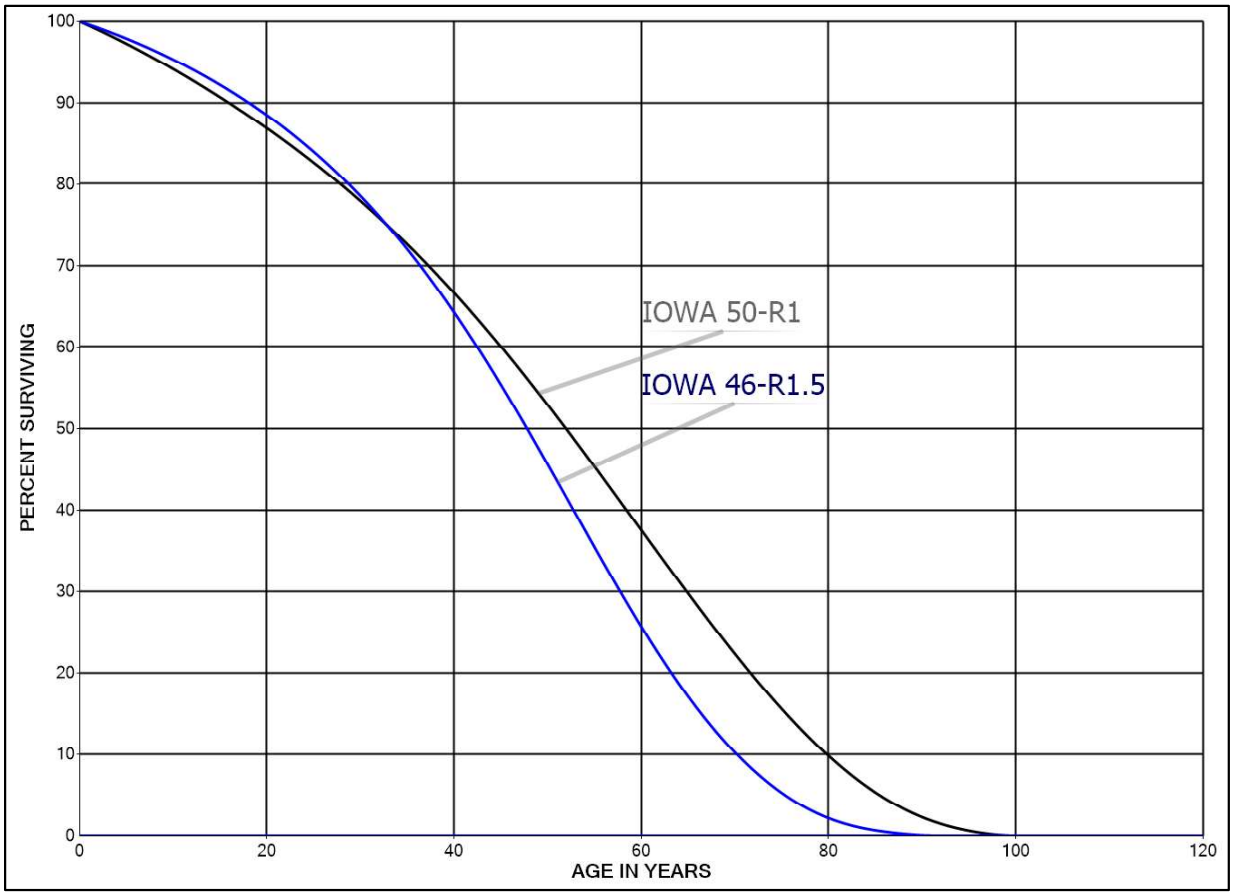
The larger asset groups in this account include 752 vacuum breakers, 786 disconnect switches, 5,688 current transformers, 819 potential transformers, 538 VLA batteries, 506 MR protection relays, 301 EMR protection relays, 225 series reactors with unknown subtype, 170 air breakers, 156 phase series reactors, 110 station service transformers and 69 single phase regulators. Other asset groups include TMP batteries, battery chargers, oil breakers, SF6 breakers, motor operated switches, shunt capacitors, shunt reactors, voltage regulators and related station equipment.

See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

PG&E retires substation equipment based on condition and performance. While the San Francisco actuarial analysis suggests a shorter life than 50 years, many substations are indoor and it is anticipated that this equipment will be less susceptible to physical deterioration in the future. In the 2020 GRC the 46-R1.5 survivor curve was authorized. The 50-R1 survivor curve was proposed in the 2023 GRC. The 50-R1 for PG&E's system as a whole is reasonable for PG&E's assets serving San Francisco and is shown, along with the 46-R1.5.


100
90
80
70
60
50
40
30
20
10
0
PERCENT SURVIVING
0
20
40
60
80
100
120
AGE IN YEARS
IOWA 50-R1
IOWA 46-R1.5

DISTRIBUTION

OVERHEAD

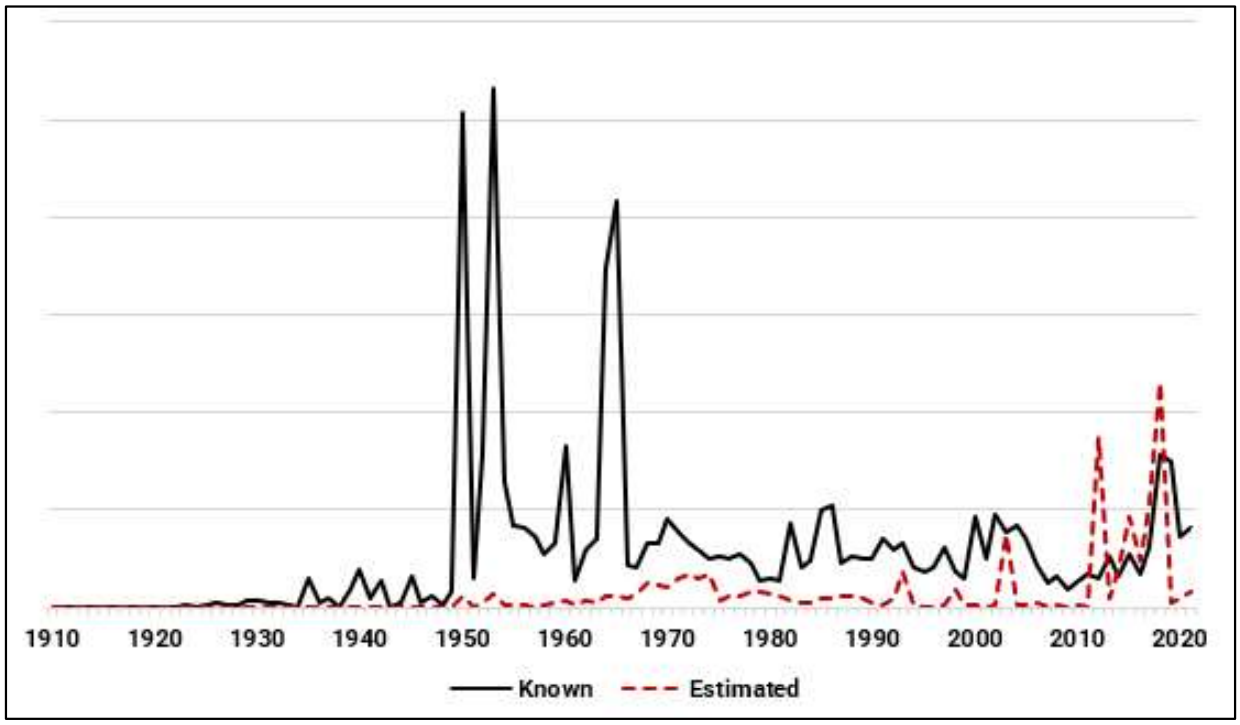
Account 364 Poles and Fixtures

Information obtained from PG&E's San Francisco database included pole and fixture assets by material and structure type. The account includes 6,445 electroliers, 292 guy stubs, 430 other structures, and 30,897 poles, for a total quantity of 38,064. The pole population includes wood, throughbore, steel, concrete, fiberglass, aluminum, other, and unknown pole types.

ASSET AGE ANALYSIS

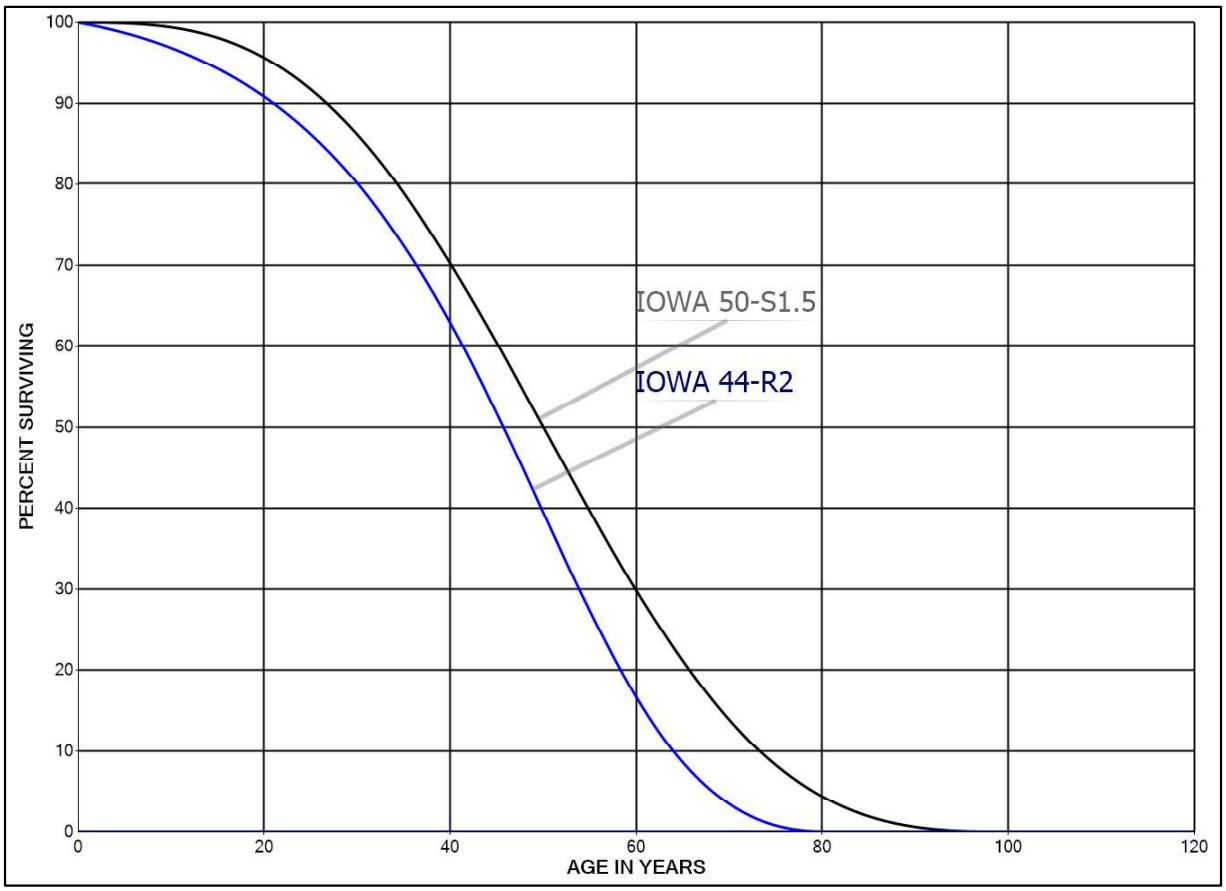
Information obtained from PG&E's San Francisco database included pole and fixture assets by material and structure type. For the assets with unknown installation years, vintages were assigned in proportion to known vintages for similar assets. Pole vintages were aligned by size and type. Guy stubs and other structures were aligned to similar assets with known vintages, and electroliers were aligned with Account 373.04 vintage detail from accounting records.

See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

The 44-R2 survivor curve was authorized for all of PG&E's distribution poles account in the 2020 GRC and proposed in the 2023 GRC. The actuarial life analysis for San Francisco supports a longer service life than this estimate. A longer service life for poles in San Francisco is reasonable due to less moisture, lower wind loading and less wildfire risk. Further, the logistical and economic challenges of replacing poles in a populated urban area can impact the overall service life of assets. Finally, the current age distribution of San Francisco poles supports a longer service life than the 44-R2 survivor curve. The 50-S1.5 survivor curve is recommended and shown in the chart below, along with the 44-R2 survivor curve.



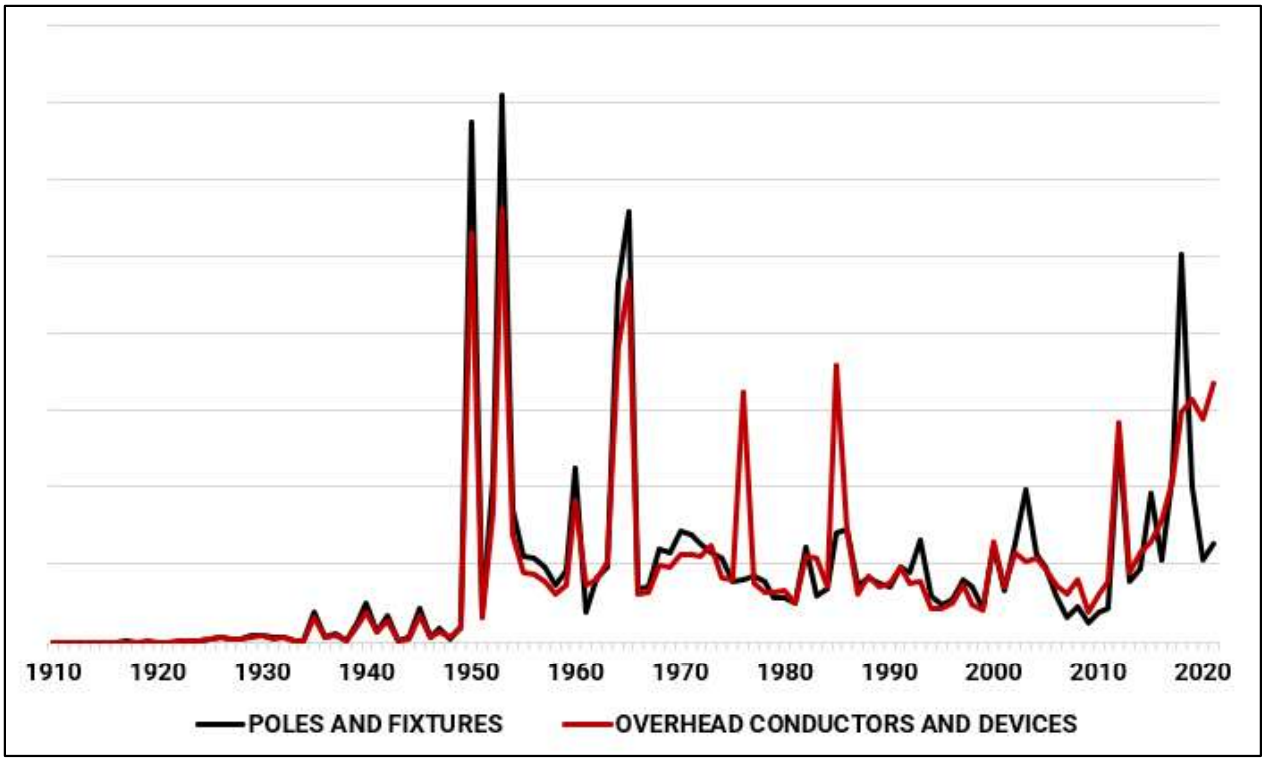
Account 365 Overhead Conductors and Devices

This account includes the cost of electric overhead conductors and devices used for distribution purposes. The Company has a variety of types of conductor, ranging from copper to aluminum to steel and aluminum composites. Replacements of conductor are commonly due to capacity upgrades or other reconductoring projects, as well as other physical or external factors such as failure, deterioration or damage from storms.

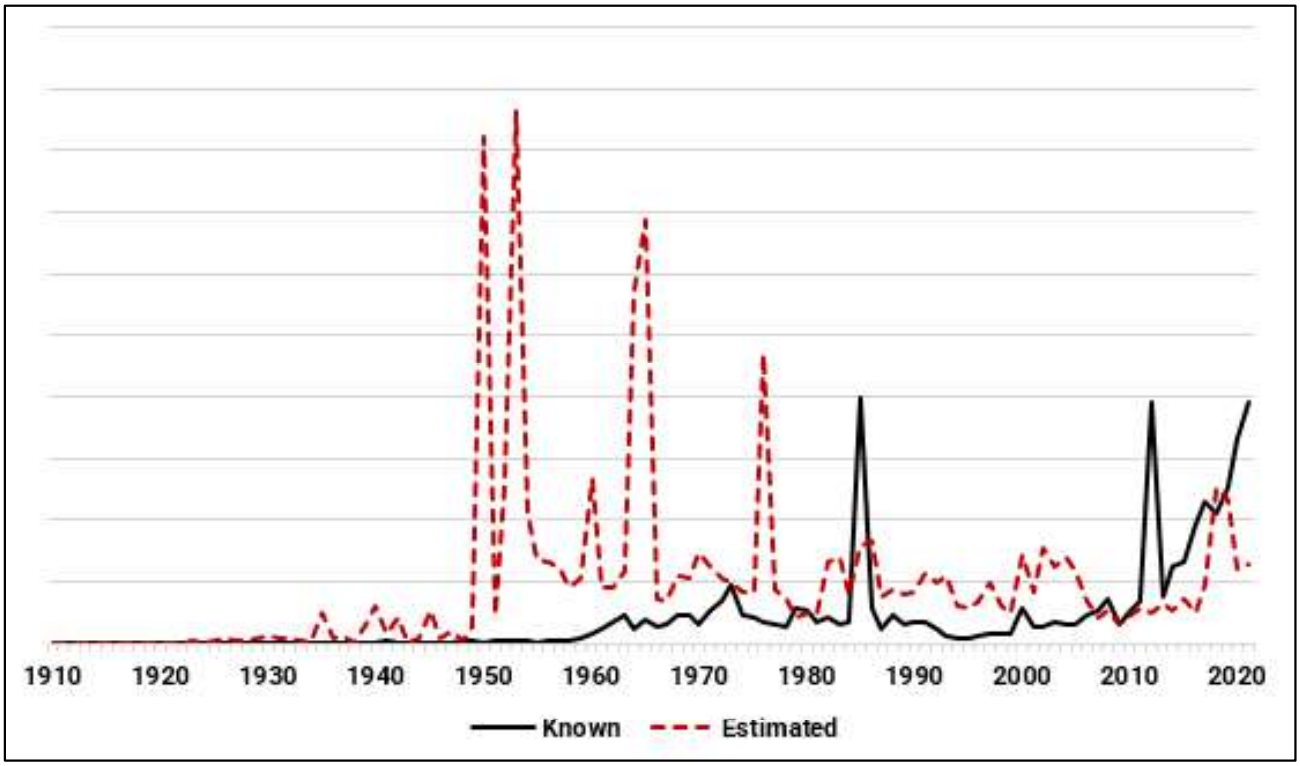
ASSET AGE ANALYSIS

PG&E-owned overhead conductor in San Francisco includes primary overhead conductor, secondary overhead conductor, overhead DC conductor, capacitor banks, fuses, interrupters, reclosers and switches. The account includes 25,840 primary overhead conductor records, 45,747 secondary overhead conductor records, six overhead DC conductor records, 93 overhead capacitor banks, 1,800 overhead fuses, four overhead interrupters, 178 reclosers and 2,547 overhead switch records, for a total of 76,215 overhead conductor and device records.

For the overhead conductor assets with unknown installation years, vintages were assigned in proportion to the installation dates of PG&E's San Francisco poles, as shown in the chart below. Overhead DC conductor was aligned with final DC workpaper vintages. Capacitor banks, fuses, reclosers, interrupters and switches with unknown installation years were aligned with known vintages for the same asset type.

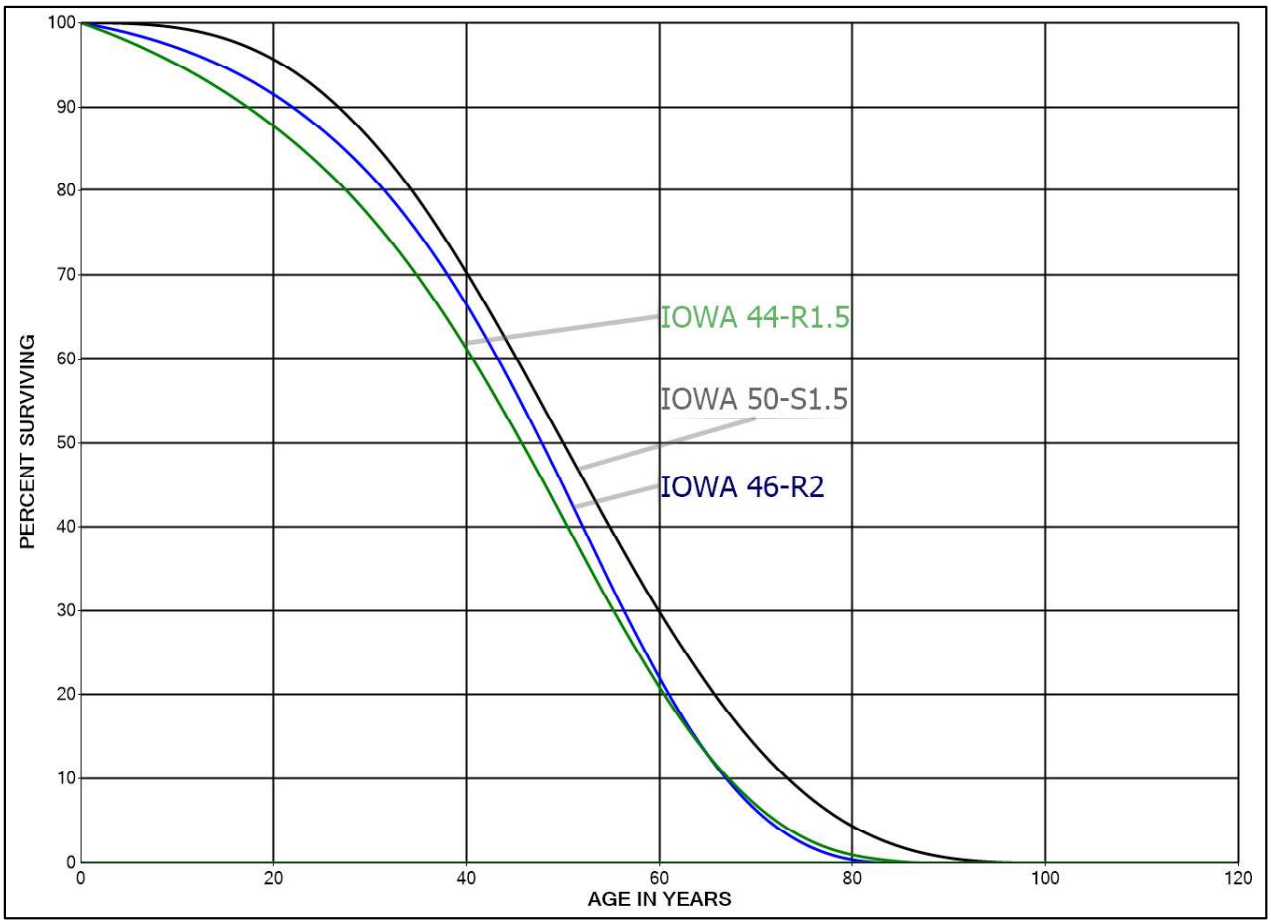


See the figure below for the asset quantities (known and estimated) by vintage for Account 365:



SERVICE LIFE ANALYSIS

Overhead conductor is retired primarily as the result of wildfire hardening, deterioration, inadequate capacity, Rule 20 undergrounding, road widening, and storms. In the 2020 GRC the 46-R2 survivor curve was authorized. The 44-R1.5 survivor curve was recommended in the 2023 GRC. As discussed above, PG&E's service lives for poles and overhead conductor have been reasonably correlated and, similarly, service lives from PG&E's depreciation studies for Accounts 364 and 365 have typically been similar to one another for many years. Many of the reasons to expect longer lives, on average, for San Francisco poles as compared to all PG&E poles also apply to overhead conductor. For these reasons, the same 50-S1.5 survivor curve recommended for Account 364 is recommended for Account 365, Overhead Conductors and Devices.



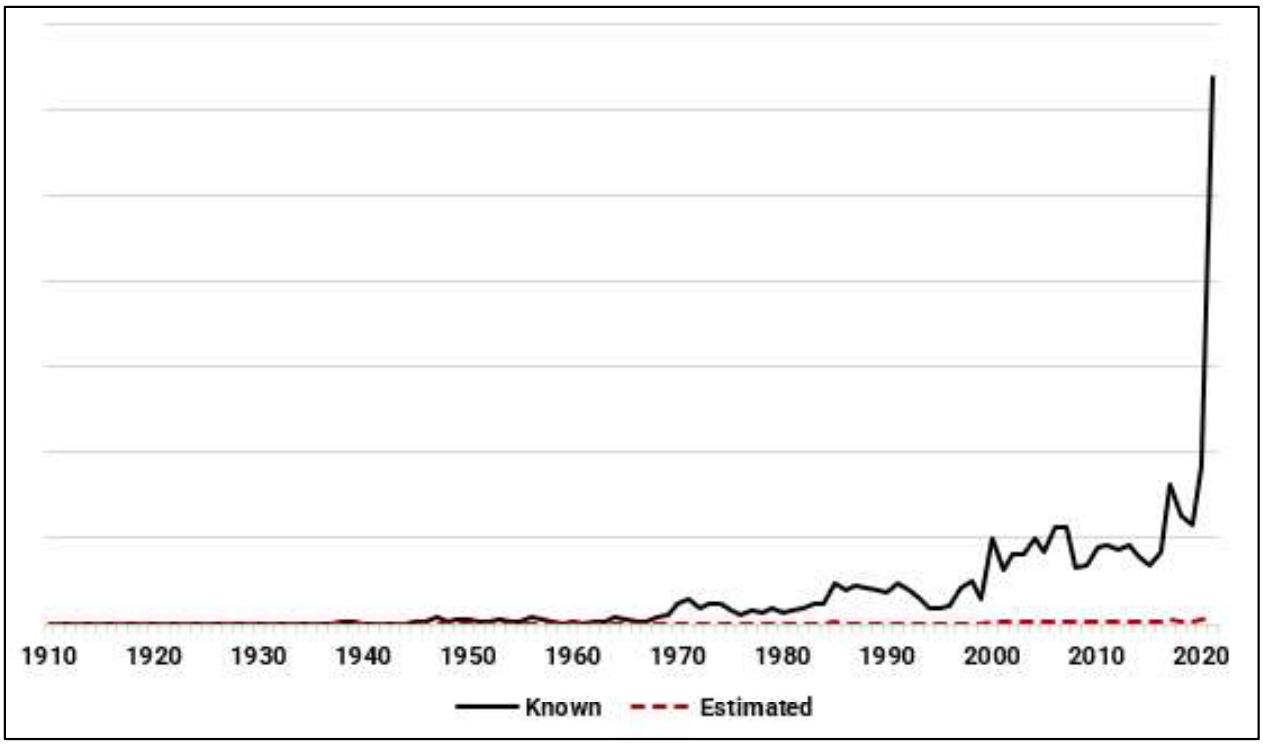
Account 368.01 Line Transformers – Overhead

This account includes the cost of overhead line transformers and devices directly associated with transforming electricity to the voltage at which it is used by the customer. Pole mounted overhead transformers, while added when distribution lines and services are originally constructed, have historically had shorter average lives than poles and conductors. Replacements typically happen due to failures or proactive replacements, but also occur for capacity reasons and due to external forces such as storms. Overhead transformers are subject to different factors that can impact service lives than pad mount or network transformers. For example, surface level or below grade transformers are exposed to more corrosive forces than those on poles, while assets mounted on poles are subject to more of the loading and storm exposure than those on or below ground.

ASSET AGE ANALYSIS

The subset of PG&E-owned line transformers in San Francisco includes 772 distribution transformer spares, 16 overhead DC rectifiers, 6,635 overhead distribution transformers and 28 streetlight transformers, for a total of 7,451 overhead transformer and related device records. For almost all of these assets, the vintage years were known. For the assets with unknown installation years, vintages were assigned in proportion to the installation dates of known overhead line transformers according to subtype and operating voltage. Overhead DC rectifiers were aligned with final DC workpaper vintages.

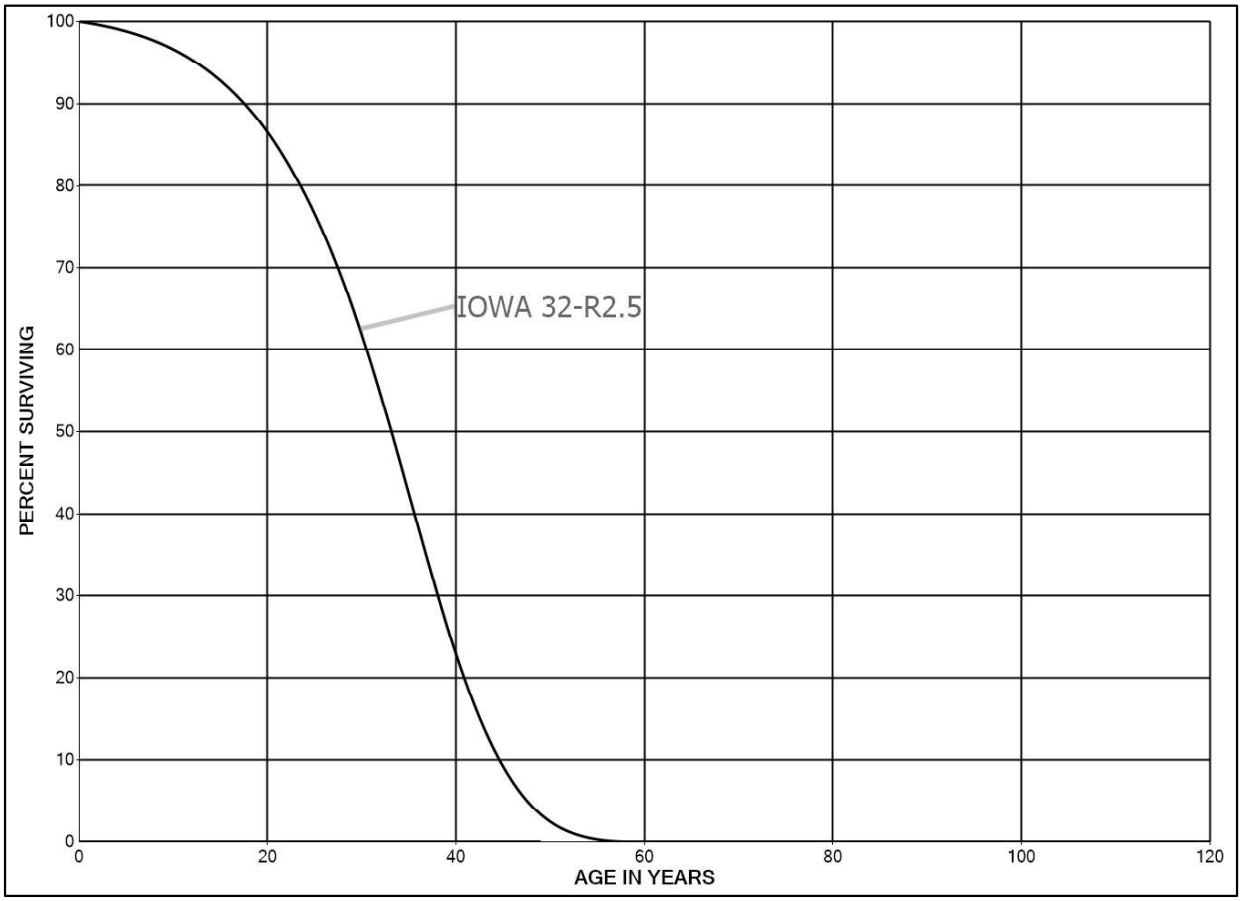
See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

Overhead line transformers are typically retired due to failure, capacity, inadequacy, deterioration and lightning. The 32-R2.5 survivor curve was authorized in the 2020 GRC and proposed in the 2023 GRC. While other San Francisco overhead assets have longer service lives than those in the system as a whole, line transformers have had shorter lives than other overhead assets which suggests that physical lives of transformers may be a more dominant cause of retirement and impact on the service life.

For these reasons, it is reasonable to expect PG&E's assets serving San Francisco to have a life similar to PG&E's assets as a whole, particularly because the life analysis data set for the GRC is more extensive and contains a much larger sample size. The 32-R2.5 survivor curve is recommended and shown in the figure below.



Account 369.01 Services – Overhead

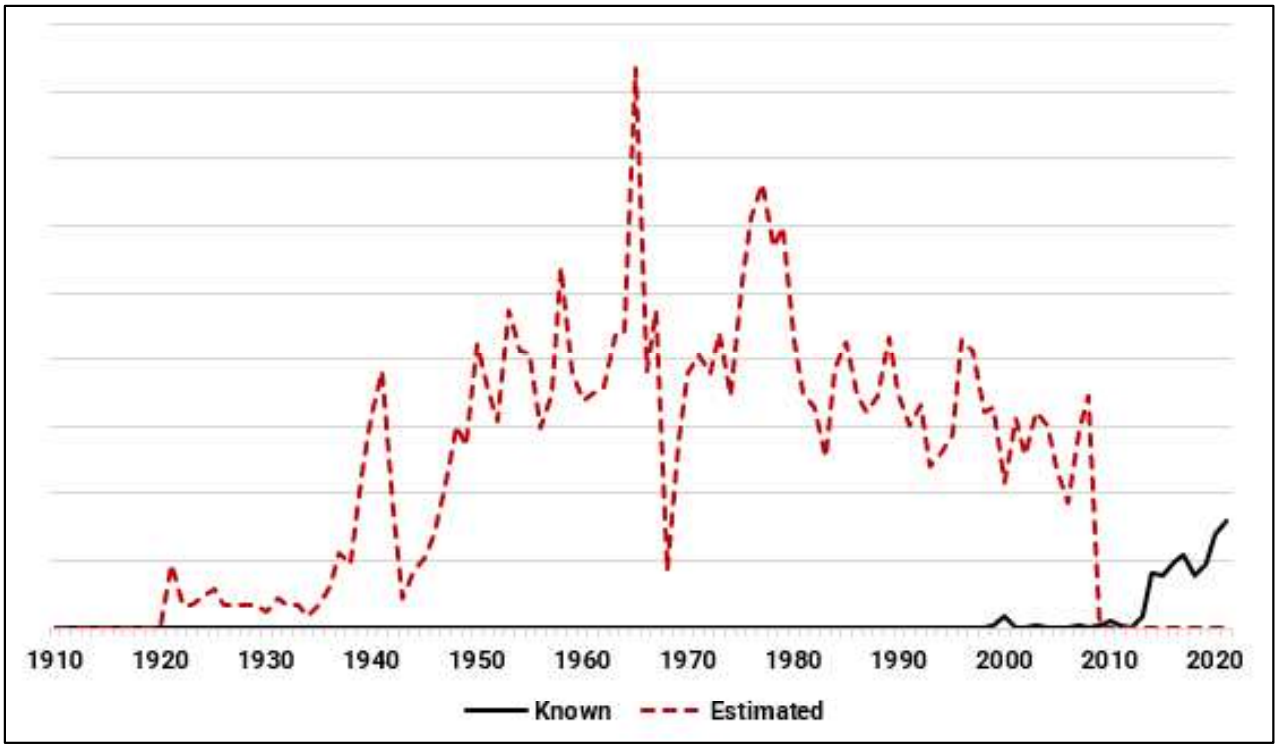
This account includes the cost of electric distribution overhead conductor leading from a point where wires leave the last pole of the overhead system to the point of connection with the customer's outlet or wiring. Services may be replaced for capacity reasons, but currently a larger share of replacements are due to trouble or emergency situations.

ASSET AGE ANALYSIS

The subset of PG&E-owned services in San Francisco includes 130,854 overhead service location records. Because the majority of vintages were unknown, information related to other accounts was needed to estimate the age of services.

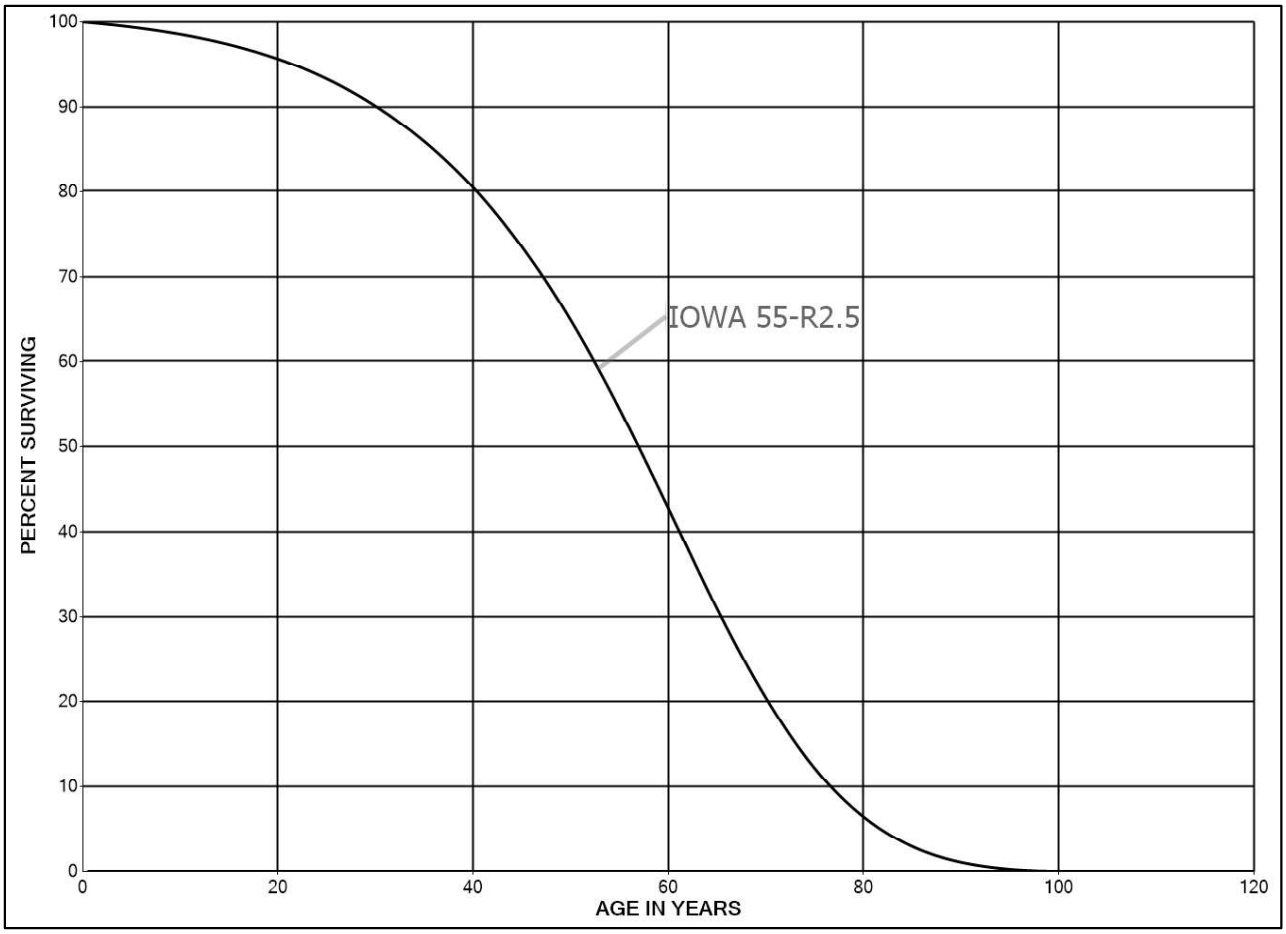
For service locations without a known installation vintage, GFT estimated the service vintage using available meter installation data. Unknown service vintages were allocated to the years 1921 through 2008 in proportion to the distribution of known meter installations during those same years. This allocation assumes that the historical pattern of meter installations provides a reasonable basis for estimating the vintages of services for which direct installation records are not available. The same methodology was applied to both overhead and underground services.

The figure below provides the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

Overhead services are retired as the result of failures, often due to cracked insulation or damage from vegetation. Services may also be replaced due to factors such as capacity and relocations. The 55-R2.5 survivor curve was authorized in the 2020 GRC and proposed in the 2023 GRC. This life expectation is reasonable for San Francisco assets and is recommended.


IOWA 55-R2.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120

UNDERGROUND

Account 366 Underground Conduit

This account includes the cost of electric underground conduit and tunnels used for housing distribution cables or wires. PG&E's San Francisco underground assets include those in downtown network systems and those in radial systems elsewhere in the City and County. Network underground systems were initially constructed in San Francisco in the 1930s and for many years construction was PILC in rigid conduits such as concrete ducts. More recent construction has used similar conduit, which can often be reused for new cable, but more modern types of cable such as XLPE. Conduit in network systems tends to have long service lives, particularly if ducts can be reused for new cable. However, conduit can be replaced when damaged or if larger size cable is needed, as well as for other factors such as relocations.

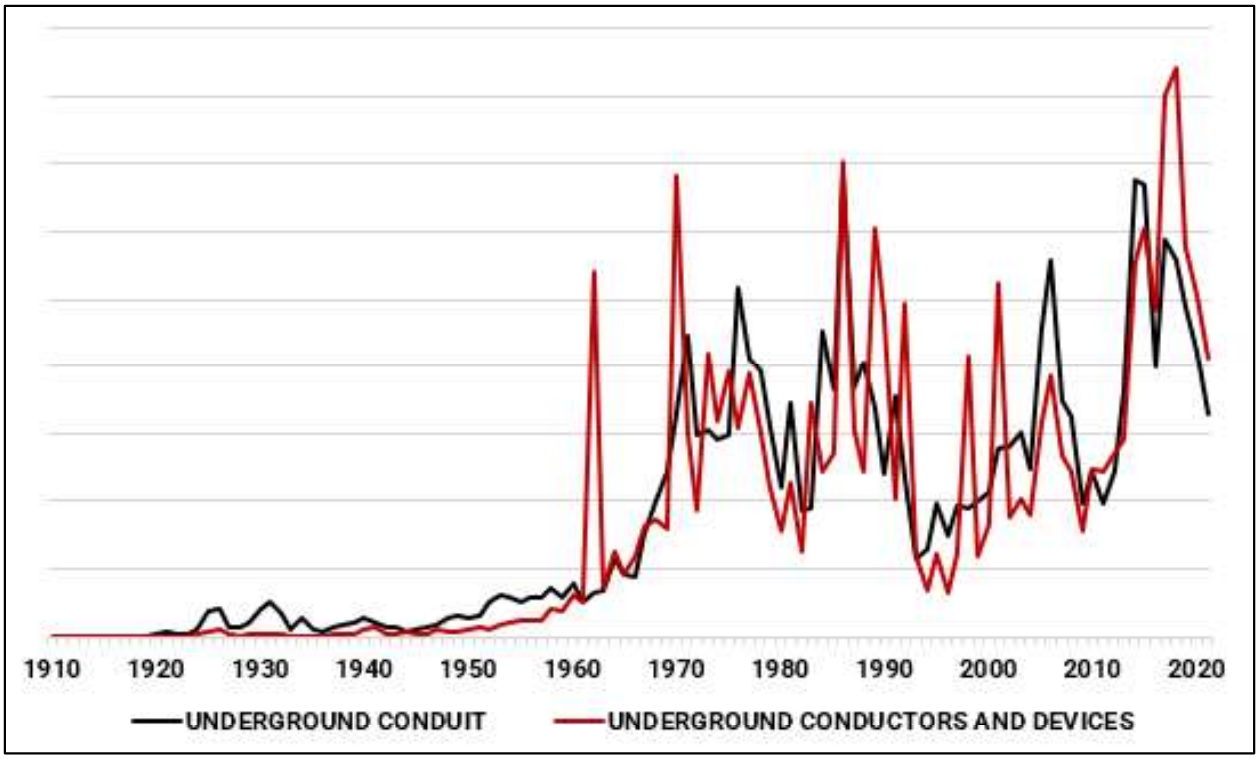
Radial systems also use rigid conduit and, originally, PILC. However, there are also other types of direct buried, CIC and PVC conduit construction similar to other parts of PG&E's system. Many of these assets typically have shorter lives than large, urban network system conduit has experienced due to construction type and other characteristics of the different systems.

ASSET AGE ANALYSIS

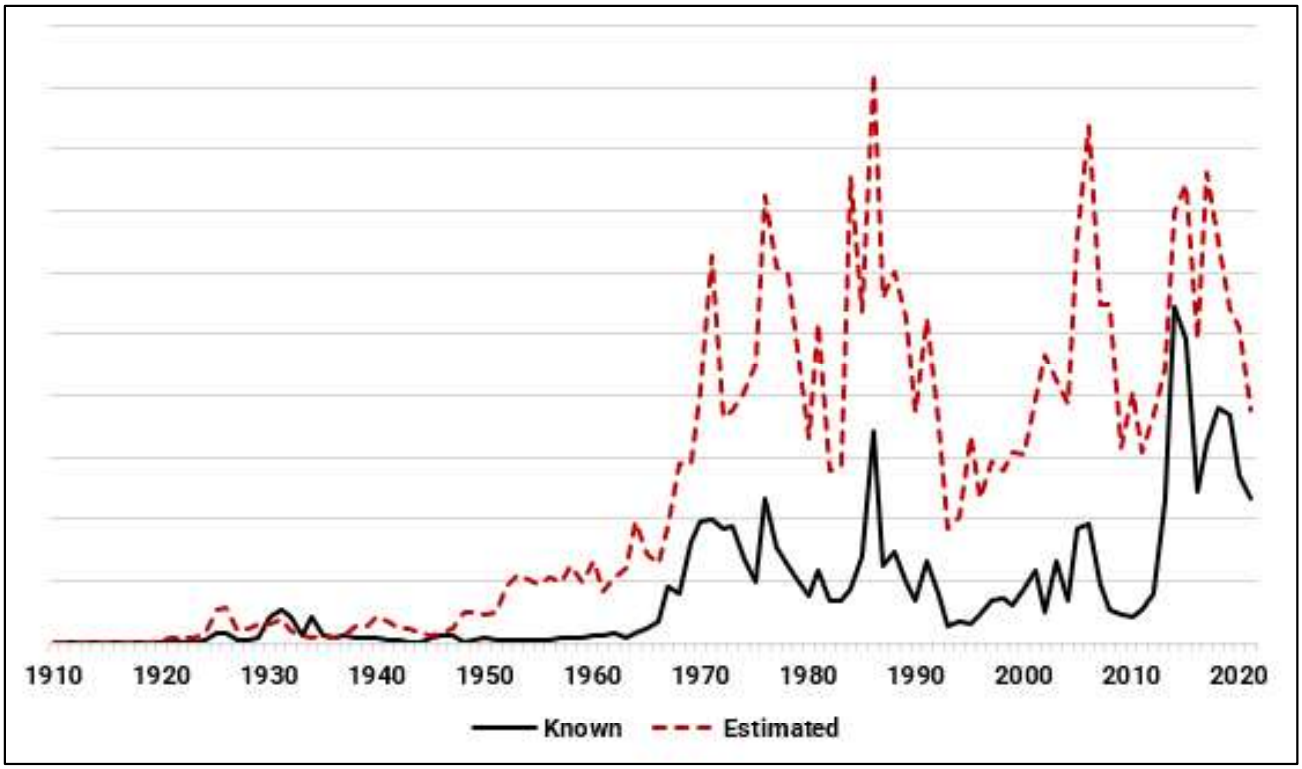
The subset of PG&E-owned underground conduit in San Francisco includes 29,155 CIC records, 4,170,572 conduit records, 3,051,268 duct bank records, 4,990 duct junction records, 42 MV manhole records, 96 primary and secondary enclosure records, 8,041 primary enclosure records, 28,687 secondary enclosure records, 22 subsurface duct junction records, eight subsurface primary enclosure records, one subsurface secondary enclosure record, 26 subsurface vault records and 6,595 vault records. The following procedures were taken to estimate vintages for unknown assets:

1. There was insufficient detail in the GIS data for conduit to clearly identify which conduit segments were network and which were non-network. These were determined in proportion to known network vs. non-network underground conductors in the data set.

2. For network conduit, vintages were assigned using the same methodology as was done for underground network conductor. Based on other sources, including meetings with SMEs for this and previous studies, 60 percent of all network conduit was estimated to have been installed in the years 1920 through 1960. Using PG&E's systemwide accounting data, for which additions are known dating to the 1930s, an age distribution was developed for the 1920 through 1960 period. Because almost all of PG&E's older network assets are located in San Francisco, the only other portion being in Oakland, it is reasonable to infer that most underground distribution additions for this time period were for San Francisco assets. This age distribution was used to proportionally assign vintages for San Francisco underground conduit.
3. For non-network conduit, unaged conduit was assigned a vintage in proportion to the known non-network conductor vintages.
4. As further support for Gannett Fleming's recommendations, an analysis of PG&E's accounting data, similar to that performed for Account 365 and described more fully for that account, confirmed that the vintages of underground conduit and underground conductor should be relatively correlated, although conduit is expected to skew somewhat older because conduit may be reused when conductor is replaced. A comparison of the vintages for these asset categories is shown in the chart below.

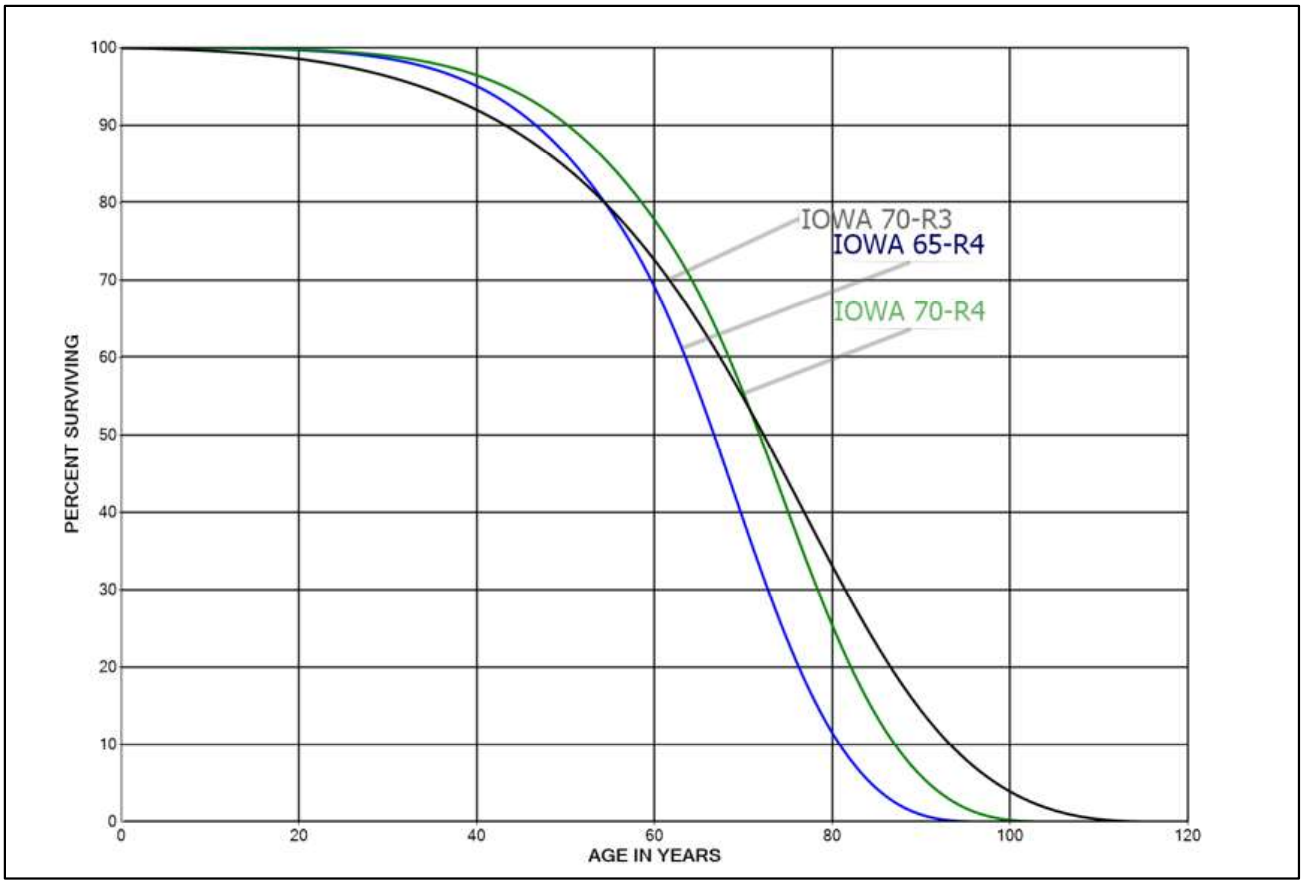


See the figure below for the asset quantities (known and estimated) by vintage for Account 366:



SERVICE LIFE ANALYSIS

PG&E's San Francisco system has a much higher proportion of network assets than PG&E's system as a whole. The radial system also includes a higher proportion of duct-type construction. Due to these characteristics, as well as the logistical and economic challenges of replacing underground conduit in a large, densely populated urban area, a longer service life for underground conduit and conductor in San Francisco is reasonable. In the 2020 GRC the 65-R4 survivor curve was authorized. The 70-R4 survivor curve was proposed in the 2023 GRC. The 70-R3 survivor curve is recommended for this account and is shown below along with the GRC estimates.



Account 367 Underground Conductors and Devices

This account includes the cost of electric underground conductors and devices used for electric distribution purposes. Network underground systems were initially constructed in San Francisco in the 1930s and for many years construction was PILC in rigid conduits such as concrete ducts. Construction has evolved to the use of newer cable types such as XLPE. Most PILC has been replaced over time but had relatively long lives.

Radial systems also have construction similar to network systems with rigid conduit and, originally, PILC. However, there are also other types of direct buried, CIC and PVC conduit construction similar to other parts of PG&E's system. Many of these assets typically have shorter lives than large, urban network system conductor has experienced.

ASSET AGE ANALYSIS

The subset of PG&E-owned underground conductors and devices in San Francisco includes 163 pad mounted capacitor banks, 19,434 CIC records, 28 DC fuses / distribution box records, 138 DC risers, 363 fuse records, 573 interrupter records, three primary riser records, 23,663 primary underground conductor records, 34,285 primary underground conductor and conduit records, 2,452 primary riser records, 5,777 secondary riser records, 64,456 secondary underground conductor records, 455 streetlight box records, 9,335 switch records, 1,391 subsurface or underground switch records, 41 underground DC secondary conductor records and five underground DC service conductor records.

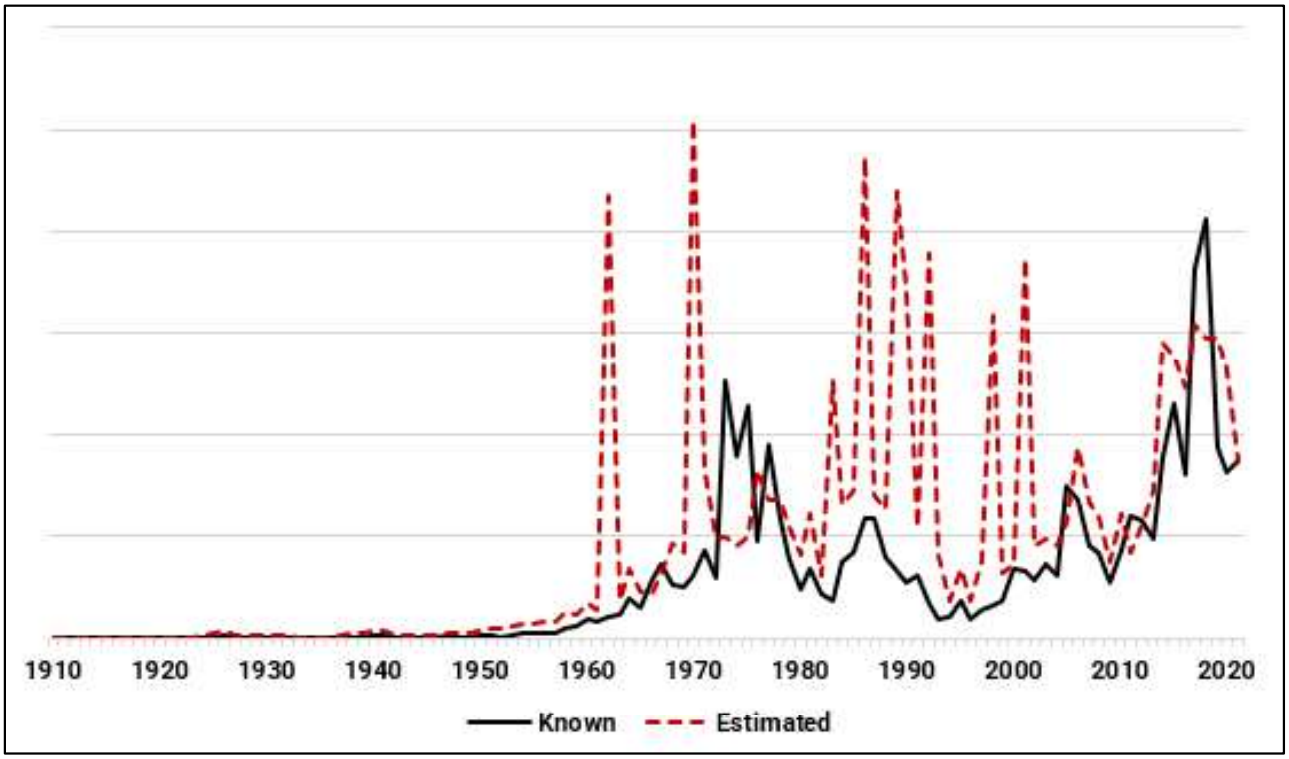
For underground conductor assets with unknown installation years, the "CircuitID" identification, which corresponded with a matching ID in the GIS data for line transformers, was used to estimate which underground conductors were network and which were non-network.

For network underground conductor, there were two distinct methods for determining vintages. These were done sequentially and informed one another. Judgments in determining how to apportion the weighting to each method were informed by Gannett Fleming's knowledge and experience with studying PG&E's assets, including meetings and site visits conducted over the past two decades. Forty percent of all unaged network conductor was assigned a vintage from 1920 through 1960. Because almost all

of PG&E's older network assets were located in San Francisco, with the only other portion in Oakland, it is reasonable to infer that most underground distribution additions for this time period were for San Francisco assets. This vintage distribution was used to proportionally assign vintages for San Francisco underground conductors. The remaining 60 percent of unaged network conductor was assigned a vintage in proportion to the known network conductor vintages.

For non-network underground conductor, unaged conductor was assigned a vintage in proportion to the known non-network conductor vintages. Capacitor banks, fuses, interrupters and switches with unknown installation years were aligned with known vintages for the same asset type. Primary and secondary risers were aligned to conduit. DC-related assets were aligned with final DC workpaper vintages. Streetlight boxes were aligned with streetlight workpaper vintages.

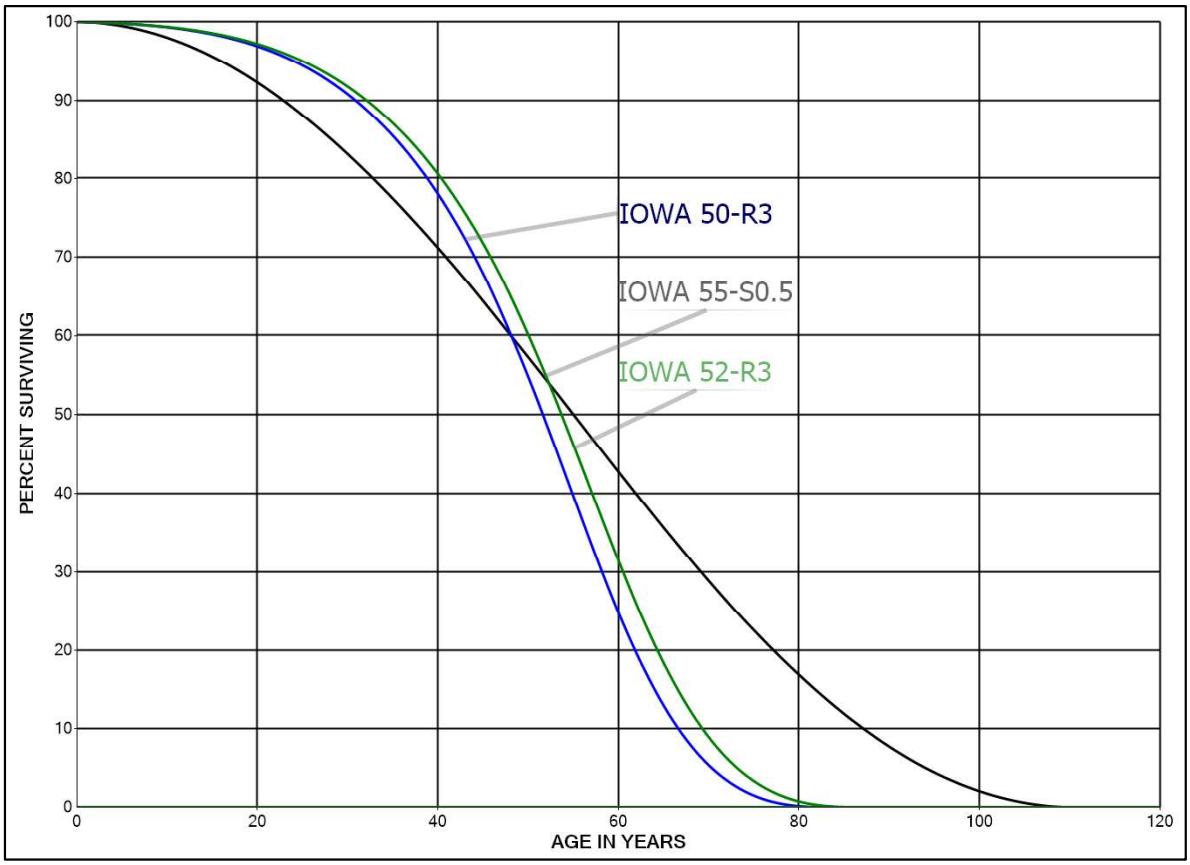
See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

Underground conductor is most commonly replaced due to capacity upgrades, as well as damage and other physical factors. PG&E's San Francisco system has a much

higher proportion of network assets than PG&E's system as a whole. Due to these characteristics, as well as the logistical and economic challenges of replacing underground conductor in a large, densely populated urban area, a longer service life for underground conductor in San Francisco is reasonable. In the 2020 GRC the 50-R3 survivor curve was authorized. The 52-R3 survivor curve was proposed in the 2023 GRC. The 55-S0.5 survivor curve is recommended for Account 367, Underground Conductors and Devices, and is shown in the chart below.



Account 368.02 Line Transformers - Underground

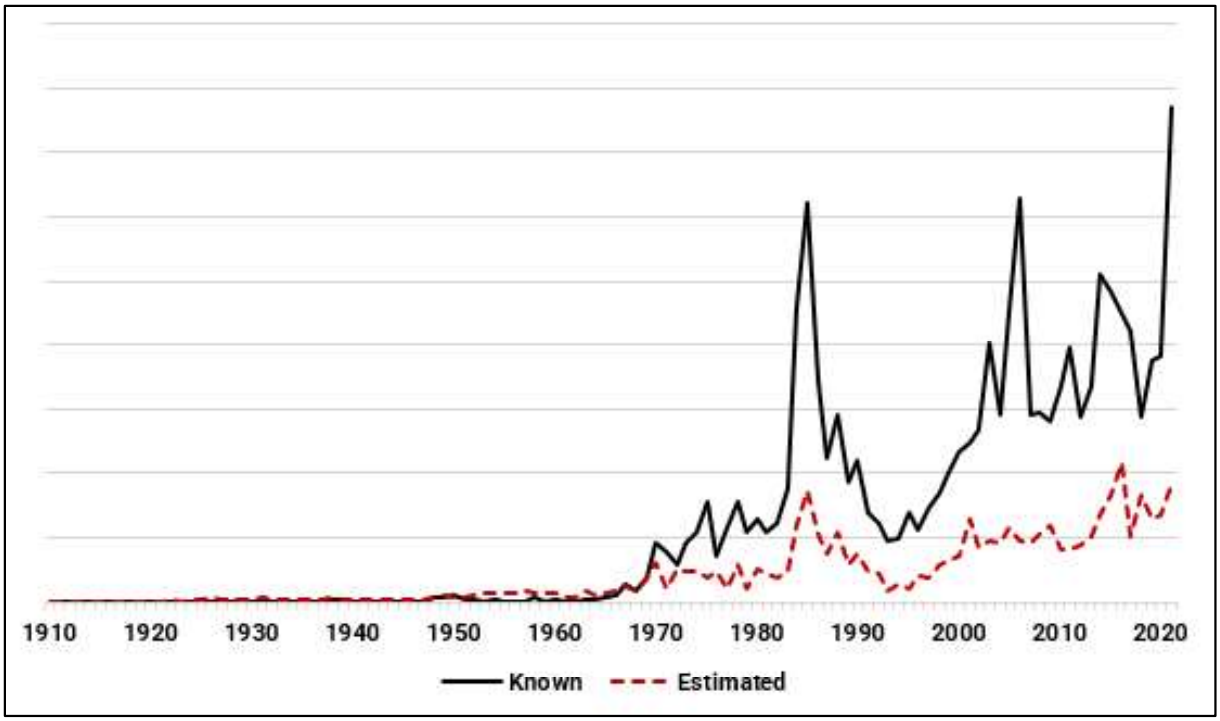
This account includes the cost of underground line transformers and voltage regulators directly associated with transforming electricity to the voltage at which it is used by the customer. Both pad mount and network transformers are included in this account. These types of assets have, at least in part, different functionalities and construction as well as factors which impact the service life and, therefore, the age of the current population. They are also subject to different forces of deterioration and retirement due to, for example, the differences in exposure to elements in underground manholes or vaults and those for pad mount transformers in residential neighborhoods.

ASSET AGE ANALYSIS

The subset of PG&E-owned underground line transformers in San Francisco includes 1,144 network protectors, 66 network protector spares, 29 network transformer spares, 1,372 pad mount structure pads, 50 pad mount structure pedestals, 1,376 distribution pad mount transformers, 3,767 distribution subsurface transformers, seven equipment transformers, 1,184 network transformers, three secondary transformers and 158 underground DC rectifiers, for a total of 9,156 underground transformer and related device records.

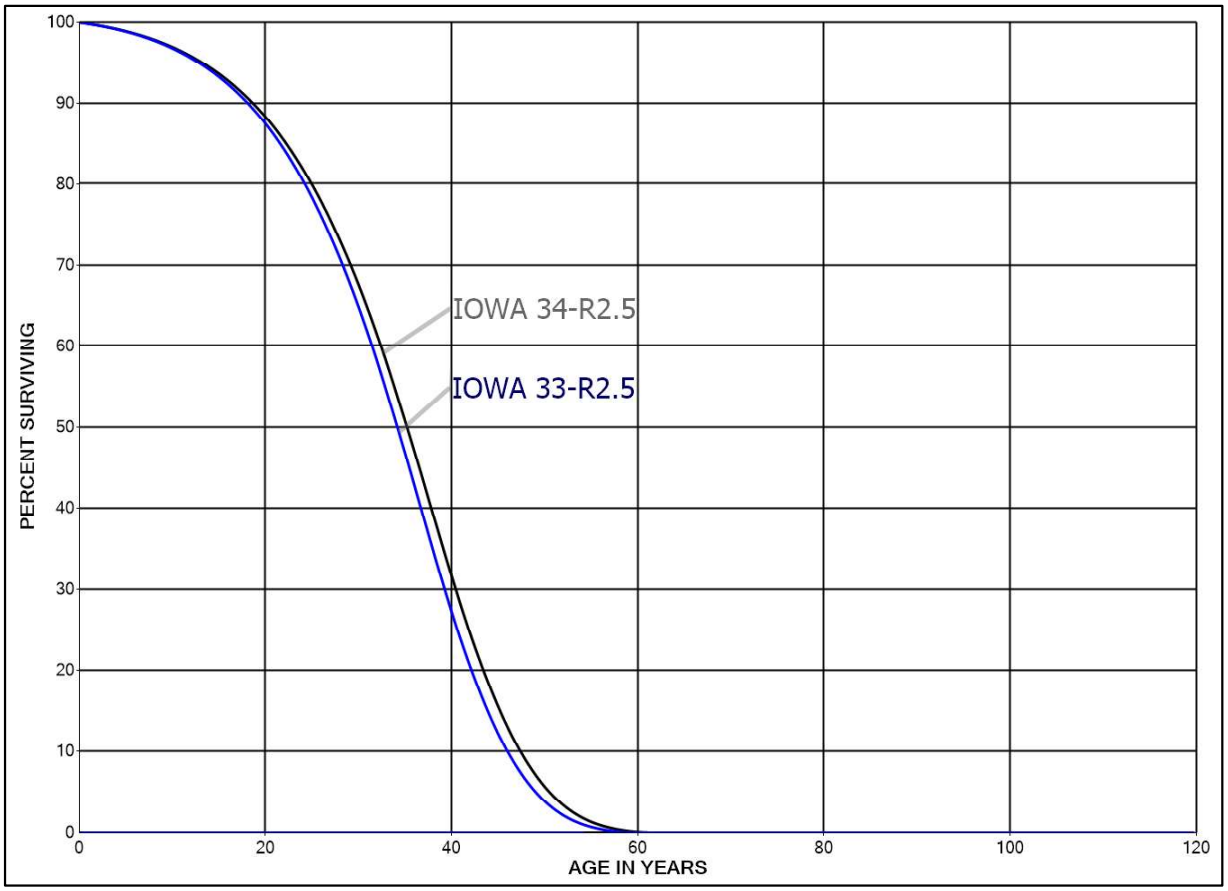
For the assets with unknown installation years, vintages were assigned in proportion to the installation dates of known underground line transformers according to subtype and operating voltage. Network protectors were aligned to network conductor vintages. Pad mount structures were aligned to pad mount line transformers. Underground DC rectifiers were aligned with final DC workpaper vintages.

See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

This account includes both network and non-network line transformers. The 33-R2.5 survivor curve was authorized in the 2020 GRC. The 34-R2.5 survivor curve was proposed in the 2023 GRC. Network transformers were replaced in the 1980s and many of that generation have been replaced recently, which suggests that network transformers may not have significantly longer lives than the overall average service life for PG&E's underground transformers account. A 34-year life expectation is, therefore, reasonable for San Francisco assets as that estimate is based on the larger and more extensive data set for all of PG&E's assets in this account. The 34-R2.5 survivor curve is recommended and shown below along with the 33-R2.5.


IOWA 34-R2.5
IOWA 33-R2.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120

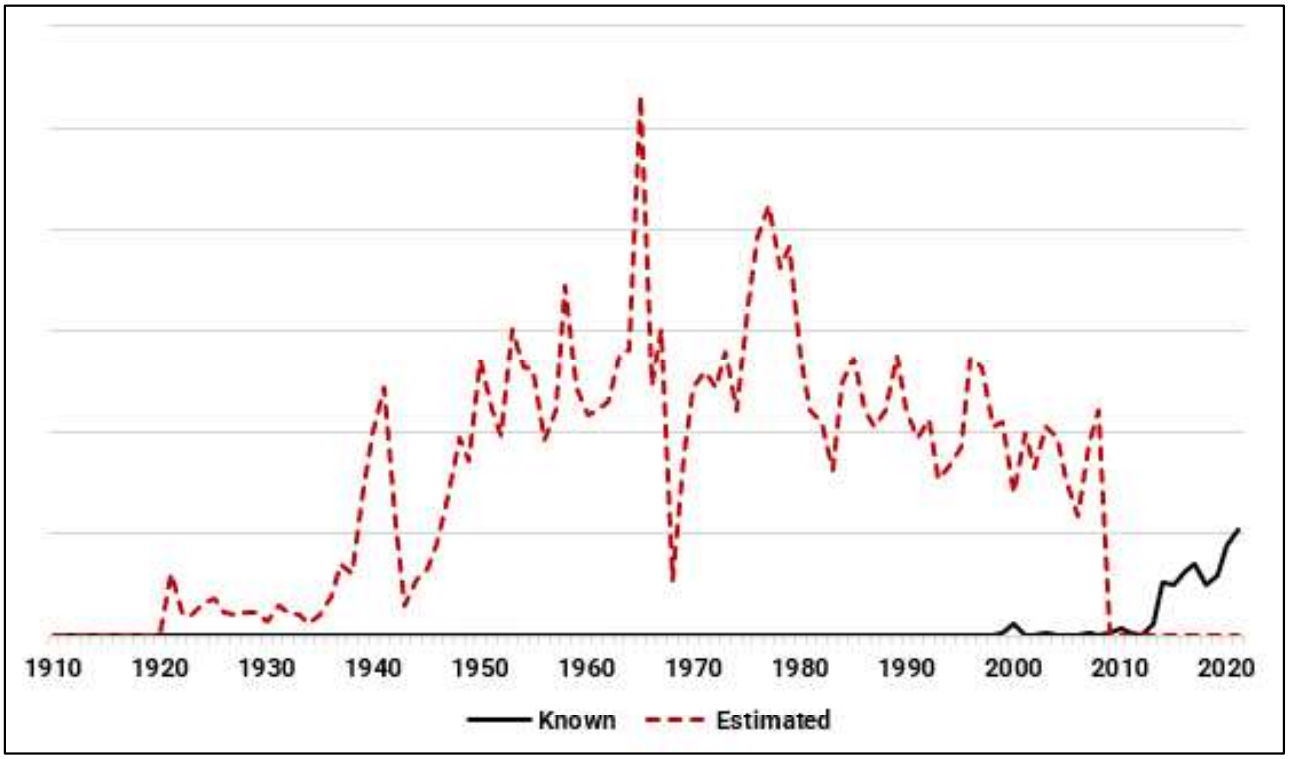
Account 369.02 Services - Underground

This account includes the cost of electric distribution underground conductor leading from a point where wires leave the distribution box or manhole to the point of connection with the customer's outlet or wiring.

ASSET AGE ANALYSIS

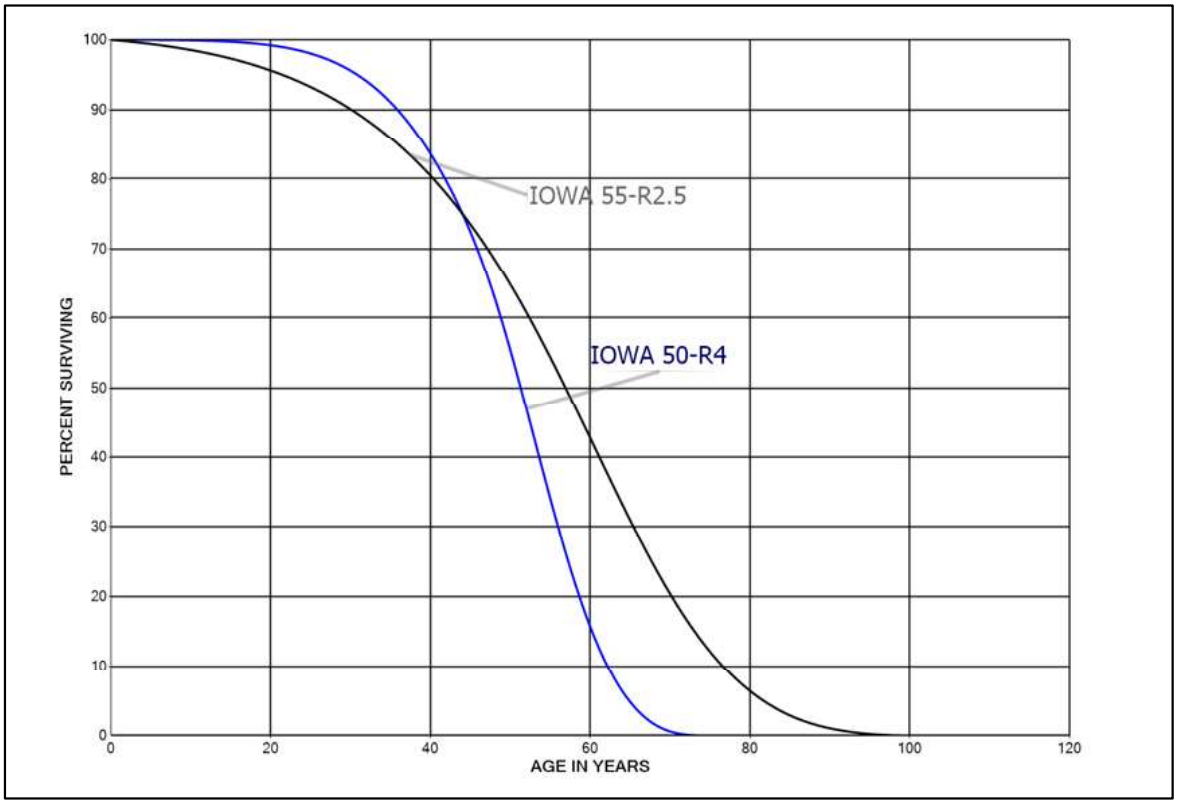
The subset of PG&E-owned underground services in San Francisco includes 83,660 underground service location records. Of these records, 2,960 had known installation years and 80,700 had unknown installation years. The vintages in this account were determined in a similar manner as for Account 369.01, the process for which is explained further in the discussion of estimates for that account. Unknown underground services were allocated in proportion to PG&E's San Francisco known meter installation years.

See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

Retirements of underground services are caused by third party damage; insulation deterioration; conditions during installation; capacity needs and other customer requirements. San Francisco's actuarial analysis supports a longer life than the 50-year average service life for PG&E's system as a whole. The 50-R4 survivor curve was authorized in the 2020 GRC and proposed in the 2023 GRC. A longer life in San Francisco is reasonable consistent with the factors discussed for other underground distribution accounts. The 55-R2.5 survivor curve is recommended and shown along with the 50-R4 in the chart below.



OTHER

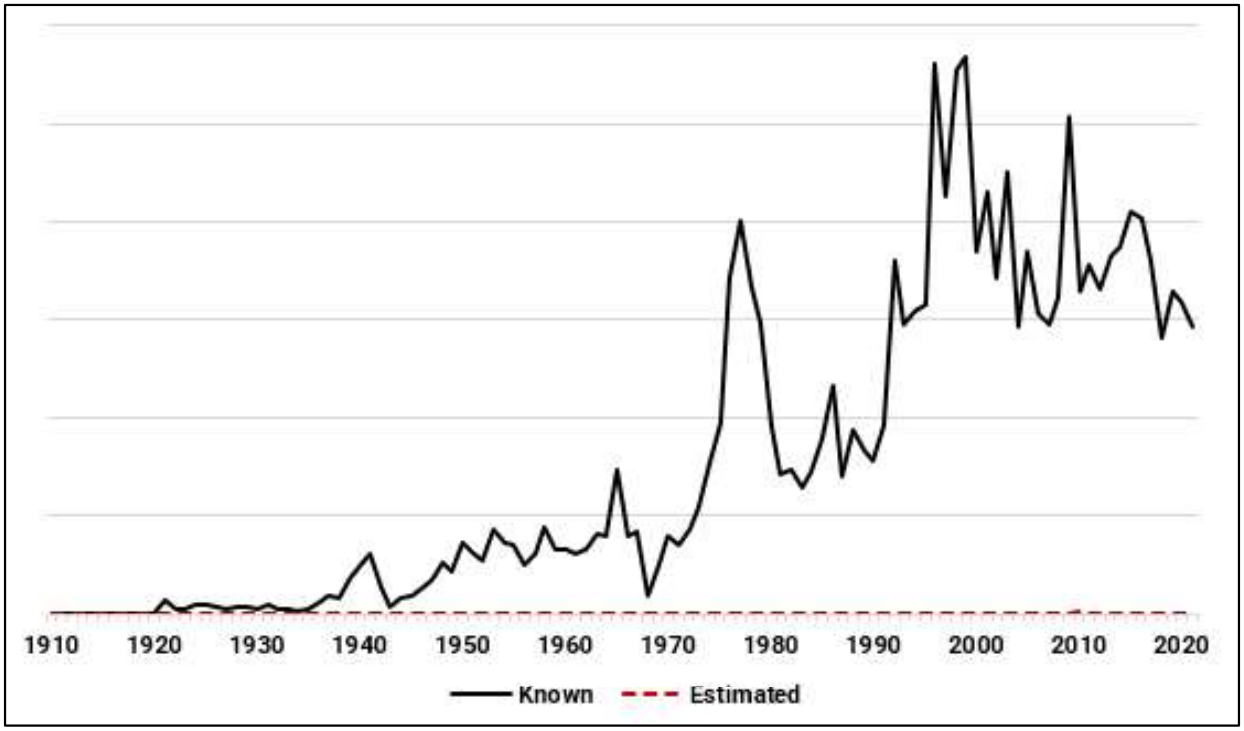
Account 370.00 Meters

This account includes the cost of meters or devices and appurtenances for the use in measuring the electricity to the users or customers. AMI meters are not included in this account.

ASSET AGE ANALYSIS

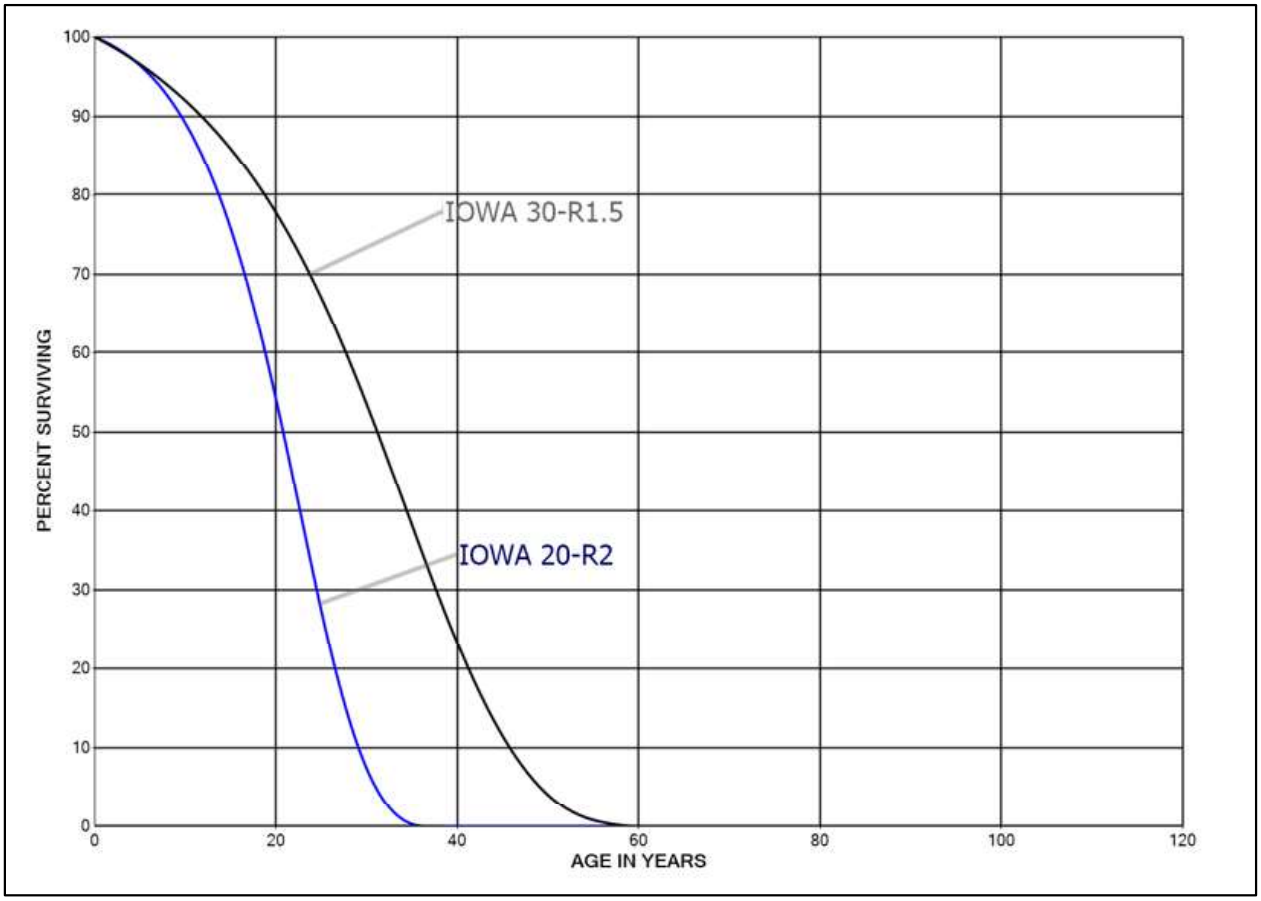
PG&E-owned meters in San Francisco include 23,468 current transformers, 10,188 legacy customer meters, 32 low-voltage potential transformers, 561 medium-voltage potential transformers, 16 primary meters with location not populated, 174 overhead primary meters and two underground primary meters, for a total of 34,441 meter and meter-related records. Vintages for customer meters, current transformers and potential transformers were available in the source records. For primary meters with unknown installation years, vintages were assigned in proportion to known meter vintages.

See the figure below for the asset quantities, known and estimated, by vintage for this account:



SERVICE LIFE ANALYSIS

The available statistical analysis for prior depreciation studies was considered together with the age distribution of the population of assets and PG&E's broader service life experience. Based on those considerations, the 30-R1.5 survivor curve is recommended for Account 370.00. It is shown below alongside the approved 2020 GRC estimate of 20-R2.



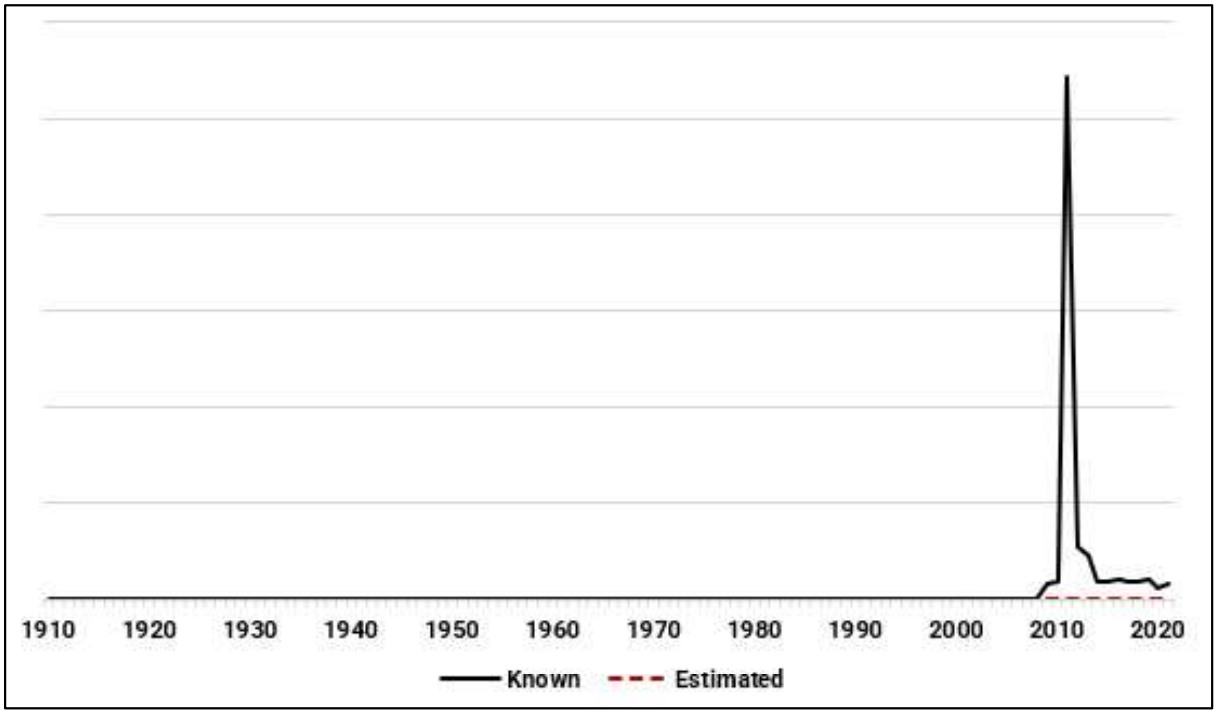
Account 370.01 Meters - AMI

This account includes the cost of meters or devices and appurtenances for the use in measuring the electricity to the users or customers.

ASSET AGE ANALYSIS

PG&E-owned AMI meters in San Francisco include 407,422 customer AMI meters, 74 smart meter access point devices and 132 smart meter relay devices, for a total of 407,628 AMI meter and related device records. Installation years for AMI customer meters were available in the source records. For smart meter access point and relay devices with unknown installation years, vintages were aligned with AMI meter vintages.

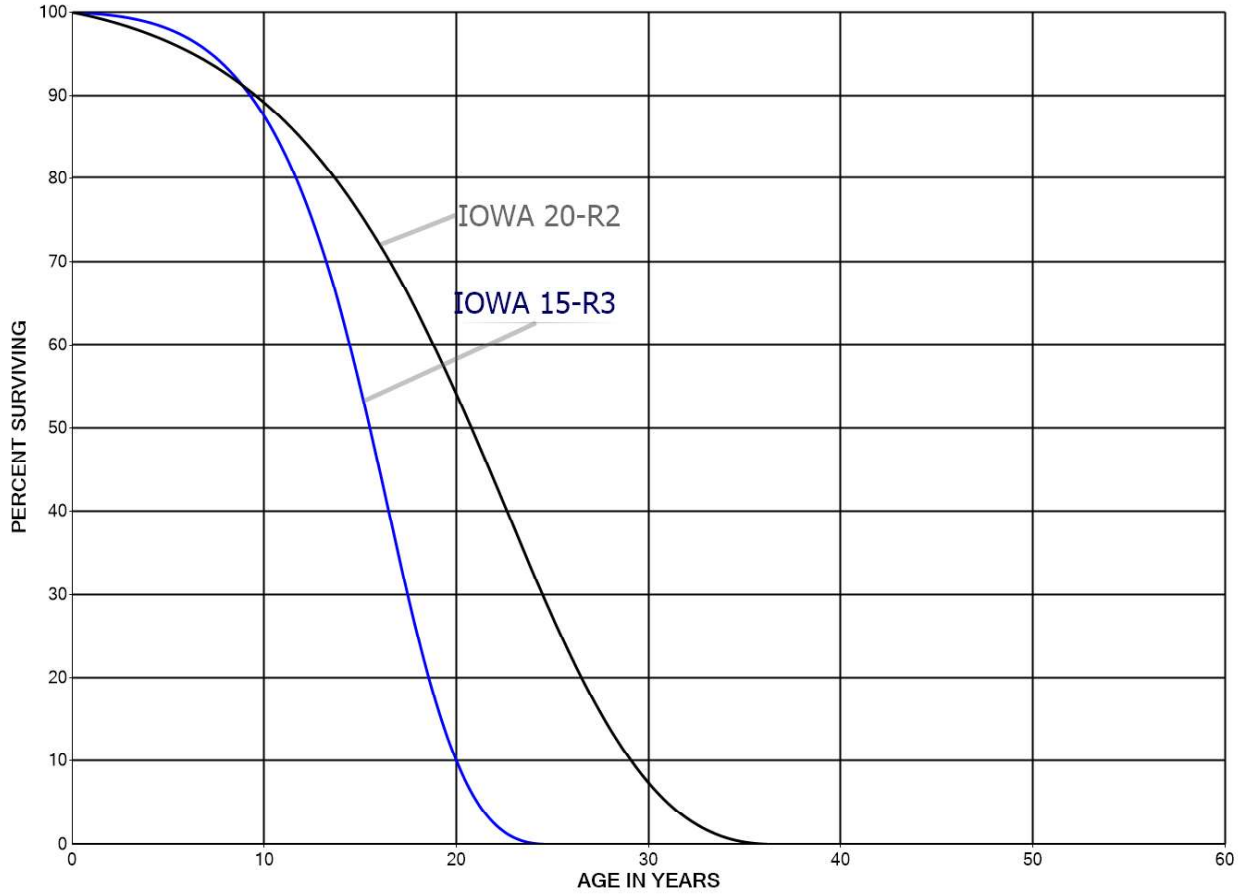
See the figure below for the asset quantities, known and estimated, by vintage for this account:



SERVICE LIFE ANALYSIS

The actuarial analysis for San Francisco meters is not definitive but it does support the currently proposed 20-year life for AMI meters. The 20-R2 survivor curve was authorized in the 2020 GRC. The 15-R3 survivor curve was proposed and authorized in

the 2023 GRC. Based on the available information for San Francisco assets, GFT recommends the 20-R2 survivor curve.



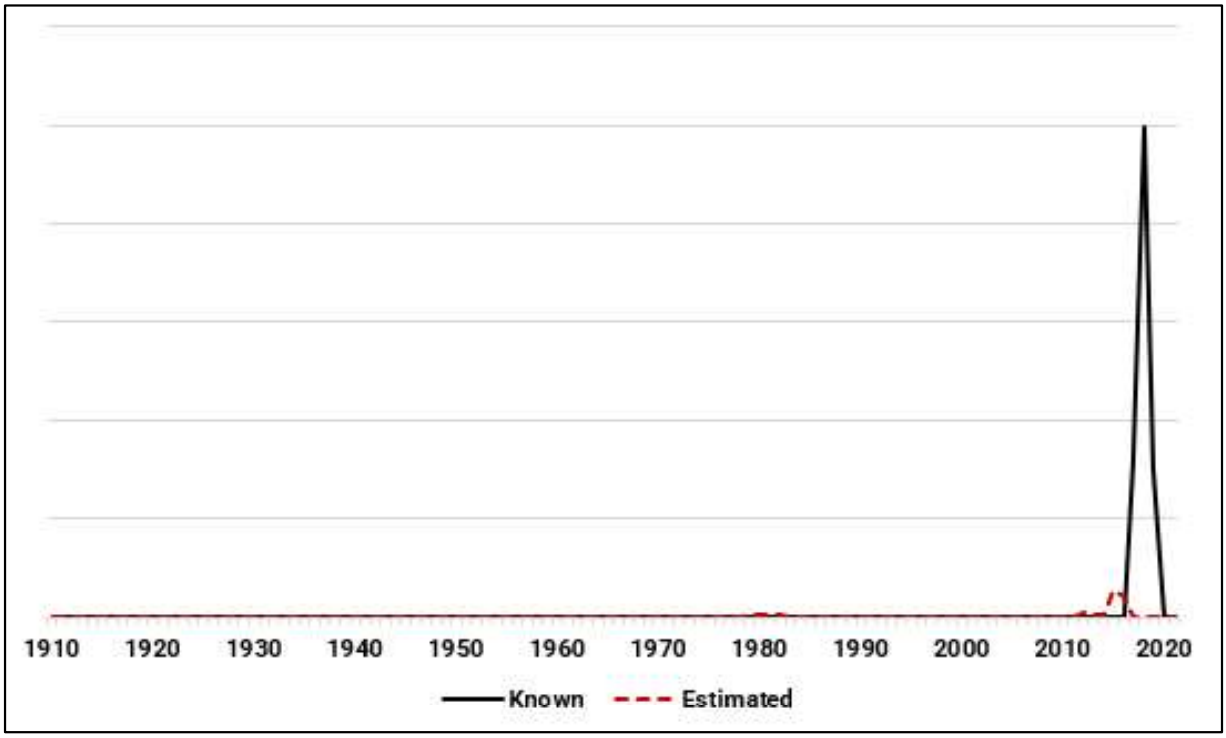
Account 373.03 Street Lighting and Signal Systems

This account includes the cost of lamps and all component parts and equipment used for public outdoor lighting.

ASSET AGE ANALYSIS

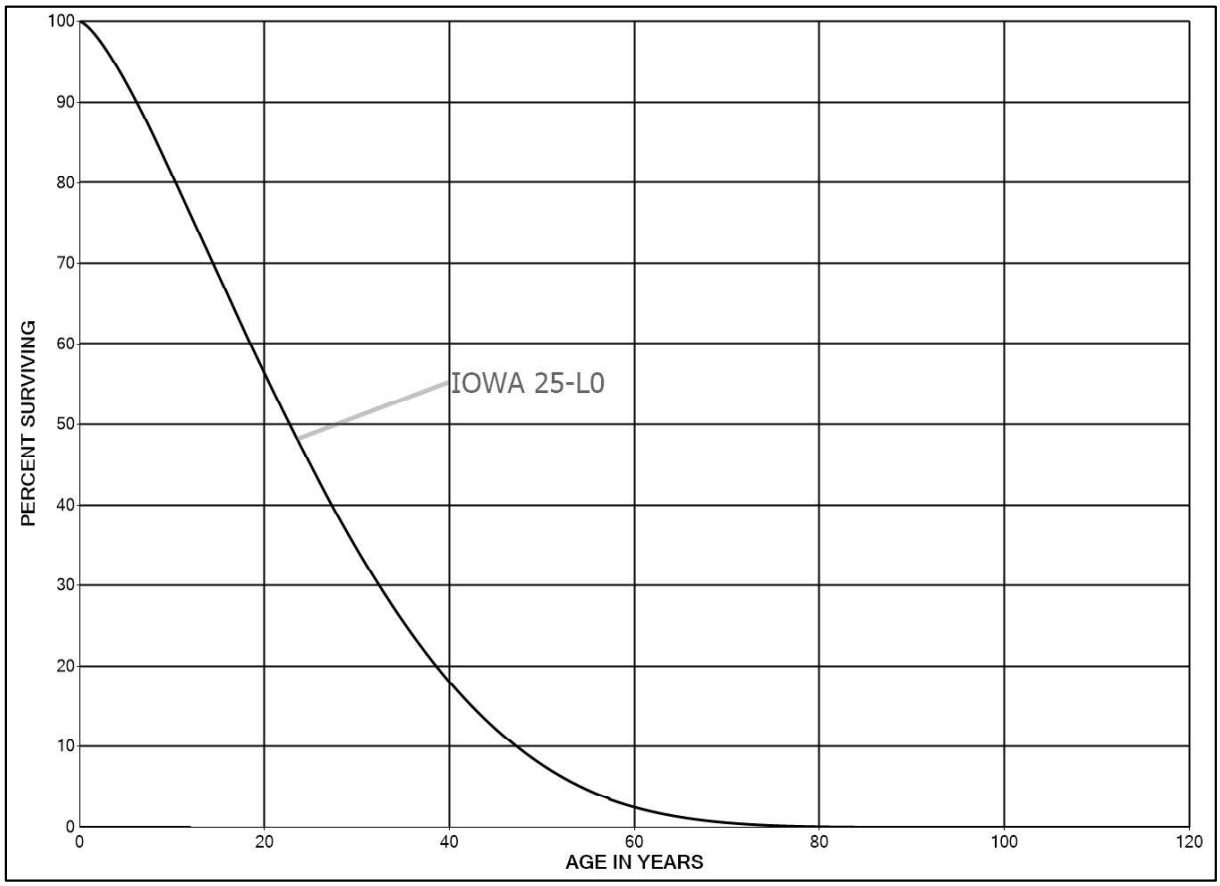
The subset of PG&E-owned street lighting assets in San Francisco includes 17,969 streetlight records, of which 16,180 had known installation years and 1,789 had unknown installation years. Cobra LED conversion dates were known for many of the assets. PG&E's accounting data for San Francisco was used in the effort to assign vintages to unknown streetlights. The Company provided surviving plant balances as of July 2021. These balances were Handy-Whitman cost-adjusted such that the remaining distribution of balances could serve as a reasonable proxy for estimated surviving units by vintage. This distribution served as the basis for which the unknown streetlights were vintaged.

See the figure below for the asset quantities (known and estimated) by vintage for this account:



SERVICE LIFE ANALYSIS

The actuarial analysis for this account considered a 2010 through 2022 experience band. The 25-L0 survivor curve was authorized in the 2020 GRC, proposed in the 2023 GRC, and proposed for San Francisco.



GENERAL PLANT

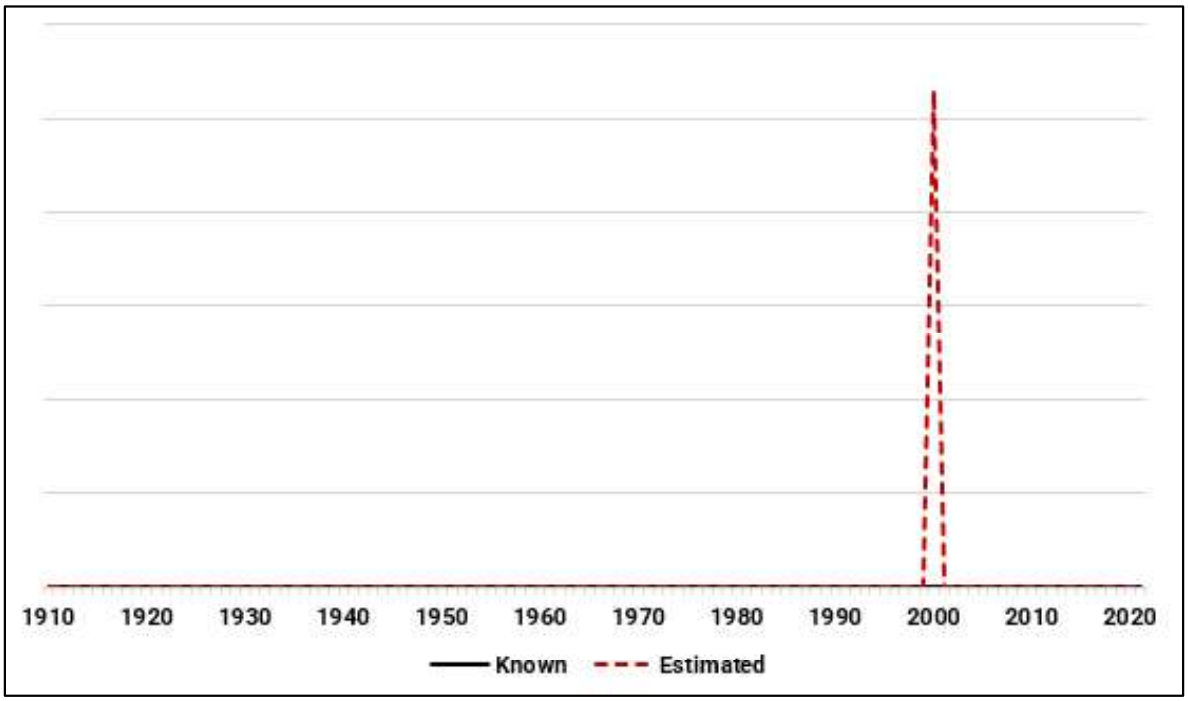
Account 397.08 Communication Equipment

Assets in Account 397.08 Communication Equipment include telecom, distribution and transmission fiber. The fiber in San Francisco is primarily underground.

ASSET AGE ANALYSIS

The assets aged in this account include 59 distribution underground fiber records, 26 telecom underground fiber records, one transmission overhead fiber record and 20 transmission underground fiber records, for a total of 106 communication equipment records. No installation years were available for these assets. The age distribution was aligned with PG&E's San Francisco surviving plant balances, which are all assumed to be the year 2000.

See the figure below for the asset quantities (known and estimated) by vintage for each asset category:



SERVICE LIFE ANALYSIS

For this account, the recommendation is to use the 15-SQ, which is the same survivor curve that was proposed in the 2023 GRC.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

REAL PROPERTY APPRAISAL

WITNESSES: WALTER D. CARNEY AND MICHAEL WALDRON

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
REAL PROPERTY APPRAISAL
WITNESSES: WALTER D. CARNEY AND MICHAEL WALDRON

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
REAL PROPERTY APPRAISAL

A. Introduction

Our names are Walter D. Carney of Valbridge Property Advisors ("Valbridge") and Michael Waldron of Waldron & Associates, Inc. ("Waldron & Associates"). In this testimony, we summarize the valuation of the real property component of the Subject Assets, Pacific Gas & Electric Company's ("PG&E") integrated electrical transmission and distribution grid within and serving San Francisco, which the City and County of San Francisco ("CCSF") seeks to acquire. Attachment A to this testimony is our Appraisal Report, which we incorporate into this testimony as if fully set forth herein. Except where otherwise stated, both of us (Mr. Carney and Mr. Waldron) jointly submit this testimony.

Our testimony and the accompanying Report were prepared for, and are submitted on behalf of, PG&E. As further described in Section D, below, the real estate assets we valued as part of this appraisal include 33 properties owned in fee simple[1] (over 87 acres); all land, buildings, and site improvements on those properties; and over 175 additional acres of easements[2] traversing third party private property. The purpose of our testimony and the accompanying Appraisal Report is to provide the fair market value[3] of this property as of the date of value ("DOV"), which is July 27, 2021.

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1 A fee simple estate means "[a]bsolute ownership unencumbered by any other interest or estate, subject only to the limitations imposed by the governmental powers of taxation, eminent domain, police power, and escheat." *The Dictionary of Real Estate Appraisal*, Seventh Edition (2022) at 73. This testimony includes definitions of key terms in footnotes; for a fuller glossary of key terms involved in this appraisal, see the Introduction section of the Appraisal Report at pages 18–24.

2 An easement is "[a]n interest in real property that conveys use, but not ownership, of a portion of an owner's property." *The Dictionary of Real Estate Appraisal*, Fourth Edition; Appraisal Institute (2002) at 90.

3 California law defines fair market value as "the highest price on the date of valuation that would be agreed to by a seller, being willing to sell but under no particular or urgent necessity for so doing, nor obliged to sell, and a buyer, being ready, willing, and able to buy but under no particular necessity for so doing, each dealing with the other with full knowledge of all the uses and purposes for which the property is reasonably adaptable and available." Civ. Proc. Code § 1263.320(a).

The fair market value of that real property is summarized as follows:

TABLE 4-1
TOTAL FAIR MARKET VALUE CONCLUSION

Line No.	FMV Land	FMV Easements	Plus: Building & Site Improvements	FMV Total
1	$1,572,430,340	$2,210,000,000	$516,957,599	$4,299,387,939

The remainder of our testimony proceeds in sections that generally parallel our Appraisal Report. Section B discusses the scope of work we performed. Section C provides an overview of the real estate market in the San Francisco region as of the DOV. Section D describes the property valued herein, including both the fee simple property (Mr. Carney's focus) and the easement interests (Mr. Waldron's focus), in more detail. Section E describes the highest and best use for the Subject Property, and Section F explains the methodology we used to value it. Section G (submitted by Mr. Carney) further describes the valuation process for the fee simple properties' land, buildings, and improvements thereon, and Section H (submitted by Mr. Waldron) does the same for easement interests. Section I explains the need for a corridor enhancement factor, and Section J provides a reconciliation of the final value of the real property interests CCSF seeks to take.

Finally, Section K provides a critique of CCSF's valuation of these real property assets, which grossly underestimates their value, and explains the major flaws that plague the testimony of CCSF's real estate expert, Timothy Runde. The complete omission of a fair market value component for the private easements CCSF plans to acquire and the lack of an upward adjustment for entitlements and a corridor enhancement factor leads to Mr. Runde's gross undervaluation of the fair market value and required compensation to PG&E.

B. Scope Of Work

To prepare this testimony and the accompanying Appraisal Report and develop the fair market value conclusions stated therein, we performed a variety of tasks, more fully described in the Scope of Work section of the appraisal report. Those tasks included:

- Identification of the properties to be appraised, including their legal, economic, and physical characteristics;

- Property inspections and field investigations, either on-site/in-person or remotely via aerial and street scene photographs from Google Earth;
- Review, categorization, and analysis of easements, particularly private circuit miles of easements across non-PG&E owned properties;
- Market research for comparable sales transactions;
- Highest and best use analysis;
- Valuations for fee properties' land, buildings, site improvements, easement properties, and corridor enhancement;
- Preparation of an Appraisal Report as defined by Standards Rule 2-2(a) of the Uniform Standards of Professional Appraisal Practice ("USPAP").

C. Regional And Market Area Analysis

The properties appraised herein are in the San Francisco Bay Area, a region comprised of nine counties bordering the San Francisco Bay. With the exception of one substation—the Martin Substation, described in Section D.1, below—all the properties appraised herein are within San Francisco.

As of the DOV (and still today), San Francisco was (and is) one of the most expensive real estate markets in the country. As of the DOV, the average price for an industrial building in San Francisco was $417 per square foot, the average price for logistics properties was $350 per square foot, and the average price for flex buildings was $510 per square foot. Office space was even more expensive: sale prices for office space hit a high of around $950 per square foot in 2019, and although prices dropped during the COVID pandemic, average prices still hovered around $850 per square foot as of the DOV. In 2021, the median and average prices for a detached residence were $1,800,000 and $2,304,380, respectively.

Comparable land sales on which we rely in our fee simple and easement valuations range from: $125 to $1,100 per square foot for neighborhood residential zoned lands; $325 to $1,200 per square foot for neighborhood commercial zoned lands; $400 to $900 per square foot for mixed commercial-residential zoned lands; $185 to $425 per square foot for industrial zoned lands; and $1,175 to $6,350 per square foot for high-density, high-rise, CBD (Central Business District) located and zoned lands.

In sum, real property in San Francisco is in demand and priced accordingly, with several years of positive trends leading up to 2020. Although the COVID-19

pandemic triggered a market downturn around San Francisco and in much of the country, by the DOV many market participants were optimistic because of vaccine rollouts and expected a market recovery as early as late 2021 or early 2022.

D. Property Description

The property appraised herein is part of a larger parcel,[4] namely, PG&E's electric and gas grid. PG&E has assembled a collection of fee simple properties, easements, and other property rights into an operating corridor, which it uses to provide most of northern California with electric and natural gas services. Although the fee simple properties and easement interests are discussed and valued in separate sections in our testimony and Report, it is critical to bear in mind that these properties are interconnected under PG&E's ownership and are used for a common highest and best use purpose.[5]

1. Fee Simple Property (Submitted by Walt Carney)

I focused on the appraisal of PG&E's 33 fee-owned properties.[6] These properties are identified by a sequential numbering system assigned by CCSF, which I adopt for ease of reference between reports.

Of those 33 fee-owned properties, 32 are situated within San Francisco. Combined, these properties total 50.366 acres. As of the DOV, the 32 properties within San Francisco consisted of 29 active substations[7] (Property Nos. 1–29); one inactive substation (Property 33); and two lots (Property Nos. 30 and 32) that were vacant as of the DOV. Property No. 30

---

[4] In condemnation, the larger parcel consists of "the tract or tracts of land that are under the beneficial control of a single individual or entity and have the same, or an integrated, highest and best use. Elements for consideration by the appraiser in making a determination in this regard are contiguity, or proximity, as it bears on the highest and best use of the property, unity of ownership, and unity of highest and best use." *The Dictionary of Real Estate Appraisal*, Seventh Edition, Appraisal Institute (2022) at 105.

[5] Gas line facilities and associated real property interests are excluded from CCSF's acquisition and therefore excluded from this valuation analysis, but other witnesses address gas assets as part of severance damages.

[6] Some of these properties consist of multiple parcels of land. For example, Subject Property 1, Substation Z (Embarcadero) is comprised of multiple parcels at 405 and 425 Folsom Street, San Francisco, numbered Property 1.1 and Property 1.2.

[7] As noted in Chapter 2, PG&E has two additional active customer-dedicated substations. PG&E does not own real property associated with these two substations. *See* PG&E Testimony, Ch. 2 (Bahramirad *et al.*), § E.3 (Crawford).

is planned for the development of a 230 kV switching station. Property No. 32 is traversed by underground electric transmission lines. A map showing these properties is included below (and in the Appraisal Report at page 11).

FIGURE 4-1
MAP OF PG&E'S FEE PROPERTIES WITHIN SAN FRANCISCO

The remaining fee-owned property—Property No. 31, the Martin Substation—is the only fee-owned property outside of San Francisco included in this appraisal. The Martin Substation property is a major transmission and distribution substation that straddles two cities, Brisbane and Daly City, within San Mateo County. Unlike the other substations included in this appraisal, which serve San Francisco only, the Martin Substation is used to provide electrical service to San Francisco and to other communities on the peninsula.

CCSF proposes to acquire an approximately 36.784-acre portion of the Martin Substation, which is entirely situated within the geographic boundaries of Brisbane, California. Of those 36.784 acres, approximately 7.00 acres are wetlands and habitat lands, as depicted by the blue outlines on the map below (and on page 142 of the Appraisal Report). The Martin Substation site is improved with buildings, substation equipment, and other site improvements. There is some onsite contamination at the Martin Substation, which PG&E has encapsulated.

FIGURE 4-2
MARTIN SUBSTATION

Net Acreage in Red; Wetland/Habitat Land Area in Blue
(Photo Source: Google Earth)

Site-by-site descriptions of the 33 properties appear on pages 55–156 of the Appraisal Report, in the "Property Description – 33 Fee-Owned Properties" section.

2. Private Easement Interests (Submitted by Michael Waldron)

I focused on the appraisal of PG&E's private easements in San Francisco. PG&E owns more than 2,400 easements, franchises, licenses, and similar agreements and land use rights within San Francisco. Broadly speaking, these rights enable PG&E to place electric transmission and distribution lines throughout San Francisco to connect its substations to one another and, ultimately, to electric customers within the city. Within San Francisco, this network of land rights creates an electric corridor occupying public property and public rights of way as well as privately owned lands. The segments occupying private property total 137.56 miles of linear distance, also referred to as "circuit miles," reasonably representing the private easement lengths. A map reflecting the segments of this corridor

occupying private property (highlighted in green) is reproduced below and appears at page 13 of the Appraisal Report:

FIGURE 4-3
PG&E'S PRIVATE EASEMENTS IN SAN FRANCISCO

PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - PRIVATE EASEMENTS
CITY AND COUNTY OF SAN FRANCISCO
ELECTRIC TRANSMISSION (UNDERGROUND AND OVERHEAD)
ELECTRIC DISTRIBUTION (UNDERGROUND FACILITIES MANAGEMENT, UNDERGROUND AND OVERHEAD)

	OVERALL (ET & ED)	TRANSMISSION (ET)	DISTRIBUTION (ED)
CIRCUIT MILES:	137.56 miles	2.16 miles	135.40 miles
LINEAR FEET:	726,292 linear feet	11,387 linear feet	714,904 linear feet
LAND AREA:	7,661,472 square feet	512,428 square feet	7,149,044 square feet
	175.88 acres	11.76 acres	164.12 acres
RIGHT-OF-WAY WIDTH:	10 & 45 feet	45 feet	10 feet

"Private" circuit miles represent those portions of the electric corridor traversing private property, which PG&E has the right to use by virtue of subsurface, surface, and/or aerial easements. This appraisal focuses on private circuit miles because PG&E's rights to use easements on public land stem from PG&E's franchise and license agreements with CCSF, which CCSF does not intend to take.[8]

The segments of this electric corridor can also be classified into five categories based on their use:

- Electric Transmission – Underground ("ET-UG") are, as the name suggests, traversed by underground electric transmission lines;
- Electric Transmission – Overhead ("ET-OH") are traversed by overhead electric transmission lines;
- Electric Distribution – Underground Facilities Management ("ED-UFM") are traversed by underground facilities;
- Electric Distribution – Underground ("ED-UG") are traversed by underground electric distribution lines; and
- Electric Distribution – Overhead ("ED-OH") are traversed by overhead electric distribution lines.

Historically, PG&E has obtained easements with widths of 45 feet for transmission lines (*i.e.*, ET-UG and ET-OH segments) and widths of between 10 and 30 feet for distribution easements (ED-UFM, ED-UG, and ED-OH segments). This appraisal conservatively assumes a standard width of 10 feet for all distribution easements within San Francisco.

The total linear distances and areas for each of these five types of easements on private property (*i.e.*, private circuit miles) within San Francisco are as follows. Note that, because there are no overhead transmission easements traversing private circuit miles in San Francisco, the remainder of this testimony discusses only the other four types of easements.

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8 Ex. CCSF-003C – Prepared Direct Testimony of Timothy P. Runde on Behalf of the City and County of San Francisco at 10:13–14 (Apr. 20, 2026) (Errata May 21, 2026) ("Runde Testimony") (testifying that CCSF "will not acquire any easements or other non-fee property interest granted to PG&E by the City").

TABLE 4-2
EASEMENT LENGTH AND AREA BY TYPE

Line No.	Easement Type	Width	Private Circuit Miles	Easement Area
1	ET-UG	45 ft	2.16 miles	11.764 acres
2	ET-OH	45 ft	–	–
3	ED-UFM	10 ft	54.02 miles	65.479 acres
4	ED-UG	10 ft	20.87 miles	25.302 acres
5	ED-OH	10 ft	60.50 miles	73.339 acres
6	Total		137.55 miles	175.884 acres

E. Highest And Best Use

The highest and best use of a property is the reasonably probable use that is legally permissible, physically possible, financially feasible, and maximally productive.

The property described above is an "assembled corridor"—a collection of fee-owned land tethered together by easements, licenses, franchises, leases, and other agreements, all improved and operating for electrical transmission and distribution purposes. The current use of this property as an assembled corridor is the highest and best use of the property, "as if vacant" and "as improved."

F. Valuation Approaches

There are three traditional valuation methodologies used in appraisals: the Sales Comparison Approach, the Cost Approach, and the Income Approach.[9] In this appraisal, we valued PG&E's fee simple land using a combination of the Sales Comparison Approach and the Cost Approach.

- The Sales Comparison Approach determines market value by comparing the subject property with similar, proximate property sales within a reasonable time before and after the date of value, and adjusting for differences in property rights, market conditions, property location, property sizes, and other features. We used the Sales Comparison Approach to value PG&E's fee simple parcels as well as for the base land value for PG&E's private easements.

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9 This real property appraisal does not use the Income Approach; other witnesses discuss that approach in other testimony chapters.

- The Cost Approach estimates the reproduction or replacement cost new of an existing physical structure and then deducts accrued depreciation (physical, functional, and economic) to arrive at the value of the structure. We (specifically, Mr. Carney) used this approach to value substation building structures and real property site improvements.

For PG&E's easement interests, we (specifically, Mr. Waldron) used the "across the fence" ("ATF") method. That approach is designed and commonly used to value special use corridors—such as railroad corridors or, as applicable here, an electric grid—that are not frequently bought and sold wholesale on the open market. The ATF method is similar to the Sales Comparison Approach insofar as it looks to comparable property sales, but it treats these sales as "market indicators" to value the corridor property as though it were part of the adjacent land parcels.[10] However, because easement rights are typically less valuable than fee simple rights, this appraisal discounts the value accordingly, as further described in Section H of this testimony and in the accompanying Appraisal Report.

Finally, to account for the property's highest and best use as a fully assembled utility operating corridor, we applied a corridor enhancement factor to the fee simple and easement properties, as further described in Section I of our testimony.

G. Appraisal Of Fee Simple Property (Submitted by Walt Carney)

With the support of others at Valbridge, I led the appraisal of the fee simple property. To generate the fair market value of those properties (prior to the corridor enhancement factor), I used the following steps:

(1) Calculate the fair market value of the land as of the DOV using the Sales Comparison Approach.

(2) Calculate the reproduction or replacement costs new ("RCN") of the real property improvements on the land using cost sources (either actual costs or surveyed costs) as of the DOV.

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[10] For a fuller description of the ATF Approach, see pages 176–179 of the Appraisal Report.

(3) Calculate and deduct the appropriate forms of depreciation as of the DOV, including obsolescence, to yield reproduction or replacement cost new less depreciation ("RCNLD").

(4) Add the fair market value of the land to the RCNLD of the real property improvements.

1. Fair Market Value of Land

To determine the fair market value of the land under the Sales Comparison Approach, I identified 80 comparable transactions through a search of public records and commercial public databases (such as CoStar and the regional Multiple Listing Service), field surveys, interviews with knowledgeable real estate professionals in San Francisco, and a review of Valbridge's internal database. Details about these comparable sales, including the price per square foot of each sale, are listed on pages 185–187 of the Appraisal Report, and their locations are mapped on pages 188–190 of the Appraisal Report.

Each comparable sale has certain "elements of comparison," which include features of the specific sale ("transactional characteristics") and features of the property itself ("property characteristics"). The most relevant transactional characteristic for this appraisal involves market conditions: The comparable sales occurred between 2015 and 2023, and market conditions at different times in this period differed from the market conditions on the DOV; comparable sale prices were adjusted accordingly to approximate market conditions on the DOV. Relevant property characteristics include the property's location, its size and shape, whether it contains any buildings or other improvements, the zoning districts in which it sits, and its entitlement status.

Of these property characteristics, entitlements are among the most significant. "Entitlements" is a term of art meaning that a specific development has already been approved at the appropriate governmental planning levels. Paired sales of the same sites—before and after entitlements are obtained—illustrate that entitled properties commonly sell for double the price of unentitled properties, and sometimes more. However, entitlements depreciate in much the same way that buildings and other substation site improvements do. Because the overall remaining life of

the real property substation improvements is 67%, I estimated the quantitative measure of subject properties' existing entitlements at 65%. Therefore, in this valuation, I applied a 65% upward adjustment to unentitled properties that I compared to entitled subject properties.[11]

I used the comparable sales and the elements of comparison to determine the fair market value of each of the 33 subject properties. For each property, I selected the 4–6 most comparable properties based on the property location, date of sale, size, physical condition, land use constraints, functional utility, and/or economic characteristics. Those comparable sales appear in a "Sale Summary" table for each property. I then adjusted the sales prices of those comparable properties based on market conditions and property characteristics. I documented these adjustments in an "Adjustment Grid" for each property. Based on the results of the adjustment grid and other features of the subject property affecting its value, I determined the applicable price per square foot of land and total land price of each property, as documented more fully on pages 195–263 of the Appraisal Report.

2. RCNLD of Buildings and Site Improvements

Fourteen of the 33 properties, Properties 1, 2, 3, 4, 5, 6, 7, 8, 9, 11, 12, 15, 31, and 33, are improved with one or more buildings, which I valued using RCNLD. I first calculated the reproduction or replacement costs new ("RCN"), as follows:

- For buildings on four of these properties (six buildings)—Properties 1 (which includes component parcels 1.1 and 1.2), 2 (including component parcels 2.1 and 2.2), 5 (including component parcels 5.1 and 5.2), and 6, which PG&E built or improved relatively recently before the DOV—I estimated fair market value of the buildings applying the reproduction cost new. I used either PG&E's actual construction costs for those buildings, or PG&E's actual construction costs for similar buildings, and escalated costs for increasing costs between the dates of construction and the DOV.

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[11] The only exception is Property 30, also called the "Egbert Switching Station Site," which was partially entitled as of the DOV. I applied an upward adjustment of 15% when comparing unentitled properties to Property 30.

- For the remaining buildings, I calculated the replacement cost new. I used building and other site costs from the Marshall Valuation Service ("MVS") and applied various refinements to account for the DOV, local market conditions, and characteristics of the buildings.
- As a final step in RCN valuation, I applied a 10% entrepreneurial incentive enhancement, which reflects the amount an entrepreneur expects to receive for their contribution to a project.

After calculating the RCN, I calculated the depreciation using the Age-Life Table in the MVS, indexing the improvements' economic life, with their effective age and their remaining economic life. The results are shown in the table on the next page[12] and are described more fully at pages 266–268 of the Appraisal Report.

In addition to buildings, most of the subject properties are improved with features such as site preparation (rough and finish grading), drainage, underground and above ground utilities, cover (asphalt, concrete, gravel or compacted dirt), lighting, and striping. The chart on page 270 of the Appraisal Report shows my step-by-step valuation of these improvements.

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12 The "cost source" column in that table specifies whether the costs listed are derived from (1) the costs that PG&E actually incurred to construct the specific listed improvements ("Actual"), (2) the costs that PG&E incurred to construct similar improvements ("PG&E Costs"), or (3) Marshall Swift Valuation.

TABLE 4-3
RCNLD FOR BUILDINGS ON PG&E'S FEE PROPERTY

CCSF No.	PG&E Substation/ Property Name	Cost Source (Marshall Swift)/Actual	RCN per SF	RCN/SF Less 5%*	Entreprenerial Incentive	RCN Total	Age/Life Depreciation (%)	RCNLD Building Improvements
1.1	Z Embarcadero	PG&E Costs	$2,271	$2,157.07	10%	$282,549,663	33%	$189,308,274
1.2	Z Embarcadero (GIS)	Actual	$1,593	$1,513.73	10%	$22,791,930	1%	$22,564,011
2.1	A Potrero	Marshall Swift Valuation	$128	$127.84	10%	$813,763	45%	$447,570
2.2	A Potrero (GIS)	Actual	$1,575	$1,496.06	10%	$27,864,417	1%	$27,585,773
3.1	P Hunter's Point	Marshall Swift Valuation	$299	$299.44	10%	$100,790	58%	$42,332
3.2	P Hunter's Point	Marshall Swift Valuation	$129	$129.48	10%	$108,669	72%	$30,427
3.3	P Hunter's Point	Marshall Swift Valuation	$129	$129.48	10%	$44,721	72%	$12,522
4	W Bayshore	Marshall Swift Valuation	$82.81	$82.81	10%	$70,137	58%	$29,458
5.1	Y Larkin	PG&E Costs	$1,450	$1,377.49	10%	$144,554,252	38%	$89,623,636
5.2	Y Larkin (GIS)	Actual	$1,605	$1,524.56	10%	$23,109,280	1%	$22,878,188
6	X Mission	PG&E Costs	$1,593	$1,513.73	10%	$148,360,677	16%	$124,622,969
7.1	L	Marshall Swift Valuation	$479	$478.58	10%	$1,766,721	71%	$512,349
7.2	L	Marshall Swift Valuation	$410	$410.15	10%	$823,384	78%	$181,144
8	G	Marshall Swift Valuation	$359	$358.74	10%	$9,196,203	65%	$3,218,671
9	E	Marshall Swift Valuation	$423	$423.27	10%	$7,798,834	65%	$2,729,592
11	K	Marshall Swift Valuation	$297	$297.06	10%	$3,580,045	48%	$1,861,624
12	J	Marshall Swift Valuation	$431	$430.77	10%	$12,438,544	57%	$5,348,574
15	M - Brick	Marshall Swift Valuation	$299	$299.44	10%	$553,359	50%	$276,679
15	M - Metal Lean-To	Marshall Swift Valuation	$25	$24.51	10%	$28,797	8%	$26,494
33	Substation I	Marshall Swift Valuation	$410	$410.15	10%	$4,940,304	78%	$1,086,867
	Total Within San Francisco							**$492,387,153**
31	Martin Substation	Marshall Swift Valuation	$460	$460.10	10%	$4,627,918	80%	$925,585
		Marshall Swift Valuation	$285	$285.36	10%	$5,527,081	38%	$3,426,790
		Marshall Swift Valuation	$129	$129.48	10%	$1,666,348	34%	$1,099,790
		Marshall Swift Valuation	$129	$129.48	10%	$1,823,014	1%	$1,804,783
	Total Within Brisbane							**$7,256,948**
	Total Buildings San Francisco & Brisbane							**$499,644,101**

3. Total Value of Fee Properties

The total fair market value for each of the fee simple properties and site improvements is $1,726,519,399, prior to the application of the corridor enhancement factor. The chart below provides a property-by-property breakdown of that total; a more detailed chart appears on page 272 of the Appraisal Report.

TABLE 4-4
FAIR MARKET VALUE OF FEE SIMPLE PROPERTY

No.	PG&E Substation	FMV Land	FMV Structural Improvements	FMV Site Improvements	FMV Conclusion
1	Substation Z (Embarcadero)	$199,278,000	$211,872,285	$0	$411,150,285
2	Substation A (Portrero)	$96,730,375	$28,033,342	$0	$124,763,717
3.1	Substation P (Hunter's Point)	$27,091,200	$42,332	$558,756	$27,692,288
3.2	Substation P (Hunter's Point)	$70,414,750	$30,427	$1,773,750	$72,218,927
3.3	Substation P (Hunter's Point)	$21,436,750	$12,522	$150,325	$21,599,597
3.4	Substation P (Hunter's Point)	$81,427,250	$0	$889,536	$82,316,786
3.5	Substation P (Hunter's Point)	$686,700	$0	$49,088	$735,788
3.6	Substation P (Hunter's Point)	$128,463,660	$0	$5,138,648	$133,602,308
4	Substation W (Bayshore)	$32,159,750	$29,458	$381,971	$32,571,178
5	Substation Y (Larkin)	$46,875,000	$112,501,824	$0	$159,376,824
6	Substation X (Mission)	$156,159,500	$124,622,969	$0	$280,782,469
7	Substation L	$11,099,400	$693,494	$75,540	$11,868,434
8	Substation G	$18,562,800	$3,218,671	$35,120	$21,816,591
9	Substation E	$30,302,500	$2,729,592	$36,362	$33,068,454
10	Substation F (Marina)	$12,456,400	$0	$232,567	$12,688,967
11	Substation K	$9,298,500	$1,861,624	$40,020	$11,200,144
12	Substation J	$8,395,000	$5,348,574	$0	$13,743,574
13	Substation N	$4,869,000	$0	$115,152	$4,984,152
14	Randolph Substation	$3,162,250	$0	$34,116	$3,196,366
15	Substation M	$5,197,500	$303,174	$23,378	$5,524,052
16	Portola Substation	$2,936,250	$0	$55,554	$2,991,804
17	Beach Substation	$5,062,500	$0	$44,344	$5,106,844
18	6th Avenue	$2,025,000	$0	$18,150	$2,043,150
19	Silver Substation	$991,900	$0	$17,146	$1,009,046
20	Ocean Substation	$1,792,125	$0	$16,063	$1,808,188
21	Yosemite Substation	$562,500	$0	$15,125	$577,625
22	Taraval Substation	$1,687,500	$0	$15,125	$1,702,625
23	Judah Substation	$1,875,000	$0	$15,125	$1,890,125
24	Plymouth Substation	$1,687,500	$0	$15,125	$1,702,625
25	Noriega Substation	$1,569,375	$0	$16,304	$1,585,679
26	18th Street Substation	$2,475,000	$0	$13,613	$2,488,613
27	Acton Substation	$1,518,750	$0	$13,613	$1,532,363
28	Castro Substation	$2,300,000	$0	$6,050	$2,306,050
29	21st Avenue Substation	$1,265,625	$0	$5,672	$1,271,297
30	Egbert Switching Station	$16,950,000	$0	$0	$16,950,000
32	Beeman Lane	$1,227,460	$0	$16,878	$1,244,338
33	Substation I	$10,500,000	$1,086,867	$6,346	$11,593,213
		$1,020,492,770	**$492,387,154**	**$9,824,560**	**$1,522,704,483**
31	Martin Substation	**$189,069,030**	**$7,256,948**	**$7,488,938**	**$203,814,916**
Total Land and Improvements Value: *		**$1,209,561,800**	**$499,644,102**	**$17,313,498**	**$1,726,519,399**

** Not Including Enhancement Corridor Factor*

H. Appraisal Of Private Easement Interests (Submitted by Michael Waldron)

With the support of others at Waldron & Associates, I led the appraisal of PG&E's easement assets. I determined their value through the following steps:

(1) For each of the four categories of existing easements that traverse private property within San Francisco, determine the per-square-foot value of the land that the easements traverse, as though owned in fee simple.

(2) Determine, based on the particular bundle of rights included within each category of easement, what percent of the fee value each of the four categories of easements are worth.

(3) Multiply the land area of each easement type by the per-square-foot value from Step (1), and multiply that value by the percent from Step (2), to determine the value for each type of easement.

(4) Sum the values of each of the four easement types to obtain the total value of the easements, before a corridor enhancement adjustment. A before and after analysis was also utilized in the determination of the easement contribution.

1. Fair Market Value of Land As Though Owned in Fee

To value the land using the Across the Fence method, I compiled a data set of market indicators. I included all the comparable sales Mr. Carney identified except for the wetland sales transactions and added additional transactions applicable to the easement appraisal. I then adjusted each of these market indicators based on their sales date to account for the market conditions on the DOV. I also adjusted the value of any unentitled market indicators upwards; however, I used a very conservative 20% upwards adjustment instead of 65% because the entitlements associated with the land accommodating the easements within the improved properties generally have less entitlement risk and are inherently more compatible with a "by-right" level of discretion as compared to a full buildout for electric substation development. The list of market indicators, together with the relevant adjustments, appears at Exhibit W-3 to the Appraisal Report.

From there, I used two variations of the ATF method to value the land covered by the easements: one approach based on relative locations of the easements in San Francisco (the "Grid Quadrant Analysis"), and one based on zoning designations (the "Zoning Use Analysis").

In the Grid Quadrant Analysis, I used the market indicator data to determine the value of the easements based on their relative location in San Francisco using the following steps:

(1) Divide San Francisco into sixteen quadrants approximately two miles by two miles each.

(2) Determine an appropriate price per square foot of land within each quadrant using market indicator data within each quadrant (or, where a given quadrant contained few or no market indicators, market indicators from adjacent quadrants).

(3) Determine the percent of each of the four types of easements in each quadrant.

(4) Multiply that percentage by the price per square foot for each quadrant.

(5) Sum the resulting weighted rates, providing a total weighted price per square foot for each easement type.

A fuller description of this approach appears at pages 279–290 of the Appraisal Report.

In the Zoning Use Analysis, I used the market indicator data to determine the value of the easements based on zoning designations, using the following steps:

(1) Determine an appropriate price per square foot of land within each zoning category using market indicator data for each zoning category.

(2) Determine the percentage of each of the four types of easements located within each of the fifteen categories of zoning designations ("zoning category") in San Francisco.

(3) Multiply that percentage by the price per square foot for each zoning category.

(4) Sum the resulting weighted rates, providing a total weighted price per square foot for each easement type.

A fuller description of this approach appears on pages 290–296 of the Appraisal Report.

These two approaches—the grid quadrant approach and the zoning approach—provide two separate value indicators (per square foot) for each of the four easement types, as illustrated by the chart below. These prices represent the price per square foot each easement would merit if the land

were owned in fee simple; the next section (Section H.2) discusses the adjustment necessary to account for the more limited land rights associated with easements; and the section after that (Section H.3) discusses the reconciliation between the different approaches.

TABLE 4-5
FEE RATES (PER SQUARE FOOT) BY EASEMENT TYPE

Line No.	Easement Type	Quadrant Approach (PSF)	Zoning Approach (PSF)
1	ET-UG	$695.28	$443.39
2	ED-UFM	$806.81	$743.52
3	ED-UG	$755.25	$486.51
4	ED-OH	$383.08	$409.54

2. Appropriate Percentage of Fee Value by Easement Type

PG&E's easements include a variety of rights that benefit PG&E and burden the private properties through which each easement passes. Those rights can be classified as "primary rights" and "secondary rights." PG&E's primary rights for each easement relate directly to their purpose, whether for transmission or distribution, underground or overhead. Secondary rights allow PG&E to manage vegetation, prohibit buildings from being built within the easement area, and to generally access the easement parcel.

The rights associated with easements, however, are only a subset of the rights associated with complete total fee ownership. Accordingly, easements are often valued as a percentage of the fee value. This valuation approach is particularly applicable here because there is a limited market for private property easements with comparable rights. I determined the appropriate percent of fee value for each easement type by reference to (1) trusted secondary sources within the appraisal industry, including the well-known Easement Valuation Matrix by Donnie Sherwood, MAI (reproduced below), and a historical Appraisal Handbook by George Schmutz; and (2) a license agreement between PG&E and the Port Commission within CCSF, which provides some evidence of the value of subsurface easement rights.

TABLE 4-6
EASEMENT VALUATION MATRIX

Line No.	Percentage of Fee Value	Features	Examples
1	90% - 100%	Severe impact on surface use Conveyance of future uses	Overhead electric, flowage easements, railroad right of way, irrigation canals, exclusive access easements
2	75% - 89%	Major impact on surface use Conveyance of future uses	Overhead electric, pipelines, drainage easements, railroad right of way, flowage easements
3	51% - 74%	Some impact on surface use Conveyance of ingress/egress rights	Pipelines, scenic easements
4	50%	Balanced use by both owner and easement holder	Water or sewer lines, cable lines, telecommunications
5	26% - 49%	Location along a property line Location along non-usable land area	Water or sewer line, cable lines
6	11% - 25%	Subsurface or air rights with minimal effect on use and utility Location with a setback	Air rights, water, or sewer line
7	0% - 10%	Nominal effect on use and utility	Small subsurface easement

Based on these sources, I concluded that the appropriate percentage of fee for each easement type is 50% of fee for overhead easements (i.e., Overhead Distribution Easements) and 33% of fee for underground easements (i.e., Underground Transmission Easements, Underground Facilities Management Electric Distribution Easements, and Underground Electric Distribution Easements).

3. Total Value of Easements

Based on the foregoing, I determined the total value of the easements using both the Grid Quadrant Analysis and the Zoning District Analysis. The calculation based on the Grid Quadrant Analysis is summarized on the following table and results in an easement valuation of $1.78 billion.

TABLE 4-7
EASEMENT VALUATION USING GRID QUADRANT ANALYSIS

PG&E ATF EASEMENT INTEREST VALUATION - BY QUADRANT
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - OVERHEAD AND UNDERGROUND
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

Description	Valuation									
	Land Area		Weighted Land Rate			ATF - Fee @ 100%		Easement Contribution		ATF - Easement Interest
Transmission - Underground	512,428 sf	x	$695.28 psf	=		$356,280,940	x	33.33%	=	$118,748,437
Transmission - Overhead	0 sf	x	$0.00 psf	=		$0	x	50.00%	=	$0
Distribution - UFM	2,852,250 sf	x	$806.81 psf	=		$2,301,223,823	x	33.33%	=	$766,997,900
Distribution - Underground	1,102,163 sf	x	$755.25 psf	=		$832,408,606	x	33.33%	=	$277,441,788
Distribution - Overhead	3,194,632 sf	x	$383.08 psf	=		$1,223,799,627	x	50.00%	=	$611,899,814
Total	7,661,473 sf					**$4,713,712,996**				**$1,775,087,939**
Indicated Rate per Square Foot						**$615.25 psf**				**$231.69 psf**

The calculation based on the Zoning Use District Analysis is summarized in the following table and results in an easement valuation of $1.62 billion.

TABLE 4-8
EASEMENT VALUATION USING ZONING USE DISTRICT ANALYSIS

PG&E ATF EASEMENT INTEREST VALUATION - BY ZONING USE DISTRICT
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - OVERHEAD AND UNDERGROUND
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

Description	Valuation									
	Land Area		Weighted Land Rate			ATF - Fee @ 100%		Easement Contribution		ATF - Easement Interest
Transmission - Underground	512,428 sf	x	$443.39 psf	=		$227,205,451	x	33.33%	=	$75,727,577
Transmission - Overhead	0 sf	x	$0.00 psf	=		$0	x	50.00%	=	$0
Distribution - UFM	2,852,250 sf	x	$743.52 psf	=		$2,120,704,920	x	33.33%	=	$706,830,950
Distribution - Underground	1,102,163 sf	x	$486.51 psf	=		$536,213,321	x	33.33%	=	$178,719,900
Distribution - Overhead	3,194,632 sf	x	$409.54 psf	=		$1,308,329,589	x	50.00%	=	$654,164,795
Total	7,661,473 sf					**$4,192,453,281**				**$1,615,443,222**
Indicated Rate per Square Foot						**$547.21 psf**				**$210.85 psf**

As these calculations show, the end results of the two analyses are similar. I therefore adopt an equally weighted average of the two

approaches as my valuation for these easements, rounded to the nearest hundred million. The value of PG&E's easements that traverse private property in San Francisco is $1,700,000,000, before an adjustment for the corridor enhancement factor.

I. Corridor Enhancement Factor

Given the nature of PG&E's properties, a corridor enhancement factor is an appropriate, and indeed, a necessary component to determine the fair market value. PG&E's properties are not simply isolated parcels and easements; rather, the properties are integrated into a single unified use along a pre-assembled corridor that produces greater utility and higher productivity than the component parts in isolation. "When a group of parcels is put together to form a corridor," as is the case with PG&E's property, "synergism results, because the value of the whole exceeds the sum of values of the parts."[13]

To determine the appropriate corridor enhancement factor, we considered the acquisition time and cost history of other transportation corridors as well as a separate study of comparable sales of transportation and utility corridors in urban and suburban locations. The study identified eight such indicators and determined that the corridors sold at between 1.10 and 1.63 times the across-the-fence values, representing a corridor enhancement factor. Considering the acquisition history of other transportation corridors, the past study comparisons, and considering PG&E's highly urbanized location and its fully integrated connection systems, a corridor enhancement factor of 1.30 is a reasonable measure of the plottage synergy intrinsic in PG&E's pre-assembled corridor.

J. Reconciliation

The PG&E properties we appraised form an integrated network of transmission and distribution corridors and substations that supplies electric power throughout San Francisco, which is a portion of PG&E's larger electric and gas grid. We calculated the overall fair market value of that property by adding the values of the fee simple land and the private easement interests, adjusting upward using the corridor enhancement factor, and adding the

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[13] John P. Dolman, MAI, CRE and Charles F. Seymour, MAI, CRE, Valuation of Transportation / Communication Corridors, The Appraisal Journal (October 1978), 515.

buildings and site improvements on the land. That produces a fair market value of $4,299,387,939 as of July 27, 2021.

TABLE 4-9
TOTAL FAIR MARKET VALUE

Line No.	Component	Base Value	Corridor Enhancement Factor	FMV
1	Fee Simple Properties	$1,209,561,800	1.30	$1,572,430,340
2	Easement Interests	1,700,000,000	1.30	2,210,000,000
3	Buildings and Site Improvements	516,957,599	N/A	516,957,599
4	TOTAL FAIR MARKET VALUE:	$3,426,519,399		$4,299,387,939

This valuation presumes several conditions—known in appraisal terms as "extraordinary assumptions"—which appear at pages 313-314 of the Appraisal Report. These extraordinary assumptions include, among other things, that PG&E has clear and marketable title, that information provided and relied upon by PG&E is accurate, that all but four of the properties are environmentally clean, and that the value of the properties is unaffected by any option-to-purchase or right-of-first-refusal agreements between PG&E and CCSF. This appraisal also incorporates and is subject to several hypothetical conditions which appear at pages 314-315 of the Appraisal Report. General assumptions and limiting conditions appear at pages 316–323 of the Appraisal Report.

K. Critique Of CCSF Appraisal

On April 20, 2026, CCSF served its Amended and Restated Testimony, including its Exhibit CCSF-003C, the Prepared Direct Testimony of Timothy P. Runde, and Mr. Runde's attached Appraisal Report. On May 21, 2026, CCSF served an errata and corrected version of Mr. Runde's testimony, which largely made non-substantive corrections and attached an additional appendix.

Overall, Mr. Runde's testimony and appraisal do not apply standard appraisal methods and approaches accepted under either federal or state rules. The appraisal "development" and the report narrative are short on or lacking standard and required descriptions, methods, and valuation analyses. There is no discussion or acknowledgement of the larger parcel of which PG&E's San Francisco assets are a critical part. The appraisal report appears to

inconsistently apply its stated valuation method and makes several factual errors throughout.

Taken together, these omissions and errors reflect a broader pattern: Mr. Runde's report and testimony are brief to the point of being underdeveloped, particularly in the valuation section, and frequently fail to disclose any analyses supporting his conclusions—or, in some instances, to state whether such analysis was performed. Where the report does describe a methodology, Mr. Runde does not apply it consistently across the subject properties. The result is a set of valuation conclusions that cannot be meaningfully tested or reconciled against USPAP's disclosure requirements and that do not reflect fair market value.

As a result of Mr. Runde's serious errors and omissions, his testimony **undervalues PG&E's real property interests by nearly $3.7 billion**. See the following chart for a summation of PG&E's fair market value conclusions for its real property interests as compared to Mr. Runde's corresponding opinions.

TABLE 4-10
DIFFERENCES IN CCSF VERSUS PG&E FAIR MARKET VALUES

Line No.		Valbridge/ Waldron FMV Opinion	Runde FMV Opinion
1	Fee Simple - Land	$1,209,561,800	$449,900,000
2	Easement Interests	1,700,000,000	–
3	Building & Site Improvements	516,957,599	156,400,000
4	Corridor Enhancement Factor *	872,868,540	–
5	Total Fair Market Value (FMV):	$4,299,387,939	$606,300,000

** Calculated at a factor of 1.3x on Fee Simple Land and Easement Interests*

1. Limited Comparable Sales and Unsupported Value Conclusions

Mr. Runde relies upon a very limited set of market data: only 21 sales to evaluate 33 unique properties dispersed throughout San Francisco (and, in the case of the Martin Substation, in northern San Mateo County). This represents less than one sale per Subject Property. By contrast, we rely upon 80 land sales (for Valbridge) and 104 land sales (for Waldron & Associates). Valbridge has nearly 4 times more market data, and a ratio of more than 2 to 1 for comparables to substation Subject Property, while Waldron & Associates has almost 5 times more data in San Francisco. In

other words, Mr. Runde does not have sufficient market data to support his valuation conclusions, whereas we have taken a far more comprehensive approach to evaluate and support the fair market value of PG&E's property interests.

Additionally, the values Mr. Runde derives for the Subject Properties are far lower than even his limited comparable sales suggest they should be. Mr. Runde's fair market value opinion of the underlying land for the 33 substation sites is $449,886,799 or $131.33 per square foot for the 3,425,532 square feet (78.6394 acres). The average price per square foot for his 21 comparable sales is $324.81 per square foot, approximately 2.5 times higher than Mr. Runde's concluded average rate per square foot. **A direct application of this adjustment would increase Mr. Runde's land value to over $1.1 billion, an increase of over $660 million.**[14] Comparing Mr. Runde's result to the full set of 104 comparable sales we identified generates an even starker differential. The total of all 104 sale prices ($836,414,950) divided by the total land area of all 104 sales transactions (1,646,724 square feet), resulted in a weighted average price per square foot of $507.93, a factor of 3.87 times Mr. Runde's average rate of $131.33 psf. In other words, Mr. Runde's valuation is only 26% of the average price of market data.

Our appraisal, by contrast, is much closer to the weighted average price of our comparable sales. Focusing on San Francisco (i.e., excluding the Martin Substation in San Mateo County), Mr. Carney concluded to an overall land value of $1,020,492,770 (before enhancement factor) for 2,193,322 square feet of total land area, corresponding to an average rate of $465.27 per square foot. This is within about 8% of the market data's weighted average rate. Based upon two methodologies (Grid and Zone), Waldron & Associates' midpoint indicator is $4,453,083,139 (before easement adjustment and enhancement factor) for 7,661,473 square feet of total land

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14 Even totaling all 21 sale prices ($166,790,000) divided by the total land area of all 21 sales transactions (712,400 square feet) will result in a weighted average price per square foot of $234.12, a factor of 1.78 times greater than Mr. Runde's overall average rate of $131.33 psf. A direct application of this weighted rate would increase Mr. Runde's land value to over $800 million, an increase of over $352 million.

area. This relates to an average rate of $581.23 per square foot, within about 13% of the market data's weighted average rate.

TABLE 4-11
AVERAGE VALUE PER SQUARE FOOT

Line No.	Source:	Average Value (PSF)	Range of Values/Prices (PSF)
1	Mr. Runde's Appraisal	$131.33	$45.00 - $525.00
2	Mr. Runde's Comparable Sales	324.81	$71.00 - $566.00
3	Valbridge/Waldron Comparable Sales	507.93	$77.00 - $6,360.00
4	Mr. Carney's Appraisal (fee simple land, before enhancement factor)	465.27	$50.00 - $6,000.00
5	Mr. Waldron's Appraisal (before easement adjustment and enhancement factor)	581.23	$383.08 - $806.81

While we recognized that appraisers perform a comparative analysis of sales data to the Subject Properties, and therefore some variance from comparables is to be expected, Mr. Runde's variances from the base data are significant and materially below both his own very limited market evidence and the more comprehensive data we have compiled.

2. Failure to Account for Development Entitlements

All the land proposed to be taken is entitled for its existing, developed highest and best use. As noted above, market evidence indicates that entitled property commonly resells for double the price of unentitled property or greater (see Section G.1, above). Each PG&E Property and all of its easement interests are entitled and approved for the respective existing improvements.

Mr. Runde ignores the market value contribution of entitlements. Mr. Runde's set of comparable sales appears, with at most one exception, to include only unentitled land sales, meaning that Mr. Runde is comparing PG&E's entitled property to unentitled properties on the market. The result is **a systematic undervaluation of the real property interests by over $760 million.**

3. Failure to Apply Reproduction Cost New

Standard appraisal practice is to value specialized, single-purpose utility buildings and other real property improvements using reproduction cost new (i.e., the cost to reproduce the existing improvements), not replacement cost new (i.e., the cost to replace those improvements with other, different assets that may provide similar functionality). This is particularly true where the improvements have no ready substitute and/or where actual construction costs may be available, as they were to Mr. Carney and Valbridge in this matter (see Section G.2, above).

Mr. Runde acknowledges that the Subject Properties "represent special purpose, limited market properties" for which the Sales Comparison and Income Approaches are unreliable,[15] yet he does not extend that same reasoning to his choice of cost methodology. Mr. Runde values improvements using Replacement Cost New Less Depreciation,[16] which he defines as the cost of replacing an existing property "with a property of equivalent utility"[17], not the cost of reproducing the specific existing improvement. Neither Mr. Runde's testimony nor his appraisal report uses reproduction cost, even though that is the standard most consistent with Mr. Runde's own special purpose highest and best use conclusion for the specialized, single-purpose substation buildings at issue here.

It is possible to calculate the reproduction costs for the buildings on Properties 1, 2, 5, and 6, as Mr. Carney did in the Appraisal Report. PG&E provided actual costs for Property Buildings 1.2, 2.2, and 5.2. These costs can be trended (as Mr. Runde's own replacement cost analysis does) as reasonable cost comparables to Property Buildings 1.1, 5.1 and 6. Mr. Runde inexplicably decided not to use these actual costs to calculate the reproduction cost new of PG&E substation structures, resulting in **an**

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15 Runde Testimony at 11:4–13.

16 *Id.* at 2:22–23, 11:14–15.

17 *Id.* at 12 n.30 (defining "Replacement Cost New" as "the cost of replacing an existing property with a property of equivalent utility as of a particular date").

undervaluation of nearly $345 million when compared to PG&E's substation buildings 1.1, 1.2, 2.2, 5.1, 5.2 and 6.[18]

4. Zero Easement Valuation

Perhaps most egregiously, Mr. Runde assigned zero value to the more than 2,000 "easements, licenses, permits, agreements, and similar rights held by PG&E to use property owned in fee by others."[19] Mr. Runde's conclusion that PG&E's easements have $0 value is grossly inaccurate and inappropriate, and it follows from multiple important flaws in Mr. Runde's analysis.

First, Mr. Runde's testimony effectively ignores the key categories of easements that PG&E's testimony discusses at length, namely, transmission and distribution easements over private land. Mr. Runde testified that "[e]ach of the comparables" in his analysis "reflects a site serviced with electricity," and therefore "the land value based on comparable land sales necessarily includes the contributory value of [PG&E's] easements."[20] In so testifying, Mr. Runde implicitly focuses on so-called "service drops," the land rights that connect individual properties to the grid.[21] But service drops are fundamentally different from private transmission and distribution easements. Service drops generally only extend very short distances, and as Mr. Runde notes, are "granted as a condition of providing electrical service."[22] By contrast, the electric

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18 This is not Mr. Runde's only error in valuing PG&E's buildings and improvements. Another example is floor height. At least eight PG&E buildings are constructed with greater-than-typical floor heights to support specialized electrical transmission/distribution improvements. Marshall Swift Valuation Service cost handbook, on which both CCSF and PG&E appraisers relied, provides a story height multiplier index intended to be referenced for above-typical story heights. Mr. Runde recognized the greater-than-typical buildings heights in only one of the eight affected substation buildings.

19 Runde Testimony at 9:15–16.

20 *Id*. at 9:19–10:6.

21 Mr. Runde also makes passing reference to "general" easements that "authorize installation of water, gas, and electrical equipment" and to "easements or other non-fee property interest granted to PG&E by [CCSF]." *Id*. at 10:8–14. But PG&E's private electric transmission and distribution easements do not fall within these categories, either.

22 *Id*. at 9:18–19; *see also* CPUC Electric Rule 16.

transmission and distribution easements discussed and valued in PG&E's testimony do not simply connect individual electric customers to the grid; they enable PG&E to place the hundreds of miles of transmission and distribution lines necessary to serve thousands of *other* properties.

Relatedly, Mr. Runde's testimony confuses the value of electrical service with the value of an easement that facilitates provision of that service. Mr. Runde is factually correct that "[e]ach of the comparables" in his analysis "reflects a site serviced with electricity," which "enhances its value."[23] However, the value of electric service to a property owner is very different from the legal right to traverse another person's property to provide that service. To put it in concrete terms, the purchasers of Mr. Runde's land sale comparables bought "site[s] serviced with electricity,"[24] but they did not also purchase the right to traverse other properties to facilitate the transmission and distribution of electrical service. By contrast, PG&E does have that right, conferred by its transmission and distribution easements.

In appraisal terms, Mr. Runde's failure to assign proper value to PG&E's easements is related to his incorrect classification of those easements. His testimony repeatedly refers to "appurtenant easements,"[25] which are easements that create a burden on one parcel of land (the servient estate) for the benefit of another parcel of land (the dominant estate). But PG&E's transmission and distribution easements are not appurtenant easements. They are "easements in gross," which burden a servient estate for the benefit of an individual or entity. Specifically, these easements benefit an entity—presently, PG&E—by conferring the right to place electric transmission and distribution assets on third party property. They do not benefit some other parcel of land—much less any of Mr. Runde's comparable sale properties—and therefore they are not subsumed in the value of those properties.

Mr. Runde also testified that "[t]he vast majority of easements were granted without consideration, including easements granted as a condition

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23 See Runde Testimony at 10:3–4.

24 *Id.* at 10:3.

25 *See, e.g., id.* at 1:12, 2:9, 2:17, 6:11, 9:15.

of providing electrical service."[26] Mr. Runde's testimony misleadingly implies that the means by which PG&E acquired the easements determines their fair market value. That is incorrect. The fair market value of a house would not change based on whether its owner bought the house, inherited the house, or received it as a gift. Likewise, the fair market value of PG&E's easements does not change based on whether PG&E paid cash for them, acquired them as a condition of providing electrical service, or paid nominal or no consideration. In a subsequent response to a data request, Mr. Runde agreed that "the historical cost of those non-fee interest acquisitions where monetary consideration was paid would not be relevant to the valuation of the real property as of the effective date of value."[27] We agree. Whether and how much consideration PG&E paid for its easements has no bearing on their fair market value and certainly cannot justify a $0 valuation for PG&E's easements.

Mr. Runde's conclusion that PG&E's easements have no independent value is further undercut by real-world transactions that assign easements considerable value. CCSF itself values easements and similar interests very highly when it is selling, licensing, or buying land. For example:

- A June 10, 2014, license agreement between the CCSF (by and through the San Francisco Port Commission) and PG&E concerned a license for use of submerged land. Consistent with our appraisal in this matter, the parties utilized an Across-the-Fence valuation methodology, identified zones of value per proposed usage rights, and assigned a percentage of the underlying fee land value (there, 25% to 50% of fee).
- More recently, CCSF sold to PG&E a non-exclusive, subsurface electrical transmission easement within McLaren Park. The purchase price is $950,000 for an easement over a 44,717.19 square foot, 15-foot-wide strip of land, extending for a distance of 2,981 linear feet, with PG&E required to install full-width street improvements to City standards. The Resolution approving this sale transaction, along with

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26 *Id.* at 9:17–19.

27 CCSF Response to PG&E Data Request Set 19, No. 9.

the Draft Purchase and Sale Agreement, were heard at the Budget and Finance Committee meeting on July 15, 2026.

Incredibly, Mr. Runde assigns considerable value to easements within the Subject Properties when those easements reduce the fair market value of the Subject Property. Mr. Runde recognizes the burden of existing gas line easements on the Potrero Substation (Property 2) and the Martin Substation (Property 31) and the burden of a perpetual easement on the Randolph Substation (Property 14). He determines the value of these easements using a methodology nearly identical to our own, namely, by (1) determining the underlying fee land value and (2) multiplying by the percentage of easement interest per rights inherent in the easements to the fee simple interest. For Properties 2 and 31, he applies a rate of 20% of fee simple to determine the value of each gas line easement.[28] For Property 14, Mr. Runde applies a rate of 100% of fee simple to the value of the perpetual easement; in other words, he concludes that the easement is as valuable as the underlying land in fee simple. Clearly, Mr. Runde acknowledges considerable value in utility easements, and his decision to assign $0 to PG&E's easements is contrary to other portions of his own testimony. In sum, Mr. Runde's failure to assign any value to thousands of PG&E easements is non-sensical, unjustified, unsupportable, and inconsistent with his own testimony.[29] This failure is also highly consequential: By deciding to assign no value to PG&E's easements, all of which are a part of the "electrical grid" and being taken by CCSF, **Mr. Runde undervalued PG&E's real property easement rights by $1.7 billion**, before consideration of an upward adjustment for a corridor enhancement factor.

5. Lack of Corridor Enhancement Factor

Mr. Runde's testimony values the land and improvements thereon in isolation. He does not meaningfully acknowledge that these properties form an integrated, operational corridor with greater utility, productivity, and worth than the simple sum of its parts; accordingly, he assigns no additional value

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28 *See* Runde Testimony, App'x II ("Runde Appraisal") at 49, 60.

29 *Id*. at 44.

to account for this synergistic assemblage and integration that allows for an operative, integrated electric service system, despite his highest and best use opinion as an electrical grid serving San Francisco. Mr. Runde's failure to acknowledge the enhanced value of the corridor ignores both sound appraisal techniques and real-world comparable transactions. As detailed more fully in the Appraisal Report, a corridor enhancement factor is justified, and indeed necessary, to properly value PG&E's property. Widely respected expert appraisers ranging from Dolman and Seymour to Arthur G. Rahn recognize the importance of including a corridor enhancement factor to account for the additional value stemming from continuity and assemblage: The costs and time to construct corridors like PG&E's are immense, and transactions involving assembled corridors typically sell for a premium over ATF value. By contrast, Mr. Runde provides no justification for his omission of any corridor enhancement factor.

Mr. Runde's omission of a corridor enhancement factor **results in an undervaluation of approximately $870 million** when compared to PG&E's base land valuation for the substation sites and the private easements.

6. Conclusion

Taken as a whole, Mr. Runde's testimony reflects a valuation built on a series of interlocking errors. He assigns no value to more than 2,000 PG&E easements, while separately assigning considerable value to comparable easements he does recognize when it benefits his client. He ignores the enhanced value that PG&E's assembled, operating corridor must command over the sum of its individual parcels. His universe of only 21 comparable land sales – less than one sale per substation, against the 80 and 104 sales relied upon by Valbridge and Waldron & Associates, respectively – falls far short of the available market data or reasonable analysis, and his concluded land values sit well below even that limited data set's own averages. His cost approach improperly relies solely on *replacement* cost despite the availability of PG&E's actual construction costs, where *reproduction* cost is the more appropriate standard. And he fails to account for the fair market value of the entitlements the Subject Properties already possess.

Individually, each of these errors—characterized in the table below under four main headings—understates the fair market value of PG&E's real

property interests. Aggregated, they explain the nearly $3.7 billion gap ($4.3B - $606.3M) between Mr. Runde's $606.3 million valuation and Valbridge and Waldron & Associates' $4.3 billion conclusion.

TABLE 4-12
KEY DRIVERS OF DIFFERENCES IN FAIR MARKET VALUE CONCLUSIONS

Line No.		
1	Difference in Entitlements Value:	$760,000,000
2	Difference in Reproduction Costs New Value:	345,000,000
3	Difference in Corridor Enhancement Value:	870,000,000
4	Difference in Easement Interests Value:	1,700,000,000
5	Total:	$3,675,000,000

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT A

RETROSPECTIVE APPRAISAL REPORT,

PG&E ELECTRIC GRID CORRIDOR – REAL PROPERTY

Valbridge PROPERTY ADVISORS

WALDRON & ASSOCIATES, INC.
REAL ESTATE APPRAISERS AND CONSULTANTS

Henry Weissmann, Esq.
Munger, Tolles & Olson LLP
350 South Grand Avenue, 50th Floor
Los Angeles, California 90071

October 13, 2026

RE: Retrospective Appraisal Report
PG&E Electrical Grid Corridor - Real Property
City and County of San Francisco, California

Dear Mr. Weissmann:

At your request, we have prepared an appraisal of the fair market value of Pacific Gas and Electric Company's (PG&E) real property rights proposed to be acquired by the City and County of San Francisco (CCSF). Property and property rights proposed to be acquired are described in more detail in the attached report.

Appraised lands, property rights, and improvements are a portion of PG&E's electrical utility grid situated within and serving San Francisco and nearby Brisbane, in San Mateo County. These consist of fee simple land, substation improvements including electrical and distribution improvements, and easements.

This appraisal sets forth the pertinent data that we gathered, the techniques that we employed, and our reasoning in developing our fair market value opinions, retrospectively as of July 27, 2021.[1] This letter of transmittal does not constitute an appraisal report. The rationale underlying the value opinion(s) reported herein cannot be adequately understood without the accompanying appraisal report.

The real property that we appraised includes 33 PG&E fee-owned substation sites, with 32 of the 33 sites situated in the City and County of San Francisco. One is in San Mateo County.

[1]This letter of transmittal does not constitute an appraisal report. The rationale underlying the value opinion(s) reported herein cannot be adequately understood without the accompanying appraisal report.

In total, the properties proposed by CCSF for taking consist of land with substation buildings and/or site improvements, along with two vacant sites. The Egbert site, Subject Property 30, proposed as a 230 kV switching station site, is one of the vacant sites. The Beeman Lane site, Subject Property 32, is the other vacant site. The thirty-two (32) fee-owned properties located in San Francisco comprise a total of 50.352 acres of combined land area.

The remaining single fee-owned property located outside of San Francisco is an improved substation ("Martin Property") in adjacent San Mateo County. The Martin Substation site spans across two cities, Brisbane and Daly City, and CCSF has proposed taking a portion located on the Brisbane side of the city limits that comprises 36.784 acres.

A list of the PG&E fee-owned properties appraised is included on Page 10 and depicted on an aerial map on Page 11 of this report.

PG&E transmission and distribution easements, rights-of-way, and other land-related agreements are also included in the proposed acquisition of real property rights. These easements encumber privately-owned properties and total 137.56 net private circuit miles (or 175.883 acres of easement area). Property rights appraised include the fee simple and easement rights. A summation of the circuit miles representing the private easement areas appraised are included on Page 13 and depicted on an aerial map on Page 14 of this report.

Facts, analyses, opinions, and conclusions are investigated, developed, prepared, and reported in conformity with the Uniform Standards of Professional Appraisal Practice (USPAP) of the Appraisal Foundation, and the Code of Professional Ethics and Standards of Professional Practice of the Appraisal Institute

The Client in this assignment is Pacific Gas and Electric Company (PG&E), represented by Henry Weissmann, Esq., of Munger, Tolles & Olson LLP, as legal counsel for PG&E, together with William V. Manheim, Esq., Clifford Gleicher, Esq., and Joshua Levenberg, Esq., in-house legal counsel at PG&E. The intended users of this report are these specifically identified representatives of the Client.

The intended use of this appraisal report is for consideration by the California Public Utilities Commission in connection with valuation of the assets sought by CCSF through its proposed acquisition of PG&E's electrical transmission and distribution assets in the city/county.

The fair market value conclusions for the real property that CCSF proposes to take from PG&E, as of July 27, 2021, a retrospective valuation date, is based on the analyses and narrative descriptions and discussions included in this report following this transmittal and summarized in the following tables.

TOTAL FAIR MARKET VALUE CONCLUSION

FMV Land	FMV Easements	Plus: Building & Site Improvements	FMV Total
$1,572,430,340	$2,210,000,000	$516,957,599	$4,299,387,939

The value opinions reported herein are subject to the definitions, general assumptions and limiting conditions, and certifications contained in this report. The findings and conclusions are further contingent upon the extraordinary assumptions and/or hypothetical conditions, the use of which might have an effect on the assignment results. For the reader's reference, these are included in the "Reconciliation" section of this appraisal report.

Any additional value associated with PG&E's non-real property interests are not included in this real property appraisal.

Respectfully submitted,
Valbridge Property Advisors | Northern California and
Waldron & Associates, Inc.

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How to Read the Appraisal Report

Before you begin: the Letter of Transmittal (LOT)

The Letter of Transmittal is a brief cover letter, typically one to two pages, addressed directly to the client. It formally delivers the report, identifies the property and the interest appraised, states the effective date, presents the appraiser's value conclusion, and confirms the report complies with USPAP. Think of it as the signed hand-off: the short version of the answer, before the full report begins. It precedes the Executive Summary.

1 Start with the Bottom Line

Letter of Transmittal, Executive Summary

Read these first. It states who ordered the appraisal, what is being valued, the effective date, and the concluded value.

2 Understand the Assignment

Introduction, Scope of Work

Defines the property rights appraised, the intended use and users, and how much investigation the appraisers performed.

3 See the Market Context

Regional & Market Area Analysis

Establishes the economic and market conditions that shape value before any property-specific analysis begins.

4 Know What Is Being Valued

Property Description (33 Fee Owned PG&E Sites; PG&Es Private Easement Interests)

Details the physical and legal characteristics of both the 33 owned sites and the private easement interests.

5 Follow the Valuation Logic

Highest and Best Use > Valuation Approaches (PG&E's Fee-Owned Sites and Private Easement Interests, plus Corridor Enhancement Factor)

Moves from the highest and best use to the approaches applied — the Cost Approach for fee sites, plus separate easement and corridor analyses.

6 Reach the Conclusion

Reconciliation – Fair Market Value Conclusion; Extraordinary Assumptions and Hypothetical Conditions; Exposure Time and Marketing Period

Weighs the approaches into a single supported value, then estimates how long the assets would take to sell. Because the subject property is a special purpose property with no demonstrable market, an analysis of marketing period and exposure time is not relevant or applicable.

7 Read the Supporting Conditions

General Assumptions and Limiting Conditions; Certification of Appraisers

Sets the conditions that bound the value opinion and provides the appraisers' signed USPAP attestation.

Executive Summary

Overview

The City and County of San Francisco (CCSF) proposes to acquire PG&E's San Francisco electrical distribution and transmission grid system, including associated PG&E property interests, such as those owned in fee simple and held in easement rights.

These assets include a significant network of real property interests, consisting of land parcels, improvements, easements, and other rights-of-way. The PG&E operating energy grid system includes other physical assets, including but not limited to, poles, electrical lines, towers, transformers, substations, conduits, and vaults, that we understand are being valued and summed in other chapters of testimony and are not valued herein.

Thirty-one (31) improved substation sites, plus two (2) vacant sites, are included in this appraisal. One of the two vacant sites, Egbert (Subject Property 30), is a proposed 230 kV switching site. The other vacant site, Beeman Lane (Subject Property 32), is improved with substantial underground electrical transmission improvements. Combined, these 33 properties total up to 87.136 acres in land area. The properties are improved with up to 503,311 square feet of building area. Additionally, 137.56 net private circuit miles of easement rights and grid improvements, containing 175.883 acres of property rights, are included as part of the proposed taking. Reference is made to the series of aerials, maps, and summary table exhibits in this Executive Summary, beginning on Page 10.

All but one of the proposed acquisitions is situated in CCSF's jurisdiction. The exception is the "Martin Substation" situated in adjacent San Mateo County. The Martin Substation property straddles two cities, Brisbane and Daly City. CCSF proposes to acquire an approximate 36.784-acre portion of the property entirely situated within the geographic boundaries of Brisbane, California. The list of PG&E fee-owned properties included in this appraisal report totals 33 properties. Combined, the proposed acquisition of properties and property rights are a portion ("Parts Taken") of PG&E's larger energy grid.

The date of value ("DOV"), and the effective appraisal date, is July 27, 2021. As of the DOV, PG&E's acquisition property is an integrated assemblage of land (fee-owned, substation sites) and strips of land (tethered together by easements, licenses, franchises, leases, and other agreements) connected, improved, utilized, and operating for electrical transmission and distribution purposes, i.e., is an "assembled corridor." It is a collection of integrated properties, improved with various facilities, forming an electronic transmission and distribution network / corridors laid out into an energy grid.

The combined properties, the assembled energy grid corridor, as-is, is a special purpose use. This use is the property's highest and best use. The highest and best use includes proposed new facilities for expansion and upgrading and on-going improvements to the grid system. It includes entitling and developing the proposed Egbert switching station (Subject Property 30).

To appropriately evaluate the fair market value of PG&E's energy system that CCSF seeks to take ("Parts Taken"), PG&E has retained multiple experts to consider various approaches to value. Retained experts include real property appraisers with the firms Valbridge Property Advisors and Waldron & Associates,

Inc. The real property appraisal report contained herein is the valuation, by appraisers of these two firms of PG&E's fee simple and easement rights, those proposed for taking by CCSF.

Standard appraisal methods and approaches are applied in valuing the property rights proposed to be taken. The Cost Approach is concluded to be the only relevant appraisal approach in valuing special purpose property and operating utility corridors, such as the property rights proposed to be acquired by CCSF. Under the Cost Approach, fair market value is analyzed by determining land and improvement value. Land value is analyzed consistently with the Sales Comparison Approach. Improvements are valued applying Reproduction/Replacement Cost New Less Depreciation ("RCNLD") techniques.

The Cost Approach begins with the determination of the fair market value of the fee simple property rights in the land proposed to be taken. Improvement value is then added. Site and building improvements – real property improvements, excluding electrical distribution and transmission improvements/fixturization – are valued in this appraisal report based on the cost to *reproduce* the actual improvements as-is or on the cost to *replace* the functional substitutes, as applicable.

Reproduction/Replacement Cost New (RCN) are available from actual PG&E costs provided or from the Marshall Swift Valuation (MSV) cost source where actual recent PG&E construction costs are not available or applicable. Depreciation from all causes is deducted from RCN to derive RCNLD.

Other additive value components analyzed by other experts are not included in this real property appraisal report. The focus of this appraisal report is on real property rights. Excluded cost components and values to be prepared by others, include but are not limited to, fixtures, equipment, and system improvements (poles, electrical lines, towers, transformers, substation fixtures, conduits, and vaults), intangible assets, and severance damages.

Land and improvement value opinions (fee and easement) are based on a highest and best use determination, reflecting the inherent land corridor assemblage premium (a measure of the inherent plottage value increment within the operating corridor at its highest and best use), for PG&E's development of its energy grid system in San Francisco and adjacent (San Mateo County) jurisdictions.

The collection of land segments, owned by and/or held in the beneficial interest and control of PG&E, otherwise physically and/or constructively contiguous as it relates to highest and best use, integrated into a single unified use functioning as a network of utility corridors and substations that form an energy grid and deliver reliable energy to a mix of customers throughout San Francisco, California, is the highest and best use. Lands and rights comprising PG&E's electrical grid system is a special purpose property, primarily and historically, assembled from portions of adjacent properties.

Property and Property Rights Appraised

In summary, this appraisal report describes, analyzes, and values:

- **Fee Simple Rights in 33 PG&E Fee-Owned Properties**
    a. Thirty-two (32) properties are situated in San Francisco. Combined these properties total 50.352 acres.
    b. ***Plus***: An additional site (Martin Substation) situated in adjacent San Mateo County. CCSF proposes to acquire a 36.784-acre portion of the site comprising land within the geographic boundary of Brisbane, California.
    c. ***Plus***: Building and site improvements, including substation buildings, situated on these 33 properties. Substation buildings and structures total up to 503,311 square feet.

- **PG&E Easement Rights Over Private Properties**
    a. 137.56 net private circuit miles
    b. Containing 175.883 acres or 7,661,472 square feet of private easement area.

PG&E Private Easement Interest Properties

PG&E utilized the San Francisco FF Electric Master dated 12-31-2021 to identify total "circuit miles" in San Francisco. The circuit miles are expressed as a linear distance. PG&E has defined the locations for each of the five (5) types of electric corridor segments, identified as follows:

- Electric Transmission – Underground ("ET-UG")
- Electric Transmission – Overhead ("ET-OH")
- Electric Distribution – Underground Facilities Management ("ED-UFM")
- Electric Distribution – Underground ("ED-UG")
- Electric Distribution – Overhead ("ED-OH")

Each of the five (5) categories of electric corridor segments was reviewed, inventoried, and analyzed utilizing the PG&E GIS mapping of "Private" circuit miles. "Private" circuit miles represent those portions of the electric power system energy grid traversing private property, whereby PG&E conferred use and occupancy by way of easements (subsurface, surface, and/or aerial). Furthermore, the identified easement interests, by way of a circuit mile study, cover easements situated only within San Francisco.

This appraisal assignment excludes all "Public" circuit miles (derived from franchises, licenses, agreements, service extensions or other forms of use and occupancy). PG&E has no real property interest in these types of use agreements. Rights of occupancy are not being conferred by an easement. This analysis covers private easements determined by calculating "Private" circuit miles for each of the five (5) types of electric corridor segments, also identified as "Private Easements": Electric Transmission - Underground (ET-UG), Electric Transmission - Overhead (ET-OH), Electric Distribution - Underground Facilities Management (ED-UFM), Electric Distribution - Underground (ED-UG), Electric Distribution - Overhead (ED-OH). Service extensions into a single property, by way of CPUC Tariff Rule 16, were also excluded.

The network of private circuit miles is highlighted in green and depicted on the following summary and aerial exhibit (Pages 16 and 17).

Approach to Valuation

Two Appraisal Teams, headed by Valbridge Property Advisors ("*Valbridge*") and Waldron & Associates, Inc. ("*Waldron*"), divided the PG&E Subject Property into two appraisal task groups: (1) Fee Ownerships and (2) Easement Interests. Valbridge focuses on Subject Property – Fee Owned. Waldron focuses on Subject Property – Easement Interests.

The Cost Approach is concluded to be the only applicable approach to valuing the Fee Simple Ownerships. This includes valuing the land with the substation building and site improvements. Comparable land sales are investigated, researched, and confirmed, and are applied in the valuation of property rights appraised, utilizing a Sales Comparison Approach methodology – in both fee simple and easement valuation. Building and site improvements are valued on the contributory RCNLD value it adds to the fee simple land value.

The fair market value of easement rights is similarly based on comparative analysis of land sales, and on the percentage of rights the easements convey by use and occupancy of subsurface, surface, and/or aerial space, as part of the integrated electrical and transmission grid system. The total value of real property and property rights CCSF proposes to take are adjusted for the enhancement factor, consistent with the property's highest and best use.

Total Fair Market Value Conclusion

The total fair market value of the property interests appraised is the aggregation of all property rights appraised – of the fee simple and easement interests. The total fair market value includes substation building and site improvements, and total fair market value of the land and easement rights. Reference is made to the following summary table.

TOTAL FAIR MARKET VALUE CONCLUSION

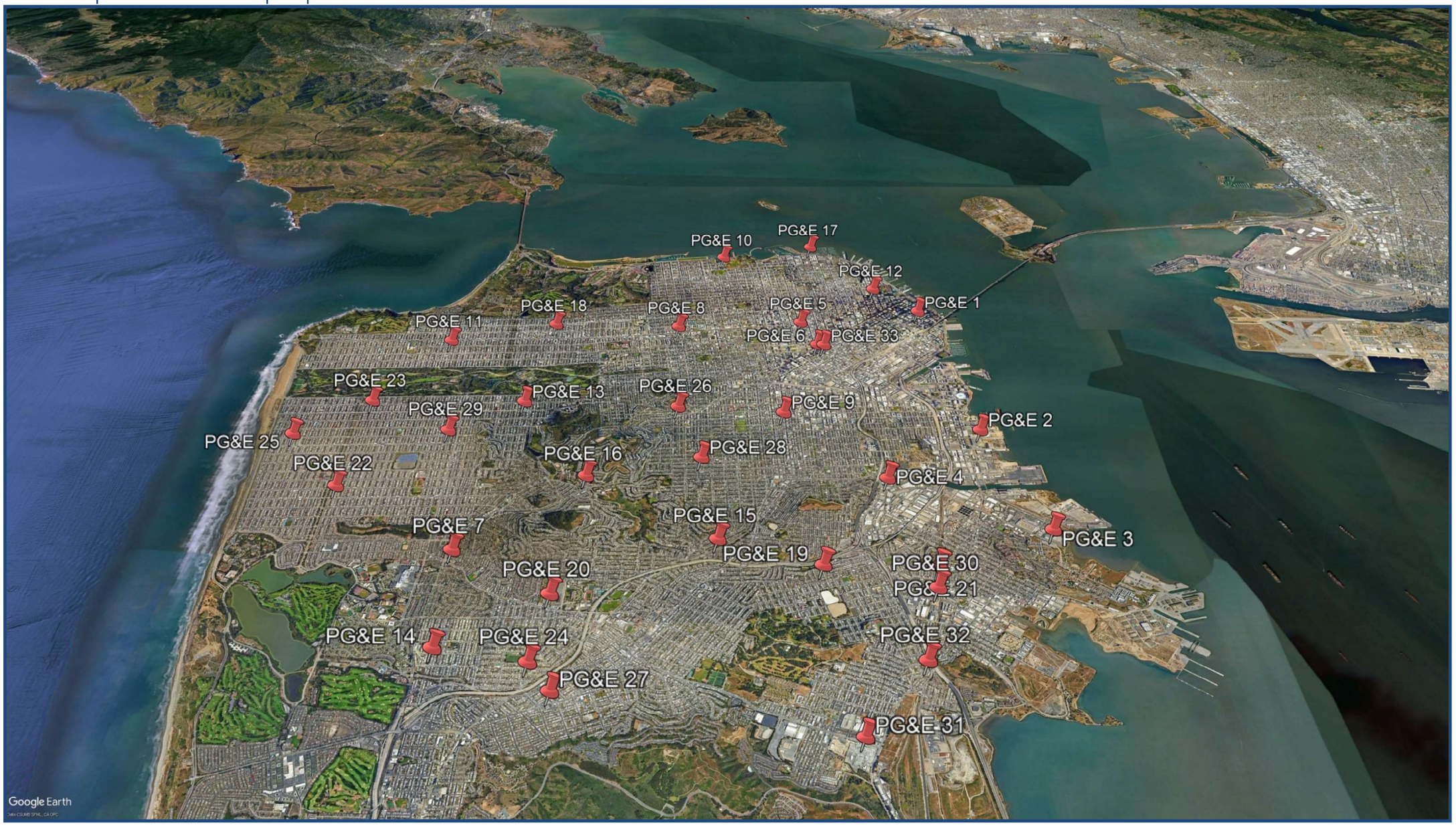
FMV Land	FMV Easements	Plus: Building & Site Improvements	FMV Total
$1,572,430,340	$2,210,000,000	516,957,599	**$4,299,387,939**

The value opinions reported herein are subject to the definitions, general assumptions and limiting conditions, and certifications contained in this report. The findings and conclusions are further contingent upon the extraordinary assumptions and/or hypothetical conditions, the use of which might have an effect on the assignment results. For the reader's reference, these are included in the "Reconciliation" section of this appraisal report.

Summary Table: PG&E Fee Ownership Properties

#	PG&E Property ID	Address/ Location	Assessor's Parcel #'s (APN's)	SBE Parcel No.	Site Area (SF)	Site Area (ac)	Bldg Size (SF)	Floor Area Ratio (FAR)	Zoning District	Height/Bulk District
1	Substation Z (Embarcadero)	405 & 425 Folsom Street	3748-001, -003, -004, -005 & -029	135-38-033A-1 & A-2	33,213	0.762	132,768	3.997	RH-DTR	85/200-R
2	Substation A (Portrero)	1101 Illinois Street	4175-018 (ptn)	135-38-024D-2,-3 (ptn)	293,960	6.748	22,719	0.077	P70-MU; PPS-MU; M-2	65-PPS/240-PPS; 65-X; 40-X
3.1	Substation P (Hunter's Point)	1180 Evans Avenue	4570-024	135-38-018D-1	79,680	1.829	306	0.004	PDR-2	65-J
3.2	Substation P (Hunter's Point)	1010-1030 Evans Avenue	4604A-002	135-38-018E-1	281,659	6.466	763	0.003	M-1, M-2	40-X
3.3	Substation P (Hunter's Point)	1135 Evans Avenue	4602A-014	135-38-026A-1	85,747	1.968	314	0.004	NC-2	40-X
3.4	Substation P (Hunter's Point)	1059-1075 Evans Avenue	4603A-002, -005; 4647A-013	135-38-026A-2	325,709	7.477	----	----	NC-2, RH-1	40-X
3.5	Substation P (Hunter's Point)	5000 Hunter's Point Boulevard	4629A-012	135-38-026A-3	13,734	0.315	----	----	M-1	40-X
3.6	Substation P (Hunter's Point)	1000 Evans Avenue	4580-002	135-38-018A-2	713,687	16.384	----	----	M-2	40-X
4	Substation W (Bayshore)	151-157 Bayshore Boulevard	5559-004,-005,-006	135-38-031-1	55,930	1.284	770	0.014	PDR-2	65-J
5	Substation Y (Larkin)	538 Eddy Street	0335-037	135-38-030A-1, -2, & -3	46,875	1.076	109,180	2.329	RC-4	80-T
6	Substation X (Mission)	1250 Mission Street	3701-053	135-38-015A-2	44,617	1.024	89,100	1.997	C-3-G	150-S; 180-S
7	Substation L	2475 Ocean Avenue	6901-001	135-38-001-19	17,076	0.392	5,181	0.303	NC-1	26-X
8	Substation G	1200 Broderick Street	1101-013	135-38-002-4	15,469	0.355	23,304	1.506	RM-3	40-X
9	Substation E	205 Lexington Avenue	3596-104	135-38-003-6	13,175	0.302	16,750	1.271	RTO-M	55-X
10	Substation F (Marina)	1570 Bay Street	0459-032	135-38-001D-1	13,112	0.301	----	----	NC-2, RM-4	40-X
11	Substation K	679 24th Avenue	1567-012	135-38-002-5	12,398	0.285	10,956	0.884	RH-2	40-X
12	Substation J	530 Sacramento Street	0228-006	135-38-004-6	8,395	0.193	26,250	3.127	C-3-O	75-X
13	Substation N	1437-1449 9th Avenue	1844-053	135-38-02A-1	6,492	0.149	----	----	RH-2	40-X
14	Randolph Substation	724 Randolph Street	7084-024	135-38-019A-1	4,865	0.112	----	----	NC-1	26-X
15	Substation M	20 Rousseau Street	6747-016	135-38-005B-1	4,725	0.108	2,748	0.582	RH-2	40-X
16	Portola Substation	610 Portola Drive	2892-003	135-38-023-1	4,698	0.108	----	----	NC-1	26-X
17	Beach Substation	330 Beach Street	0013-010	135-38-018B-1	3,750	0.086	----	----	C-2	40-X
18	6th Avenue	365 6th Avenue	1438-014	135-38-015-3	3,000	0.069	----	----	NCD	40-X
19	Silver Substation	1086 Silver Avenue	5915-001	135-38-025-1	2,834	0.065	----	----	RH-1	40-X
20	Ocean Substation	1155 Ocean Avenue	6944-040	135-38-020-1	2,655	0.061	----	----	NCT	45-X
21	Yosemite Substation	1802 Yosemite Avenue	5417-007	135-38-011-1	2,500	0.057	----	----	RH-1	65-J
22	Taraval Substation	2533 Taraval Street	2390-044	135-38-010-2	2,500	0.057	----	----	NCD	40-X
23	Judah Substation	2927 Judah Street	1819-042	135-38-010-1	2,500	0.057	----	----	RH-3	40-X
24	Plymouth Substation	214 Plymouth Avenue	7112-012A	135-38-025-2	2,500	0.057	----	----	NC-1	40-X
25	Noriega Substation	3819 Noriega Street	2082-001L	135-38-013-1	2,325	0.053	----	----	NC-1	40-X
26	18th Street Substation	4430 18th Street	2650-020	135-38-008-1	2,250	0.052	----	----	RH-3	40-X
27	Acton Substation	5889 Mission Street	6472-021D	135-38-013-5	2,250	0.052	----	----	NCD	40-X
28	Castro Substation	1510-1512 Castro Street	6546-004	135-38-014-1	2,000	0.046	----	----	RH-2	40-X
29	21st Avenue Substation	1340 Noriega Street	2029-025	135-38-013-2	1,875	0.043	----	----	NCD	40-X
30	Egbert Switching Station	1755 Egbert Avenue	5431-001A	135-38-057-1 & -2	70,446	1.617	----	----	PDR-2	65-J
32	Beeman Lane	3789 San Bruno Avenue	5067-001A	135-38-018	4,721	0.108	----	----	RH-1	40-X
33	Substation I	117 8th Street	3727-135	135-38-003A-1	10,000	0.230	10,950	1.095	WMUG/MUO	65-X
		Subtotal: San Francisco County Substation and Land Properties:			**2,193,322**	**50.352**	**452,059**			
	Martin Substation									
31	Martin Substation	3150 Geneva Avenue, Brisbane, CA	005-141-999 (ptn)	135-41-28B-3 (ptn)	1,602,313	36.784	51,252		C/P-U	Not Applicable
		Subtotal: San Mateo County Substation and Land Properties:			**1,602,313**	**36.784**	**51,252**			
		Total: San Francisco County & San Mateo County Substations and Land Properties:			**3,795,635**	**87.136**	**503,311**			

Location Map: PG&E Fee Ownership Properties



Summary Table: PG&E's Private Easement Interests

PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - EASEMENT INTERESTS
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

PG&E PRIVATE EASEMENT INTERESTS	ELECTRIC TRANSMISSION ("ET")			ELECTRIC DISTRIBUTION ("ED")				TOTAL
	ET - UG	ET - OH	ET - TOTAL	ED - UFM	ED - UG	ED - OH	ED - TOTAL	
Distance								
Circuit Miles	2.16 miles	0.00 miles	2.16 miles	54.02 miles	20.87 miles	60.50 miles	135.40 miles	137.56 miles
Circuit Linear Feet	11,387.28 lf	0.00 lf	11,387.28 lf	285,224.99 lf	110,216.29 lf	319,463.15 lf	714,904.43 lf	726,291.71 lf
Right of Way Width	45 feet	45 feet	45 feet	10 feet	10 feet	10 feet	10 feet	
Land Area								
Square Feet	512,428 sq. ft.	0 sq. ft.	512,428 sq. ft.	2,852,250 sq. ft.	1,102,163 sq. ft.	3,194,632 sq. ft.	7,149,044 sq. ft.	7,661,472 sq. ft.
Acres	11.764 acres	0.000 acres	11.764 acres	65.479 acres	25.302 acres	73.339 acres	164.119 acres	175.883 acres

PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - PRIVATE EASEMENTS

CITY AND COUNTY OF SAN FRANCISCO

ELECTRIC TRANSMISSION (UNDERGROUND AND OVERHEAD)

ELECTRIC DISTRIBUTION (UNDERGROUND FACILITIES MANAGEMENT, UNDERGROUND AND OVERHEAD)

	OVERALL (ET & ED)	TRANSMISSION (ET)	DISTRIBUTION (ED)
CIRCUIT MILES:	137.56 miles	2.16 miles	135.40 miles
LINEAR FEET:	726,292 linear feet	11,387 linear feet	714,904 linear feet
LAND AREA:	7,661,472 square feet	512,428 square feet	7,149,044 square feet
	175.88 acres	11.76 acres	164.12 acres
RIGHT-OF-WAY WIDTH:	10 & 45 feet	45 feet	10 feet

Location Map: PG&E Fee Interest and Easement Interest Properties

Introduction

This Introduction section of the appraisal report provides basic information about the appraisal, including the client, the intended use and purpose of the appraisal, descriptions and various characteristics of the property appraised, the applicable appraisal standard under California law, and a glossary of key appraisal terms used in this Appraisal Report.

Client and Intended Users of the Appraisal

The Client in this assignment is Pacific Gas and Electric Company (PG&E), represented by Henry Weissmann, Esq., of Munger, Tolles & Olson LLP, as legal counsel for PG&E, together with William V. Manheim, Esq., Clifford Gleicher, Esq., and Joshua Levenberg, Esq., in-house legal counsel at PG&E. The intended users of this report are these specifically identified representatives of the Client and the California Public Utilities Commission.

Date of Report and Effective Date of Valuation

The date of this report is October 13, 2026. The valuation date is July 27, 2021. This is a *retrospective* valuation.

Assumptions and Conditions of the Appraisal

This appraisal assignment and the opinions reported herein are subject to the General Assumptions and Limiting Conditions contained in the report, and to Extraordinary Assumptions and Hypothetical Conditions, the use of which might have affected the assignment results. These are included in the "Reconciliation" section of this appraisal report.

Intended Use of the Appraisal

The intended use of this appraisal report is for consideration by the California Public Utilities Commission in connection with a valuation of the assets sought by the City and County of San Francisco (CCSF) through its proposed acquisition of PG&E's electrical transmission and distribution assets in the city. These include PG&E fee-owned real estate, including substations and operational facilities, vacant and improved land parcels, and overhead and underground transmission and distribution easements on private properties. We are informed that CCSF does not propose acquiring PG&E's natural gas line transmission and distribution assets at this time.

Purpose of the Appraisal

The purpose of this appraisal is to set forth an opinion of and support for a cost component in the summation of the RCNLD method and Market Approach as a measure of total compensation due based upon the fair market value of the fee simple and easement interests in the Parts Taken as it relates to the highest and best use of the Larger Parcel, as of July 27, 2021 (Date of Value). For avoidance of doubt, we understand and approve of this Appraisal being used as part of PG&E's Testimony in P. 21-07-012, including by other PG&E witnesses and experts.

The appraisal firms of Valbridge Property Advisors and Waldron & Associates, Inc. are providing specific opinions relating to valuations of PG&E's substation properties owned in fee and the private

easements which, in part, represent the real property interests in the operating energy grid serving the customers within San Francisco, California.

Excluded cost components and values to be prepared by others, include but are not limited to, fixtures, equipment, and system improvements (poles, electrical lines, towers, transformers, substation fixtures, conduits, and vaults), intangible assets, and severance damages.

Property Rights Appraised

Property Rights: *Property rights appraised are the fee simple rights owned, and easement rights held in the PG&E properties listed and described herein.*

The subject property appraised consists of a total of 33 PG&E fee-owned properties; 32 such properties are situated in San Francisco. These consist of land (with building and substation improvements) comprising 48.944 acres. In addition, a 36.784-acre portion of "Martin Substation," located nearby and straddling the Cities of Brisbane and Daly City, in San Mateo County, is appraised. Land and improvements included in the CCSF appraisal descriptions are situated in the geographic boundaries of Brisbane.

In total, approximately 85.728 acres (3,734,295 square feet), owned in fee simple may be acquired. The fee simple rights are appraised in these 33 PG&E sites.

PG&E transmission and distribution easements, rights-of-way, and other land-related agreements are operation assets included in the proposed acquisition of real property rights. These easements encumber privately-owned properties and total 137.56 net private circuit miles (or 175.883 acres (7,661,473 square feet) of easement area). The easement property rights held by PG&E in these properties are appraised.

The combined land area of fee simple rights and easement rights is 261.611 acres or 11,395,768 square feet.

Real Estate Identification

The subject property appraised consists of the following:

- Thirty-Three (33) sites, consisting of the same 33 sites appraised by CCSF.
    - Thirty-One (31) sites are improved with substation and/or operational facilities. All 31 substation sites are improved with special-purpose industrial buildings and/or site improvements housing or providing electrical transmission and/or distribution equipment. Fourteen (14) sites are improved with buildings. Seventeen (17) sites are not improved with buildings and are improved with transmission equipment on the sites.
    - An additional two (2) sites are vacant land. One is a vacant 70,446 net square foot (or 1.617 net acres) parcel planned for the development of a 230 kV switching station ("Egbert Switching Station"). The second is the "Beeman Lane" Site comprising approximately 4,721 square feet (0.108 Acres).

- Multiple overhead and underground easements for electrical power transmission and distribution totaling 137.56 net private circuit miles (or 175.883 acres of easement area) on privately-owned properties.

All but one of the fee properties within this assignment are situated in San Francisco. This remaining property ("Martin Substation") is located within the geographic boundaries of the cities of Brisbane and Daly City, in San Mateo County; the land areas proposed to be taken in San Mateo are situated in Brisbane. A complete list of the PG&E fee-owned properties appraised is included in Page 10 of this report.

The reader will note that properties are identified and listed by a sequential numbering system assigned by CCSF. This appraisal (PG&E) adopts this sequencing for common reference among readers. In addition, properties are identified and listed with PG&E's nomenclature, by station names, including alphabetized naming, by legal street address, and by APN- and SBE-assigned tax identification numbers.

Legal Description

Title reports for the PG&E-owned properties comprising the identified subject property component were not available for review. Legal descriptions, California State Board of Equalization (SBE) parcel maps, and City and County of San Francisco Assessor's Parcel Maps are available for review.

It is assumed (known under appraisal standards as an *extraordinary assumption*) that the property owner (PG&E) has clear and marketable title and that there are no adverse easements, encumbrances, covenants, and/or land use restrictions, other than those noted in this appraisal report, that would affect the marketability and utility of the subject properties.

Use of Real Estate as of the Effective Date of Value

As of the effective date of value (July 27, 2021), the properties were (and still are) a part of PG&E's electrical grid that serves the constituents of San Francisco. Properties include PG&E fee-owned real estate, including substations and operational facilities, private overhead and underground transmission and distribution easements, and rights-of-way easements.

Use of Real Estate as Reflected in this Appraisal.

The as-is opinion of value for the subject reflects use as a special purpose property – specifically as an operating electric utility grid/corridor.

Ownership of the Property

According to public records, title to the identified subject properties is vested in **Pacific Gas and Electric Company**.

History of the Property

The ownership of the property has not changed within a five-year period prior to the valuation date, except for the purchase of a vacant 70,446-net square foot parcel situated at 1755 Egbert Avenue, San Francisco (APN: 5431-001). This property transferred ownership on January 29, 2021; the reported sale price was $16,950,000. The grantor was Egbert Ents, LLC, and the grantee was Pacific Gas and Electric Company. The transaction was recorded with the City and County of San Francisco (CCSF) Clerk

Recorder's Office under document number 2021-1500848. The purchase/sale is included and analyzed as a comparable sale in the Valuation section of this appraisal report. As a prelude to that analysis, it is our conclusion that the site sold at its fair market value.

As of July 27, 2021 (valuation date), we are not aware of any other listings or pending sale transactions involving any of the fee properties that comprise any of the subject properties.

It is understood that CCSF intends to acquire the subject properties, including the 33 substation properties, plus underground transmission and/or distribution lines, and easements (subsurface, surface, and/or aerial) from PG&E. The Egbert Property was purchased by PG&E before the valuation date, as noted in the paragraph above, and continues as an ongoing PG&E development project as of the preparation date of this appraisal.

Type and Definition of Market Value

Market value, as is used in this appraisal, is "Fair Market Value," (FMV) which is defined in ***Section 1263.320*** of the California Code of Civil Procedures as:

> *(a) The fair market value of the property taken is the highest price on the date of valuation that would be agreed to by a seller, being willing to sell but under no particular or urgent necessity for so doing, nor obliged to sell, and a buyer, being ready, willing, and able to buy but under no particular necessity for so doing, each dealing with the other with full knowledge of all the uses and purposes for which the property is reasonably adaptable and available.*
>
> *(b) The fair market value of property taken for which there is no relevant, comparable market is its value on the date of valuation as determined by any method of valuation that is just and equitable.*

§ 1263.330: Increases or Decreases Not Included

The fair market value of the property taken shall not include any increase or decrease in the value of the property that is attributable to any of the following:

> *a) The project for which the property is taken.*
> *b) The eminent domain proceeding in which the property is taken.*
> *c) Any preliminary actions of the plaintiff relating to the taking of the property.*

Remainder

§ 1263.410: Measure of Compensation

> *a) Where the property acquired is part of a larger parcel, in addition to the compensation awarded pursuant to Article 4 (commencing with Section 1263.310) for the part taken, compensation shall be awarded for the injury, if any, to the remainder.*
>
> *b) Compensation for injury to the remainder is the amount of the damage to the remainder reduced by the amount of benefit to the remainder. If the amount of the benefit to the remainder equals or exceeds the amount of the damage to the remainder, no compensation shall be awarded under this article. If the amount of the benefit to the remainder exceeds the amount of damage to the remainder, such excess shall be*

deducted from the compensation provided in Section 1263.510, if any, but shall not be deducted from the compensation required to be awarded for the property taken or from the other compensation required by this chapter.

Damages

§ 1263.420: Damage to the Remainder

Damage to the remainder is the damage, if any, caused to the remainder by either or both of the following:

a) The severance of the remainder from the part taken.

b) The construction and use of the project for which the property is taken in the manner proposed by the plaintiff whether or not the damage is caused by a portion of the project located on the part taken.

Benefits

§ 1263.430: Benefit to the Remainder

Benefit to the remainder is the benefit, if any, caused by the construction and use of the project for which the property is taken in the manner proposed by the plaintiff whether or not the benefit is caused by a portion of the project located on the part taken.

Appraisal Terminology – Definitions (Glossary)

The next part of this Introduction section is a glossary of key terms that appear in this report but that may be unfamiliar to non-appraiser audiences. The terms are organized by subject matter per the below headings.

Condemnation and Partial Takings

Parcel

The term "parcel" as used herein means any contiguous tract of land in the same ownership, used for the same purpose, whether such tract consists of one or more plotted lots or a fractional part thereof. The identification of specific parcels in this report is based on Assessor's Parcel Block Maps (APN), State Board of Equalization (SBE) lots and assessment roll summaries, and circuit mile GIS mapping and engineering provided by the Client.

Larger Parcel

In condemnation, "*the tract or tracts of land that are under the beneficial control of a single individual or entity and have the same, or an integrated, highest and best use. Elements for consideration by the appraiser in making a determination in this regard are contiguity, or proximity, as it bears on the highest and best use of the property, unity of ownership, and unity of highest and best use*".[2]

[2] *The Dictionary of Real Estate Appraisal*; Seventh Edition; Appraisal Institute; 2022; Page 105.

Damages
"*In condemnation, the loss in value to the remainder in a partial taking of property. Generally, the difference between the value of the whole property before the taking and the value of the remainder after the taking is the measure of the value of the part taken and the damages to the remainder*".[3]

Benefits
"*In eminent domain valuation, the advantageous factors that arise from a public improvement for which private property has been taken. The law in some jurisdictions makes a distinction between general benefits and special benefits because only special benefits are considered in determining the value of the remainder in a partial acquisition. The distinction between special benefits and general benefits is both a factual and a legal question, so appraisers may need to consult legal counsel to resolve questions about the classification of benefits. See also general benefits; set-off rule; special benefits*".[4]

Real Property Interests

Fee Simple Estate
"*Absolute ownership unencumbered by any other interest or estate, subject only to the limitations imposed by the governmental powers of taxation, eminent domain, police power, and escheat*".[5]

Easement
"*An interest in real property that conveys use, but not ownership, of a portion of an owner's property*".[6]

"*The right to use another's land for a stated purpose*"[7] including, but not limited to, surface, subsurface, and aerial rights as may be included in these easement rights.

Easement in Gross
"*An easement that benefits a legal person or entity (individual, corporation, partnership, LLC, government entity, etc.) and not a particular tract or land; an easement having a servient estate but no dominant estate*".[8]

Easement Appurtenant
"*An easement that that is attached to, benefits, and passes with the transfer of the dominant estate; runs with the land for the benefit of the dominant estate and continues to burden the servient estate, although such an estate may be transferred to new owners*".[9]

Subsurface Easement
"*The right to use land at a designated distance below the surface, e.g., for pipelines, electric and telephone circuits and cables, storage facilities*".[10]

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[3] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 48.
[4] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 17.
[5] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 73.
[6] *The Dictionary of Real Estate Appraisal*, Fourth Edition; Appraisal Institute; 2002; Page 90.
[7] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 58.
[8] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 58.
[9] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 58.
[10] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 184.

Subsurface Rights
"*The right to construct and maintain tunnels, subways, pipelines, sewers, etc.*". [11]

Dominant Estate
"*A property that is served or benefitted by an easement. The opposite of the servient estate, which granted the easement*".[12]

Servient Estate
"*A property burdened by an easement*".[13]

PG&E Power System

The Power System is defined as electric transmission and/or distribution facilities owned by PG&E regardless of whether the facilities are operated by PG&E or are under the Operational Control of the California ISO.

PG&E's electric system is designed and built to deliver safe, reliable power to customers in Northern and Central California. PG&E produces or buys its power from a mix of conventional and renewable generating resources, which travel through PG&E's electric transmission and distribution systems to reach its customers.[14]

Electrical Power Transmission
Transmission is the portion of PG&E's Power System at a voltage of 60 kV and above. The transmission system is under the operational control of the ISO (although ISO protocols delegate certain operational activities to PG&E).

Electric power transmission is the movement of electrical energy over the bulk energy grid, a network of high-voltage transmission lines that connect the generating site, such as power plants to electrical substations and link the PG&E power system to neighboring ones.[15]

Electrical Power Distribution
Distribution is the portion of PG&E's Power System at a voltage less than 60 kV. The distribution system continues to be controlled by PG&E.

The distribution system links the transmission system and most of PG&E's customers. It includes main or "primary" lines and lower voltage or "secondary" lines, which deliver electricity either overhead or underground; distribution transformers, which lower the voltage to usage levels; and switching equipment to permit the lines to be connected in various combinations and patterns.[16]

[11] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 184.
[12] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 56.
[13] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 174.
[14] PG&E Energy Grid Map.
[15] PG&E Energy Grid Map.
[16] PG&E Energy Grid Map.

Substations

Substations are critical junctions and switching points in the electric system, connecting the transmission system to the distribution system. Substations use transformers to lower the voltage of electricity.[17]

Valuation Methods, Principles & Terminology

Highest and Best Use

"*The reasonably probable use of property that results in the highest value. The four criteria that highest and best use must meet are legal permissibility, physical possibility, financial feasibility, and maximum productivity*".[18]

> *"As Though Vacant"*
> Among all reasonable, alternative uses, the use that yields the highest present land value, after payments are made for labor, capital, and coordination. The use of a property is based on the assumption that the parcel of land is vacant or can be made vacant by demolishing any improvements.
>
> *"As Improved"*
> The use that should be made of a property as it exists. An existing improvement should be renovated or retained as is so long as it continues to contribute to the total market value of the property, or until the return from a new improvement would more than offset the cost of demolishing the existing building and constructing a new one.

Assemblage

"The combining of two or more parcels, usually but not necessarily contiguous, into one ownership or use; the process that may create plottage value. The combining of separate properties into units, sets, or groups, i.e., integration or combination under unified ownership."[19]

Assemblage Corridor

"A strip of land used for transportation or transmission purposes (e.g., rail, highway, power, information, slurries, liquids) under single control (not necessarily ownership) that was assembled from two or more separate and distinct land parcels not having a common owner."[20]

Corridor

"*A strip of land used for transportation or transmission purposes (e.g., rail, highway, power, information, slurries, liquids)*".[21]

Corridor Valuation

"*The process of estimating value associated with rights to corridor real estate. Valuation approaches may include methods such as across-the-fence method, sales comparison, the alternate route (cost avoidance) approach, and estimate of net liquidation value*".[22]

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[17] PG&E Energy Grid Map.
[18] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 88.
[19] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 11.
[20] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 11.
[21] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 43.
[22] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 43.

Plottage Value

"The increment of value that often occurs when two or more sites are combined to produce greater utility, resulting in a higher productivity or income than could be obtained from individual smaller sites."[23]

Across the Fence (ATF) Method

"*A land valuation method used in the appraisal of corridors. The across-the-fence method is used to develop a value opinion based on comparison to abutting land*".[24]

Across the Fence (ATF) Value

"*In the valuation of real estate corridors, the value concluded based on a comparison with adjacent lands before the consideration of any other adjustment factors*".[25]

Corridor Factor

"*In corridor valuation, the ratio of the market value (or market price) of a corridor to the corridor's across-the-fence value. Corridor factors are applied to reflect the benefit or advantage, if any, of the corridor having already been assembled. Typically used in the valuation of existing corridors and not the assembly of a new corridor. Sometimes called an enhancement factor or continuity factor*".[26]

Sales Comparison Approach

"*The process of deriving a value indication for the subject property by comparing sales of similar properties to the property being appraised, identifying appropriate units of comparison, and making adjustments to the sale prices (or unit prices, as appropriate) of the comparable properties based on relevant, market-derived elements of comparison. The sales comparison approach may be used to value improved properties, vacant land, or land being considered as though vacant when an adequate supply of comparable sales is available*".[27]

Cost Approach

"*A set of procedures through which a value indication is derived for the fee simple estate by estimating the cost new as of the effective date of the appraisal to construct a reproduction of (or replacement for) the existing structure, including an entrepreneurial incentive; deducting depreciation from the total cost; and adding the estimated land value. The contributory value of any site improvements that have not already been considered in the total cost can be added on a depreciated-cost basis. Adjustments may then be made to the indicated value of the fee simple estate in the subject property to reflect the value of the property rights being appraised*".[28]

Income Approach

"*Specific appraisal techniques applied to develop a value indication for a property based on its earning capability and calculated by the capitalization of property income*".[29]

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[23] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 143.
[24] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 3.
[25] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 43.
[26] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 43.
[27] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 170.
[28] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 43.
[29] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 94.

Assumptions and Limiting Conditions

Extraordinary Assumption
"*An assignment-specific assumption as of the effective date regarding uncertain information used in the analysis, if found to be false, could alter the appraiser's opinions or conclusions.*

Comment*: Uncertain information might include physical, legal, or economic characteristics of the subject property; or conditions external to the property, such as market conditions or trends; or the integrity of data used in an analysis*".[30]

Hypothetical Condition
"*A condition, directly related to a specific assignment, which is contrary to what is known by the appraiser to exist on the effective date of the assignment results but is used for the purpose of the analysis.*

Comment: Hypothetical conditions are contrary to known facts about physical, legal, or economic characteristics of the subject property; or about conditions external to the property, such as market conditions or trends; or about the integrity of data used in an analysis".[31]

Exposure Time
Reasonable exposure time is one of a series of conditions in most market value definitions. Exposure time is always presumed to precede the effective date of the appraisal.

Exposure time may be defined as follows:

> "*An opinion, based on supporting market data, of the length of time that the property interest being appraised would have been offered on the market prior to the hypothetical consummation of a sale at market value on the effective date of the appraisal*".[32]

Exposure time is different for various types of property and under various market conditions. It is noted that the overall concept of reasonable exposure encompasses not only adequate, sufficient, and reasonable time but also adequate, sufficient, and reasonable effort.

> "*The fact that exposure time is always presumed to occur prior to the effective date of the appraisal is substantiated by related facts in the appraisal process: supply/demand conditions as of the effective date of the appraisal; the use of current cost information; the analysis of historical sales information (sold after exposure and after completion of negotiations between the seller and buyer); and the analysis of future income expectancy projected from the effective date of the appraisal*".[33]

[30] *Uniform Standards of Professional Appraisal Practice*; 2024 Edition; effective January 1, 2024; Definitions; Page 4.
[31] *Uniform Standards of Professional Appraisal Practice*; 2024 Edition; effective January 1, 2024; Definitions; Page 4.
[32] *Uniform Standards of Professional Appraisal Practice*; 2024 Edition; effective January 1, 2024; Definitions; Page 4.
[33] *2024 USPAP Guidance and Reference Manual, Companion Volume to 2024 USPAP*; Advisory Opinion 35; Pages 101 and 103.

Scope of Work

The elements addressed in the Scope of Work section of this Appraisal Report are (1) the extent to which the subject is identified, (2) the extent to which the property is inspected, (3) the type and extent of data researched, (4) the type and extent of analysis applied, (5) the type of appraisal report prepared, and (6) the inclusion or exclusion of items of non-realty in the development of the value opinion. These items are discussed below.

Extent to Which the Property Was Identified

The three components of the property identification are summarized as follows:

- Legal Characteristics – The subject properties were legally identified via a review of provided legal descriptions, San Francisco, and San Mateo County Assessor's Parcel Maps, and SBE Parcel Maps.
- Economic Characteristics – The subject properties' economic characteristics, based on their respective concluded highest and best use(s), were identified via a review of regional and local market statistics and trends, as well as a review of the larger macroeconomic trends on a state and national scale, and to a comparison to sales of similar properties with the same uses as those properties that would be acquired for and compatible with the subject property's (i.e. Larger Parcel's) "Highest and Best Use."
- Physical Characteristics – The subject's physical characteristics were identified via an onsite property inspection and offsite review(s) of aerial photographs via Google Earth.

Extent to Which the Property Was Inspected

As of the date of this appraisal, onsite inspections of the following substation and facilities comprising the subject property were made by Walter D. Carney, MAI on June 21, 2023, June 28, 2023, December 20, 2023, and May 22, 2026. An onsite inspection was not made by Michael F. Waldron, MAI and/or Christer Fiege-Kollmann, MAI.

Embarcadero Substation (Substation Z)	Potrero Substation (Substation A)
Hunter's Point Substation (Substation P)	Bayshore Substation (Substation W)
Larkin Substation (Substation Y)	Substation X (Mission Substation)
Substation L	Substation G
Substation E	Substation K
Substation J	Substation N
Randolph Substation	Substation M
Martin Substation	Substation I

Offsite and/or on-site inspections of each of the 33 PG&E fee-owned properties were made by Walter D. Carney, MAI. Neighborhood areas of the easement properties were inspected by Michael F. Waldron, MAI, and Christer Fiege-Kollmann, MAI. Each appraiser made a review of historic and current aerial and street scene photographs available on Google Earth, along with a review of provided maps and data from the client.

Type and Extent of Data Researched

The following data was researched and analyzed: (1) market area data, (2) property-specific market data, (3) zoning and land-use data, and (4) current data on comparable listings and transactions. Professionals familiar with the subject market/property type were also interviewed.

Type and Extent of Analysis Applied (Valuation Methodology)

Surrounding land use trends, the condition of any improvements, demand for the subject properties, and relevant legal limitations were observed in the process of concluding the highest and best use for the property. The subject properties were then valued based on this highest and best use conclusion.

Appraisers develop an opinion of property value with specific appraisal procedures that reflect three distinct methods of data analysis: the cost approach, sales comparison approach, and income capitalization approach. One or more of these approaches are used in all estimations of value.

- Cost Approach – In the cost approach, the value indication reflects the sum of current depreciated replacement or reproduction cost, land value, and an appropriate entrepreneurial incentive or profit.
- Sales Comparison Approach – In the sales comparison approach, value is indicated by recent sales and/or listings of comparable properties in the market, with the appraiser analyzing the impact of material differences in both economic and physical elements between the subject and the comparable sales.
- Income Capitalization Approach – In the income capitalization approach, value is indicated by the capitalization of anticipated future income. There are two types of capitalization: direct capitalization and yield capitalization, more commonly known as discounted cash flow (DCF) analysis.

The subject properties, as a part of the larger PG&E electrical grid system, are situated in the San Francisco-area and constitute a *special purpose* and a *limited market* property. For the reader's reference, a special purpose property is defined as follows:

> *"An improved property with a unique physical design, special construction materials, or a layout that particularly adapts its utility to the use for which it was built and may be costly to modify to another use."* [34]

And "limited market" is defined as follows:

> *"A property (or property right) that has relatively few potential buyers."* [35]

Based on these definitions, the Subject Property's use as an operating utilities corridor (i.e., electrical grid system) is a special purpose use with a limited market. As such, the Cost Approach is used in this valuation. The Sales Comparison Approach is also used to determine the value of the underlying land.

PG&E's property is an assemblage of land (fee-owned) and strips of land (easements, licenses, franchises, leases, and other agreements) improved, utilized, and operating for electrical transmission

[34] *The Dictionary of Real Estate Appraisal*, Seventh Edition, The Appraisal Institute, Chicago, IL, p. 178.
[35] Ibid., p. 108.

and distribution purposes, i.e., an "*assembled corridor*". It is a collection of integrated properties, subsequently improved with various facilities, forming an electronic transmission and distribution network / corridors laid out into an energy grid. PG&E's energy grid is comprised of many system facilities throughout Northern and Central California. This power system energy grid is comprised of a collection of land segments forming corridors, owned by and/or under the beneficial interest and control of PG&E.

Corridor valuation is defined as:

> *"The process of estimating value associated with rights to corridor real estate. Valuation approaches may include methods such as across-the-fence method, sales comparison, the alternate route (cost avoidance) approach, and estimate of net liquidation value."* [36]

Across-the-Fence (ATF) Method

The land valuation technique utilized in the appraisal of corridors is the **Across-the-Fence (ATF) Method**. It is a method used to develop a value indication based on a comparison to abutting lands. In the valuation of real estate corridors, the value indicator concluded is based on a comparison with adjacent lands before the consideration of any other adjustment factors. In other words, the ATF value is not the fair market value.

Once the adjusted ATF value is determined, a corridor factor or enhancement factor is a potential additional adjustment to reflect the inherent increment of value, the plottage value, associated with the corridor having already been assembled. Assembled operating corridors, like PG&E's assembled, operating corridor, produce greater utility and higher productivity by maximizing the highest and best use as a power system energy grid.

Further discussion of the extent of our analysis and the methodology of each approach is provided later in the respective valuation sections.

Work Performed

The fair market value conclusions stated in this report are based on the following tasks (Scope of Work) performed by the appraisers:

- Gathered, reviewed, and studied background documents regarding valuation issues and CCSF's proposed taking of PG&E's energy system facilities within its jurisdiction as well as the Martin Substation in the County of San Mateo.
- Interviewed PG&E Land, Engineering, Acquisition and Appraisal departments.
- Reviewed documents provided by CCSF.
- Reviewed documents provided by PG&E from system record research pertaining to the proposed CCSF acquisition. This list was then filtered by PG&E to only include all documents that were granted "To" PG&E as well as the Type of Interest (TOI) which identified the five (5) sub-categories of easements.

[36] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 43.

- Identified, to the extent practical, all PG&E's real property ownership/interests situated within the CCSF jurisdiction proposed for acquisition.
- Reviewed various GIS mapping overlays provided by PG&E with inventories of fee-owned properties and utility easement interests.
- Separately identified and studied each fee-owned property.
- Requested and received from PG&E and relied upon reported information pertaining to each of the fee-owned substation properties with respect to building characteristics, site improvement characteristics, environmental status, historical cost, and other related information.
- Separately identified, studied, and inventoried each category of private easements as Electric Transmission – Underground (ET-UG), Electric Transmission – Overhead (ET-OH), Electric Distribution – Underground Facilities Management (ED-UFM), Electric Distribution – Underground (ED-UG), Electric Distribution – Overhead (ED-OH).
- Utilized the San Francisco FF Electric Master dated 12-31-2021 to identify private "circuit miles," after PG&E determined that in the best interest of the company and its customers, a complete, detailed, and exhaustive inventory of over 2,400 unique easements was not financially practical, would require an undue consumption of time and cost, and that a reasonable alternative method would adequately define these easement interests.
- Utilized the circuit miles expressed as a linear distance, as locationally defined by PG&E for each of the five types of electric corridor segments. This appraisal assignment focuses only on "Private" circuit miles assumed to reflect each of the five types of easements.
- Reduced the "Private" circuit miles by any overlap within PG&E fee-owned parcels.
- Reviewed, inventoried, and analyzed the PG&E GIS mapping of "Private" circuit miles and the zoning overlays.
- Studied the PG&E reported typical easement rights, identifying specific rights, both primary and secondary, together benefiting the easement holder and burdening the servient estate.
- Analyzed each easement category, depending upon the nature and scope of PG&E's easement rights, by recognizing the primary and secondary rights and the division of property rights by way of a "before and after" easement analysis and a direct summation analysis.
- Requested and received from PG&E and relied upon reported assumed physical widths for Transmission and Distribution private easements. Assumed historical widths are reported as ten (10) feet for Distribution easements and forty-five (45) feet for Transmission easements. PG&E notes that the widths of easements have varied and changed with operational and maintenance needs throughout the years. With technology and design changes, PG&E's current practice is to acquire a 30-foot-wide easement for Distribution Overhead and a 10-foot-wide easement for Distribution Underground. So, the overall assumed width for Distribution, Overhead at ten (10) feet is considered conservative compared to thirty (30) feet for current practices.

- Walter D. Carney, MAI, conducted multiple inspections of PG&E's fee-owned properties within the CCSF electrical grid, documenting site characteristics, interior and exterior details, and overall quality and condition as well as use and occupancy characteristics.
- Michael F. Waldron, MAI, and Christer Fiege-Kollmann, MAI, conducted several inspections of PG&E's private easement interests by way of aerial photography, and physical tours of selected neighborhoods in the vicinity of the private circuit mile easements within the CCSF electrical grid, documenting neighborhood characteristics.
- Conducted field investigations of the Subject Property neighborhoods; and studied trends in the nearby and adjacent market areas.
- Retrieved and reviewed various documents for neighborhood zoning districts, land use, general plan, zoning, and other information from CCSF's Planning department.
- Conducted interviews with people knowledgeable of property prices, activity, and trends in the subject area.
- Conducted a highest and best use analysis, through a study of the existing operating electrical grid within the jurisdiction of the City and County of San Francisco, considering "as if vacant" and "as improved".
- Concluded to a highest and best use opinion for the Parts Taken as it contributes to, and is a part of, the larger parent holding.
- Researched the market for vacant and improved comparable electric grid / corridor sales to determine whether a relevant comparable market exists for comparison purposes and to determine a proper valuation methodology.
- Gathered, researched, verified, field inspected and / or aerially inspected, land transactions as market indicators for application of the Across-the-Fence methodology, along with consideration of the companion Sales Comparison Approach – Land.
- Utilized these nearby relevant transactions for consideration, analyses and value application for the Fee-Owned substation sites.
- Utilized these nearby relevant transactions for consideration, analyses and value application for the Easement Interests, employing a 16-grid zone of value overlay (section quadrants) and a by-use district analyses.
- Analyzed the division of property rights by way of a consideration of a "before and after" easement analysis and a direct summation analysis.
- Utilized a cost methodology to determine replacement cost new, accrued depreciation and contributory value in place for the building and site improvements within the thirty-three (33) Fee-Owned substations.
- Adjusted and reconciled the indications of value to a fair market value summation as of July 27, 2021, for PG&E's fee-owned land [thirty-three (33) sites containing a total of up to 87.150 acres, including the related onsite substation building and site improvements], and PG&E's easements over private properties (137.56 net private circuit miles containing 175.883 acres or 7,661,472 square feet of private easement area).

- The total of these value components, adjusted for the enhancement factor consistent with its highest and best use, reflects the line-item for "FMV – Land", which is utilized in the Cost Approach ("RCNLD") to be prepared by other experts, providing an indication of the fair market value of the total Parts Taken.
- Prepared the joint appraisal report.

Appraisal Conformity and Report Type

The analyses, opinions, and conclusions were developed, and this report was prepared in conformity with the Uniform Standards of Professional Appraisal Practice (USPAP) of the Appraisal Foundation, the Code of Professional Ethics and Standards of Professional Practice of the Appraisal Institute, and the requirements of our client.

This is an Appraisal Report as defined by the Uniform Standards of Professional Appraisal Practice under Standards Rule 2-2a.

Standards Rule 2-2

Each written real property appraisal report must be prepared under one of the following two options and prominently state which option is used: *Appraisal* Report or *Restricted Appraisal* Report.

> **Comment**: The essential difference between these two options is the content and level of information provided. The appropriate reporting option and the level of information necessary in the report are dependent on the intended use and the intended users.

The Client has requested an *Appraisal* Report for negotiations or, if necessary, valuation support for a Public Utilities Commission for the State of California ("Commission") proceeding to determine just compensation for the taking in this matter. The date of valuation is July 27, 2021. This document represents a retrospective Appraisal Report in conformance with USPAP and the Client's intended purpose and scope of work.

Competency Statement

We, Walter D. Carney, MAI, Michael F. Waldron, MAI, and Christer Fiege-Kollmann, MAI, are designated members of the Appraisal Institute, and we each hold the Certified General Real Estate Appraiser license from the State of California. We appraise and have appraised special purpose properties, operating corridors, and utility easements. Because of our education, experience in the subject market area, and experience with the subject property type, we have the competency necessary to perform this appraisal report.

Professional Assistance

This report was prepared with the assistance of Neil N. Shah, who performed and assisted in the preparation of the report under Walter D. Carney, MAI's direct supervision. Assisted tasks include exhibits preparation, market research, and data collection. Neil N. Shah additionally assisted with the writing of portions of the appraisal report and accompanied the appraiser on property inspections.

Waldron & Associates, Inc. recognizes the professional assistance of Walter D. Carney, MAI and Neil N. Shah, Senior Appraisal Analyst, both with Valbridge Property Advisors, who performed and assisted in the preparation of the report under Walter D. Carney, MAI's direct supervision. Assisted tasks include

exhibits preparation, market research, and data collection. Neil N. Shah additionally assisted with the writing of portions of the appraisal report.

Waldron & Associates, Inc. also recognizes the professional assistance of Kevin R. Waldron, Research Appraiser and Petros Berhane, Senior Appraiser, both with Waldron & Associates, Inc. who performed and assisted in the preparation of this report under the direction of Michael F. Waldron, MAI and Christer Fiege-Kollmann, MAI. Assisted tasks include exhibit preparation, market data collection, market research, aerial mapping and analysis, and data verification.

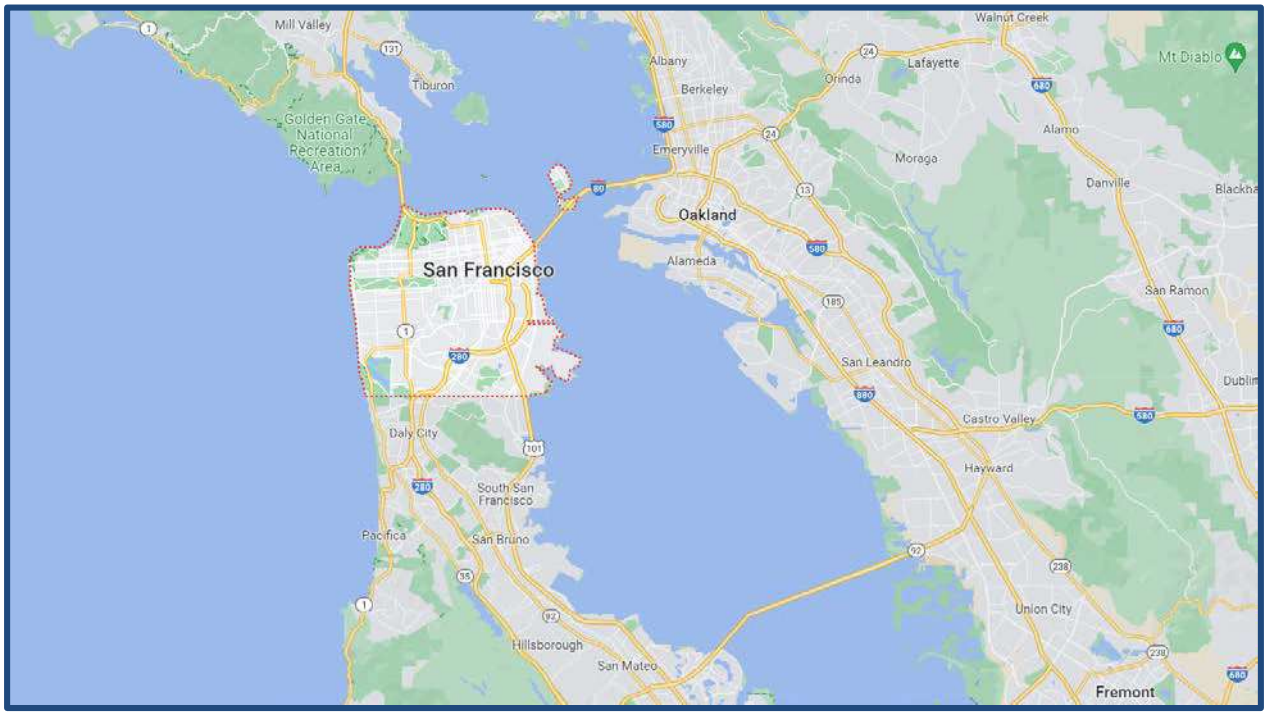
Personal Property/FF&E

All non-realty items of value are excluded from this analysis. Fair market value opinions concluded herein are only those owned and/or held by PG&E as its real property rights.

Regional and Market Area Analysis

This Regional and Market Area Analysis of the appraisal report provides a description of the regional real property market where the appraised property is located at the time of the DOV. This section provides context for the detailed property descriptions and valuation conclusions that follow in later sections of this report.

REGIONAL MAP



Overview

The Regional and Market Area analysis is reflective of the period in-and-around the July 27, 2021, date of valuation. The subject property is in the San Francisco Bay Area, a region comprised of nine counties bordering the San Francisco Bay. According to the State of California Department of Finance, the area had a combined population of approximately 7.70 million as of January 1, 2021. The Department of Finance characterizes the San Francisco Bay Area by a moderate climate, diversified economy and one of the highest standards of living in the United States.

Population

Established in 1850, San Francisco is one of the first original counties in California. The Consolidation Act of 1856 combined the City and County of San Francisco. It was (and is) the second most populous city in the Bay Area after San Jose, which overtook its northern neighbor. According to the California Department of Finance, as of January 2021, San Francisco had a population of 875,010, denoting a 1.66% decrease from the previous year.

According to Site to Do Business projections, presented on the next page, the county's population was expected to increase annually 0.8% between 2021 and 2026.

Population

Area	2010	2021	Annual Δ 2010 - 21	Projected 2026	Annual Δ 2021 - 26
United States	308,745,538	333,934,112	0.7%	345,887,495	0.7%
California	37,253,956	39,476,705	0.5%	40,507,842	0.5%
San Francisco-Oakland-Berkeley, CA (MSA)	4,335,391	4,641,032	0.6%	4,789,448	0.6%
San Francisco - City & County	805,235	873,035	0.8%	908,019	0.8%

Source: ESRI (ArcGIS)

City Overview

San Francisco encompasses 47.3 square miles, has 29.5 miles of shoreline, including 7.5 miles of waterfront at the Port of San Francisco, and 850 miles of streets. Geographically, the combined City and County of San Francisco is at the northernmost tip of the San Francisco Peninsula. Once the original metropolitan center of the Bay Area, as well as the commercial center of the entire West Coast prior to and immediately following World War II, San Francisco has since been overshadowed by its Southern California rival, Los Angeles, and more locally, by San Jose and the Silicon Valley in the South Bay.

Leading attractions include Fisherman's Wharf, Chinatown, the Golden Gate Bridge, Union Square, Coit Tower, Pier 39, Lombard Street, and cable car rides to name a few. Another attraction is the city's 1,017-acre Golden Gate Park. It is located on the western end of the city and spans 7.5 miles from the tip of Ocean Beach. It provides an outdoor playground for city dwellers and many cultural opportunities. The city is an area with unique neighborhoods and macro markets. The look and feel of a neighborhood can change from one block to the next, creating a city that is culturally rich and diverse.

As of the valuation date, after the "re-opening" of the State in June 2021, following the pandemic, tourism was on the rise, but nowhere near as high as the area's 2019 peak. In 2021, there were 17 million visitors to San Francisco. By 2022, the number of annual visitors increased to 21.9 million. While tourism has helped San Francisco generate income throughout 2021, the region had not recovered from the pandemic-related office and business shutdowns.

San Francisco is divided into ten districts (*excluding Golden Gate Park, Lake Merced, and the Presidio*). Neighborhoods in the prestigious north section include Pacific Heights, The Marina, Russian Hill, North Beach, and Downtown San Francisco. Southern neighborhoods include China Basin, Hunter's Point, and Dogpatch, the Outer Mission, and Ingleside.

Many of the industrial buildings in the older industrial areas of China Basin, Hunter's Point, and Dogpatch are being converted into loft style residential or commercial/service buildings. The city is highly encouraging redevelopment in this area to accommodate increased mixed-use development with housing over ground floor commercial. Real estate in these neighborhoods is still moderately priced, but as the neighborhood evolves, the transformation is likely to be reflected in overall property values.

District 1 – Northwest and Central West

The Northwest District (also referred to as the "Richmond District") is known for having a laid back, beach town feel. These neighborhoods have modest homes with easy access to the coast. The district

is located north of Golden Gate Park and extends to Ocean Beach, and south of Lincoln Park and Park Presidio.

District 2 – Central West

The Central West district is bordered by the Pacific Ocean to the west and Golden Gate Park to the north. It includes the Sunset and Parkside areas, both of which are known for being quiet, safe communities for those who want to live in an area with more of a small-town feel. Most of the buildings in the area were constructed in the mid-1940's, following World War II. The area is served by the N-Judah and L-Taraval MUNI light rail system, which provides convenient access to the downtown area.

District 3 – Southwest

The Southwest district was one of the last regions of San Francisco to be developed. With convenient access to major highways and the edge of the city, this area is home to many students and families alike. San Francisco State University, with an average enrollment of 30,000 students per year, is located within the district's Stonestown area.

District 4 – Twin Peaks

Twin Peaks is an area full of exclusive neighborhoods and beautiful views of the city, as the name suggests. Many find this to be a more suburban area, with residential as the primary land use. The district is located at the southwestern side of Twin Peaks and Mount Davidson. It also has a total of 16 neighborhoods and is considered to be one of the most upscaled districts in San Francisco.

District 5 – Central District

The Central district is identified by the Diamond Heights, Haight-Ashbury, Castro, and Mission Dolores neighborhoods. These areas are known for their eclectic vibe and rich histories including Haight Ashbury's "hippie" subculture and the Castro district's strong LGBTQ+ community. The area is home to Buena Vista Park, Mission Dolores Park, and Mission Dolores.

District 6 – Central North

The Central North district includes the Western Addition, Alamo Square, Anza Vista, North Panhandle, Hayes Valley, and Lower Pacific Heights neighborhoods. Real estate in this district exudes San Francisco charm and is full of historically and architecturally significant homes and buildings, including the "Painted Ladies," consisting of six Victorian houses at the edge of Alamo Square Park.

District 7 – North District

The North district is home to some of the city's wealthiest citizens, blending the old with the new in its four neighborhoods – Cow Hollow, the Marina, Pacific Heights, and Presidio Heights. Real estate in these four prestigious communities is varied and includes nearly every architectural style that can be found in the city. Area parks and recreational areas include Crissy Field, Fort Mason, and Marina Green; the latter provides some of the best views of the Golden Gate Bridge, Angel's Island, and Alcatraz Island.

District 8 – Northeast District

The Northeast district includes the areas that most visitors flock to when visiting the city, including Fisherman's Wharf, Chinatown, Coit Tower, Transamerica Pyramid, downtown skyline, cable cars, and Union Square. Neighborhoods include Downtown San Francisco, Financial District, Nob Hill, North Beach, North Waterfront, Russian Hill, Telegraph Hill, the Tenderloin, Van Ness, and Civic Center.

The Financial District, which serves as the main Central Business District, has the city's largest concentration of corporate headquarters, law firms, and financial institutions.

District 9 – Central East District

The Central East District includes Bernal Heights, Central Waterfront, Dogpatch, Inner Mission, Mission Bay, Potrero Hill, South Beach, South of Market, and Yerba Buena. It is sometimes called the South Financial District, as many businesses have expanded into this developing area. The face of residential real estate in this district is evolving. Cottages, bungalows, and single-family homes help give Bernal Heights and Potrero Hill their friendly neighborhood feel, while SoMa and South Beach are being transformed by an infusion of lofts and condominiums.

It has also been home to a vast amount of development over the past two decades, including many hi-rise residential and mixed-use projects, office buildings and Oracle Park, home of the San Francisco Giants. Easy access to Highway 101, I-280, and I-80 make commuting to all points north, south, east, or west straightforward and convenient.

District 10 – Southeast District

The Southeast district is, to a large degree, a light industrial and warehouse district, but also includes the neighborhoods of Bayview: Bayview Heights, Crocker Amazon, Excelsior, Hunters Point, Mission Terrace, Outer Mission, Portola, Silver Terrace, and Visitacion Valley.

Transportation

Excellent transportation routes and linkages to all major cities within the region and throughout the state were (and are) primary reasons for the advancement of business activity in San Francisco County. Bay Area Rapid Transit District (BART) and Caltrain serve the city. The latter runs commuter trains between Gilroy and the South of Market Street area. Additionally, ferryboats from Larkspur in Marin County, as well as from Alameda and Oakland, bring commuters into the Embarcadero and Financial District daily.

Within its boundaries, San Francisco also has one of the most extensive public transit systems of any city in the United States with streetcars, buses, and its world-famous cable cars. The San Francisco Municipal Railway provides a comprehensive network of rail and bus links covering the entire City of San Francisco. This network is focused on Market Street, which runs through the heart of the Central Business District.

The area is also served by Southern Pacific Railroad. Although originally a factor in site selection for warehouse and distribution facilities, these routes have become less of a criterion and are seen as a detriment by many high-technology firms due to vibration and noise. Most industrial users now depend on truck service because of the relatively small, fragile, and valuable products that characterize high technology, as opposed to heavy manufacturing.

Caltrain provides daily commuter service that runs along the Peninsula from Gilroy to San Francisco. Air service in the area is provided by San Francisco International Airport (SFO), which, although operated by the city, lies to the south in San Mateo County on land fronting San Francisco Bay between the cities of Burlingame and South San Francisco. The major international terminal for Northern California is one of the 30 busiest in the world. The airport is accessible from Highway 101, Interstate 280, and BART. San Jose and Oakland airports are also within an hour's drive from San Francisco.

San Francisco also is a seaport with cargo facilities that handle a small amount of ocean-going freight. However, most ships coming to the Bay Area make port at Oakland, which has extensive facilities and direct "inter-modal" connections to trucks and freight trains. With its freight operations in decline, San Francisco's port has in recent years oriented itself toward real estate development and tourism.

The area has a well-developed freeway system although traffic congestion is unquestionably one of the negative aspects. Interstate 280 and Highway 101, both major freeways, extend into the City of San Francisco. The city is also connected to Oakland and the greater East Bay by way of the San Francisco-Oakland Bay Bridge and to Marin County and the North Bay by way of the Golden Gate Bridge. In addition to the freeway system, the county's transportation network includes several expressways, which provide streamlined access to most interior locations.

Although many routes are at gridlock during peak commute hours, routes are being extended or expanded, public transportation is being developed, and the employment/housing balance is becoming a geographic issue and important consideration for municipalities when considering new development. Prospects for improvement in the transportation system in keeping with population growth are better than for many other Bay Area communities.

Employment

Significant employment sectors within San Francisco included (and includes) manufacturing, transportation, retail trade, finance, insurance, real estate, and professional services. As of the valuation date in July 2021, the unemployment rate in San Francisco was equal to the national rate and below the state rate. San Francisco's unemployment rate was at 5.4% in July 2021; the statewide and national unemployment rates were at 7.4% and 5.4%, respectively.

Economic Overview

The following economic overview reflects information that was known as of the date of valuation.

National Economic Overview

In March 2020, the COVID-19 outbreak was declared a pandemic and shelter-in-place and social distancing efforts to minimize the impacts of the virus were put in place at the national, state, and local government levels. The U.S. economy went into a recession but at the end of 2020 and early into 2021, there was hope of a recovery due to a waning of the virus and creation of vaccines.

Federal fiscal relief efforts and a softening of shelter-in-place mandates helped, and California "opened for business" in June 2021, but reports of new variants of the virus led to a return of mandates in some areas. Employers and employees alike were adjusting nationwide to work-from-home (remote) trends and e-commerce spending while being hesitant to spend discretionary income on entertainment and restaurants. Business and international travel were down from pre-COVID levels but began to increase as the state and country "re-opened." Global supply chains were disrupted as factories closed abroad, and pandemic protocols impacted the transport of goods.

GDP declined in 2020 but subsequently increased in 2021. As of the valuation date, the overall U.S. economy was down 5.3 million payroll jobs from its pre-COVID peak. Economic growth surged through

2021, partially because of historically low interest rates and about $6.4 trillion in government borrowing and spending – in addition to an increase in consumer spending.

Looking back at the valuation date, the inflation rate began making its ascent from the favored "2% target rate" in the second quarter of 2021.

Economic Relief Packages

In the wake of the COVID-19 pandemic, Congress passed three economic relief packages to stimulate the economy. These include the "Coronavirus Aid, Relief, and Economic Security" (CARES) Act, a $2.2 trillion stimulus package, which was signed into law in March of 2020. In December of 2020, Congress approved the second economic aid package comprising a $900 billion COVID-relief plan, which included an extension and an increase of unemployment insurance, as well as funds for business owners and assistance for renters. The final of the three economic aid packages, "American Rescue Plan Act of 2021," a $1.9 trillion COVID relief package, was signed into law in March of 2021.

A fourth package, the "Infrastructure Investment and Jobs Act," would pass in November 2021 (after the valuation date). This act provided funding to improve basic infrastructure and to provide affordable housing units – among others.

Federal Funds Rate

To maximize employment and stabilize inflation, the Fed raised the Federal Funds Rate nine times from 2015 when interest rates were near zero percent through 2018. Incremental rate decreases were made up to March 2020. In response to the COVID pandemic, the Fed began to aggressively lower the Funds Rate – first by 50 basis points, and then, again, by 100 basis points. In addition, the Fed began purchasing $120 billion a month in U.S. Treasury bonds and mortgage-backed securities to hold long-term interest rates down and to stimulate the economy. By the valuation date, in July 2021, the rate was near zero.

Median Household Income

High-technology employment and a skilled workforce translate into relatively high-income levels. San Francisco ranked second out of the nine Bay Area counties in terms of household income.

Total median household income for the region is presented in the following table. Overall, the subject's MSA and county compared favorably to the state and the country.

Median Household Income

Area	Estimated 2021	Projected 2026	Annual Δ 2021 - 26
United States	$62,203	$67,325	1.6%
California	$80,044	$90,664	2.7%
San Francisco-Oakland-Berkeley, CA (MSA)	$112,557	$128,847	2.9%
San Francisco - City & County	$120,910	$143,667	3.8%

Source: ESRI (ArcGIS)

San Francisco Real Estate Market Analysis

The following is a narrative-and-data-driven overview of the San Francisco economic positioning and of the trends in its real property segments and markets. Additional data is maintained in the appraisal file.

San Francisco is one of three major Bay Area markets, with the other two being the East Bay and the San Jose/Peninsula markets. The major centers for business activity are the Financial District and the South of Market Area submarkets. The coronavirus pandemic triggered a downturn that disrupted the area's economic base and impacted the performance of key commercial real estate sectors, most notably the office and retail markets. The for-rent multi-family residential market was impacted during the pandemic but was beginning to rebound as of the July 2021 valuation date.

Landlord optimism was beginning to increase as of the valuation date due to the official "reopening" of the State in June 2021 and the vaccine rollout that had been underway. At the end of June 2021, it was reported that San Francisco had passed the 70% vaccination rate.

It is noted that the higher cost of living in the area was already causing a decline in San Francisco's population prior to the COVID-19 pandemic, but this trend was also exacerbated by the remote work trend that grew in the aftermath of state and local government(s) requirement to "shelter-in-place."

San Francisco Industrial Market

As of the DOV, San Francisco was (and still is) one of the most expensive metros in the country for industrial space and worker compensation. It is located geographically on a Peninsula. Highways leading up the Peninsula into San Francisco are often choked with traffic, which makes moving and storing goods in the market cumbersome. Distribution facilities are more prevalent in the nearby East Bay, which also contains far more manufacturing and warehouse space, land for development, and infrastructure conducive to distribution.

San Francisco's industrial market is more localized, and many tenants are in the area by necessity, either to be very close to their delivery points or a highly skilled employee base. These tenants include food distributors, select retailers, delivery services such as USPS, FedEx, biotech, and flex tenants and, in the future, a 650,000 square foot Amazon "last mile" distribution warehouse. Expensive real estate and business costs present headwinds for the market. Operation costs and an ever-rising tax burden have challenged lower revenue generating business operations in the Bay Area.

Demand for San Francisco's generally small-sized industrial market had been generated by last-mile logistics tenants, tech firms absorbing flex space, and biotech firms taking lab space. Structural factors such as a lack of available industrially zoned land, weak infrastructure, and confined port capacity limit the market's distribution facility potential. The market demand drivers and historically strong rent growth were appealing to investors, but its relatively limited and aged inventory muted sales volume. Pricing registered well above the national average, and cap rates were among the lowest in the nation.

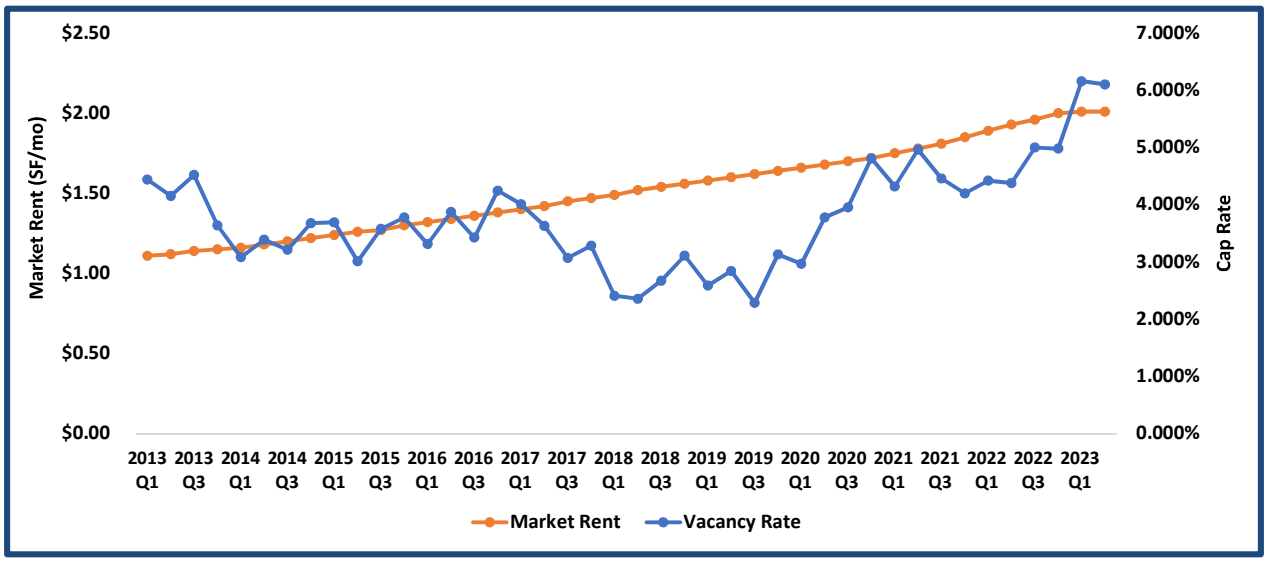
Land constraints, zoning, and prohibitive construction costs have restrained new development, outside of newer biotech clusters, for decades.

Industrial Vacancy and Rental Rates

Industrial vacancy in San Francisco had been increasing in the years preceding the July 2021 valuation date, having risen at a faster pace during the pandemic but ticking lower in Q2-2021. Biotech tenants had taken occupancy of then-recently completed buildings, driving positive net absorption in spurts, while older properties incurred occupancy losses.

Vacancies increased among flex buildings and smaller, outdated warehouses that did not easily tie into e-commerce distribution. Cost pressures were already a key concern for businesses, and disruption in revenue streams caused by the pandemic led some industrial users to relinquish space. Tenants were facing unenviable options upon lease expiration: (1) renewing at a significantly higher rate, (2) closing shop, or (3) moving out of town due to a lack of alternative viable space availability.

SAN FRANCISCO INDUSTRIAL MARKET VACANCY RATES AND MARKET RENT



Source: Costar, Inc.

At the end of the Second Quarter of 2021, vacancy among all industrial segments in San Francisco was at 5.0%, according to market data compiled and analyzed by Costar, Inc. The average market rental rate was $21.36 per square foot, on an annual basis (or $1.78 per square foot, per month).

Asking rents increased for over 10 consecutive years as enduring demand provided landlords leverage in lease negotiations, although rent growth moderated in 2019 and 2020 with leverage shifting away from landlords temporarily.

Rents in San Francisco increased steadily since Q1 2013, with minor variations quarter to quarter. Vacancy rates increase during periods of economic downturns, such as the Great Recession. The COVID-19 pandemic also presented a unique shock to the local economy, and vacancies faced further headwinds in 2021 as availability remained elevated.

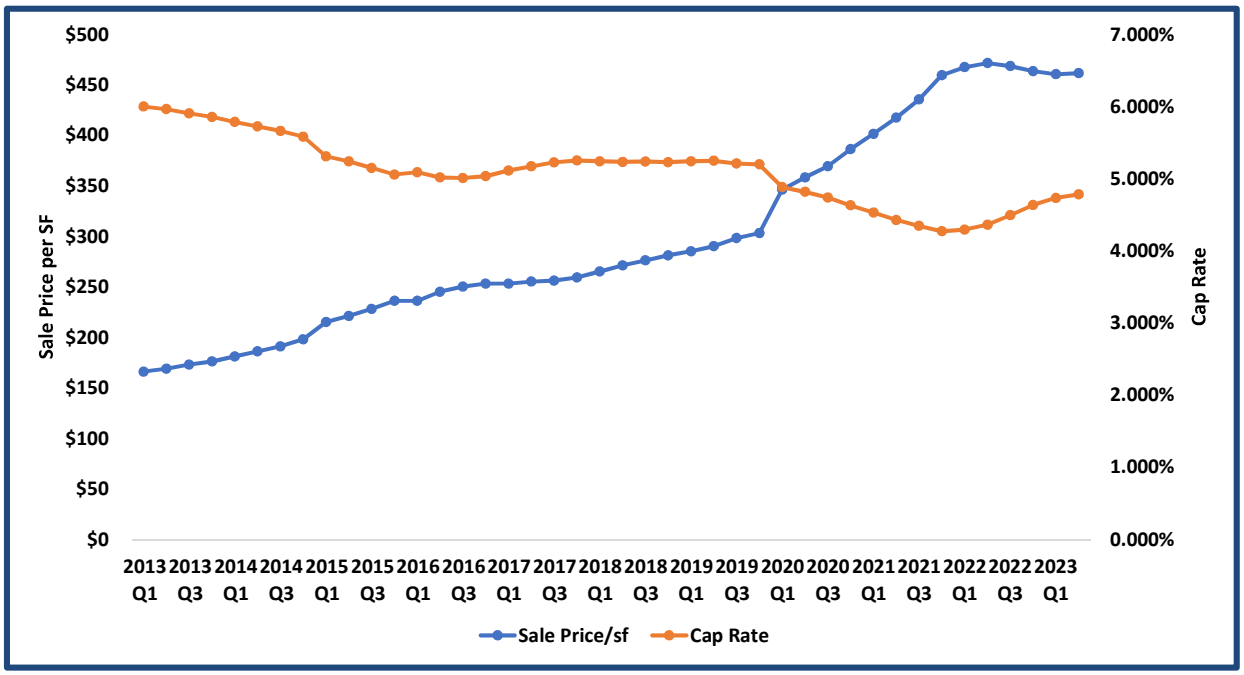
Industrial Capitalization Rates

Investment demand for San Francisco's limited supply of industrial properties (all types) intensified in the record-breaking expansion period following the Great Recession – even setting records for sales volume. Sales volume was robust as of the valuation date. Particularly of interest to investors were

well-leased industrial building assets and biotech facilities. And with the cost of capital dropping to (then) historic lows, new investors were entering the market.

Capitalization rates had been decreasing prior to the coronavirus pandemic and began to climb after the brief COVID-recession in 2020. As of Q2-2021, the average market capitalization rate was at 5.83%. The average price for an industrial building was ±$417 per square foot, according to Costar Analytics data. Logistics properties were trading at a market average of ±$350 per square foot, and flex buildings were selling at ±$510 per square foot, on average.

SAN FRANCISCO INDUSTRIAL MARKET CAPITALIZATION RATES AND SALES PRICE PER SF



Source: Costar, Inc.

Industrial Land Market

Comparable land sales included later and applied in the fee simple and easement valuation analyses range from $185 to $425 per square foot for industrial land.

San Francisco Office Market

The San Francisco office market sustained extensive losses during the COVID-19 pandemic. Beyond business closures and lost jobs, the transition to remote working fostered during the quarantine period significantly impacted the area's tech-heavy office demand.

Tech firms in the area, including Salesforce and Twitter, as of the valuation date, were offering employees long-term mobile work options. Indeed, a contemporaneous Bay Area Council survey of tech firm CEOs revealed that one fifth (or 20%) of the companies surveyed (i.e., Twitter and Square, Dropbox, Coinbase, Slack) were in favor of full remote work policies, and at least 89% of the surveyed tech firms were planning to offer hybrid work options.

The high technology market segment had previously driven demand for office space in San Francisco to new heights following the "Great Recession." The pandemic, however, challenged the necessity of

in-office work, and vacancy levels spiked to levels last seen in the aftermath of the "dot com" crash. In addition, co-workspace that had been prevalent pre-COVID was in the process of being eliminated by their operators as the need for social distancing wiped out their operational viability.

Cost-sensitive tenants began leaving the area during the expansionary cycle preceding the COVID-19 pandemic and began seeking space in more affordable submarkets, such as the downtown Oakland submarket in the nearby East Bay market area. Rent growth had begun to slow in 2019 – perhaps in anticipation of a future slowdown and/or apprehension of the upcoming election year – and began to decline in the aftermath of the pandemic. Year-over-year rental growth declined between 10.3% to 13.3% between the Second Quarter of 2020 and the Second Quarter of 2021.

With landlords adjusting to weaker tenant demand and increasing sublease space availability, asking rents declined precipitously during the pandemic and continued to tick lower as of the valuation date. Opportunity was ripe for tenants seeking to re-enter the market and competing for discounted space leases in premium buildings.

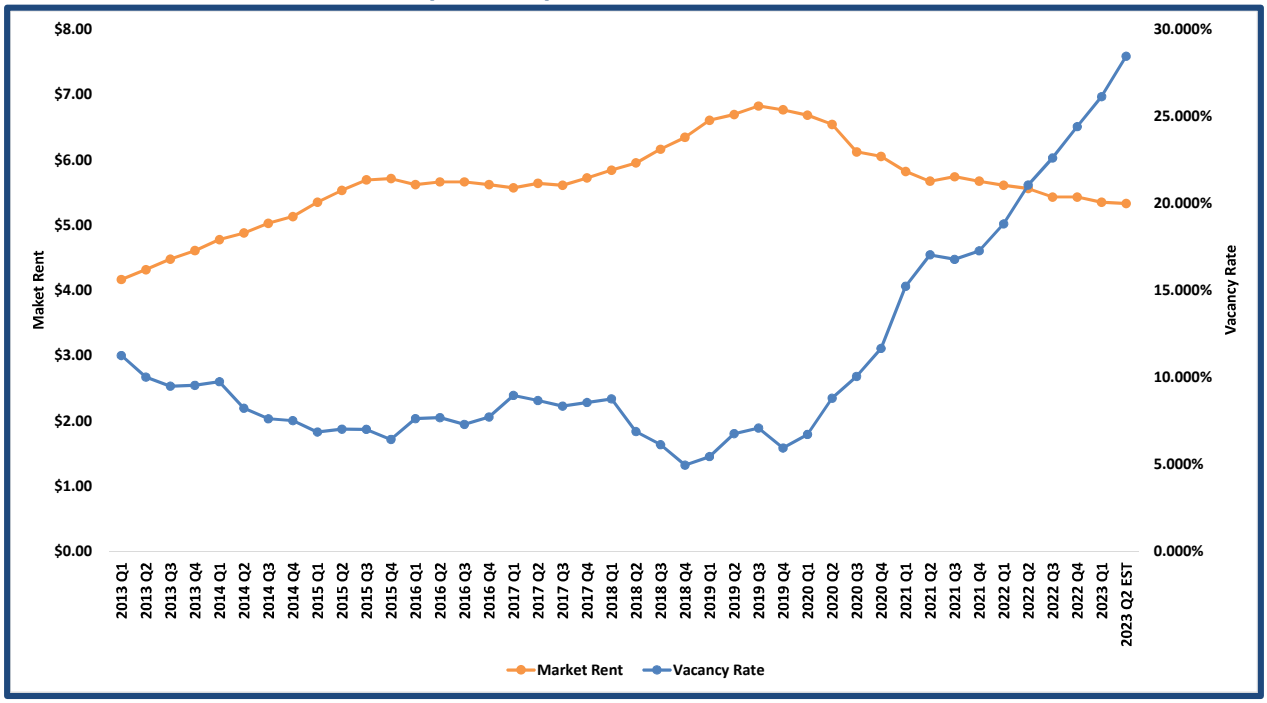
Office Vacancy and Rental Rates

Office fundamentals in San Francisco had deteriorated in response to the pandemic-related shutdown of nonessential office use in the city and to the increase in remote office work that it fostered. Some tenants began delaying lease commitments, while others began shedding space while seeking cheaper locales or adopting long-term remote work policies. It was reported by several commercial brokerage firms that leasing activity had greatly decreased from historical averages.

According to market analytics data collected and published by Costar, Inc., vacancies for Class A office space in the city began to hit double digits in the Third Quarter of 2020. As of the valuation date, near the Second Quarter of 2021, the citywide vacancy rate for Class A office space was 17.016%; by comparison, one year prior, the vacancy rate was 8.80%.

As stated, in the expansionary cycle following the Great Recession, rent growth in San Francisco was extremely strong, with year-over-year gains exceeding 10%. However, with vacancy rates reversing its course and rising sharply throughout 2020 and into 2021, and with increasing amounts of discounted sublease space flooding the market, landlords began lowering asking rents for available office spaces. As of the Second Quarter 2021, the average asking rental rate for Class A office space in the city was at $67.92 per square foot, per year (or $5.66 per square foot, monthly).

SAN FRANCISCO OFFICE (CLASS A) MARKET RENTAL RATE AND VACANCY RATE

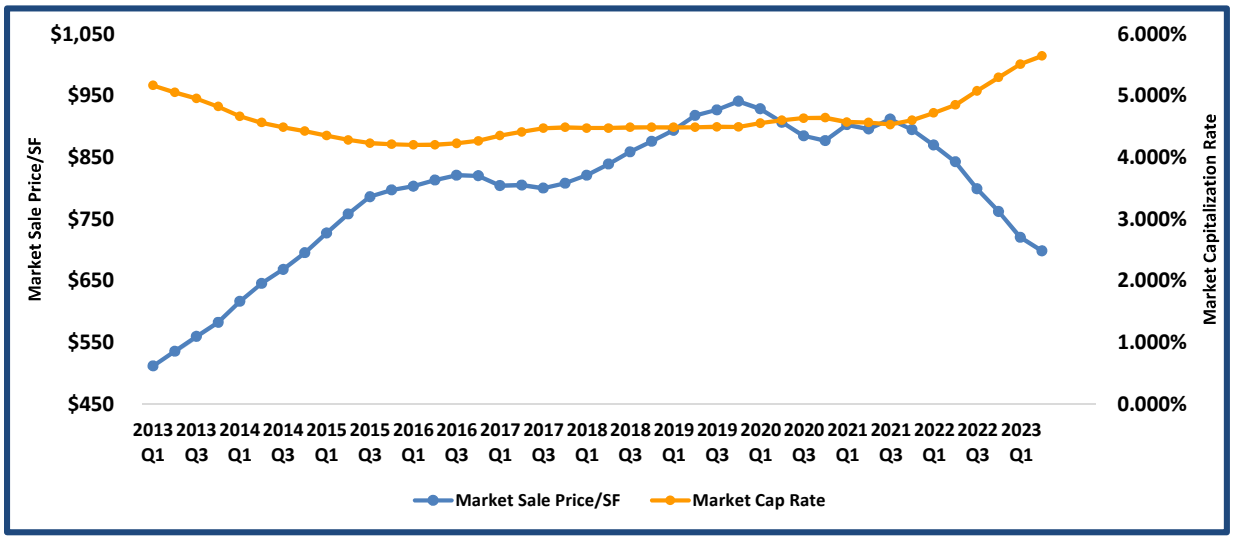


Source: Costar, Inc.

Office Capitalization Rates

Office properties in San Francisco were acquired at escalating prices throughout the 2010's expansion cycle, but with the coronavirus pandemic slowing tenant demand and sending asking rental rates lower as of the valuation date, transaction activity had slowed, and deals had closed at a discount from pre-COVID pricing guidance. Capitalization rates, which had been on a declining trend during the first few years into the post-Great Recession recovery period, stabilized through 2018 and into 2019 – and even into 2020 through mid-to-late 2021.

SAN FRANCISCO CLASS A OFFICE SALES PRICE PER SF AND CAPITALIZATION RATES



Commercial Land Market

Comparable land sales included later and applied in the fee simple and easement valuation analyses range from $1,175 to $6,350 per square foot for high-density, high-rise CBD (Central Business District) located and zoned commercial lands in the Mid-Market, SoMa, and North Financial Districts.

San Francisco Multi-Family Residential Market

Many renters abandoned San Francisco during the onset of the coronavirus pandemic. Job losses were devastating and without access to the restaurants, nightlife, shops, museums, and parks that created the city's desirable work-live-play environment, its higher cost of living was not as attractive to some. Most residents who left relocated short distances, to cheaper, less dense, suburban towns within the Bay Area, and often only on a temporary basis.

Vacancy rates, which began climbing in 2019, spiked throughout 2020 and then declined throughout 2021. Asking rents also reclaimed lost ground during the first half of 2021. As of the valuation date in July 2021, the asking rental rate had not yet recovered to pre-pandemic levels.

Housing affordability has long been a growing concern among San Franciscan renters, and as of 2021, the city continued to rank among the most expensive markets in the nation – despite the substantial drop in asking rents in 2020. According to Zumper, the average asking rents for one-, two-, and three-bedroom apartment units in July 2021 were $2,750, $3,795, and $4,500 per month, respectively.

As of the valuation date, near the Second Quarter 2021, asset values began to swing upward in tandem with the rent growth potential. Capitalization rates were also inching down from a slight rise during 2020.

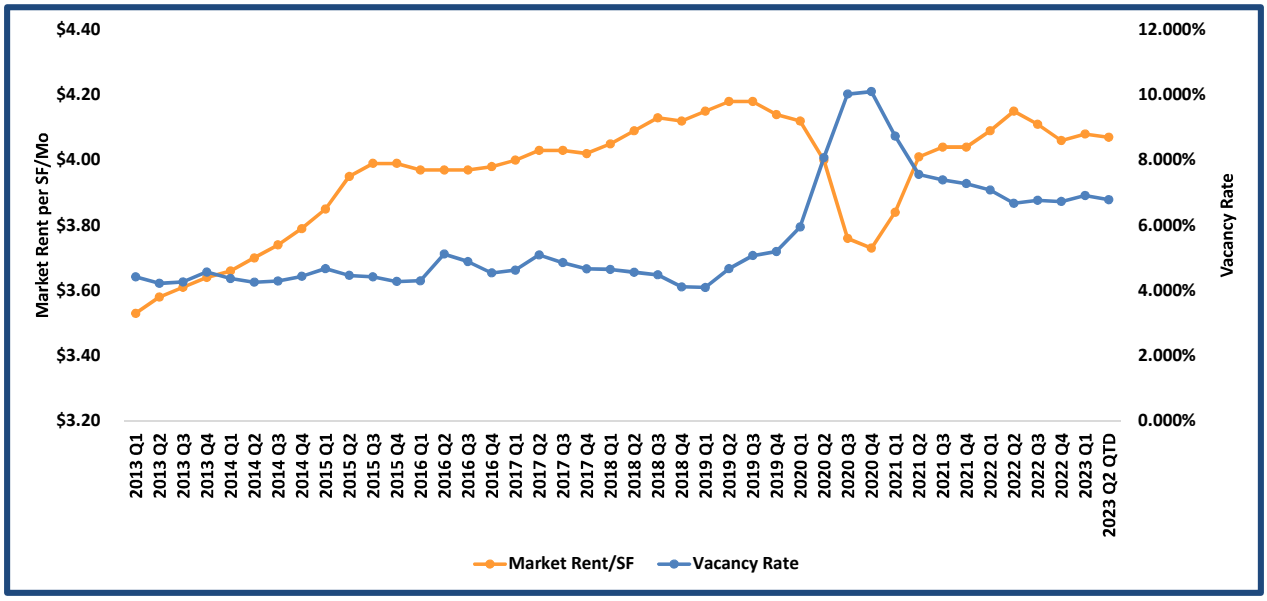
Multi-Family Vacancy and Rental Rates

Apartment vacancy in San Francisco spiked during the onset of the COVID-19 pandemic, nearly doubling in 2020 to a peak of 10.10% in the fourth quarter of the year, as renters faced job losses and fled expensive apartments in the city. The market found a bottom toward the end of 2020 though, and positive demand returned abundantly in 2021. As of the Second Quarter 2021, the vacancy rate was at 7.56%, per Costar's marketplace analytic data.

Likewise, apartment rents began an upward trajectory on the valuation date, as workers and students rushed back to the city and newcomers moved in for the first time. Roughly 60% of 2020's downfall was recovered in the first half of 2021, but the rise towards pre-pandemic rent levels was upended due to a spread of the delta variant of COVID-19 virus. Rents rebounded strongest in the hard-hit urban SoMa and the Marina-Pacific Heights-Presidio submarkets. According to Costar's market analytic data, the average unit rental rate was at $2,850 per month, or about $4.00 per square foot.

As stated, housing affordability is partially responsible for the occupancy losses during the pandemic. During the expansion period following the Great Recession, rents greatly rose, leading San Francisco to become the most expensive metro in the country for renters – even surpassing New York City in 2012. Rent levels contemporaneous with the valuation date commanded between 25% to 30% of San Francisco's median household income; at the market's peak, it was estimated that the apartment rents comprised nearly 40% to 50% of the median household income.

SAN FRANCISCO MULTI-FAMILY MARKET RENTS AND VACANCY RATES



Source: CoStar, Inc.

Multi-Family Construction

A construction boom hit the city during the last economic expansion cycle. Because of the multi-year timeline needed to erect large apartment complexes, deliveries remained elevated throughout 2021. Geographically, development is (and was) concentrated in the city's southern submarkets, including SoMa, Mission Bay, China Basin, and Potrero Hill. These areas have been favored by residents because of the easier access to freeways and to Caltrain. The development cycle previously peaked in 2016 and 2017, and about 2,600 market rate units were delivered in 2020, amid the pandemic. About 2,800 units were delivered in 2021. As of the valuation date, development feasibility had taken a hit as construction costs increased; about 4,300 units were under construction as of the Second Quarter 2021.

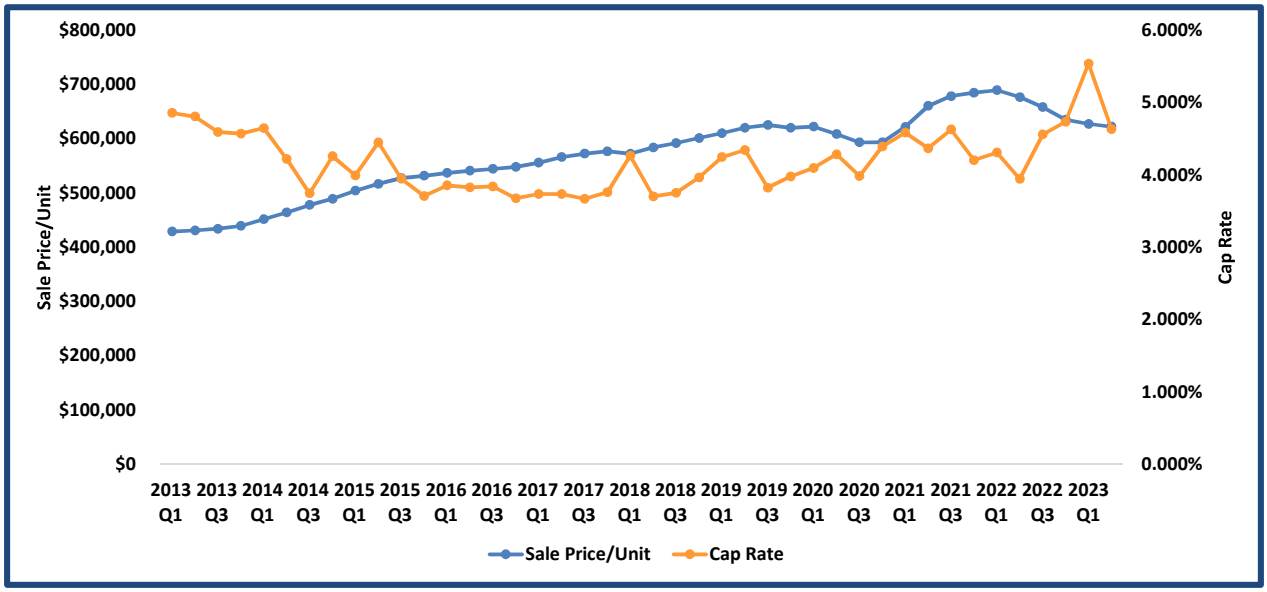
Multi-Family Capitalization Rates

Investors have historically been attracted to San Francisco's sound fundamentals and rent growth prospects. The city has attracted institutional and foreign investment. Fallout from the coronavirus pandemic gave lenders and buyers pause as sales activity slowed by roughly two-thirds from 2019's pace. Over the decade preceding the valuation date, competition among investors drove asset pricing higher and led to capitalization rate compression.

Capitalization rates inched slightly higher during the pandemic, but their compression over the decade, in addition to rapid rent growth, had led to higher asset sale prices. San Francisco's average market price, which is based on the estimated value of all properties in the market, informed by actual transactions that have occurred, increased from a low of roughly $240,000/unit in 2009 to a high of $650,000/unit in 2019.

After faltering in 2020, average pricing is climbing back toward its high-water mark; as of the Second Quarter 2021, the average sale price was approximately $661,000 per unit, according to Costar analytic data.

SAN FRANCISCO MULTI-FAMILY CAPITALIZATION RATES AND SALE PRICE/UNIT



Source: CoStar, Inc.

Historically, apartment properties have remained a preferred investment over other commercial real estate because of their favorably perceived risk/return position. As of the valuation date, because of investor demand and a spike in rental rates (despite the brief COVID-related downturn), capitalization rates have (and had) been on a decreasing trend.

High-Density, High-Rise Residential Land Market

Comparable land sales included later and applied in the fee simple and easement valuation analyses range from $1,175 to $6,350 per square foot for high-density, high-rise CBD (Central Business District) located and zoned residential lands in the Mid-Market, SoMa, and North Financial Districts.

San Francisco Residential Market

Residential land values are directly tied to the supply and demand of current housing products. Land values vary depending on location, size, permitted use, and density. The for-sale residential market has (and had) been on an upward swing since the market recovery following the Great Recession.

The following graph for the S&P/Case-Shiller San Francisco Home Price Index depicts the increasing trend in housing prices through the Great Recession, the economic recovery period, the brief COVID-recession period, and the post-COVID recovery period (as of the valuation date). The index measures the change in the value of the San Francisco MSA (which also includes San Mateo, Marin, Alameda, and Contra Costa Counties) housing market by tracking the purchase prices of single-family homes. Prices paid for detached single-family residential (SFR) housing were on an upward trajectory as of the valuation date.

While the for-rent residential market experienced a decline during the COVID-era, the market segment for detached housing continued its upward trajectory. A study by the Federal Reserve Bank of San Francisco found that remote working was a major contributor for the increase in demand for Bay Area detached single-family residences.

S&P/CASE-SHILLER SAN FRANCISCO HOME PRICE INDEX

Note*: Shaded areas denote recessionary periods.*

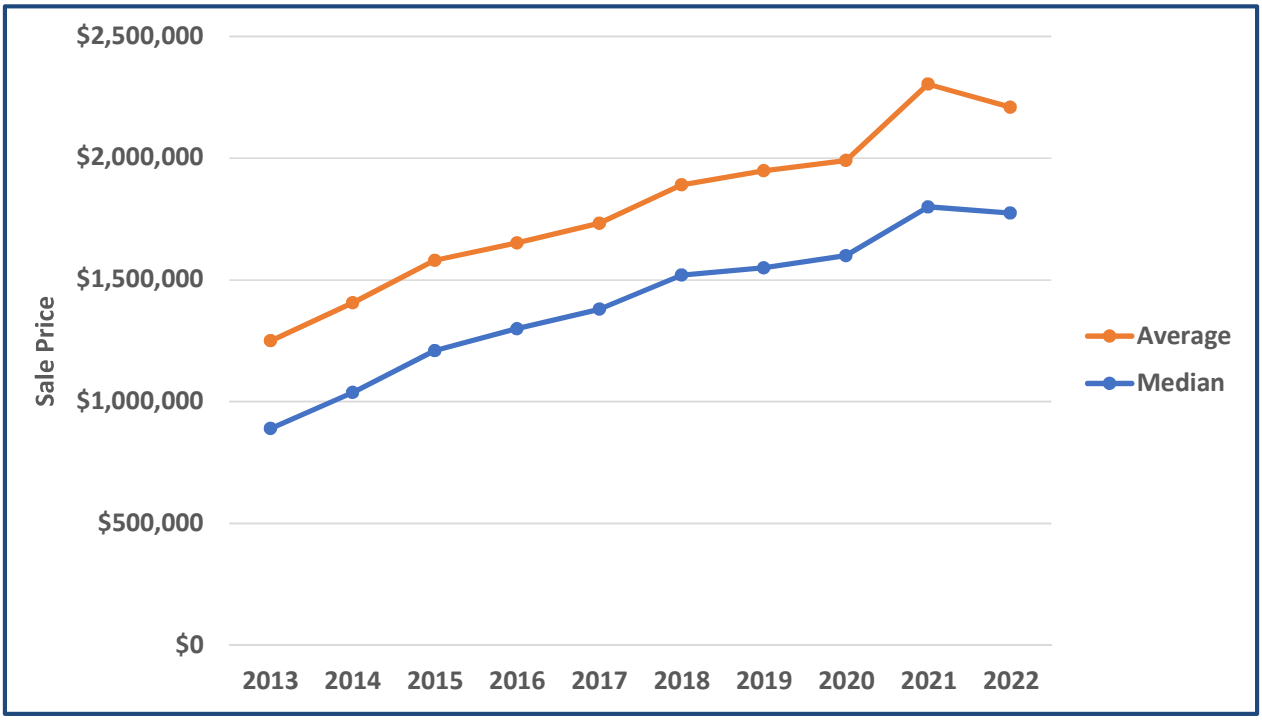
Interest rates were also at an all-time low as of the valuation date. This spurred additional demand for detached housing. The first half of 2021 marked a high-volume period for residential home sales. The upward trend in home prices also placed upward pressure on land values.

A survey of San Francisco area home sales was made on the local Multiple Listing Service (MLS). The average and median prices paid for a detached residence at the end of 2021 were $2,304,380 and $1,800,000, respectively. Home prices generally increased at an overall 8% per year; this includes the post-COVID spike in sales. As depicted on the following graph, 2021 (year) marked a high point for home sale prices. Following multiple interest rates increases throughout 2022 and into 2023, the for sale residential market began to show signs of softening, with increased listing periods and lower sale-to-list price ratios.

SAN FRANCISCO DETACHED RESIDENTIAL MARKET TRENDS

Year	Average	% Change	Median	% Change
2013	$1,250,423	-----	$890,000	
2014	$1,406,439	12.48%	$1,038,000	16.63%
2015	$1,580,711	12.39%	$1,210,000	16.57%
2016	$1,652,577	4.55%	$1,300,000	7.44%
2017	$1,732,845	4.86%	$1,380,000	6.15%
2018	$1,890,423	9.09%	$1,520,000	10.14%
2019	$1,948,597	3.08%	$1,550,000	1.97%
2020	$1,990,602	2.16%	$1,600,000	3.23%
2021	$2,304,380	15.76%	$1,800,000	12.50%
		8.05%		**9.33%**

SAN FRANCISCO DETACHED HOME SALE PRICES (2013-2022)



Pricing trends for attached housing sales in San Francisco generally mirrored their detached housing sales counterpart – apart from the 2021 post-COVID boom. The market was on an upward trajectory through the recovery period following the Great Recession and through the brief COVID-era recession and post-COVID periods. This is evident based on both an analysis of price trends on MLS and a review of the following Case-Shiller Condo Price Index for San Francisco chart.

S&P/CASE SHILLER CONDO PRICE INDEX FOR SAN FRANCISCO

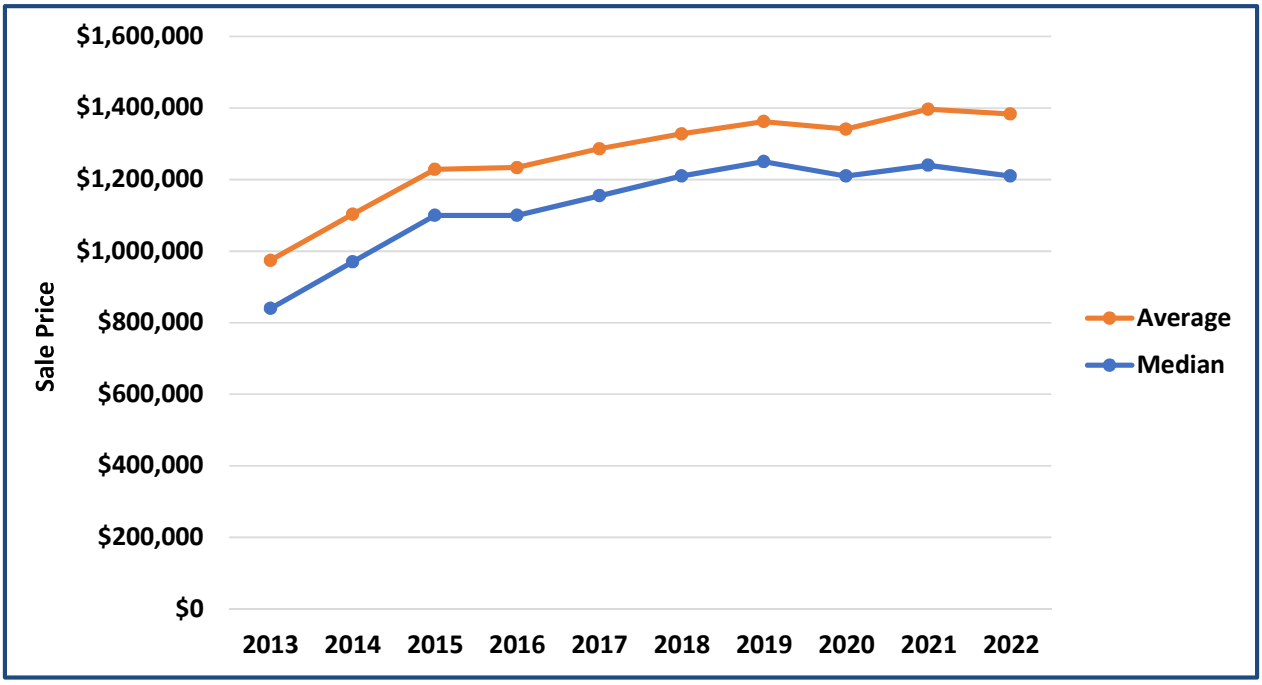
Note*: Shaded areas denote recessionary periods.*

According to an MLS survey of closed sale transactions, average and median prices paid for an attached residence at the end of 2021 were $1,396,844 and $1,240,000, respectively. Attached home sale prices generally increased at an overall 5% per year. Reference is made to the following table and graph.

SAN FRANCISCO ATTACHED RESIDENTIAL MARKET TRENDS

Year	Average	% Change	Median	% Change
2013	$974,435	-----	$840,000	
2014	$1,103,657	13.26%	$970,000	15.48%
2015	$1,228,688	11.33%	$1,100,000	13.40%
2016	$1,233,619	0.40%	$1,100,000	0.00%
2017	$1,286,137	4.26%	$1,155,000	5.00%
2018	$1,327,847	3.24%	$1,210,000	4.76%
2019	$1,362,459	2.61%	$1,250,000	3.31%
2020	$1,341,158	-1.56%	$1,210,000	-3.20%
2021	$1,396,844	4.15%	$1,240,000	2.48%
		4.71%		**5.15%**

SAN FRANCISCO ATTACHED HOME SALE PRICES (2013-2022)



Neighborhood Residential and Mixed-Use Land Market

Comparable land sales included later and applied in the fee simple and easement valuation analyses range from $125 to $1,100 per square foot for neighborhood residential zoned lands (typically R-1 through R-3 districts), and from $400 to $900 per square foot for mixed-use commercial-residential zoned lands.

San Francisco Retail Market

San Francisco is characterized by general retail along popular urban streets or areas, such as Chestnut Street, in the Marina District; Valencia Street in the Mission District; and Hayes Street, in Hayes Valley.

The main retail destination in the city is Union Square. The regional retail market faced the same set of challenges that plagued the sector nationwide. In addition to forced and voluntary store closures during COVID lockdowns, retailers struggled with slower foot traffic, declining consumer sentiment, and a weak return to the area by both office workers and tourists.

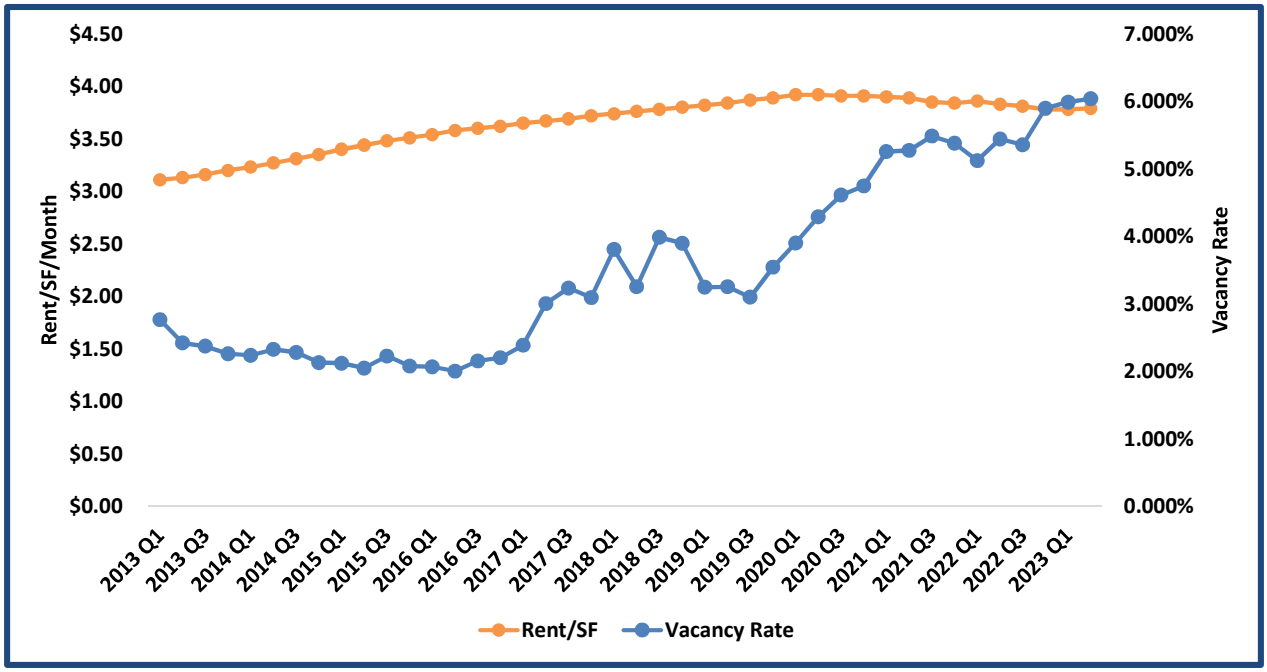
Traditional "brick and mortar" retailers were already weathering a slew of headwinds over the past several years, especially with a surge in online shopping. The temporary closing of shopping malls, indoor shopping, and entertainment venues during the pandemic-era added more uncertainty for landlords, tenants, investors, and lenders alike. Store closings had amplified during the lockdowns, particularly among smaller retailers short on cash reserves.

Retail demand, as of the valuation date, was generated by experimental retail stores, small-footprint fitness centers (i.e., Orangetheory), an expansion of "clicks-to-bricks" retailers like Amazon Go, and omnichannel supermarkets (i.e., Whole Foods). Upscale bistros and electronically enabled lunch eateries with a focus on local, fresh ingredients were also opening as newcomers took their shot at success in the country's densest city for restaurants.

Retail Vacancy and Rental Rates

In the Second Quarter of 2021, the overall retail vacancy rate in San Francisco rose to 5.3%, according to Costar's market analytic data. The increase in vacancies in the Second Quarter was attributed to supply growth following ±200,000 square feet of new retail space available for lease. According to our prior conversations with market participants, contemporaneous to the valuation date, vacancies of retail spaces were prevalent throughout the city during 2021. Absorption began to turn around during the Second Quarter of 2021 after six quarters in the red. Activity was dominated by the reopening of stores and eateries which were closed during the lockdown efforts to curb the spread of the COVID-19 virus.

SAN FRANCISCO RETAIL MARKET RENTAL RATE AND VACANCY RATE



Source: CoStar, Inc.

Rent growth in San Francisco's retail market decelerated from 2015 through 2019 as tenant demand weakened. As of the valuation date, landlords were tested by an environment where retail sales had dropped, and leasing activity had plunged. Also, adding to the downward pressure on retail space rents were social distancing requirements. The overall market rent at the end of the Second Quarter 2021 was $46.68 per square foot, on an annual basis, or $3.89 per square foot, per month.

Neighborhood Commercial Land Market

Comparable land sales included later and applied in the fee simple and easement valuation analyses range from $325 to $1,200 per square foot for neighborhood commercial zoned land.

Conclusion

The City and County of San Francisco is (and has been) considered a desirable place to live and to work. It was (and is) a worldwide leader in technology and a regional employment center, with a diversified economy. While many cited traffic congestions as a major problem, San Francisco residents were among the most affluent in the country.

Prior to the COVID-recession in 2020, the real estate market in general was several years into positive trends after a period of deep recession.

The outlook for the second half of 2021 was clouded by unknowns associated with COVID-19; however, many market participants were becoming optimistic because of vaccination rollouts. Their expectation was for a market recovery as early as late 2021 or early 2022, as more restrictive regional efforts to minimize the effects of the pandemic were lifted. The historic reasons for growth in the region remained the same. The expectation was for “normal” economic growth to resume over time.

Property Description – 33 Fee-Owned PG&E Sites

This section provides descriptions of each of the PG&E fee-owned properties appraised in this report, namely, 33 individual substation sites and/or vacant land parcels. These properties, together with the easement properties described in the next subsection, comprise the integrated electrical grid within San Francisco. The 33-count number includes one property, the "Martin Substation," located outside of San Francisco, in San Mateo County.

Each of the 33 "fee-owned" properties were previously listed on a summary table included on Page 10, in the "Executive Summary" section of this appraisal report. For the reader's convenience, the same summary table is reproduced on Page 54. The table is then followed by individual property descriptions for each of the 33 fee-owned sites.

How to Read the Property Descriptions That Follow

Each property description is organized into two parts, as applicable: a Site Description and an Improvements Description. (Note: Two of the 33 parcels are vacant and unimproved.) Together, these sections present the factual, analytical, and conclusory information relevant to each property's appraisal and valuation. The following is a brief overview of the categories the reader will see and, where helpful, an explanation of the terminology used.

Site Description

Location and Access identify the property's street address, neighborhood or planning area, and Assessor's Parcel Number(s) (APNs).

Gross Land Area and Shape state the total site size (in square feet and in acres) and describe the parcel's geometric configuration (e.g., rectangular, irregular).

Topography, Grade, and Drainage describe the physical character of the land, whether it is level or sloped, at street grade or above/below it, and whether surface water drains adequately.

Utilities and Off-Site/Site Improvements note the availability of municipal services (water, sewer, electricity, gas, and telecommunications) and describe physical improvements to the site and its street frontages (sidewalks, curbing, fencing, paving, etc.).

Flood Zone identifies the property's designation under the Federal Emergency Management Agency (FEMA) National Flood Insurance Program maps, which classify properties by their relative risk of flooding. "Zone X" indicates a minimal flood hazard area.

Earthquake Fault Zone (Alquist-Priolo) indicates whether the property falls within an Alquist-Priolo Earthquake Fault Zone, as designated by the California State Geologist under the Alquist-Priolo Earthquake Fault Zone Act.

Properties within these zones are subject to special study requirements and development restrictions due to their proximity to active fault traces capable of surface rupture. Even where a property is not within a designated Alquist-Priolo zone, general seismic hazard - as is typical throughout the San

Francisco Bay Area - is noted. Liquefaction potential (the risk that saturated soils may lose strength and behave like a liquid during an earthquake) is also identified where applicable.

Maher Ordinance Area identifies whether the property falls within the geographic boundary of the Maher Ordinance (San Francisco Health Code Article 22A). Enacted in 1986, the Maher Ordinance was established to address the legacy of "*made land*," areas of San Francisco that were historically filled with foreign material, including debris, rubble, and other matter, much of it following the 1906 earthquake and fire.

Because this fill-material may contain soil and/or groundwater contamination, any development activity within the Maher Ordinance Area requires a preliminary site assessment prior to obtaining a building permit. A property identified as being "In" the Maher Ordinance Area is subject to these requirements; one identified as "Out" is not.

Environmental Issues summarize known or potential environmental conditions affecting the property, including the existence of contamination, active or completed remediation, land use covenants or restrictions, and the identity of any lead oversight agency. Where no contamination is known and the property is appraised as clean, this is noted as an extraordinary assumption, meaning the appraisal proceeds on that basis, but the conclusion of value could be affected if the assumption proves incorrect.

Planning Area, Zoning, and Height & Bulk identifies the property's location within one of San Francisco's defined Planning Areas and states its assigned zoning district and Height and Bulk District under the San Francisco Planning Code. These designations govern permitted land uses and maximum building heights and densities and are directly relevant to the highest and best use analysis.

Improvements Description

Number of Buildings and Stories identifies how many structures exist on the site and their general vertical configuration, including the presence of basements, mezzanine levels, or multiple floors.

Construction Class is derived from the Marshall Valuation Service (MVS), an industry-standard cost reference used by appraisers and cost estimators. Construction classes range from Class A (fire-resistive, highest quality) to Class D (wood frame, lowest quality), with Class S (steel frame) and other designations also used. The class reflects the structural system and the fire-resistance of the primary building components and is a key input in cost-approach valuation.

Construction Quality describes the overall quality of materials and workmanship, rated on a scale from "poor" to "excellent." Quality is assessed relative to the intended use and typical construction standards for the building type.

Gross Building Area (GBA) is the total enclosed floor area of a building, measured from the exterior walls, including all levels. It is distinguished from rentable or usable area in that it includes all interior spaces regardless of function.

Floor Area Ratio (FAR) is the ratio of total building floor area to the total land area of the site. It is a standard planning and appraisal metric used to measure the intensity of development. For example, a

10,000-square-foot building on a 10,000-square-foot site has an FAR of 1.0 (e.g., 10,000 SF building ÷ 10,000 SF site).

Year Built, Actual Age, and Effective Age distinguish between the chronological age of a building and its functional or market-perceived age.

- *Actual (or chronological) age* is the number of years since original construction.
- *Effective age* reflects the condition, utility, and modernization of the building relative to a new structure, a well-maintained or recently renovated building may have an effective age significantly less than its chronological age, while a poorly maintained one may appear older than it is. Effective age is the age used in estimating depreciation.

Typical Building Life and Remaining Economic Life are estimates derived from the Marshall Valuation Service's Remaining Life Tables (Section 97).

- *Typical building life* is the expected total useful life of a building of a given construction class and use.
- *Remaining economic life* is the estimated number of years the building will continue to contribute positively to the value of the property, calculated by subtracting effective age from typical building life (the Economic Age-Life Method). This is a market-based approach to estimating physical depreciation; when remaining economic life reaches zero, the improvements are generally considered to have no further contributory value to the land.

Historical Designation notes whether any building is listed on, eligible for, or excluded from the National Register of Historic Places, the California Register of Historical Resources, or the City and County of San Francisco's local landmark or cultural resource inventories. A historical designation can affect permitted alterations, redevelopment potential, and value.

Foundation, Frame, Exterior Walls, and Roof describe the primary structural and envelope components of each building.

Highest and Best Use presents the appraiser's conclusion regarding the most probable, legally permissible, physically possible, financially feasible, and maximally productive use of the property, evaluated both as if vacant (i.e., as unimproved land) and as improved (i.e., with the existing buildings in place).

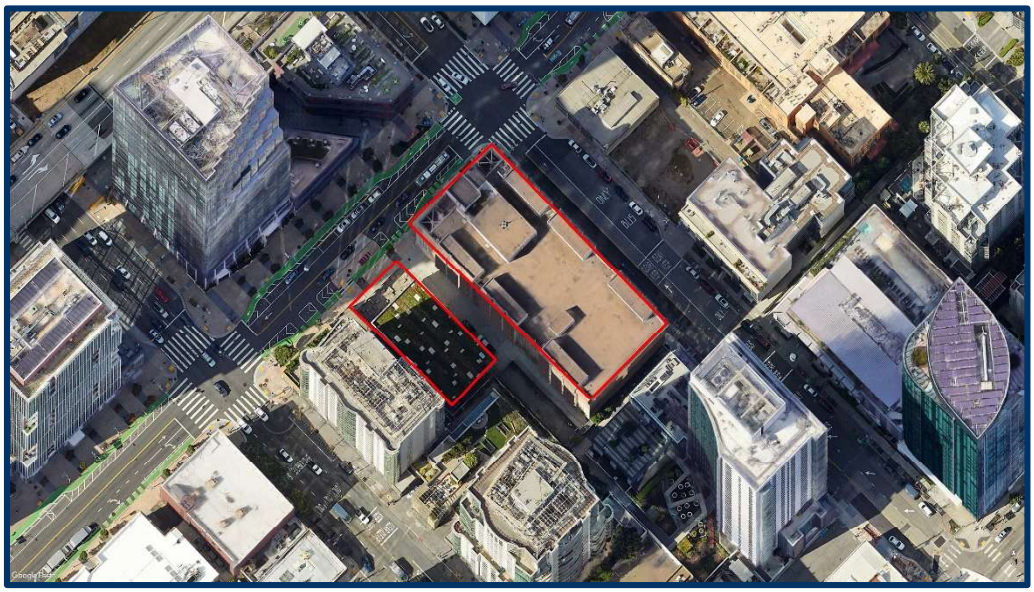
For the subject properties, the as-improved highest and best use is consistently the continued operation of each site as a component of the larger PG&E integrated electrical transmission and distribution utility corridor. That is, the improvements continue to contribute greater value to the property than demolishing the improvements to create a vacant site.

PG&E FEE OWNERSHIP PROPERTIES – SUMMARY TABLE

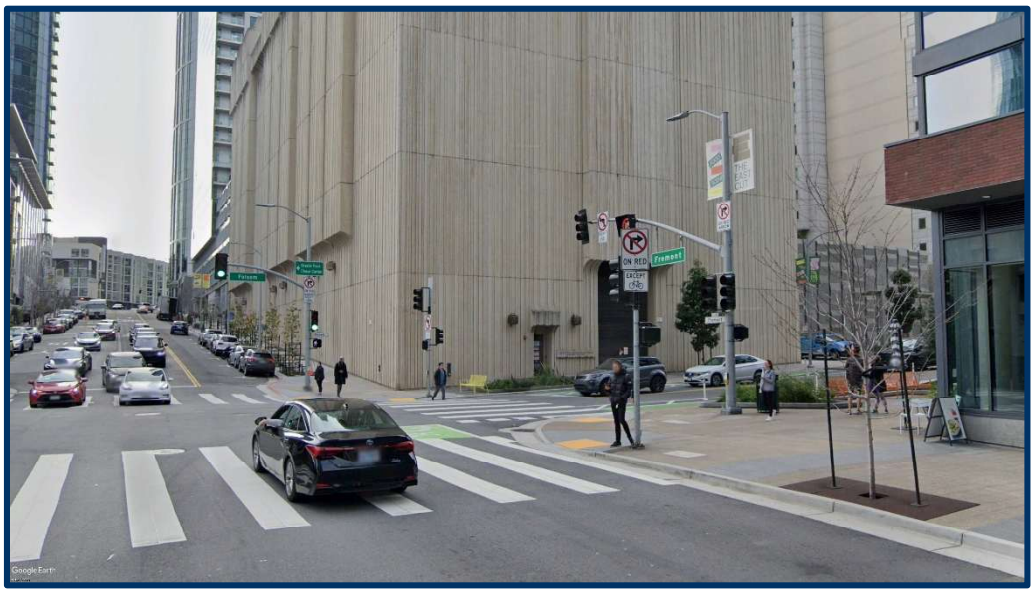
#	PG&E Property ID	Address/ Location	Assessor's Parcel #'s (APN's)	SBE Parcel No.	Site Area (SF)	Site Area (ac)	Bldg Size (SF)	Floor Area Ratio (FAR)	Zoning District	Height/Bulk District
1	Substation Z (Embarcadero)	405 & 425 Folsom Street	3748-001, -003, -004, -005 & -029	135-38-033A-1 & A-2	33,213	0.762	132,768	3.997	RH-DTR	85/200-R
2	Substation A (Portrero)	1101 Ilinois Street	4175-018 (ptn)	135-38-024D-2,-3 (ptn)	293,960	6.748	22,719	0.077	P70-MU; PPS-MU; M-2	65-PPS/240-PPS; 65-X; 40-X
3.1	Substation P (Hunter's Point)	1180 Evans Avenue	4570-024	135-38-018D-1	79,680	1.829	306	0.004	PDR-2	65-J
3.2	Substation P (Hunter's Point)	1010-1030 Evans Avenue	4604A-002	135-38-018E-1	281,659	6.466	763	0.003	M-1, M-2	40-X
3.3	Substation P (Hunter's Point)	1135 Evans Avenue	4602A-014	135-38-026A-1	85,747	1.968	314	0.004	NC-2	40-X
3.4	Substation P (Hunter's Point)	1059-1075 Evans Avenue	4603A-002, -005; 4647A-013	135-38-026A-2	325,709	7.477	----	----	NC-2, RH-1	40-X
3.5	Substation P (Hunter's Point)	5000 Hunter's Point Boulevard	4629A-012	135-38-026A-3	13,734	0.315	----	----	M-1	40-X
3.6	Substation P (Hunter's Point)	1000 Evans Avenue	4580-002	135-38-018A-2	713,687	16.384	----	----	M-2	40-X
4	Substation W (Bayshore)	151-157 Bayshore Boulevard	5559-004,-005,-006	135-38-031-1	55,930	1.284	770	0.014	PDR-2	65-J
5	Substation Y (Larkin)	538 Eddy Street	0335-037	135-38-030A-1, -2, & -3	46,875	1.076	109,180	2.329	RC-4	80-T
6	Substation X (Mission)	1250 Mission Street	3701-053	135-38-015A-2	44,617	1.024	89,100	1.997	C-3-G	150-S; 180-S
7	Substation L	2475 Ocean Avenue	6901-001	135-38-001-19	17,076	0.392	5,181	0.303	NC-1	26-X
8	Substation G	1200 Broderick Street	1101-013	135-38-002-4	15,469	0.355	23,304	1.506	RM-3	40-X
9	Substation E	205 Lexington Avenue	3596-104	135-38-003-6	13,175	0.302	16,750	1.271	RTO-M	55-X
10	Substation F (Marina)	1570 Bay Street	0459-032	135-38-001D-1	13,112	0.301	----	----	NC-2, RM-4	40-X
11	Substation K	679 24th Avenue	1567-012	135-38-002-5	12,398	0.285	10,956	0.884	RH-2	40-X
12	Substation J	530 Sacramento Street	0228-006	135-38-004-6	8,395	0.193	26,250	3.127	C-3-O	75-X
13	Substation N	1437-1449 9th Avenue	1844-053	135-38-02A-1	6,492	0.149	----	----	RH-2	40-X
14	Randolph Substation	724 Randolph Street	7084-024	135-38-019A-1	4,865	0.112	----	----	NC-1	26-X
15	Substation M	20 Rousseau Street	6747-016	135-38-005B-1	4,725	0.108	2,748	0.582	RH-2	40-X
16	Portola Substation	610 Portola Drive	2892-003	135-38-023-1	4,698	0.108	----	----	NC-1	26-X
17	Beach Substation	330 Beach Street	0013-010	135-38-018B-1	3,750	0.086	----	----	C-2	40-X
18	6th Avenue	365 6th Avenue	1438-014	135-38-015-3	3,000	0.069	----	----	NCD	40-X
19	Silver Substation	1086 Silver Avenue	5915-001	135-38-025-1	2,834	0.065	----	----	RH-1	40-X
20	Ocean Substation	1155 Ocean Avenue	6944-040	135-38-020-1	2,655	0.061	----	----	NCT	45-X
21	Yosemite Substation	1802 Yosemite Avenue	5417-007	135-38-011-1	2,500	0.057	----	----	RH-1	65-J
22	Taraval Substation	2533 Taraval Street	2390-044	135-38-010-2	2,500	0.057	----	----	NCD	40-X
23	Judah Substation	2927 Judah Street	1819-042	135-38-010-1	2,500	0.057	----	----	RH-3	40-X
24	Plymouth Substation	214 Plymouth Avenue	7112-012A	135-38-025-2	2,500	0.057	----	----	NC-1	40-X
25	Noriega Substation	3819 Noriega Street	2082-001L	135-38-013-1	2,325	0.053	----	----	NC-1	40-X
26	18th Street Substation	4430 18th Street	2650-020	135-38-008-1	2,250	0.052	----	----	RH-3	40-X
27	Acton Substation	5889 Mission Street	6472-021D	135-38-013-5	2,250	0.052	----	----	NCD	40-X
28	Castro Substation	1510-1512 Castro Street	6546-004	135-38-014-1	2,000	0.046	----	----	RH-2	40-X
29	21st Avenue Substation	1340 Noriega Street	2029-025	135-38-013-2	1,875	0.043	----	----	NCD	40-X
30	Egbert Switching Station	1755 Egbert Avenue	5431-001A	135-38-057-1 & -2	70,446	1.617	----	----	PDR-2	65-J
32	Beeman Lane	3789 San Bruno Avenue	5067-001A	135-38-018	4,721	0.108	----	----	RH-1	40-X
33	Substation I	117 8th Street	3727-135	135-38-003A-1	10,000	0.230	10,950	1.095	WMUG/MUO	65-X
		Subtotal: San Francisco County Substation and Land Properties:			**2,193,322**	**50.352**	**452,059**			
	Martin Substation									
31	Martin Substation	3150 Geneva Avenue, Brisbane, CA	005-141-999 (ptn)	135-41-28B-3 (ptn)	1,602,313	36.784	51,252		C/P-U	Not Applicable
		Subtotal: San Mateo County Substation and Land Properties:			**1,602,313**	**36.784**	**51,252**			
		Total: San Francisco County & San Mateo County Substations and Land Properties:			**3,795,635**	**87.136**	**503,311**			

PG&E Property #1: Substation Z (Embarcadero)

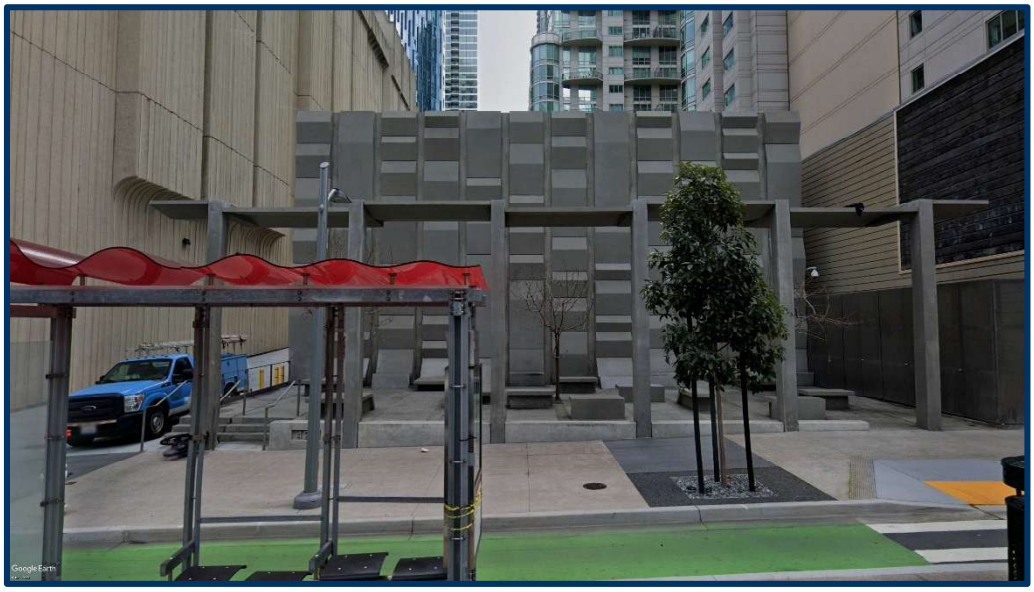
SUBJECT PROPERTY PHOTOGRAPH



Substation Z – Embarcadero (Photo Source: Google Earth)



405 Folsom Street (Photo Source: Google Earth)



425 Folsom Street (Photo Source: Google Earth)

Site Description

Location/ Access:	Substation Z is generally located at the southwest corner of Folsom Street and Fremont Street, in the Rincon Hill area of SoMa. The property is assigned to physical addresses at 405 & 425 Folsom Street and is further identified as APN's 3748-001, -003, -004, -005, and 029.
Gross Land Area:	The combined site area is 33,212.50 square feet, or 0.762 acre.
Shape:	Overall site configuration consists of two rectangular-shaped parcels, measuring 22,900 square feet and 10,312.5 square feet, respectively. The two parcels are separated by a public alley (Grote Place).
Topography:	Level
Drainage:	Adequate
Grade:	At Grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Paved yard; benches
Interior or Corner:	Double Corner
Signalized Intersection:	Traffic signals are in place along Folsom Street, at the intersection with First Street and Fremont Street.
Excess/Surplus Land:	None
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980117A
Flood Map Date	3/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	Partially within an area susceptible to earthquake-induced liquefaction.
Maher Ordinance Area	The "Maher Ordinance" (also known as San Francisco Health Code Article 22A) was established in 1986 for the purpose of identifying areas with a potential for soil and/or groundwater contamination resulting from a historic use of foreign fill material. Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco and is within the Rincon Hill Planning Area. The assigned zoning/land use designation is RH-DTR, or "Rincon Hill, Downtown Residential" district. Maximum building heights, per the property's assigned "Height and Bulk District," are 85 feet for podium buildings and 200 feet for towers.

Improvements Description

Number of Buildings:	Two buildings – at 405 Folsom Street (**Building 1.1**) and 425 Folsom Street (**Building 1.2**).
Approx. Building Height:	**Building 1.1:** 114 feet **Building 1.2:** 30 feet
Number Stories/ Floor Levels:	**Building 1.1:** Three levels, plus basement, and two mezzanine levels, and **Building 1.2:** One level, plus basement and mezzanine

Construction Class (Marshall Valuation Services):	A (both buildings)
Construction Quality:	Excellent (both buildings)
Gross Building Area (GBA):	**Building 1.1**: 119,080 square feet, and **Building 1.2:** 13,688 square feet
Floor Area Ratio:	The buildings cover the entire site. The combined FAR (both buildings) is 3.998.
Year Built:	Reported/estimated construction dates are as follows: **Building 1.1:** 1974 **Building 1.2:** 2016
Renovated:	No
Historical Designation	**Building 1.1**: While age-eligible for landmark status, it is not historically designated on the State or National Registry lists or on the citywide Cultural Resource Survey. **Building 1.2**: This is a recently completed building. It is not eligible for historical status.
Actual Age:	**Building 1.1**: 47 years **Building 1.2:** 6 years
Effective Age:	**Building 1.1**: 45 years **Building 1.2:** 5 years
Typical Building Life:	70 years (both buildings)
Remaining Economic Life:	**Building 1.1:** 25 years[37] **Building 1.2**: 65 years
Foundation	Concrete

[37] *Marshall & Swift Valuation Service (MSVS),* CoreLogic, June 2021 Publication, Section 97, "Remaining Life Tables." Remaining economic life of building and/or site improvements throughout this appraisal report is taken from the Remaining Life Tables found in Section 97 of the June 2021 MSVS publication. Remaining economic life is calculated on the basis of the Economic Age-Life Method, a market- based method for estimating physical depreciation and remaining economic life.

Building Frame	Concrete/Steel
Exterior Walls	Concrete/Steel
Roof Material	**Building 1.1**: Composite; **Building 1.2**: Agri-Turf
Electrical/ Plumbing	Adequate
Heating/ Cooling	None
Fire Sprinklers/ Protection	Yes – Fire Sprinklers
Elevators	An elevator provides vertical circulation at the 405 and 425 Folsom Street buildings (i.e., Building 1.1 and 1.2). Both buildings are built out with staircases.
Comments:	The buildings are in good to excellent condition for their age. Their exteriors consist of decorative concrete panels. The building at 405 Folsom Street (1.1) is equipped with an elevator and an overhead crane. There is also a single roll-up metal door at the north elevation. The second of the two buildings, at 425 Folsom Street (1.2), is built out with a control room, storage area, and a restroom at the mezzanine level and houses GIS equipment. The building is also equipped with an overhead crane and high-capacity freight elevator.

Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #2: Substation A (Potrero)

SUBJECT PROPERTY PHOTOGRAPH

Substation A - Potrero (Photo Source: Google Earth)

Potrero Substation, Building 2.1 (Photo Source: Google Earth)

Potrero Substation, Building 2.2 (Photo Source: Google Earth)

Site Description

Location/ Access: Substation A ("Potrero") is located on the east side of Illinois Street between 22nd and 23rd Streets in the Central Waterfront/Dogpatch neighborhood. The property is assigned to a physical address at 1101 Illinois Street and is further identified as APN 4175-018.

Gross Land Area: The total site size is 382,021 square feet, and of this, 293,960 square feet (or 6.748 acres) consists of the electrical substation portion – which is the part proposed to be acquired by CCSF.

The site is encumbered by an underground PG&E gas transmission pipeline. Based on information provided to us by CCSF and PG&E, the proposed acquisition of the site by CCSF will require the granting of a 50-foot-wide easement in favor of PG&E. While the easement language has yet to be perfected, it is our understanding that the proposed easement area will extend 25 feet in either direction from the centerline of the pipeline and will contain 35,175 square feet. The easement area has not been surveyed, and measurements are estimated by CCSF via the use of Google Earth.

A summary table, as provided by CCSF, is reproduced below for the reader's reference. Size, dimensions, and locations are assumed. Revision to the appraisal may be warranted if actual easement deed and legal description differ from that appraised.

	Gross Length (LF)	Overlap (LF)	Net Length (LF)	Width (LF)	Total SF
No. ROW	430	(50)	380 x	35 =	13,300
E/W ROW	270	(25)	245 x	50 =	12,250
So. ROW	385	----	385 x	25 =	9,625
				Total:	**35,175**

Remainder land and improvements (including on and of the "Hoe Down Yard" at the northeast corner of 22nd Street) and/or severance damages are not appraised at this time, as requested.

Shape:	Irregular shaped
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Site improvements include perimeter fencing, walls, gates, and a paved lot.
Interior or Corner:	Corner
Excess/Surplus Land:	Remainder (not appraised)
Signalized Intersection:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980119A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	Partially within an area susceptible to earthquake-induced liquefaction.
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases revealed the existence of site contamination and remediation work.

The historical uses of the property were for a manufactured gas plant and its operations included onsite oil storage. Improvements and equipment consisted of gas holders, purifiers, lampblack separators and pits, generator houses, tar storage facilities, retort houses, and several aboveground storage tanks. A site assessment found traces of arsenic, lead, benzene, cyanide (free), petroleum, and polynuclear aromatic hydrocarbons (PAHS) within the subsurface (i.e., soil and groundwater) areas of the site.

Because of the onsite contamination, a Land Use Covenant and Environmental Restriction has been placed on the property. The covenant was made on September 15, 2011 (and recorded on January 5, 2012), and its provisions run with the land in perpetuity. Restrictions on use include that any future site development be limited to industrial or commercial land uses, and that no residences, hospitals, health care facilities, schools, day care centers (for both children and senior citizens), or agricultural activities for production of items for consumption be permitted onsite. The Covenant and Environmental Restriction is reviewed as a part of this appraisal; a copy is retained in the appraiser's work file.

The lead agency overseeing the remediation work is the State Regional Water Quality Control Board (San Francisco office). It is our understanding that PG&E (landowner) has voluntarily agreed to remediate the site. PG&E has encapsulated the contamination and is continuing to use the sites as a part of its operations. A "Certificate of Completion" was issued on February 22, 2023, by the Regional Water Quality Control Board, subsequent to the valuation date.

Planning Area /Zoning/ Height & Bulk:

The site is within the land use jurisdiction of the City and County of San Francisco and is within the Central Waterfront Planning Area. The assigned zoning/land use designation are PPS-MU, or Potrero Power Station, Mixed Use, on the north side of Humboldt Street, and M-2, or "Heavy Industrial District" on the south side of Humboldt Street.

The maximum building height for the portion of the property within the PPS-MU district, and on the north side of Humboldt Street, is 65 feet for podium buildings and 240 feet for towers. The maximum building height for the industrial zoned portion is 65 feet at the western half (at the corner of Illinois Street and 23rd Street) and 40 feet at the eastern half.

Improvements Description

Number of Buildings:	Two main buildings, including a 115KV **Building #2.1** and a 230KV GIS **Building #2.2**.
Approx. Building Height:	Both buildings are approximately 32 feet in height. **Building #2.1** has a clear height of 20 feet.
Number Stories/ Floor Levels:	Both buildings are single story. **Building 2.1** has no basement or mezzanine levels. **Building 2.2** has a lower-level basement floor.
Construction Class (Marshall Valuation Services):	**Building 2.1** – S **Building 2.2** – A
Construction Quality:	Construction quality is good and excellent for **Buildings #2.1 and #2.2,** respectively.
Gross Building Area (GBA):	**Building #2.1** contains 5,787 gross square feet of area. **Building #2.2** contains 16,932 gross square feet of area.
Floor Area Ratio:	The combined Floor Area Ratio (buildings-to-land) is 0.077.
Year Built:	Reported/estimated construction dates are as follows: **Building #2.1** was constructed in 1961. **Building #2.2** was constructed in 2016.
Renovated:	Not applicable.
Historical Designation	**Building 2.1**: While age-eligible for a landmark status, it is not historically designated on the State or National Registry lists or on the citywide Cultural Resource Survey. The Central Waterfront Third Street District, where the building is located, appears on the California Register of Historical Resources under "Criterion 1," for its association with the industrial development of the city from 1872 to 1958. **Building 2.2** is a recently constructed structure and is not eligible for historical status.
Actual Age:	**Building 2.1:** 60 years

	Building 2.2: 6 years
Effective Age:	**Building 2.1:** 35 years **Building 2.2:** 5 years
Typical Building Life:	**Building 2.1:** 50 years **Building 2.2**: 70 years
Remaining Economic Life:	**Building 2.1:** 15 years **Building 2.2:** 65 years
Foundation	Concrete
Building Frame	**Building 2.1:** Metal-frame **Building 2.2:** Concrete/Steel
Exterior Walls	**Building 2.1:** Metal walls **Building 2.2:** Concrete/steel decorative walls
Roof Material	**Building 2.1**: Steel; **Building 2.2**: Agri-Turf
Electrical/ Plumbing	Adequate
Heating/ Cooling	**Building 2.1**: No **Building 2.2:** Mechanical ventilation
Fire Sprinklers/ Protection	Yes
Elevators	None
Comments:	**Building #2.1** is metal-constructed, single-story building in average to good condition. **Building #2.2** is a steel-framed structure with decorative concrete walls and a vegetated roof area in excellent condition. The building houses GIS equipment and there is an overhead crane mounted near the ceiling of the ground floor.

Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #3: Substation P (Hunter's Point)

SUBJECT PROPERTY PHOTOGRAPH

Substation P – Hunter's Point (Photo Source: Google Earth)

Hunter's Point Substation (Photo Source: Walter D. Carney, MAI)

Site Description

Location/ Access:

Substation P is located near the intersection of Evans Avenue and Jennings Street/ Middle Point Road in the Hunters Point area. The property is assigned to the following site addresses and Assessor's Parcel Numbers. The property is broken into six components, Properties 3.1 through 3.6, using CCSF's numbering nomenclature, which is adopted here for consistency across appraisals. The preceding aerial exhibit identifies their respective locations.

	Address	APN
3.1	1180 Evans Avenue	4570-024
3.2	1010-1030 Evans Avenue	4604A-002
3.3	1135 Evans Avenue	4602A-014
3.4	1059-1075 Evans Avenue	4603A-002, -005; 4647A-013
3.5	5000 Hunter's Point Boulevard	4629A-012
3.6	1000 Evans Avenue	4580-002

Gross Land Area:

The gross land area is approximately 1,500,216 square feet (or 34.440 acres), including portions of the property consisting of intertidal lands and pond. Portions of the site are improved with segments of the San Francisco Bay Trail. The total site area, net of the intertidal lands, pond, and trail segments is 1,193,737 square feet (or 27.404 acres), as summarized in the following table.

A site survey has not been provided for review. A land survey has not been provided for review. Site area for the water acreage (i.e., intertidal lands and/or pond and lagoon) and Bay Trail segments were measured on Google Earth. A revision to the appraisal may be warranted if a site survey is prepared.

Property 3.5, the "Pit Parcel," is appraised as-if encumbered by an easement for an underground electric transmission line. Based on information provided to us by CCSF and PG&E, the proposed acquisition of the site by CCSF will require the granting of a 25-foot-wide easement in favor of PG&E. While the easement language has yet to be perfected, it is our understanding that the proposed easement area will extend 25 feet in either direction from the centerline of the transmission line and will contain 2,655 square feet.

As of the valuation date, the easement does not encumber the property.

	Gross Land Area (SF)	Portions Intertidal/ Pond (SF)	Portions SF Bay Trail (SF)	Net Land Area (SF)
3.1	76,680			76,680
3.2	281,659	19,511	4,788	257,309
3.3	85,747			85,747
3.4	325,709			325,709
3.5	13,734			13,734
3.6	713,687	255,206	23,923	434,558
	1,500,216	**274,717**	**28,762**	**1,193,737**

Shape:	Irregular
Topography:	Varies
Drainage:	Adequate
Grade:	At grade and below grade; a portion of the property consists of intertidal and submerged tidal lands, and pond.
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements	Partially paved lot; fencing
Interior or Corner:	Corner
Excess/Surplus Land:	None
Signalized Intersection:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980232A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	Partially within an area susceptible to earthquake-induced liquefaction.
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.

Environmental Issues

The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases revealed the existence of site contamination and remediation work.

The historical use of the property was for ship and barge building. The original power generation plant was constructed in the 1920's and used fuel oil. Additional steam units and multiple aboveground storage tanks were added over the ensuing decades. In 2002, PG&E removed 8 of 9 aboveground fuel storage tanks. The Plant was shut down in 2006. Environmental sampling conducted onsite indicated that the soil and groundwater was contaminated with hazardous substances, including hydrocarbons (TPH's and PAH's), metals and polychlorinated biphenyls (PCB's). Fill material used to develop the site was derived from serpentine, containing naturally occurring asbestos.

The lead agency overseeing site remediation efforts is the State Department of Toxic Substances Control. It is our understanding that PG&E has removed and encapsulated the contamination and is continuing to use the sites as a part of its operations. The cover included asphalt, clean imported gravel/rock backfill, and clean imported soils with vegetation. Site remediation was completed in 2012. In December 2018, DTSC certified completion of the remedial actions and issued Certificates of Completion. Much of the site was remediated to residential use standards; an approximate 4.18-acre portion, identified as the "Shoreline Area" was remediated to recreational use standards.

Per the Certificates of Completion, PG&E voluntarily recorded Land Use Covenants ("LUCs") on March 16, 2018. The LUCs require ongoing maintenance of the protective cover systems installed across the affected areas, implementation of DTSC-approved operation and maintenance and soil management procedures, and compliance with restrictions governing any future disturbance of soil, groundwater, or cover materials.

Future site development or redevelopment of the property is not prohibited, but intrusive work is subject to the applicable LUC and Soil Management Plan requirements, including soil handling and disposal controls, dust mitigation, protection of groundwater and stormwater features, and the restoration of the protective covering following completion of work. These requirements are intended to minimize exposure to residual contaminants, naturally occurring metals, and naturally occurring asbestos that may remain beneath the engineered covers.

Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco and is within the Bayview Hunters Point Planning Area. The assigned zoning/land use designations are M-1, or "Light Industrial," M-2, or "Heavy Industrial District," and NC-2, or "Neighborhood Commercial, Small Scale." The area of the property at the northeast corner of Evans Avenue and Jennings Street is assigned to the PDR, or "Production, Distribution, and Repair" zoning district. The maximum building height on most of the property is 40 feet. The area of the property within the PDR zoning district has a maximum allowable building height at 65 feet.
Improvements Description	
Comments:	Structural improvements include three small industrial buildings, built in 1925 (Building 3.1) and in 1965 (Buildings 3.2 and 3.3). The total combined Floor Area Ratio (buildings-to-land) is 0.001. **Building 3.1** consists of a single-story, poured-in-place concrete structure built in 1925. The building measures 306 square feet and is 12 feet high. Construction quality is good. The condition of improvements is average. The chronological age of the building is 96 years, and its effective age is estimated at 50 years. The expected life of the building is 60 years. Estimated remaining economic life is 11 years. **Building 3.2** consists of a single-story, metal-constructed structure built in 1965. The building measures 763 square feet and is 13 feet high. Construction quality is good. The condition of improvements is average. The chronological age of the building is 56 years, and its effective age is estimated at 45 years. The expected building life is 50 years. Estimated remaining economic life is seven years. **Building 3.3** consists of a single-story, metal-constructed structure built in 1965. The building measures 314 square feet and is 12 feet high. Construction quality is good. The condition of improvements is average. The chronological age of the building is 56 years, and its effective age is estimated at 45 years. The expected building life is 50 years. Estimated remaining economic life is seven years.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.

As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #4: Substation W (Bayshore)

SUBJECT PROPERTY PHOTOGRAPH

Substation W – Bayshore (Photo Source: Google Earth)

Bayshore Substation (Photo Source: Walter D. Carney, MAI)

Site Description

Location/ Access:	Substation W is located on the east side of Bayshore Boulevard in the Bayview neighborhood. The site is assigned to a physical address at 151-157 Bayshore Boulevard and is further identified as APNs 5559-004, -005, and -006.
Gross Land Area:	55,930 square feet (or 1.284 acres)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks, curbing, and security fencing around the perimeter.
Site Improvements:	Paved yard and perimeter fencing
Interior or Corner:	Interior
Excess/Surplus Land:	None
Signalized Intersection:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980232A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	Partially within an area susceptible to earthquake-induced liquefaction.
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.

Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco and is within the Bayview Hunters Point Planning Area. The assigned zoning/land use designation is PDR-2, or "PDR Production, Distribution, and Repair"; the maximum building height is 65 feet.

Improvements Description

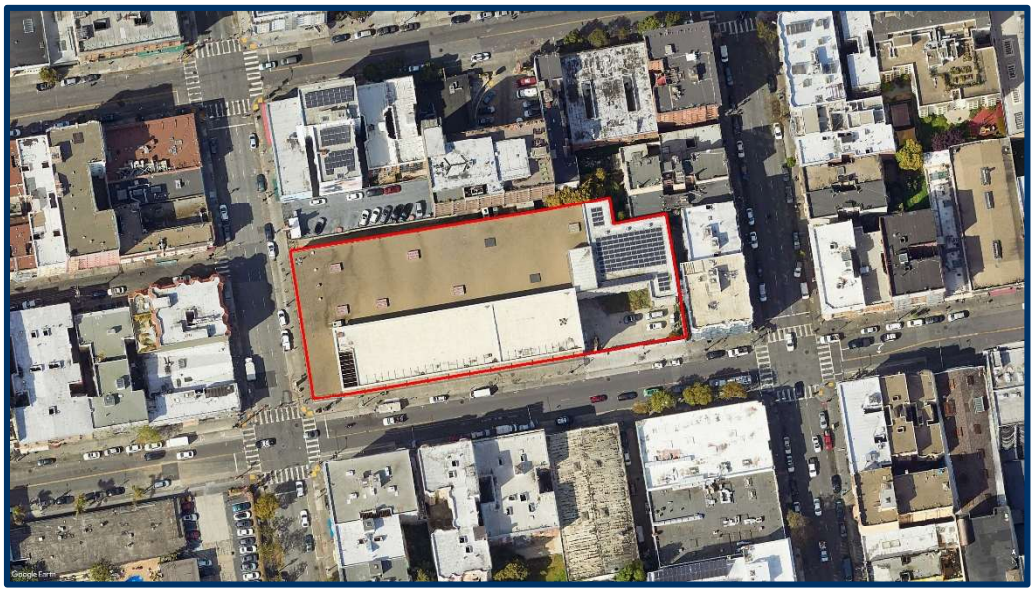
Number of Buildings:	One
Approx. Building Height:	13 feet.
Number Stories/ Floor Levels:	Single story
Construction Class (Marshall Valuation Services):	C
Construction Quality:	Average
Gross Building Area (GBA):	770 square feet
Floor Area Ratio:	The Floor Area Ratio (buildings-to-land) is 0.014.
Year Built:	1971
Renovated:	No
Historical Designation	None.
Actual Age:	50 years
Effective Age:	35 years
Typical Building Life:	45 years
Remaining Economic Life:	10 years
Foundation	Concrete
Building Frame	Concrete
Exterior Walls	Concrete Block
Roof Material	Composite
Electrical/ Plumbing	Adequate
Heating/ Cooling	None
Fire Sprinklers/ Protection	Yes
Elevators	None

Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #5: Substation Y (Larkin)

SUBJECT PROPERTY PHOTOGRAPH



Substation Y - Larkin (Photo Source: Google Earth)

Larkin Substation (Photo Source: Google Earth)

Site Description

Location/ Access:	Substation Y is located at the northeast corner of Larkin Street and Eddy Street, specifically at 538 Eddy Street, in the Tenderloin. It is further identified as APN 0335-037.
Gross Land Area:	46,875 square feet (or 1.076 acres)
Shape:	Rectangular
Topography:	Sloping

Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing
Interior or Corner:	Corner
Excess/Surplus Land:	None
Signalized Intersection:	Yes
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980116A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The zoning designation is RC-4, or Residential-Commercial District, High Density. The maximum building height is 80 feet.

Improvements Description

Number of Buildings:	Two
Approx. Building Height:	**Building 5.1** is a 30-foot high (at the "front") and a 46-foot high (at the "back") structure and **Building 5.2** has a height of 40 feet.

Number Stories/ Floor Levels:	Both buildings consist of two levels and a lower-level basement floor. **Building 5.2** also has a partial floor (mezzanine) area.
Construction Class (Marshall Valuation Services):	A
Construction Quality:	The construction quality of both buildings is excellent.
Gross Building Area (GBA):	**Building 5.1:** 95,400 square feet **Building 5.2:** 13,780 square feet
Floor Area Ratio:	The combined Floor Area Ratio (buildings-to-land) is 2.329.
Year Built:	Reported/estimated construction dates are as follows: **Building 5.1:** 1962 **Building 5.2:** 2018
Renovated:	No
Historical Designation	**Building 5.1** is age-eligible for historical designation. A review of planning records indicates that the property is not included on the either State or National lists of historically designated buildings in the Tenderloin District of San Francisco. **Building 5.2** is a fairly new construction; it is not age-eligible for inclusion in any historical districts or designations.
Actual Age:	**Building 5.1:** 59 years **Building 5.2:** 3 years
Effective Age:	**Building 5.1:** 50 years **Building 5.2:** 2 years
Typical Building Life:	70 years.
Remaining Economic Life:	**Building 5.1:** 20 years **Building 5.2:** 68 years
Foundation	Concrete
Building Frame	**Building 5.1:** Concrete **Building 5.2:** Concrete/Steel

Exterior Walls	Concrete and Concrete/Steel
Roof Material	Composite – Both buildings. **Building 5.2** improved with solar panels.
Electrical/ Plumbing	Adequate
Heating/ Cooling	**Building 5.1** is serviced with mechanical ventilation but no air cooling or heating. **Building 5.2** is equipped with a heating/cooling system.
Fire Sprinklers/ Protection	Both buildings are serviced with fire sprinklers.
Elevators	Elevators provide vertical circulation in both buildings.
Comments:	**Building 5.1** is a special purpose building constructed for the existing use. A single roll-up door is available. The building is in average to good condition. **Building 5.2** houses GIS equipment and is similar in structure to Buildings 1.2 and 2.2. There is a roll-up door at grade level and the roof is equipped with a mounted array of solar panels. The building and site improvement are in excellent condition.

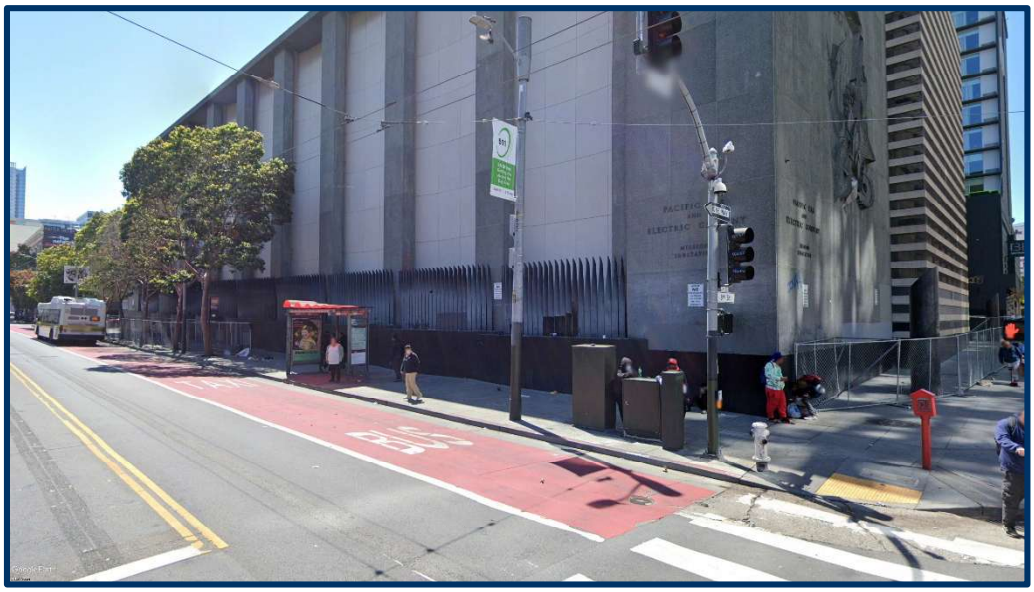
Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #6: Substation X (Mission)

SUBJECT PROPERTY PHOTOGRAPH

Substation X - Mission (Photo Source: Google Earth)



Mission Substation (Photo Source: Google Earth)

Site Description

Location/ Access:	Substation X is located on the northwest corner of Mission and 8th Street in SoMa, between the Mid-Market and Civic Center areas. The property is assigned to a physical address at 1250 Mission Street and is further identified as APN 3701-053.
Gross Land Area:	44,617 square feet (or 1.024 acres)
Shape:	Rectangular

Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Partially paved yard; partial fencing
Interior or Corner:	Corner
Excess/Surplus Land:	None
Signalized Intersection:	Yes
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980118A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	Partially within an area susceptible to earthquake-induced liquefaction.
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco and is within the Downtown Planning Area. The assigned zoning/land use designation is C-3-G, or "Downtown General Commercial District"; the maximum building height is 150 feet at the western half of the property and 180 feet at the eastern half of the property.

Improvements Description

Number of Buildings:	One

Approx. Building Height:	61 feet
Number Stories/ Floor Levels:	Basement and three partial above-grade levels
Construction Class (Marshall Valuation Services):	A
Construction Quality:	Excellent
Gross Building Area (GBA):	89,100 square feet
Floor Area Ratio:	The Floor Area Ratio (building-to-land) is 1.997.
Year Built:	The reported/estimated construction date is 1948.
Renovated:	Yes, in 2013 after undergoing fire damage.
Historical Designation	This building is not historically designated, although it has been surveyed and appears to be eligible for inclusion on the National Register of Historic Places, according to the Planning Department. The property is also identified by the City/County of San Francisco for its association with modern architectural design and with the architect William G. Merchant, who worked for PG&E during the 1950's and designed many of their power plants around the Bay Area.

Actual Age:	73 years.
Effective Age:	35 years.
Typical Building Life:	70 years.
Remaining Economic Life:	35 years.
Foundation	Concrete
Building Frame	Steel
Exterior Walls	Concrete
Roof Material	Composite
Electrical/ Plumbing	Adequate
Heating/ Cooling	Mechanical ventilation
Fire Sprinklers/ Protection	Yes
Elevators	Yes
Comments:	The building is a three-level, 61-foot tall, windowless, steel-framed structure used as a utility substation. The building's exterior is improved with decorative panels and two alto-relievo cast stone sculptures. The building is used to house electrical equipment, and the third floor is improved with GIS equipment. There are three bays at Eighth Street, and nine curve-recessed bays at Mission Street. Building and site improvements are estimated to be excellent.

Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #7: Substation L (Ocean Avenue)

SUBJECT PROPERTY PHOTOGRAPH

Substation L (Photo Source: Google Earth)

Substation L (Photo Source: Google Earth)

Site Description

Location/ Access:	Substation L is located south of Ocean Avenue, and west of Junipero Serra Boulevard, in the Inglesides Terraces neighborhood. The property is assigned to a physical address at 2475 Ocean Avenue and is further identified as APN 6901-001.
Gross Land Area:	17,076 square feet (or 0.392 acre)
Shape:	Trapezoidal

Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks, curbing and a perimeter security fence.
Site Improvements:	Partial paved yard, perimeter fencing
Interior or Corner:	Interior
Excess/Surplus Land:	None
Signalized Intersection:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980230A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The zoning designation is NC-1. Or "Neighborhood Commercial Cluster District." The maximum building height is 26 feet.

Improvements Description

Number of Buildings:	Two

Approx. Building Height:	**Building 7.1**: 37 feet **Building 7.2:** 18 feet
Number Stories/ Floor Levels:	**Building 7.1**: Single-story building with mezzanine **Building 7.2:** Single-story building
Construction Class (Marshall Valuation Services):	C
Construction Quality:	Both buildings are of good construction quality.
Gross Building Area (GBA):	**Building 7.1:** 3,356 square feet **Building 7.2:** 1,825 square feet
Floor Area Ratio:	The combined Floor Area Ratio (buildings-to-land) is 0.303.
Year Built:	Reported/estimated construction date is 1925.
Renovated:	No
Historical Designation	Age-eligible, but no historical designation
Actual Ages:	96 years
Effective Ages:	**Building 7.1:** 70 Years; **Building 7.2:** 80 years
Typical Building Lives:	70 years
Remaining Economic Life:	**Building 7.1:** 7 Years; **Building 7.2:** 4 years.
Foundation	Concrete
Building Frame	Concrete
Exterior Walls	Concrete
Roof Material	Composite
Electrical/ Plumbing	Adequate
Heating/ Cooling	No
Fire Sprinklers/ Protection	No
Elevators	No
Comments:	Both buildings are in average to fair condition for their respective ages. Building 7.2 is vacant and not actively used.

Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #8: Substation G (Broderick Street)

SUBJECT PROPERTY PHOTOGRAPH

Substation G (Photo Source: Google Earth)

Substation G (Photo Source: Google Earth)

Site Description

Location/ Access:	Substation G is located on the northeast corner of Broderick and Ellis Streets in the Anza Vista neighborhood. The property is assigned to a physical address at 1200 Broderick Street and is further identified as APN 1101-013.
Gross Land Area:	15,468 square feet (or 0.355 acre)
Shape:	Irregular

Topography:	Sloping
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Partially paved yard; partial perimeter wall and gate
Interior or Corner:	Corner
Excess/Surplus Land:	None
Signalized Intersection:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980112A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The zoning designation is RM-3. Or "Residential, Mixed Districts, Medium Density." The maximum building height is 40 feet.

Improvements Description

Number of Buildings:	One
Approx. Building Height:	32 feet
Number Stories/ Floor Levels:	Single-level building, plus basement and mezzanine

Construction Class (Marshall Valuation Services):	C
Construction Quality:	Good
Gross Building Area (GBA):	23,304 square feet
Floor Area Ratio:	The Floor Area Ratio (building-to-land) is 1.507.
Year Built:	Reported/estimated construction date is 1935
Renovated:	No
Historical Designation	Age eligible, but no historical designation
Actual Age:	86 years
Effective Age:	65 years
Typical Building Life:	70 years
Remaining Economic Life:	9 years
Foundation	Concrete
Building Frame	Concrete
Exterior Walls	Concrete
Roof Material	Composite
Electrical/ Plumbing	Adequate
Heating/ Cooling	None
Fire Sprinklers/ Protection	Partially serviced with fire sprinklers
Elevators	No
Comments:	The building and site improvements are in average to fair condition for their respective ages.

Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #9: Substation E (Lexington Avenue)

SUBJECT PROPERTY PHOTOGRAPH

Substation E (Photo Source: Google Earth)

Substation E (Photo Source: Google Earth)

Site Description

Location/ Access:	Substation E is situated between Lexington Street and San Carlos Street, on the south side of 19th Street, in the Mission district. The property is assigned to a physical address at 205 Lexington Avenue and is further identified as APN 3596-104.
Gross Land Area:	13,175 square feet (0.302 acre)
Shape:	Rectangular

Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks, curbing and fencing.
Site Improvements:	Fencing; landscaping
Interior or Corner:	Corner
Excess/Surplus Land:	None
Signalized Intersection:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980118A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	Fully within an area susceptible to earthquake-induced liquefaction.
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The zoning designation is RTO-M. Or "Residential Transit Oriented, Mission District." The maximum building height is 55 feet.

Improvements Description

Number of Buildings:	One
Building Height:	Most of the building is at a 37-foot height; portions of the building are at stepped heights of 50 feet and 56 feet.
Number Stories/ Floor Levels:	Single-level and mezzanine level.
Construction Class (Marshall Valuation Services):	C
Construction Quality:	Good
Gross Building Area (GBA):	16,750 square feet
Floor Area Ratio:	The Floor Area Ratio (building-to-land) is 1.271.
Year Built:	The reported/estimated construction date is 1930
Renovated:	None
Historical Designation	Age-eligible, but not included on the state or national historic lists. It is also not within an identified historic district. It is, however, "significant" under the California Register of Historical Resources (Criterion 3, for architecture/design).
Actual Age:	91 years
Effective Age:	65 years
Typical Building Life:	70 years
Remaining Economic Life:	9 years
Foundation	Concrete
Building Frame	Concrete
Exterior Walls	Concrete
Roof Material	Composite
Electrical/ Plumbing	Adequate
Heating/ Cooling	No
Fire Sprinklers/ Protection	Yes
Elevators	None
Comments:	The building and site improvements are in average to fair condition for their respective ages.

Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #10: Substation F (Marina)

SUBJECT PROPERTY PHOTOGRAPH

Substation F (Photo Source: Google Earth)

Site Description

Location/ Access:	Substation F (Marina Substation) is on the north side of Bay Street, east of Buchanan Street, in the Marina District. The property is assigned to a physical address at 1570 Bay Street and is further identified as APN 0459-032.
Gross Land Area:	13,112 square feet (or 0.301 acre)
Shape:	Flag shaped
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks, curbing, and fencing.
Site Improvements:	Perimeter wall; fencing and gate
Interior or Corner:	Interior
Excess/Surplus Land:	None
Signalized Intersection:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980116A
Flood Map Date	03/23/2021

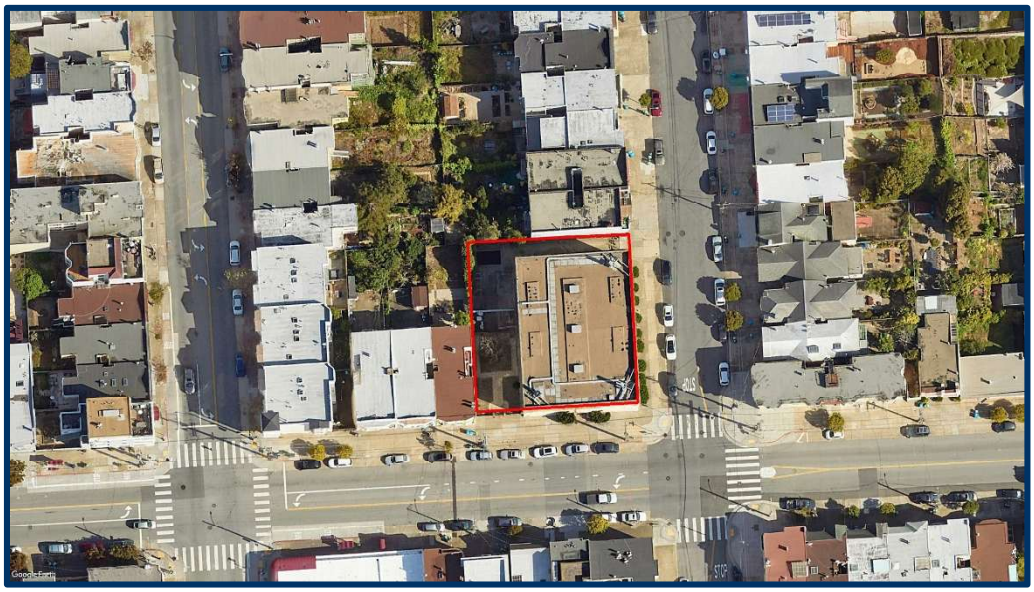
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases revealed the existence of site contamination and remediation work. The historic use of the property was as a manufactured gas plant, with the storage of oil/gas onsite. A site assessment found traces of benzene, ethylbenzene, hydrocarbons (PAH's), toluene, and xylenes within subsurface areas (i.e., soil and groundwater) of the site. The lead agency overseeing remediation work is the Department of Toxic Substance Control (DTSC). PG&E voluntarily agreed to remediate the site in 2010. However, remediation was determined to be not necessary. While other portions of the North Beach gas plant site have Land Use Covenants attached to the parcels (recorded in 2014 and in 2019), there appears to be no such use restriction and/or covenant attached to the Substation F site.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The zoning designation on the "flagpole" portion of the site is NC-2, or "Small-Scale Neighborhood Commercial District," and the zoning designation on the "flag" portion of the site is RM-4, or "Residential, Mixed District." The maximum building height, applicable to the entire site, is 40 feet.
Improvements Description Comments:	The site improvements include a perimeter concrete wall and fencing, as well as a security gate. The site is fully paved. There are no building improvements; improvements seen in the aerial are equipment and structures that are deemed not to be real property, and are therefore not included in this appraisal report.

Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #11: Substation K (24th Avenue)

SUBJECT PROPERTY PHOTOGRAPH



Substation K (Photo Source: Google Earth)

Substation K (Photo Source: Google Earth)

Site Description

Location/ Access:	Substation K is located on the Northwest corner of Balboa Street and 24th Avenue in the Central Richmond district. The property is assigned to a physical address at 679 24th Avenue and is further identified as APN 1567-012.
Gross Land Area:	12,398 square feet (or 0.285 acre)
Shape:	Rectangular

Topography:	Sloping
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks, curbing and fencing.
Site Improvements:	Partially paved lot; fencing and gate
Interior or Corner:	Corner
Excess/Surplus Land:	None
Signalized Intersection:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980113A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area
Liquefaction Potential	Fully within an area susceptible to earthquake-induced liquefaction.
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The zoning designation is RH-2, or "Residential-House, Two-Family" The maximum building height is 40 feet.

Improvements Description

Number of Buildings:	One
Approx. Building Height:	33 feet
Number Stories/ Floor Levels:	One level, plus mezzanine level

Construction Class (Marshall Valuation Services):	C
Construction Quality:	Good
Gross Building Area (GBA):	10,956 square feet
Floor Area Ratio:	The Floor Area Ratio (building-to-land) is 0.884.
Year Built:	The reported/estimated construction date is 1915
Renovated:	No
Historical Designation	According to the CCSF Planning Department's website, Substation K is on the citywide Cultural Resources Survey. It is not within the State or National Register of Historical Resources.
Actual Age:	106 years
Effective Age:	55 years
Typical Building Life:	70 years
Remaining Economic Life:	16 years
Foundation	Concrete
Building Frame	Concrete
Exterior Walls	Concrete
Roof Material	Composite
Electrical/ Plumbing	Adequate
Heating/ Cooling	No
Fire Sprinklers/ Protection	No
Elevators	No
Comments:	The building and site improvements are in average to fair condition for their respective ages.

Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #12: Substation J (Sacramento Street)

SUBJECT PROPERTY PHOTOGRAPH

Substation J (Photo Source: Google Earth)

Substation J (Photo Source: Google Earth)

Site Description:

Location/ Access:	Substation J is located on the northeast corner of Sacramento Street and Leidesdorff Street in the Financial District. The property is assigned to a physical address at 222 Leidesdorff Street and is further identified as APN 0228-006.
Gross Land Area:	8,395 square feet (or 0.193 acre)

Shape:	L-shaped
Topography:	Level
Drainage:	Not adequate; the basement was flood on the inspection date.
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	None – structural improvements cover entire lot area
Interior or Corner:	Corner
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980117A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area
Liquefaction Potential	Fully within an area susceptible to earthquake-induced liquefaction.
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco and is within the Downtown Planning Area. The assigned zoning/land use designation is C-3-O, or "Downtown Office"; the maximum building height is 75 feet.

Improvements Description

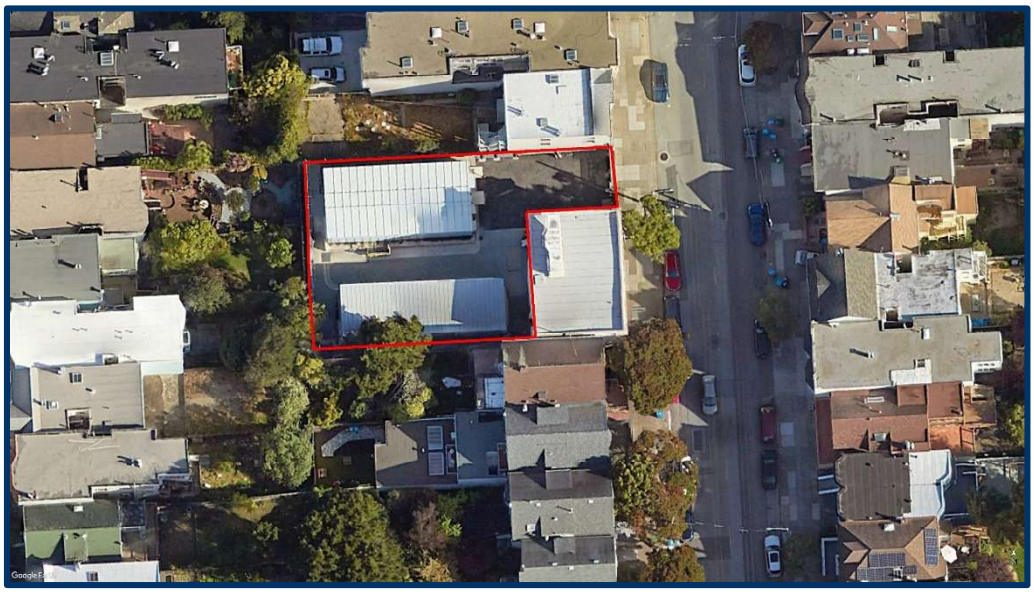
Number of Buildings:	One
Approx. Building Height:	Most of the building has a height of 33 feet; a portion of the building is 65 feet.
Number Stories/ Floor Levels:	Two levels, plus two partial levels and a lower-level basement floor.
Construction Class (Marshall Valuation Services):	C
Construction Quality:	Good
Gross Building Area (GBA):	26,250 square feet
Floor Area Ratio:	Floor Area Ratio (Building Area-to-Land) is 3.127.
Year Built:	Reported/estimated construction date is 1925
Renovated:	Yes, some seismic reinforcement on the uppermost level.
Historical Designation	The property is historically designated. It is eligible for inclusion on the National Register of Historic Places. The building has also been identified within a citywide survey as having "major importance," and has also been identified as a "significant building" as a part of a conservation district (Commercial-Leidesdorff Conservation District), under Article 11 of the San Francisco Public Resources Code.
Actual Age:	96 years
Effective Age:	60 years
Typical Building Life:	70 years
Remaining Economic Life:	12 years
Foundation	Concrete
Building Frame	Concrete
Exterior Walls	Concrete
Roof Material	Composite
Electrical/ Plumbing	Adequate
Heating/ Cooling	No
Fire Sprinklers/ Protection	Yes
Elevators	No
Comments:	The building improvements are in average-to-fair conditions for their respective ages.

Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #13: Substation N (9th Avenue)

SUBJECT PROPERTY PHOTOGRAPH



Substation N (Photo Source: Google Earth)

Site Description

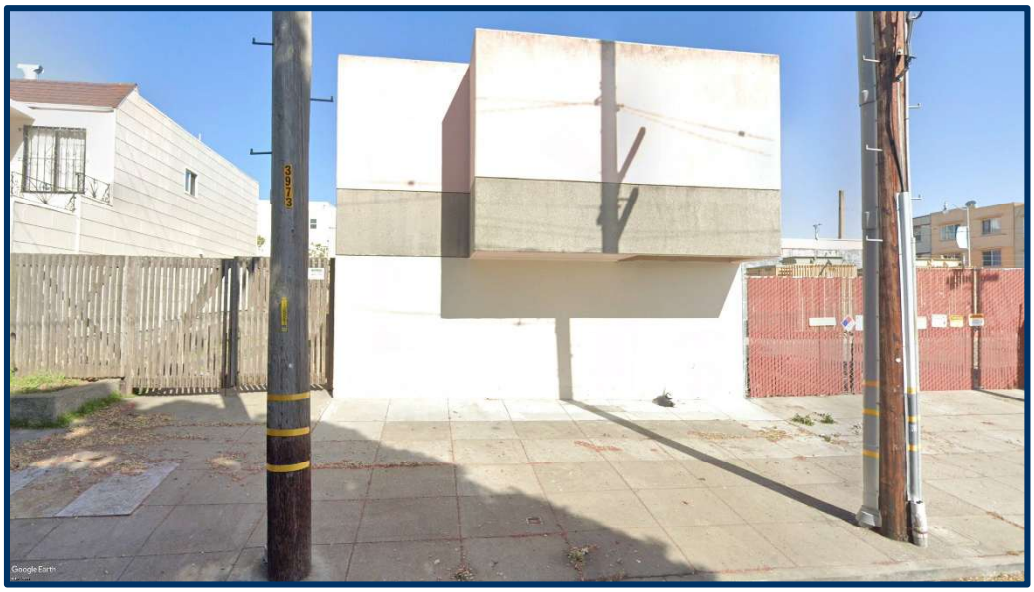
Location/ Access:	Substation N is located on the west side of 9th Avenue, between Judah Street and Kirkham Street, in the Inner Sunset neighborhood. The property is assigned to a physical address at 1437-1449 9th Avenue and is further identified as APN 1844-053.
Gross Land Area:	6,492 square feet (or 0.149 acre)
Shape:	Flag shaped
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Partially paved lot; fence and gate
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980230A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is RH-2, or "Residential, House, Two-Family"; the maximum building height is 40 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of the site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #14: Randolph Substation

SUBJECT PROPERTY PHOTOGRAPH

Randolph Substation (Photo Source: Google Earth)



Randolph Substation (Photo Source: Google Earth)

Site Description

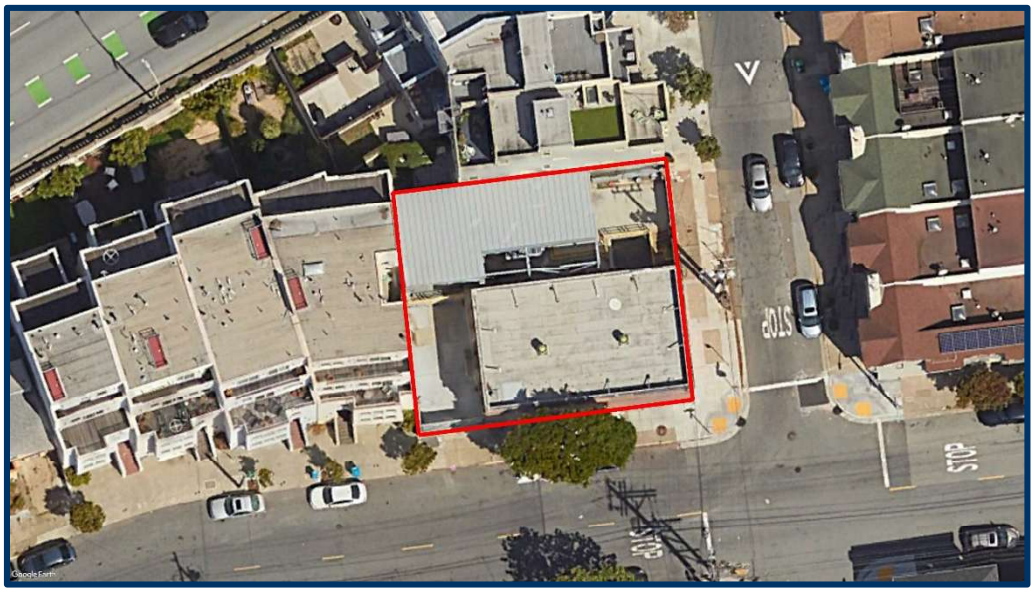
Location/ Access: Randolph Substation is located on the northeast corner of Randolph Street and Byxbee Street in the Ingleside Heights neighborhood. The property is assigned to a physical address at 724 Randolph Street and is further identified as APN 7084-024.

	The property is encumbered by a recorded easement (Book C 72, Pages 19-24) granted by Pacific Gas and Electric Company to the City and County of San Francisco on June 2, 1975, and recorded October 3, 1975. The easement grants to the City a perpetual and exclusive right to install, maintain, and operate an electrical rectifier and associated equipment, with the right to fence the encumbered area, over a ±2,215 square foot portion of Lots 7 and 8, Block 15. The easement was acquired for $12,183 as a substation site for the Municipal Railway under the Hetch Hetchy Power Improvement Program.
Gross Land Area:	4,865 square feet (or 0.112 acre)
Shape:	Generally Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing and brick/masonry wall; paved yard
Interior or Corner:	Corner
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980230A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination

	exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is NC-1, or "Neighborhood Commercial"; the maximum building height is 26 feet.
Improvements Description:	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The property is improved with an approximate 1,200-square foot structure situated upon the easement area granted to the City and County of San Francisco. The building is under the ownership of the City and County of San Francisco and is not included as a part of this valuation.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #15: Substation M (Rousseau Street)

SUBJECT PROPERTY PHOTOGRAPH



Substation M (Photo Source: Google Earth)

Site Description

Location/ Access:	Substation M is located on the northwest corner of Bosworth Street and Rousseau Street in the St. Mary's Park neighborhood. The property is assigned to a physical address at 20 Rousseau Street and is further identified as APN 6747-016.
Gross Land Area:	4,725 square feet (or 0.108 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Fence and gate
Interior or Corner:	Corner
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980231A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is RH-2, or "Residential, House, Two-Family"; the maximum building height is 40 feet.

Improvements Description

Number of Buildings:	One building; one open lean-to shelter.
Approximate Building Height:	**Building:** 15 feet **Open Lean-To Shelter:** 16 feet to 23 feet
Number Stories/ Floor Levels:	One story
Construction Class (Marshall Valuation Services):	C
Construction Quality:	Construction quality of both structures, building and open lean-to shelter is good.
Gross Building Area (GBA):	**Building:** totals 1,680 square feet. **Open Lean-To Shelter:** 1,068 square feet
Floor Area Ratio:	Floor Area Ratio (building area-to-land) is 0.582.

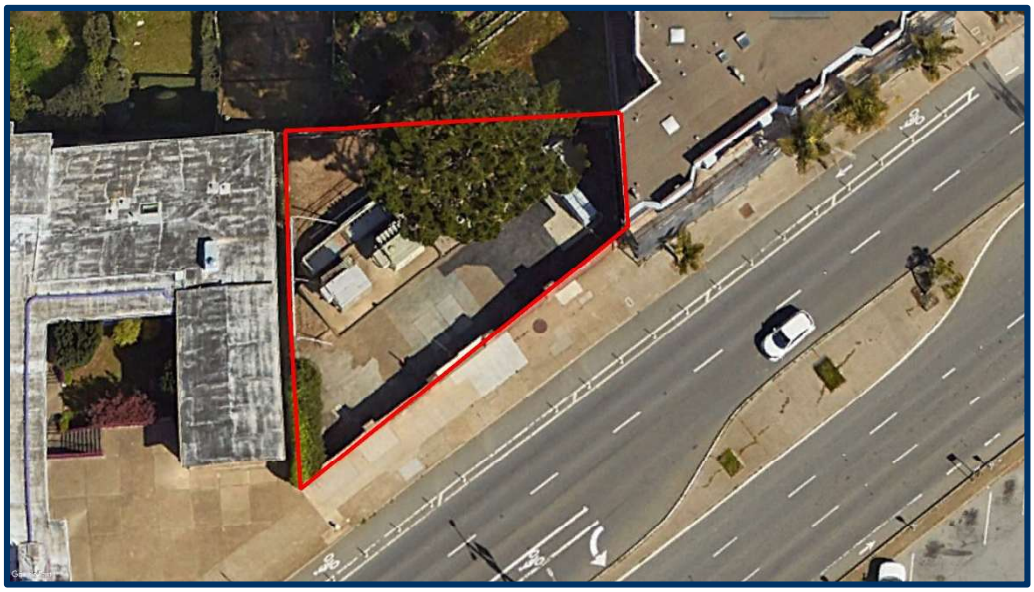
Year Built:	**Building:** Reported/estimated construction date is 1925. **Open Lean-To Shelter:** Reported/estimated construction date is 2007.
Renovated:	No
Historical Designation	**Building:** is age-eligible but is not historically designated.
Actual Age:	**Building:** 96 years **Open Lean-To Shelter:** 14 years
Effective Age:	**Building:** 45 years **Open Lean-To Shelter:** 10 years
Typical Building Life:	**Building:** 60 years **Open Lean-To Shelter:** 45 years
Remaining Economic Life:	**Building:** 15 years **Open Lean-To Shelter:** 35 years
Foundation	Concrete
Building Frame	**Building:** Concrete **Open Lean-To Shelter:** Steel
Exterior Walls	**Building:** Masonry (brick) **Open Lean-To Shelter:** Metal
Roof Material	**Building:** Composite **Open Lean-To Shelter:** Metal
Electrical/ Plumbing	Adequate
Heating/ Cooling	No
Fire Sprinklers/ Protection	Yes
Elevators	No
Comments:	The building and site improvements are in average to good condition for their respective ages.

Highest and Best Use:

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #16: Portola Substation

SUBJECT PROPERTY PHOTOGRAPH



Portola Substation (Photo Source: Google Earth)

Site Description

Location/ Access:	Portola Substation is located on the north side of Portola Drive and south of Woodside Avenue, in the Forest Hill Extension neighborhood. The property is assigned to a physical address at 610 Portola Drive and is further identified as APN 2892-003.
Gross Land Area:	4,698 square feet (or 0.108 acre)
Shape:	Trapezoidal
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing and paved lot
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980230A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is NC-1, or "Neighborhood Commercial"; the maximum building height is 26 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #17: Beach Substation

SUBJECT PROPERTY PHOTOGRAPH

Beach Substation (Photo Source: Google Earth)

Site Description

Location/ Access:	Beach Substation is located on the north side of Beach Street, and west of Mason Street, in the Fisherman's Wharf neighborhood. The property is assigned to a physical address at 330 Beach Street and is further identified as APN 0013-010.
Gross Land Area:	3,750 square feet (or 0.086 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing and paved lot
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980116A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area
Liquefaction Potential	Fully within an area susceptible to earthquake-induced liquefaction.
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco and is within the Northeast Waterfront Planning Area. The assigned zoning/land use designation is C-2, or "Community Business"; the maximum building height is 40 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #18: 6th Avenue Substation

SUBJECT PROPERTY PHOTOGRAPH

Substation A – 6th Avenue Substation (Photo Source: Google Earth)

Site Description

Location/ Access:	The 6th Avenue Substation is located on the west side of 6th Avenue, north of Geary Boulevard, in the Inner Richmond District. The property is assigned to a physical address at 365 6th Avenue and is further identified as APN 1438-014.
Gross Land Area:	3,000 square feet (or 0.069 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing and paved lot
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980112A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area
Liquefaction Potential	Fully within an area susceptible to earthquake-induced liquefaction.
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco and is within the Richmond Planning Area, in the Geary District. The assigned zoning/land use designation is NCD, or "Neighborhood Commercial District"; the maximum building height is 40 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #19: Silver Substation

SUBJECT PROPERTY PHOTOGRAPH

Silver Substation (Photo Source: Google Earth)

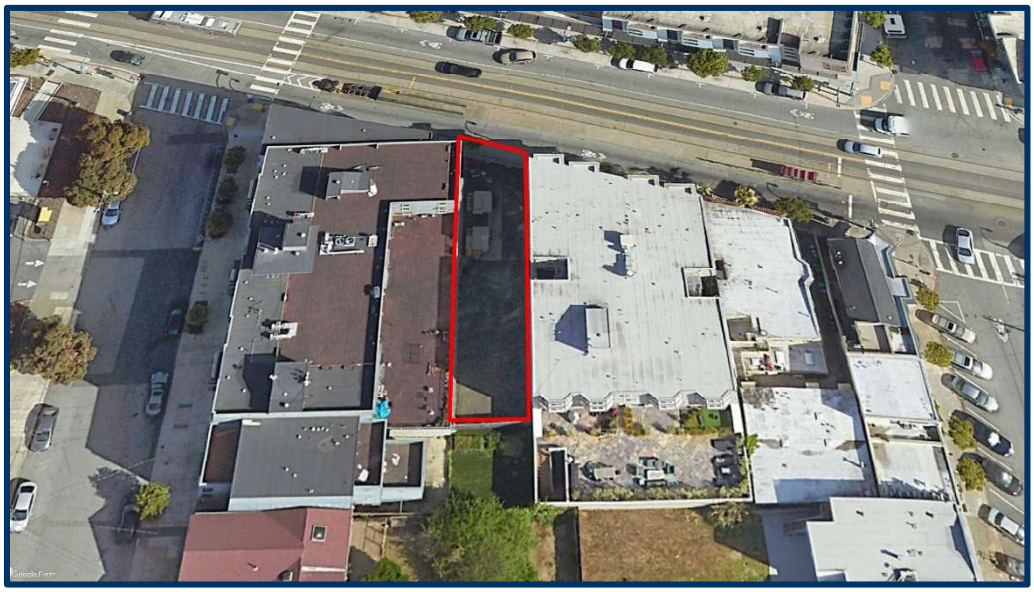
Site Description

Location/ Access:	Silver Substation is located on the southwest corner of Silver Avenue and Colby Street in the Portola neighborhood. The property is assigned to a physical address at 1086 Silver Avenue and is further identified as APN 1438-014.
Gross Land Area:	2,834 square feet (or 0.065 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing
Interior or Corner:	Corner
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980231A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is RH-1D, or "Residential, House"; the maximum building height is 40 feet.
Improvements Description Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use: As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #20: Ocean Substation

SUBJECT PROPERTY PHOTOGRAPH



Ocean Substation (Photo Source: Google Earth)

Site Description

Location/ Access:	Ocean Substation is located on the south side of Ocean Avenue, between Brighton Avenue and Lee Avenue, in the Ingleside neighborhood. The property is assigned to a physical address at 1155 Ocean Avenue and is further identified as APN 6944-040.
Gross Land Area:	2,655 square feet (or 0.061 acre)
Shape:	Generally rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980230A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco and is within the Balboa Park Planning Area. The assigned zoning/land use designation is NCT, or "Neighborhood Commercial Transit"; the maximum building height is 45 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #21: Yosemite Substation

SUBJECT PROPERTY PHOTOGRAPH

Yosemite Substation (Photo Source: Google Earth)

Site Description

Location/ Access:	Yosemite Substation is located off Williams Avenue and east of Newhall Street in the Bayview neighborhood. The property is assigned to a physical address at 1802 Yosemite Avenue and is further identified as APN 5417-007.
Gross Land Area:	2,500 square feet (or 0.057 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	None
Site Improvements:	Perimeter fencing
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980232A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco and is within the Bayview Hunters Point Planning Area. The assigned zoning/land use designation is RH-1, or "Residential, House, One Family"; the maximum building height is 65 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Assemblage with contiguous parcels and development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #22: Taraval Substation

SUBJECT PROPERTY PHOTOGRAPH

Taraval Substation (Photo Source: Google Earth)

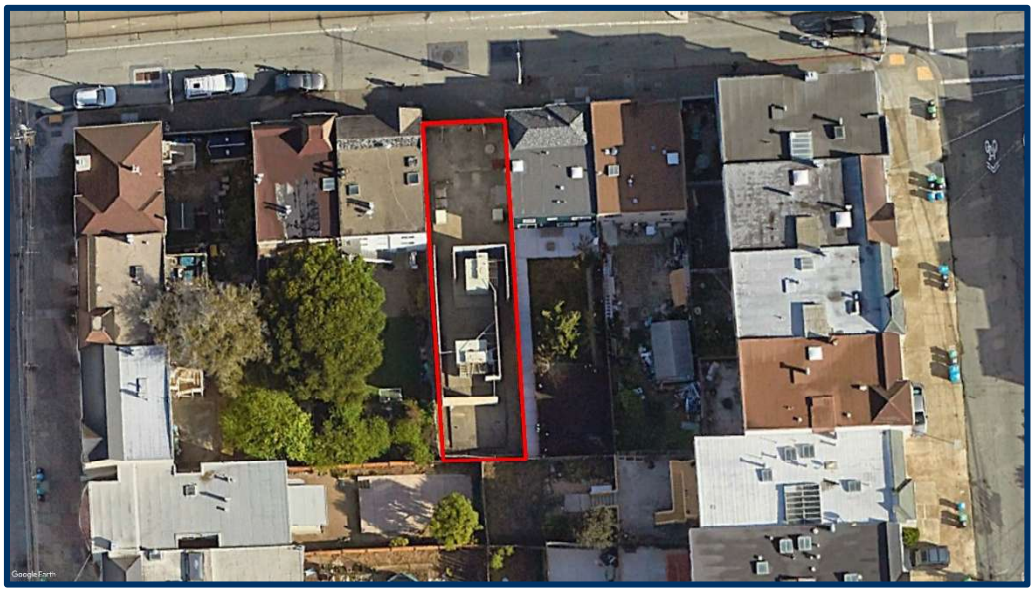
Site Description

Location/ Access:	Taraval Substation is located on Taraval Street, between 35th and 36th Avenues, in the Sunset District. The property is assigned to a physical address at 2533 Taraval Street and is further identified as APN 2390-044.
Gross Land Area:	2,500 square feet (or 0.057 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980230A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is NCD, or "Neighborhood Commercial District"; the maximum building height is 40 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #23: Judah Substation

SUBJECT PROPERTY PHOTOGRAPH



Judah Substation (Photo Source: Google Earth)

Site Description

Location/ Access:	Judah Substation is located on Judah Street, between 34th and 35th Avenues, in the Outer Sunset District. The property is assigned to a physical address at 2927 Judah Street and is further identified as APN 1819-042.
Gross Land Area:	2,500 square feet (or 0.057 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980113A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is RH-3, or "Residential-House, Three Family"; the maximum building height is 40 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #24: Plymouth Substation

SUBJECT PROPERTY PHOTOGRAPH

Plymouth Substation (Photo Source: Google Earth)

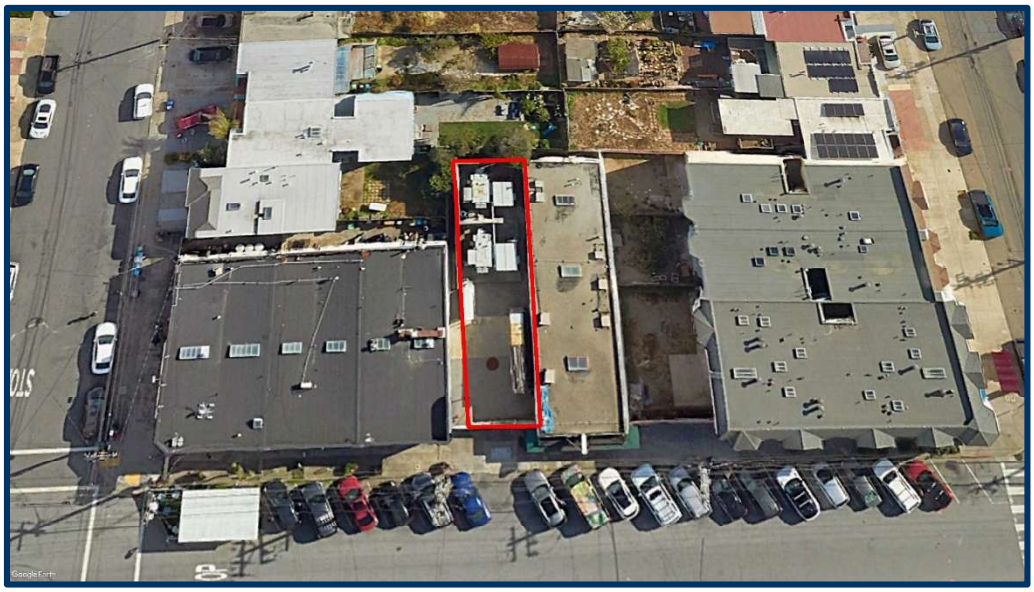
Site Description

Location/ Access:	Plymouth Substation is located on the east side of Plymouth Avenue, north of Sadowa Street, in the Oceanview neighborhood. The property is assigned to a physical address at 214 Plymouth Avenue and is further identified as APN 7112-012A.
Gross Land Area:	2,500 square feet (or 0.057 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980230A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is NC-1 or "Neighborhood Commercial, Cluster"; the maximum building height is 40 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #25: Noriega Substation

SUBJECT PROPERTY PHOTOGRAPH



Noriega Substation (Photo Source: Google Earth)

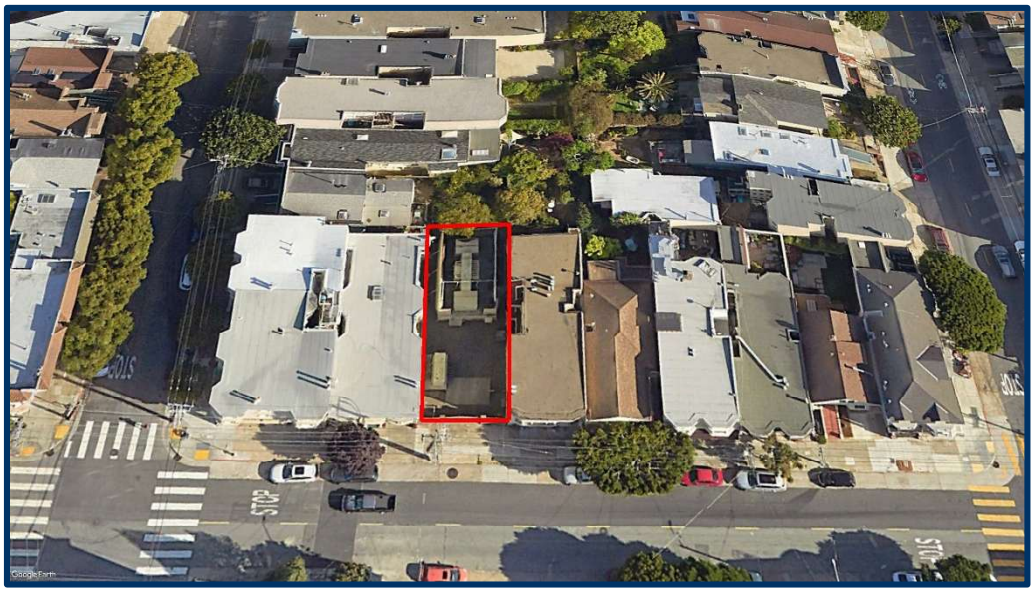
Site Description

Location/ Access:	Noriega Substation is located on the south side of Noriega Street, between 45th and 46th Avenues, in the Outer Sunset District. The property is assigned to a physical address at 3819 Noriega Street and is further identified as APN 2082-001L.
Gross Land Area:	2,325 square feet (or 0.053 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing and paved lot
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980094A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is NC-1 or "Neighborhood Commercial, Cluster"; the maximum building height is 40 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #26: 18th Street Substation

SUBJECT PROPERTY PHOTOGRAPH



18th Street Substation (Photo Source: Google Earth)

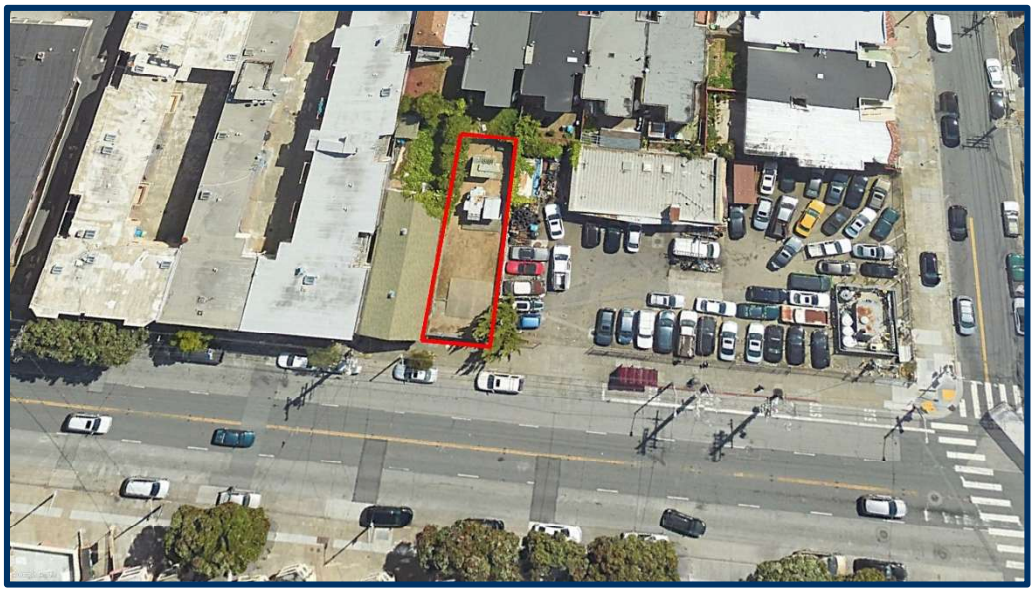
Site Description

Location/ Access:	18th Street Substation is located on 18th Street, east of Douglass Street in Eureka Valley. The property is assigned to a physical address at 4430 18th Street and is further identified as APN 2650-020.
Gross Land Area:	2,250 square feet (or 0.052 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980114A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is RH-3, or "Residential-House, Three Family"; the maximum building height is 40 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #27: Acton Substation

SUBJECT PROPERTY PHOTOGRAPH



Acton Substation (Photo Source: Google Earth)

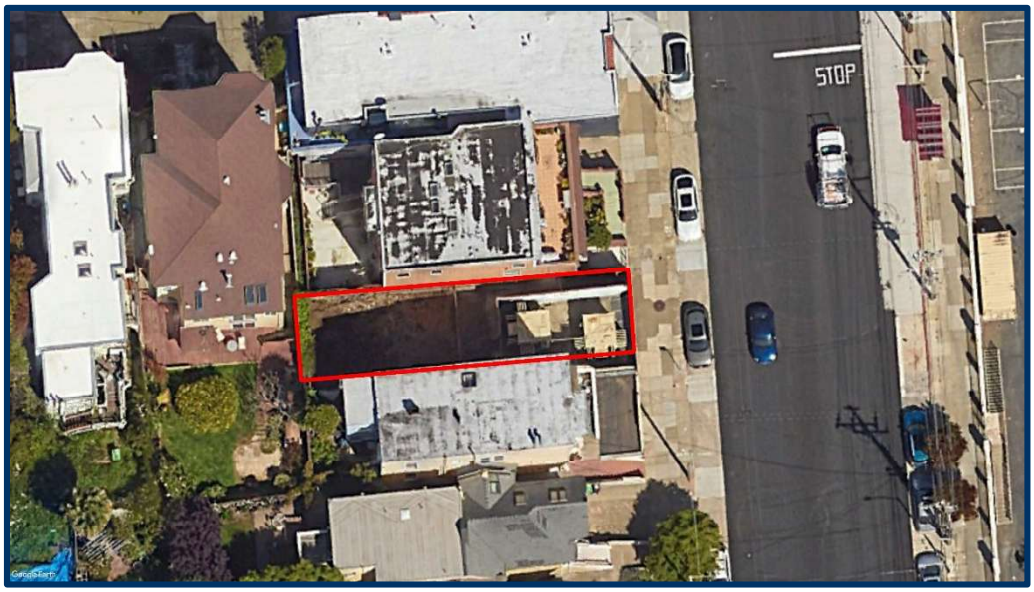
Site Description

Location/ Access:	Acton Substation is located on Mission Street and east of Acton Street in the Outer Mission District. The property is assigned to a physical address at 5889 Mission Street and is further identified as APN 6472-021D.
Gross Land Area:	2,250 square feet (or 0.052 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980230A
Flood Map Date	03/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area

Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. Its assigned zoning/land use designation is NCD, or "Neighborhood Commercial District"; the maximum building height is 40 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #28: Castro Substation

SUBJECT PROPERTY PHOTOGRAPH



Castro Substation (Photo Source: Google Earth)

Site Description

Location/ Access:	Castro Substation is located on the west side of Castro Street, between 25th Street and Clipper Street, in Noe Valley. The property is assigned to a physical address at 1510-1512 Castro Street and is further identified as APN 6546-004.
Gross Land Area:	2,000 square feet (or 0.046 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980231A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The zoning designation is RH-2, or "Residential-House, Two-Family" The maximum building height is 40 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #29: 21st Avenue Substation

SUBJECT PROPERTY PHOTOGRAPH

21st Avenue Substation (Photo Source: Google Earth)

Site Description

Location/ Access:	21st Avenue Substation is located on the north side of Noriega Street, between 21st and 20th Avenues. The property is assigned to a physical address at 1340 Noriega Street and is further identified as APN 2029-025.
Gross Land Area:	1,875 square feet (or 0.043 acre)
Shape:	Rectangular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980113A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special-purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is NCD, or "Neighborhood Commercial District"; the maximum building height is 40 feet.
Improvements Description	
Comments:	The substation property is used as a site for electrical transformers and other outdoor electrical equipment. The condition of site improvements is average.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #30: Egbert Switching Station

SUBJECT PROPERTY PHOTOGRAPH

Egbert Switching Station Site (Photo Source: Google Earth)

Site Description

Location/ Access:	Egbert Switching Station is located at the end of Egbert Avenue, in the Bayview neighborhood. The property is assigned to a physical address at 1755 Egbert Avenue and is further identified as APN 5431-001A.
Gross Land Area:	74,923 gross square feet; 70,446 net square feet (or 1.617 acres)
Shape:	Irregular
Topography:	Level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are available to the site.
Off-Site Improvements:	Street frontages are unimproved.
Interior or Corner:	Interior
Signalized Intersection:	No
Excess/Surplus Land:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980232A
Flood Map Date	03/23/2021

Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	None known. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists considering the site's location in an industrially zoned area of San Francisco. For the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco. The assigned zoning/land use designation is PDR-2, or "Production, Distribution and Repair"; the maximum building height is 65 feet.
Improvements Description	
Comments:	The property consists of vacant land. The parcel was recently purchased for the construction of a new 230 kV switching station, to be housed in an approximately 11,000 square foot building. The switching station will connect to the Martin Substation (in San Mateo County) via the Jefferson-Martin and Embarcadero-Martin transmission lines.
Highest and Best Use:	
As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing proposed use as part of the operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #31: Martin Substation

SUBJECT PROPERTY PHOTOGRAPH

Martin Substation, Net Acreage in Red; Wetland/Habitat Land Area in Blue
(Photo Source: Google Earth)

Substation improvements on Martin Substation (Photo Source: Walter D. Carney, MAI)

Building E (Photo Source: Walter D. Carney, MAI)

Building G (Photo Source: Walter D. Carney, MAI)

Building H (Photo Source: Walter D. Carney, MAI)

Site Description

Location/ Access:

The Martin Substation is located on the south side of Geneva Avenue, between Allan Street (to the west) and Bayshore Boulevard (to the east), in San Mateo County, California. A portion of the substation property lies within the Daly City municipal limits; this portion consists of the "Daly City Yard" and is not proposed for acquisition.

The "substation" land and improvements proposed for possible acquisition are situated on the north portion of the site, at the southwest corner of Geneva Avenue and Bayshore Boulevard.

The larger site is assigned a physical address at 3150 Geneva Avenue. It is further identified as a portion of San Mateo County Assessor's Parcel Number (APN): 005-141-999.

Gross Land Area:

The portion of the substation property acquired is approximately 1,602,313 square feet (or 36.784 acres). The southern portion of the site consists of 7.00 acres of wetlands and habitat lands (as measured on Google Earth), as well as an approximate 8,300-square foot area used by PG&E as a natural gas transmission pipeline control yard (and not proposed for acquisition by CCSF).

Martin Substation	Site Size (SF)	Site Size (Acres)
Improved Substation Land	1,289,093	29.594
Wetlands and Habitat Lands	304,920	7.000
Natural Gas Transmission Pipeline Control Yard	8,300	0.190
Total Site Area	**1,602,313**	**36.784**

There is also an underground, 24-inch, gas transmission pipeline along the northern and partially along the eastern perimeters of the site. It is our understanding that CCSF intends to grant an easement in favor of PG&E. While easement language has not been finalized, the proposed easement area will extend 25 feet on either side of the pipeline. The easement area has not been surveyed, and measurements are estimated by CCSF via the use of Google Earth.

A summary table, as provided by CCSF, is reproduced below for the reader's reference. Size, dimensions, and locations are assumed. A revision to the appraisal may be warranted if the actual easement deed and legal description differ from that which has been appraised.

	Gross Length (LF)	Overlap (LF)	Net Length (LF)	Width (LF)	Total SF
No. ROW	1,050	(25.0)	1,025 x	50 =	51,250.00
E. ROW	100	(12.5)	87.5 x	25 =	2,187.50
				Total:	**53,437.50**

Remainder land and improvements and/or severance damages are not appraised at this time, as requested.

Shape: Irregular

Topography: Level

Drainage: Adequate

Grade: At street grade

Utilities: All typical urban utilities are available to the site.

Off-Site Improvements: The frontages are partially improved with sidewalks, curbing, and sanitary storm drain inlets.

Site Improvements: Partially paved lot; partially gravel covered lot; security wall; electrical substation improvements.

Interior or Corner:	Corner
Signalized Intersection:	Yes
Flood Zone	Mostly within Zone X; a portion in Zone A
Flood Map Panel/ Numbers	06081C0035F
Flood Map Date	4-5-2019
Earthquake Fault Zone	Not within an Alquist-Priolo Special Studies Zone for earthquake hazards. Earthquake risks, however, are prevalent throughout the Bay Area.
Liquefaction Potential	Not Identified
Maher Ordinance Area	Not Applicable
Environmental Issues	The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases revealed the existence of site contamination and remediation work. The historical uses of the property were for a manufactured gas plant, and its operations included onsite oil storage. A site assessment found traces of arsenic, lead, benzene, cyanide (free), petroleum, and polynuclear aromatic hydrocarbons (PAHS) within the subsurface (i.e., soil and groundwater) areas of the site. Because of the onsite contamination, a Land Use Covenant and Environmental Restrictions have been placed on the property. The covenants were made on March 23, 1995, and October 17, 2002, and their provisions run with the land in perpetuity. Restrictions on use include that any future site development be limited to industrial or commercial land uses, and that no residences, hospitals, health care facilities, schools, day care centers (for both children and senior citizens), or agricultural activities for production of items for consumption be permitted onsite. The Covenants and Environmental Restrictions are reviewed as a part of this appraisal; copies are retained in the appraiser's work file. The lead agency overseeing remediation work is the Department of Toxic Substance Control (DTSC). It is our understanding that PG&E (landowner) has voluntarily agreed to remediate the site. PG&E has encapsulated the contamination and is continuing to use the sites as a part of its operations. Because the contamination remains in place, PG&E (per the executed Land Use Covenants) is

required to prepare and submit project specific Soil Management and Air Monitoring Plans for any proposed earthmoving projects.

Zoning and General Plan

The property is within the jurisdiction of the City of Brisbane. The assigned Zoning and General Plan land use designations are both C/P-U, or Commercial/Public Utilities District – that is, the two land use designations are identical/compatible.

Improvements Description:

Number of Buildings

There are four main buildings onsite, totaling 51,252 square feet, including:

Bldg. ID	Size (SF)	Description
E	9,144	Concrete masonry building
F	17,608	Concrete tilt up building
G	11,700	Metal storage building
H	12,800	Metal "Butler" building

Approx. Building Height:

Building E: 34 feet
Building F: 16 feet
Building G: 20 feet
Building H: 22 feet

Number Stories/ Floor Levels: Each of the four buildings are single story structures.

Construction Class (Marshall Valuation Services): Classes C (Buildings E and F) and S (Buildings G and H)

Construction Quality: Good

Gross Building Area (GBA):

Building E: 9,144 square feet
Building F: 17,608 square feet
Building G: 11,700 square feet
Building H: 12,800 square feet

Floor Area Ratio: Floor Area Ratio (building area-to-land) is 0.040.

Year Built:

Building E: Constructed in 1925 and renovated in 1947.
Building F: Constructed in 1960
Building G: Constructed in 1983
Building H: Constructed 2021

Renovated: **Building E**: renovated in 1947

Historical Designation:	No
Actual Age:	**Building E:** 96 years **Building F:** 61 years **Building G:** 38 years **Building H:** 2 years
Effective Age:	**Building E:** 70 years **Building F:** 50 years **Building G:** 30 years **Building H:** 2 years
Typical Building Life:	**Building E:** 60 years **Building F:** 70 years **Building G:** 50 years **Building H:** 50 years
Remaining Economic Life:	**Building E:** 3 years **Building F:** 20 years **Building G:** 20 years **Building H:** 48 years
Foundation:	Concrete
Building Frame:	**Buildings E & F:** Concrete **Buildings G & H:** Metal
Exterior Walls:	Concrete (Buildings E and F); Metal (Buildings G and H)
Roof Material:	Composite (Buildings E and F); Metal (Buildings G and H)
Electrical/ Plumbing:	Adequate
Heating/ Cooling:	No
Fire Sprinklers/ Protection:	No, Buildings E and F;

	Yes, Buildings G and H
Elevators:	None
Comments:	The buildings and site improvements are in overall good condition for their respective ages.

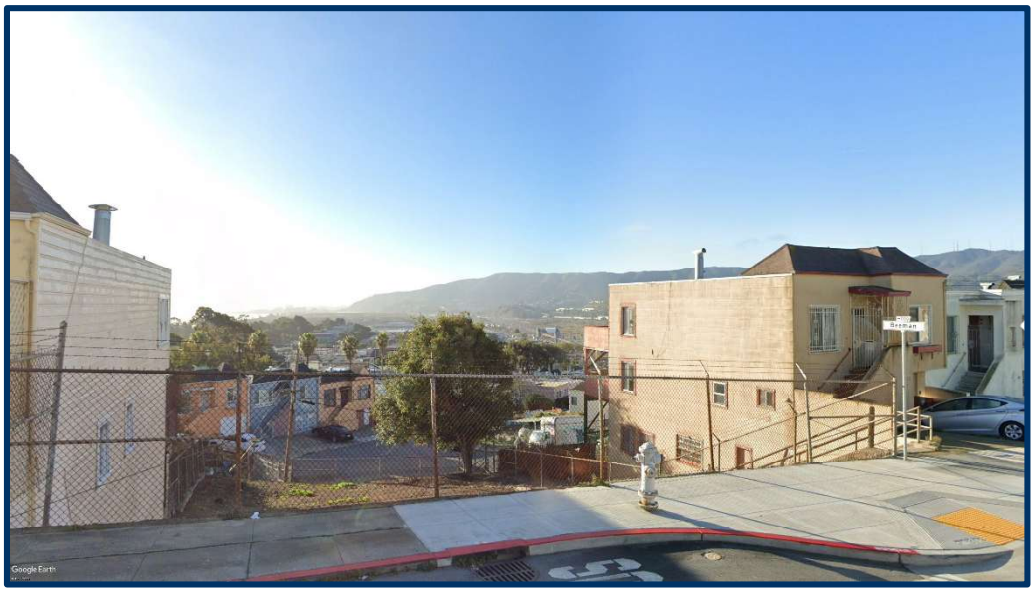
Highest and Best Use:

As-If Vacant:	Development with use(s) consistent with City of Brisbane zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #32: Beeman Lane Parcel

SUBJECT PROPERTY PHOTOGRAPH

Beeman Lane Aerial View (Photo Source: Google Earth)



Beeman Lane – Vacant Lot (Photo Source: Google Earth)

Site Description

Location/ Access: The parcel consists of a vacant residential lot located at the end of Wabash Terrace, on the south side of San Bruno Avenue, in Visitacion Valley. The site address is 3789 San Bruno Avenue. It is, however, identified by the following Assessor's Parcel Number (APN): 5067-001A, and by SBE Number 135-38-018.

Gross Land Area:	According to Assessor's records, the parcel contains 4,721 square feet of land (or 0.108 acre).
Shape:	The shape is generally rectangular.
Topography:	Downwardly sloping.
Drainage:	Adequate.
Grade:	At street grade.
Utilities:	All typical urban utilities are in the area.
Off-Site Improvements:	The parcel's frontage along San Bruno Avenue is improved with sidewalks and curbing.
Site Improvements:	Perimeter fencing
Interior or Corner:	Interior – mid-block on San Bruno Avenue.
Signalized Intersection:	No
Flood Zone	Zone X
Flood Map Panel/ Numbers	0602980118A
Flood Map Date	3/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	No
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "Out" of the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco and is within the Visitacion Valley Planning District. The assigned zoning/land use designation is RH-1, or "Residential-House, One Family" district; maximum building height is 40 feet.

Comments: The parcel consists of a vacant residential lot with a downwardly sloping topographic profile. Site improvements include chain-link perimeter fencing. It is our understanding that the property has underground PG&E electrical power transmission lines running through the site. Lines are depicted on schematics entering and exiting the site.

The SBE Map depicting the site and surrounding parcels shows a Southern Pacific Company Subsurface Tunnel Easement overlay on the subject parcel, on surrounding parcels, and then extending beyond the Map page into adjacent pages and presumably parcels. Aerial imagery shows these adjacent parcels to be fully developed, residential properties.

PG&E transmission improvements are constructed subsurface; again, presumably within the physical space depicted by the parallel lines shown on the SBE Map. A title report was not available for the site, and a title search has not been made in connection with this assignment. Based on existing uses onsite and on immediate surrounding properties, it is our conclusion the parcel could be developed consistent with zoning and with residential structures found in the immediate market area were it not for the PG&E underground electrical transmission improvements.

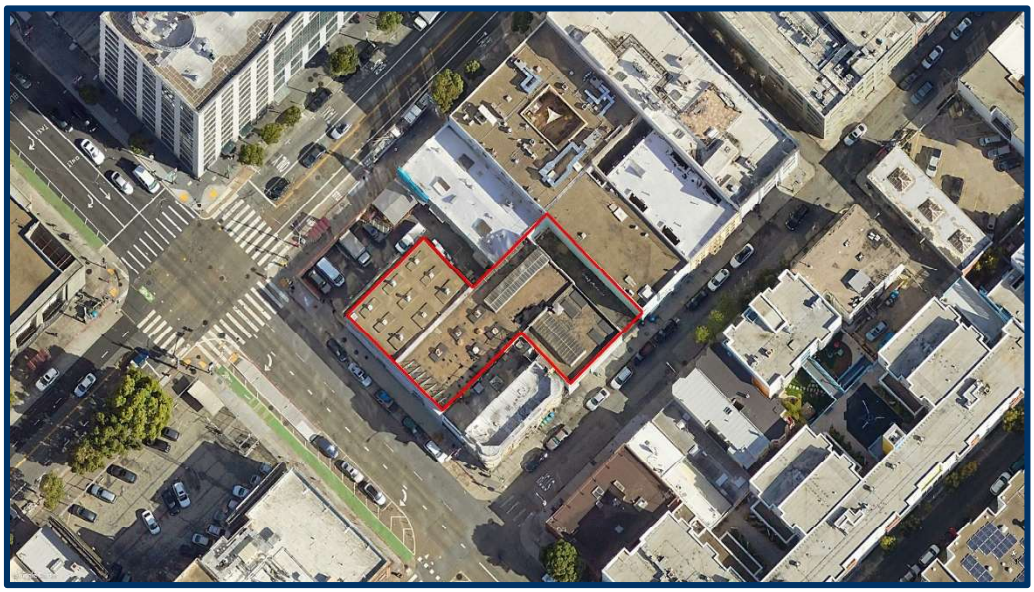
Highest and Best Use

As-If Vacant: Remain fenced, vacant land to support the underground electrical transmission line and improvements.

As-Is Improved: The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

PG&E Property #33: Substation I

SUBJECT PROPERTY PHOTOGRAPH



Substation I (Photo Source: Google Earth)

Substation I (Photo Source: Google Earth)

Site Description

Location/ Access: Substation I is located on 8th Street, between Mission Street and Minna Street, in the Mid-Market and Civic Center areas. It is assigned to a physical address at 117 8th Street, San Francisco and is further identified as Assessor's Parcel Number (APN) 5067-001A.

Gross Land Area:	The property measures 10,000 square feet, or approximately 0.23 acre, per site dimension printed on the Assessor's Parcel Map.
Shape:	The site is essentially "L" shaped, providing frontages on both 8th and Minna Streets.
Topography:	Generally level
Drainage:	Adequate
Grade:	At street grade
Utilities:	All typical urban utilities are in place
Off-Site Improvements:	Street frontages are improved with sidewalks and curbing.
Site Improvements:	None – the structural improvements cover the entire lot
Interior or Corner:	Interior – mid-block
Signalized Intersection:	Yes
Flood Zone	Zone X, an area of minimal flood risk
Flood Map Panel/ Numbers	0602980118A
Flood Map Date	3/23/2021
Earthquake Fault Zone	The property is not located in an Alquist-Priolo Special Studies Zone for earthquake hazard. Earthquake hazard, however, is typical for the overall area.
Liquefaction Potential	Yes
Maher Ordinance Area	Based on a review of Maher Ordinance Area maps available at the CCSF Planning Department website, the property is identified as being "In" the Maher Ordinance Area.
Environmental Issues	None known. The site is a part of an operating electrical corridor with a special purpose substation use. A review of regional and state databases did not reveal the existence of site contamination and/or remediation work. The potential for environmental contamination exists; for the purposes of this appraisal, the site is appraised as environmentally clean.
Planning Area /Zoning/ Height & Bulk:	The site is within the land use jurisdiction of the City and County of San Francisco and is within the West SoMA Planning District. The assigned zoning/land use designations are W-MUG ("West SoMA Mixed Use General") and MUO ("Mixed-Use Office") districts; the maximum building height is 65 feet.

Site Improvements

Number of Buildings:	One
Approx. Building Height:	33 feet to 39 feet
Number Stories/ Floor Levels:	One story plus mezzanine for equipment placement and storage.
Construction Class (Marshall Valuation Services):	C
Construction Quality:	Good
Gross Building Area (GBA):	10,950 square feet.
Floor Area Ratio:	Floor Area Ratio (building area-to-land) is 1.095.
Year Built:	Reported/estimated construction date is about 1909.
Renovated:	No
Historical Designation	The building is age-eligible but is not historically designated. It is, however, assigned to both the California and National Registers of Historic Districts.
Actual Age:	Estimate 96 Years
Effective Age:	80
Typical Building Life:	70
Remaining Economic Life:	4
Foundation	Concrete
Building Frame	Concrete
Exterior Walls	Poured in-place concrete
Roof Material	Composite
Electrical/ Plumbing	Adequate
Heating/ Cooling	No
Fire Sprinklers/ Protection	None
Elevators	One
Comments:	The building was decommissioned for electrical transmission and distribution use. It is currently vacant and used for storage. CCSF did not appraise this property in its Opening Testimony, and so far, CCSF has maintained; we are informed that it does not wish to take it. Nonetheless, PG&E asked us to include the property in this appraisal because it is an asset in the City that PG&E holds for purposes of providing electrical service in the City. PG&E has informed us that it expects to need Substation I to serve San Francisco customers starting in about five years. The substation is geographically proximate to the Mission Substation, which is operating near its capacity. Once the Mission Substation runs out of capacity, PG&E plans to use Substation I to serve the remaining load.

We understand PG&E's position to be that, if CCSF takes PG&E's transmission and distribution system in San Francisco, it should also take Substation I to enable CCSF to provide the same service that PG&E would provide absent the taking. If the property is not taken, whereas the rest of the properties are, then its value would largely be a stranded (severance) cost.

Highest and Best Use

As-If Vacant:	Development with use consistent with CCSF zoning, general plan, and land use ordinances.
As-Is Improved:	The existing use as an operating segment of the larger integrated electrical transmission and distribution utility corridor.

Property Description – PG&E's Private Easement Interests

Overview

This section of the report provides a description of the real property appraised in this report *other than* fee simple properties.

PG&E's private Easement Interests include over 2,400 unique easements. These easements were acquired over time, dating back to an era around PG&E's beginning in 1905 and the CPUC's forming in 1911. Prices paid, terms, and conditions for these acquisitions are unknown with many reflecting "no consideration" on the face of the recording documents. These land rights, by way of easement grants, represent an assemblage and an improvement of the operating electrical grid over time.

By way of background, the California Public Utilities Commission Electric Rules establish regulations that govern the interconnection and extension of electric utility service in California. PG&E abides by the Electric Rules.

Electric Rule 15 addresses distribution line extensions which are necessary to connect new commercial areas and neighborhoods to existing distribution lines. Electric Rule 16 addresses service line extensions, which connect distribution lines to a customer's electric meter.

PG&E's Distribution and Service Extension Agreement – Provisions (Form 62-0982, dated January 2024) set forth how services are to be installed in accordance with PG&E's Rules, 2, 15, and 16.

Paragraph 15 – Land Rights states:

> "*Where formal rights-of-way, easements, land leases, or permits are required by PG&E for the installation of the facilities on or over Applicant's property, or the property of others, Applicant understands and agrees that PG&E shall not be obligated to install the Facilities or accept the facilities installed by Applicant or the approved contractor unless and until any necessary permanent rights-of-way, easements, land leases, or permits, satisfactory to PG&E, are granted to or obtained for PG&E without cost to or condemnation by PG&E; however, if PG&E is unable to obtain such land rights, Applicant shall obtain them. Such easement shall include the right of access and right to trim trees as necessary to maintain required legal clearances from overhead wires*".

Paragraph 16 – Acceptance and Conveyance states:

> "*In accordance with the PG&E's General Terms and Conditions attached, and upon (a) PG&E's receipt of any required formal rights-of-way, easements, leases, and permits, and (b) PG&E's pressurization and energization of facilities installed by Applicant, Applicant hereby grants and conveys to PG&E, its successors and assigns, all rights, title and interest in and to all such work and facilities, free and clear of all liens and encumbrances*".

Accordingly, while these easement rights may have been acquired without a documented transfer price or cost to PG&E, these land rights were clearly exchanged for considerable value.

Furthermore, enumeration of the true consideration may not have been monetized in dollars, however the value in exchange was a quid pro quo between the utility purveyor and the beneficiary of electrical distribution and service, i.e. the provider/grantor of the easement. There was considerable value in the exchange of easement land rights for electrical service, allowing the user of this commodity to enhance the value of its real property.

Any historical consideration memorialized through transfer tax conversion, or any other means, is not time relevant to today's task of determining the fair market value of PG&E's electrical grid as of July 27, 2021. Additionally, these fragmented transactions are not comparable to the Larger Parcel's highest and best use as a network of assembled corridors operating as an electric grid.

Easement documents provided by PG&E were randomly selected to determine type, purpose, rights, length, width, area content and location. Due to the significant number of easements requiring research and examination by PG&E, PG&E determined that in the best interest of the company and its customers, a complete, detailed, and exhaustive review of over 2,400 unique easements was not financially practical, would require an undue consumption of time and cost, and that a reasonable alternative method, a circuit mile analysis, would adequately define and allow valuation of these easement interests.

PG&E utilized the San Francisco FF Electric Master dated 12-31-2021 to identify total "circuit miles". The circuit miles are expressed as a linear distance. PG&E has defined the locations for each of the five (5) types of electric corridor segments, identified as follows:

- Electric Transmission – Underground ("ET-UG")
- Electric Transmission – Overhead ("ET-OH")
- Electric Distribution – Underground Facilities Management ("ED-UFM")
- Electric Distribution – Underground ("ED-UG")
- Electric Distribution – Overhead ("ED-OH")

Each of the five (5) categories of electric corridor segments was reviewed, inventoried, and analyzed utilizing the PG&E GIS mapping of "Private" circuit miles. "Private" circuit miles, reasonably translated as private easement lengths, represent those portions of the electric power system energy grid traversing private property, whereby PG&E was conferred use and occupancy by way of easements (subsurface, surface, and/or aerial). Furthermore, the identified easement interests, by way of a circuit mile study, cover easements situated only within CCSF jurisdiction.

PG&E also provided estimated average physical widths for Transmission and Distribution easements which were relied upon for valuation purposes. The assumed historical widths are reported as forty-five (45) feet for Transmission corridor segments and ten (10) feet for Distribution corridor segments. PG&E notes that the widths of easements have varied and changed with operational and maintenance needs throughout the years. With technology and design changes, PG&E's current practice is to acquire a 30-foot-wide easement for Distribution Overhead and a 10-foot-wide easement for Distribution Underground. So, the overall assumed width for Distribution, Overhead, at ten (10) feet, is considered conservative as compared to thirty (30) feet for current practices.

The "circuit" miles (transmission and distribution) of corridor segments are situated throughout San Francisco. The following aerial exhibit depicts the electric transmission and electric distribution corridor within CCSF. The orange segments represent portions of the network occupying public property and public rights-of-way (franchises, licenses, agreements, service extensions or other forms of use and occupancy); the green segments represent portions of the network (private easement interests) occupying privately owned lands; and the yellow segments represent segments within PG&E fee owned properties.

PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - PUBLIC AND PRIVATE
CITY AND COUNTY OF SAN FRANCISCO
ELECTRIC TRANSMISSION (UNDERGROUND AND OVERHEAD)
ELECTRIC DISTRIBUTION (UNDERGROUND FACILITIES MANAGEMENT, UNDERGROUND AND OVERHEAD)

The linear distances (linear feet and miles) and land areas (square feet and acres) for the five (5) distinct private corridor segments (ET-UG, ET-OH, ED-UFM, ED-UG, ED-OH) are detailed in the exhibit on the following page.

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PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - LINEAR DISTANCE AND LAND AREA - PRIVATE
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

DISTANCE - PRIVATE	ELECTRIC TRANSMISSION ("ET")			ELECTRIC DISTRIBUTION ("ED")				TOTAL	
	ET - UG	ET - OH	ET - TOTAL	ED - UFM	ED - UG	ED - OH	ED - TOTAL	Linear Feet	Circuit Miles
Circuit Miles - Allocation									
Private Circuit Miles									
PG&E Easement	2.157 miles	0.000 miles	2.157 miles	54.020 miles	20.874 miles	60.504 miles	135.399 miles		137.56 miles
PG&E Fee Owned	0.674 miles	0.401 miles	1.075 miles	2.899 miles	0.008 miles	0.472 miles	3.379 miles		4.45 miles
Total - Miles	2.831 miles	0.401 miles	3.232 miles	56.919 miles	20.882 miles	60.976 miles	138.777 miles		142.01 miles
Circuit Linear Feet - Allocation									
Private Circuit Linear Feet									
PG&E Easement	11,387.28 lf	0.00 lf	11,387.28 lf	285,224.99 lf	110,216.29 lf	319,463.15 lf	714,904.43 lf	726,291.71 lf	
PG&E Fee Owned	3,558.96 lf	2,117.80 lf	5,676.76 lf	15,306.01 lf	42.24 lf	2,490.32 lf	17,838.57 lf	23,515.33 lf	
Total - Linear Feet	14,946.24 lf	2,117.80 lf	17,064.04 lf	300,531.00 lf	110,258.53 lf	321,953.47 lf	732,743.00 lf	749,807.04 lf	

LAND AREA - PRIVATE	ELECTRIC TRANSMISSION ("ET")			ELECTRIC DISTRIBUTION ("ED")				TOTAL	
	ET - UG	ET - OH	ET - TOTAL	ED - UFM	ED - UG	ED - OH	ED - TOTAL	Square Feet	Acres
Right of Way Width	45 feet	45 feet	45 feet	10 feet	10 feet	10 feet	10 feet		
Land Area - Square Feet									
Private									
PG&E Easement	512,428 sf	0 sf	512,428 sf	2,852,250 sf	1,102,163 sf	3,194,632 sf	7,149,044 sf	7,661,472 sf	175.883
PG&E Fee Owned	160,153 sf	95,301 sf	255,454 sf	153,060 sf	422 sf	24,903 sf	178,386 sf	433,840 sf	9.960
Total	672,581 sf	95,301 sf	767,882 sf	3,005,310 sf	1,102,585 sf	3,219,535 sf	7,327,430 sf	8,095,312 sf	185.843

PG&E PRIVATE EASEMENT INTERESTS	ELECTRIC TRANSMISSION ("ET")			ELECTRIC DISTRIBUTION ("ED")				TOTAL
	ET - UG	ET - OH	ET - TOTAL	ED - UFM	ED - UG	ED - OH	ED - TOTAL	
Right of Way Width	45 feet	45 feet	45 feet	10 feet	10 feet	10 feet	10 feet	
Circuit Miles	2.16 miles	0.00 miles	2.16 miles	54.02 miles	20.87 miles	60.50 miles	135.40 miles	137.56 miles
Circuit Linear Feet	11,387.28 lf	0.00 lf	11,387.28 lf	285,224.99 lf	110,216.29 lf	319,463.15 lf	714,904.43 lf	726,291.71 lf
Land Area								
Square Feet	512,428 sq. ft.	0 sq. ft.	512,428 sq. ft.	2,852,250 sq. ft.	1,102,163 sq. ft.	3,194,632 sq. ft.	7,149,044 sq. ft.	7,661,472 sq. ft.
Acres	11.764 acres	0.000 acres	11.764 acres	65.479 acres	25.302 acres	73.339 acres	164.119 acres	175.883 acres

This appraisal assignment excludes all "Public" circuit miles (interests within CCSF's public ownership derived from franchises, licenses, agreements, service extensions or other forms of use and occupancy) and focuses only on "Private" circuit miles for each of the five (5) types of electric corridor segments, also identified as "Private Easements": Electric Transmission - Underground (ET-UG), Electric Transmission - Overhead (ET-OH), Electric Distribution - Underground Facilities Management (ED-UFM), Electric Distribution - Underground (ED-UG), Electric Distribution - Overhead (ED-OH).

The five (5) "Private" electric corridor segments are discussed in the following sections. Any "Private" circuit miles situated within PG&E Fee-Owned parcels were removed from the inventory to avoid value duplication.

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Private Easements – Electric Transmission – Underground (ET-UG)

The following aerial exhibit depicts the private electric transmission – underground (ET – UG) portion of the electric transmission grid within CCSF. The ET-UG encompasses 2.16 miles or 11,387 linear feet, located primarily in the easterly portion of CCSF. Based upon a right-of-way width for transmission at 45 feet, the ET-UG encompasses 512,428 square feet or 11.764 acres.

PRIVATE ELECTRIC TRANSMISSION - UNDERGROUND (ET-UG)
CITY AND COUNTY OF SAN FRANCISCO

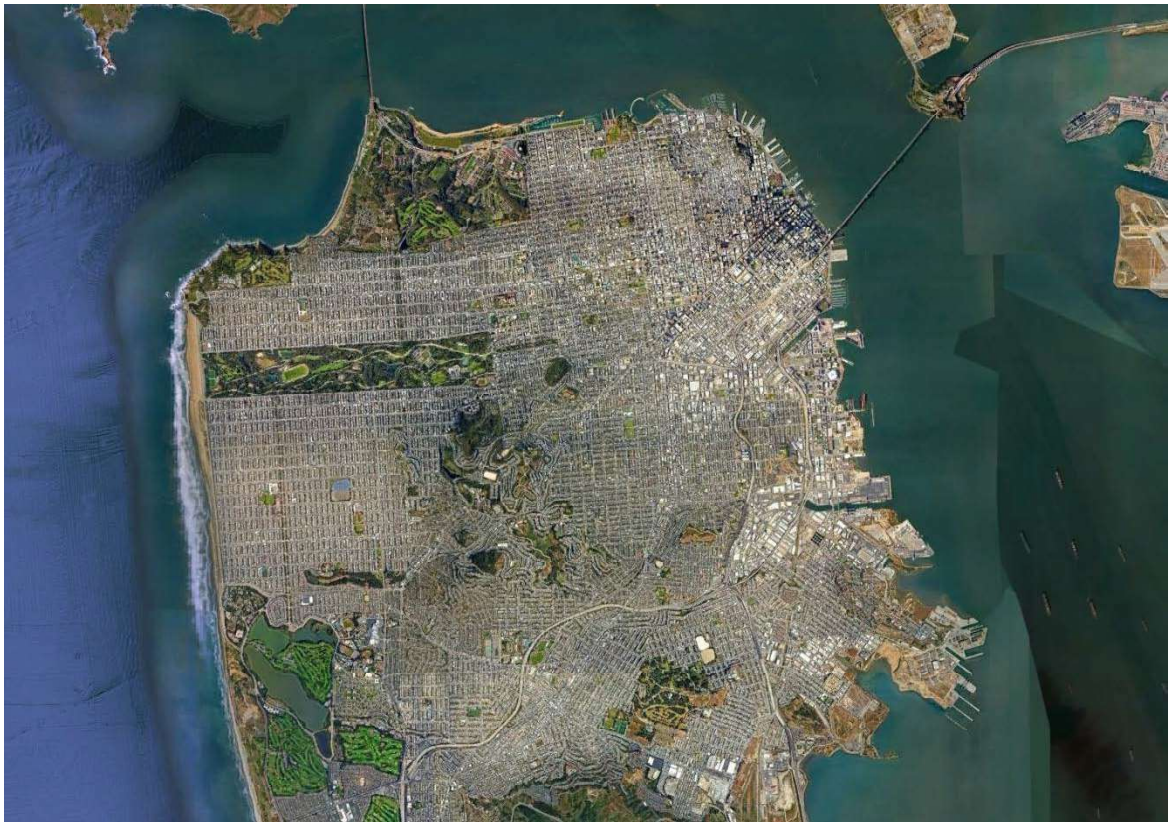
CIRCUIT MILES:	2.157	miles
LINEAR FEET:	11,387	linear feet
LAND AREA:	512,428	square feet
	11.764	acres
RIGHT-OF-WAY WIDTH:	45	feet

Private Easements – Electric Transmission – Overhead (ET-OH)

For electric transmission overhead (ET-OH), there are no transmission lines within privately owned property.

PRIVATE ELECTRIC TRANSMISSION - OVERHEAD (ET-OH)
CITY AND COUNTY OF SAN FRANCISCO

CIRCUIT MILES:	0.000	miles
LINEAR FEET:	0	linear feet
LAND AREA:	0	square feet
	0.000	acres
RIGHT-OF-WAY WIDTH:	45	feet



Private Easements – Electric Distribution – Overall

The following aerial exhibit depicts the entire private electric distribution network portions within CCSF comprised of ED-UFM, ED-UG, and ED-OH. Overall, the distribution portion of the network encompasses 135.399 miles or 714,904 linear feet, situated throughout CCSF. Based upon a right-of-way width for distribution at 10 feet, the combination of ED-UFM, ED-UG and ED-OH encompasses 7,149,045 square feet or 164.119 acres.

PRIVATE ELECTRIC DISTRIBUTION - UNDERGROUND FACILITIES MANAGEMENT (ED-UFM), UNDERGROUND (ED-UG), OVERHEAD (OH)
CITY AND COUNTY OF SAN FRANCISCO

CIRCUIT MILES:	135.399	miles
LINEAR FEET:	714,904	linear feet
LAND AREA:	7,149,045	square feet
	164.119	acres
RIGHT-OF-WAY WIDTH:	10	feet

Private Easements – Electric Distribution – Underground Facilities Management (ED – UFM)

The following aerial exhibit depicts the private electric distribution – underground facilities management (ED – UFM) portion of the electric distribution grid within CCSF. The ED-UFM encompasses 54.020 miles or 285,225 linear feet, scattered throughout CCSF. Based upon a right-of-way width for distribution at 10 feet, the ED-UFM encompasses 2,852,250 square feet or 65.479 acres.

PRIVATE ELECTRIC DISTRIBUTION - UNDERGROUND FACILITIES MANAGEMENT (ED-UFM)
CITY AND COUNTY OF SAN FRANCISCO

CIRCUIT MILES:	54.020	miles
LINEAR FEET:	285,225	linear feet
LAND AREA:	2,852,250	square feet
	65.479	acres
RIGHT-OF-WAY WIDTH:	10	feet

Private Easements – Electric Distribution – Underground (ED-UG)

The following aerial exhibit depicts the private electric distribution – underground (ED – UG) portion of the electric distribution grid within CCSF. The ED-UG encompasses 20.874 miles or 110,216 linear feet, situated throughout CCSF. Based upon a right-of-way width for distribution at 10 feet, the ED-UG encompasses 1,102,163 square feet or 25.302 acres.

PRIVATE ELECTRIC DISTRIBUTION - UNDERGROUND (ED-UG)
CITY AND COUNTY OF SAN FRANCISCO

CIRCUIT MILES:	20.874	miles
LINEAR FEET:	110,216	linear feet
LAND AREA:	1,102,163	square feet
	25.302	acres
RIGHT-OF-WAY WIDTH:	10	feet

Private Easements – Electric Distribution – Overhead (ED-OH)

The following aerial exhibit depicts the private electric distribution – overhead (ED – OH) portion of the electric distribution grid within CCSF. The ED-OH encompasses 60.504 miles or 319,463 linear feet, situated throughout CCSF. Based upon a right-of-way width for distribution at 10 feet, the ED-OH encompasses 3,194,632 square feet or 73.339 acres.

PRIVATE ELECTRIC DISTRIBUTION - OVERHEAD (ED-OH)

CIRCUIT MILES:	60.504	miles
LINEAR FEET:	319,463	linear feet
LAND AREA:	3,194,632	square feet
	73.339	acres
RIGHT-OF-WAY WIDTH:	10	feet

Zoning

Each category of easement (ET-UG, ET-OH, ED-UFM, ED-UG, ED-OH) was reviewed, inventoried, and analyzed utilizing the PG&E GIS mapping of "Private" circuit miles in conjunction with GIS zoning overlays. PG&E's private easements within CCSF total 137.57 miles, encompassing 7,661,472 square feet or 175.883 acres. The PG&E private easement interests traverse properties, either underground or overhead, within various zoning designations and zoning use districts. Each zoning use district and zoning designation is briefly summarized as follows:

Zoning Use District	Zoning Designation	
Residential House Character	RH-1	Residential, House-One Family
	RH-1(D)	Residential, House-One Family (Detached Dwelling)
	RH-1(S)	Residential, House-One Family with Minor Second Unit
	RH-2	Residential, House-Two Family
	RH-3	Residential, House-Three Family
Residential Mixed (House and Apartments)	RM-1	Residential, Mixed Low-Density
	RM-2	Residential, Mixed-Moderate Density
	RM-3	Residential, Mixed-Medium Density
	RM-4	Residential, Mixed-High Density
Residential Commercial Combined	RC-3	Residential-Commercial Medium Density
	RC-4	Residential-Commercial High Density
Residential Transit Oriented	RTO	Residential, Transit-Oriented Neighborhood
	RTO-M	Residential, Transit-Oriented Mission Neighborhood
Downtown Residential	RH DTR	Rincon Hill Downtown Residential
	SB DTR	South Beach Downtown Residential
	TB DTR	Transbay Downtown Residential
Commercial	C-2	Community Business
	C-3-G	Downtown General
	C-3-O(SD)	Downtown Office Special Development
	C-3-R	Downtown Retail
	C-3-S	Downtown Support
Neighborhood Commercial	NC-1	Neighborhood Commercial Cluster (1 Commercial Story)
	NC-2	Neighborhood Commercial Small Scale (2 Commercial Stories)
	NC-3	Neighborhood Commercial Moderate Scale (3+ Commercial Stories)
	NCD	Neighborhood Commercial Districts

	NC-S	Neighborhood Commercial Shopping Center
Neighborhood Commercial Transit	NCT	Hayes-Gough Neighborhood Commercial Transit District
	NCT-1	Neighborhood Commercial Transit Center
	NCT-2	Small-Scale Neighborhood Commercial Transit
	NCT-3	Moderate-Scale Neighborhood Commercial Transit
	RCD	Regional Commercial
Eastern Neighborhoods Mixed Use	CMUO	Central SoMa Mixed Use Office
	MUG	Mixed Use General
	MUO	Mixed Use Office
	MUR	Mixed Use Residential
	RED	Residential Enclave District
	RED-MX	Residential Enclave District Mixed
	SALI	Service/Arts/Light Industrial
	SPD	South Park
	UMU	Urban Mixed Use
	WMUG	Western SoMa Mixed Use General
	WMUO	Western SoMa Mixed Use Office
Chinatown Mixed Use	CCB	Chinatown Community Business
	CRNC	Chinatown Residential Neighborhood Commercial
	CVR	Chinatown Visitor Retail
Parkmerced Use	PM-MU1	Parkmerced Mixed Use – Social Heart District
	PM-MU2	Parkmerced Mixed Use – Neighborhood Commons
	PM-OS	Parkmerced Open Space District
	PM-R	Parkmerced Residential
Miscellaneous	HP-RA	Hunter's Point Redevelopment Area
	MB-O	Mission Bay Office
	MB-RA	Mission Bay Redevelopment
	MR-MU	Mission Rock Mixed Use
	P70 MU	Pier 70 Mixed Use
	PPS-MU	Potrero Power Station Special Use District
Industrial	M-1	Light Industrial
	M-2	Heavy Industrial

Production, Distribution, Repair	PDR-1-B	Production Distribution & Repair – Light Industrial Buffer
	PDR-1-D	Production Distribution & Repair – Design
	PDR-1-G	Production Distribution & Repair – General
	PDR-2	Production Distribution & Repair – Core Production, Distribution & Repair
Public	P	Public

Exhibit "W-1", Zoning Description Summary, located in the Addenda section of this report, provides a narrative description of each zoning designation.

Exhibit "W-2", Zoning Designation and Use District Summary, located in the Addenda section of this report, provides an allocation of linear distance (linear feet) and land area (square feet) for each zoning designation within the five (5) easement categories (ET-UG, ET-OH, ED-UFM, ED-UG, ED-OH).

A summary version of **Exhibit "W-2"** is presented on the following page, quantifying the land area within each zoning use district for the five easement categories. When considering all five (5) private easement categories, approximately 58% of the land area is located within "Residential" zoned districts, followed by approximately 15% within "Public" zoned district, 8% within various "Commercial" zoned districts, 7% within "Industrial" and "Production, Distribution & Repair" zoned districts, representing 88% of all zoning use districts. The remaining 12% are located within "Mixed Use", "Parkmerced", and "Miscellaneous" zoning use districts.

ZONING ALLOCATION - BY USE DISTRICT
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

ZONING USE DISTRICT	ELECTRIC TRANSMISSION ("ET")			ELECTRIC DISTRIBUTION ("ED")				TOTAL
	ET - UG	ET - OH	ET - TOTAL	ED - UFM	ED - UG	ED - OH	ED - TOTAL	
Land Area Allocation								
Residential, House Character	120,617 sf	0 sf	120,617 sf	981,755 sf	318,001 sf	2,324,524 sf	3,624,280 sf	**3,744,897 sf**
Residential, Mixed (Houses & Apartments)	33,978 sf	0 sf	33,978 sf	267,411 sf	72,085 sf	116,185 sf	455,681 sf	**489,659 sf**
Residential-Commercial Combined	0 sf	0 sf	0 sf	60,456 sf	291 sf	84 sf	60,831 sf	**60,831 sf**
Residential Transit Oriented	0 sf	0 sf	0 sf	67,314 sf	0 sf	2,757 sf	70,071 sf	**70,071 sf**
Downtown Residential	0 sf	0 sf	0 sf	54,298 sf	0 sf	182 sf	54,480 sf	**54,480 sf**
Commercial	0 sf	0 sf	0 sf	223,723 sf	39,704 sf	5,649 sf	269,076 sf	**269,076 sf**
Neighborhood Commercial	11,712 sf	0 sf	11,712 sf	168,649 sf	30,444 sf	32,560 sf	231,653 sf	**243,365 sf**
Neighborhood Commercial Transit	0 sf	0 sf	0 sf	103,247 sf	0 sf	10,856 sf	114,103 sf	**114,103 sf**
Eastern Neighborhoods Mixed Use	54,612 sf	0 sf	54,612 sf	156,551 sf	0 sf	6,574 sf	163,125 sf	**217,737 sf**
Chinatown Mixed Use	0 sf	0 sf	0 sf	4,240 sf	0 sf	261 sf	4,501 sf	**4,501 sf**
Parkmerced Use	0 sf	0 sf	0 sf	56,764 sf	2,789 sf	13,319 sf	72,871 sf	**72,871 sf**
Miscellaneous	39,005 sf	0 sf	39,005 sf	210,708 sf	178,657 sf	160,782 sf	550,147 sf	**589,152 sf**
Industrial	1,198 sf	0 sf	1,198 sf	21,228 sf	65,354 sf	56,646 sf	143,229 sf	**144,427 sf**
Production, Distribution & Repair	109,204 sf	0 sf	109,204 sf	174,933 sf	17,168 sf	90,192 sf	282,293 sf	**391,497 sf**
Public	142,102 sf	0 sf	142,102 sf	300,971 sf	377,670 sf	374,060 sf	1,052,701 sf	**1,194,803 sf**
Total - Square Feet	512,428 sf	0 sf	512,428 sf	2,852,248 sf	1,102,163 sf	3,194,631 sf	7,149,042 sf	**7,661,470 sf**
Total - Acres	11.764 acres	0.000 acres	11.764 acres	65.479 acres	25.302 acres	73.339 acres	164.119 acres	**175.883 acres**
Circuit Miles	2.16 miles	0.00 miles	2.16 miles	54.02 miles	20.87 miles	60.50 miles	135.40 miles	**137.56 miles**
Allocation Percentage								
Residential, House Character	23.54%	0.00%	23.54%	34.42%	28.85%	72.76%	50.70%	**48.88%**
Residential, Mixed (Houses & Apartments)	6.63%	0.00%	6.63%	9.38%	6.54%	3.64%	6.37%	**6.39%**
Residential-Commercial Combined	0.00%	0.00%	0.00%	2.12%	0.03%	0.00%	0.85%	**0.79%**
Residential Transit Oriented	0.00%	0.00%	0.00%	2.36%	0.00%	0.09%	0.98%	**0.91%**
Downtown Residential	0.00%	0.00%	0.00%	1.90%	0.00%	0.01%	0.76%	**0.71%**
Commercial	0.00%	0.00%	0.00%	7.84%	3.60%	0.18%	3.76%	**3.51%**
Neighborhood Commercial	2.29%	0.00%	2.29%	5.91%	2.76%	1.02%	3.24%	**3.18%**
Neighborhood Commercial Transit	0.00%	0.00%	0.00%	3.62%	0.00%	0.34%	1.60%	**1.49%**
Eastern Neighborhoods Mixed Use	10.66%	0.00%	10.66%	5.49%	0.00%	0.21%	2.28%	**2.84%**
Chinatown Mixed Use	0.00%	0.00%	0.00%	0.15%	0.00%	0.01%	0.06%	**0.06%**
Parkmerced Use	0.00%	0.00%	0.00%	1.99%	0.25%	0.42%	1.02%	**0.95%**
Miscellaneous	7.61%	0.00%	7.61%	7.39%	16.21%	5.03%	7.70%	**7.69%**
Industrial	0.23%	0.00%	0.23%	0.74%	5.93%	1.77%	2.00%	**1.89%**
Production, Distribution & Repair	21.31%	0.00%	21.31%	6.13%	1.56%	2.82%	3.95%	**5.11%**
Public	27.73%	0.00%	27.73%	10.55%	34.27%	11.71%	14.73%	**15.59%**
Total - Square Feet	100.00%	0.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**

Highest and Best Use

This is an extraordinarily unique, special purpose property, primarily and historically assembled from portions of adjacent properties. There is no relevant market upon which to compare.

Highest and best use is the reasonably probable use of property that results in the highest value. To be at the highest and best use, the use must be legally permissible, physically possible, financially feasible and maximally productive.

Larger Parcel and the highest and best use are interrelated. The determination of the Larger Parcel requires an analysis of the three classic common unities: ownership, contiguity, and use. More specifically, PG&E controls land in fee and as easements, that are under the beneficial control of a single entity and have the same, or an integrated, highest and best use. Elements include the recognition of a unity of ownership, a unity of physical and / or constructive contiguity, or proximity, as it bears on the highest and best use of the property, and on a unity of use as an integrated economic unit.

Physically and legally, PG&E's property and property rights are an assemblage of land (fee-owned) and strips of land (tethered together by easements, licenses, franchises, leases, and other agreements) improved, utilized, and operated for electrical transmission and distribution purposes, i.e., an "assembled corridor". It is a collection of integrated properties, subsequently improved with various facilities, forming an electronic transmission and distribution network / corridors laid out into an energy grid. PG&E's energy grid, its Parent Holding / Larger Parcel, is comprised of many system facilities throughout Northern and Central California, representing its power system.

This power system energy grid is comprised of a collection of land segments forming corridors, owned by and/or under the beneficial interest and control of PG&E, otherwise physically and/or constructively contiguous as it relates to highest and best use, and integrated into a single unified use functioning as an already-assembled network of utility corridors, with transmission systems, distribution systems and substations forming an energy grid designed to deliver reliable energy to a mix of customers throughout San Francisco, California. This is the proposed Part Taken.

It was created historically by acquiring and assembling portions of property, segments that when joined together generate greater utility and opportunity, maximizing the highest and best use, specifically used as a power system electric energy grid.

In conclusion, the highest and best use of the Subject Property, a collection of land segments and easement interests controlled by and/or under the beneficial interest and control of PG&E, otherwise physically and/or constructively contiguous as it relates to highest and best use, and integrated into a single unified use functioning as a network of utility corridors and substations forming an energy grid and delivering reliable energy to a mix of customers throughout San Francisco, California, is being put to its highest and best use, as if vacant and as improved. This is a unique, special purpose property.

In sum, the properties' highest and best use, and value, reflect their unique and special purpose use, as a larger parcel. Individually, property (land and building and site improvements) and easement

interests reflect their physically possible and legally permissible uses, including by respective zoning districts and planning regulations, and their respective financially feasible uses that return the highest fair market values in a competitive marketplace. Fair market value of the land and property rights are measured on the cost to replace. PG&E is competing with market participants seeking to maximize use that consequently will pay the highest (maximized) price.

Valuation Approaches

The fundamental purpose of an appraisal is to estimate value. Basic to the concept of valuation is the principle of substitution, the rationale that when property is replaceable, its value tends to be set by the cost of acquiring an equally desirable substitute property or income.

Each of the traditional approaches to value, Cost-Summation, Sales Comparison, and Income, utilizes the principle of substitution in an appropriate manner, drawing upon the experience of the marketplace in different ways.

While the applicability of each traditional approach and ultimately the Corridor Valuation Approach is discussed, note again that the appraisal task is to provide a fair market value opinion of PG&E's real property interest in 33 fee-owned sites – consisting of 31 substations and two electric utility-corridor sites – consisting of land and building improvements it owns in the CCSF jurisdiction, together with the Martin Substation in the county of San Mateo, and over 2,400 private transmission and distribution easements, totaling an additional 137.56 net private circuit miles.

The total of these value components, adjusted for the enhancement factor consistent with its highest and best use, reflects the line-item for "FMV – Land", which will be utilized in the Cost Approach ("RCNLD") prepared by other experts, assisting in providing an indication of the fair market value of the total Parts Taken.

- The **Cost Approach ("RCNLD")**, *applied in this appraisal to substation building structures and site improvements (real property),* is a method which estimates the reproduction or replacement cost new of the existing structure with optimal utility. An estimate of total accrued depreciation (physical, functional, and economic) is then deducted from the cost of reproduction or replacement of the structure. The land value is added to the depreciated reproduction/replacement cost new to arrive at a value indication by the Cost Approach.

- The **Sales Comparison Approach**, *indirectly applicable in this appraisal (1) to derive the underlying land value to be used within the Cost Approach ("RCNLD") and (2) as a companion method to accompany the Across-the-Fence Method*, is a method of estimating market value based upon recent sales of comparable properties. Comparable sales are adjusted for various characteristics which include, but are not limited to, the following elements of comparison: property rights conveyed, financing, conditions of sale, market conditions (time), location, physical characteristics, economic characteristics, use and non-realty items.

- The **Income Approach**, *not applicable in this appraisal*, is based primarily on the earning power generated by the property. The future benefits inherent in the property are converted, by means of one or more capitalization techniques, to a present value.

Tantamount to the application of each of these approaches and the valuation process is the highest and best use analysis. The opined use, based upon such analysis, will then determine the relevancy of each approach.

However, the three traditional approaches presume an active market with sufficient supply and sufficient market demand to comprise a meaningful and competitive market to provide evidence to shed light on value by way of the application in each approach.

As previously discussed, PG&E's operating electrical grid is an integrated network of utility corridors and substations, including both transmission and distribution facilities serving the city and county of San Francisco, California. This is a special purpose property. It is extraordinarily unique. The real estate components of such corridors / energy grids, vacant or improved, are not typically bought and sold on the open market and therefore, the commonly employed Sales Comparison Approach is not available for use and application.

A search for vacant and similar energy grid land transactions did not reveal any meaningful market data. As a result, and in part, relying upon CCP § 1263.320 (b) "The fair market value of property taken for which there is ***no relevant, comparable market*** [emphasis added] is its value on the date of valuation as determined by ***any method of valuation that is just and equitable***" [emphasis added].

Additional support in selecting the proper just and equitable valuation method is derived from recognizing the Subject Property's highest and best use as an operating electrical energy grid. It is an integrated network of utility corridors, and hence corridor valuation techniques are required in the determination of fair market value for PG&E's interest in its fee-owned properties and its private easements.

Therefore, the primary and only just and equitable measure of value in the absence of any relevant comparable market is by way of a value determination associated with the nature of the rights of this corridor real estate.

Corridor valuation is defined as:

> "*The process of estimating value associated with rights to corridor real estate. Valuation approaches may include methods such as across-the-fence method, sales comparison, the alternate route (cost avoidance) approach, and estimate of net liquidation value.*" [38]

Valuation Methodology – "Across the Fence" (ATF)

Background

Once again, PG&E's property is an assemblage of land (fee-owned) and strips of land (easements, licenses, franchises, leases, and other agreements) improved, utilized, and operated for electrical transmission and distribution purposes, i.e., an "assembled corridor". It is a collection of integrated properties, subsequently improved with various facilities, forming an electronic transmission and distribution network / corridors laid out into an energy grid. PG&E's energy grid is comprised of many system facilities throughout Northern and Central California.

This power system energy grid is comprised of a collection of land segments forming corridors, owned by and/or under the beneficial interest and control of PG&E, otherwise physically and/or constructively

[38] *The Dictionary of Real Estate Appraisal*, Seventh Edition; Appraisal Institute; 2022; Page 43.

contiguous as it relates to highest and best use, and integrated into a single unified use functioning as a network of utility corridors, with transmission systems, distribution systems and substations forming an energy grid designed to deliver reliable energy to a mix of customers throughout San Francisco.

This is a special purpose property, primarily and historically assembled from portions of adjacent properties. There is no relevant comparable market upon which to compare to the Subject Property, either vacant or improved.

Therefore, the primary and only just and equitable measure of value in the absence of any relevant comparable market is by way of a value determination associated with the nature of the rights of this corridor real estate, beginning with the Across-the-Fence Method.

Elements of Corridor Valuation date back to the Federal Valuation Act of March 1, 1913 ("Act"), where the Interstate Commerce Commission ("ICC") was directed to "investigate, ascertain and report the value of all the property owned or used by every common carrier subject to the provisions of this act." In 1918, the ICC set forth valuation rules and instructions that were being imposed upon these carriers, including railroads, to make them accountable for their land holdings and for rate setting purposes.

In guiding the valuations for these land holdings, the ICC promotes a determination as to the present value of land as measured by the "....value of the adjacent and adjoining lands computed in acres," clearly an "across-the-fence" or "ATF" methodology in evaluating corridors.

Fast forward sixty years later and the ATF Method continues to be utilized. Dolman and Seymour, in their 1978 article titled "Valuation of Transportation / Communication Corridors,"[39] were two of the first experienced real estate appraisers, both designated MAIs, to present relatively thorough research and academic thoughts on the valuation of transportation / communication / utility corridors. They note:

> *If the property to be valued is judged to enjoy the characteristics of a transportation / communication corridor, we are seeking a "value for corridor use". This requires an understanding of three additional concepts: highest and best alternative use, ATF value, and enhancement factor.*
>
> *The concept of highest and best alternative use speaks to the question: "What would the highest and best use of each segment of the corridor be if it enjoyed the characteristics of typical parcels found in the immediate vicinity, rather that its actual size, shape, and access attributes?" It is a matter of opinion as to what use each segment of the corridor would be put if its physical characteristics were "typical" of parcels found in the vicinity instead of being configured as a corridor.*
>
> *The concept of ATF value speaks to the question: "What is the unit rate at which typical parcels with this estimated noncorridor highest and best use sell in the market?" Each segment of the*

[39] John P. Dolman, MAI, CRE and Charles F. Seymour, MAI, CRE, Valuation of Transportation / Communication Corridors, The Appraisal Journal (October 1978), 509-522.

> *corridor is considered to be either part of, or made up of, one or more such typical parcels, thereby disregarding the size, shape, and access characteristics of the segment. The ATF value for a segment of a corridor is the unit rate for the typical parcel times the area of the segment.*
>
> *The concept of an enhancement factor speaks to the question: "How much more or less than ATF value is the entire corridor worth because of its ability to connect the end points?" It expresses the relationship between ATF value and value for corridor use.*[40]

According to real estate appraiser Arthur G. Rahn, Dolman and Seymour's three-step approach describes nearly identical steps outlined in the Act of 1913 and the 1918 ICC document, although the authors reportedly had no knowledge of the prior documents.[41]

The now widely accepted land valuation technique utilized in the appraisal of corridors is the **Across-the-Fence (ATF) Method**. It is a method used to develop a value indication based on a comparison to sale prices of abutting lands, particularly when there is no relevant comparable market and /or data to rely upon.

Once the ATF value is determined, a corridor factor or enhancement factor is a potential additional adjustment to reflect the inherent increment of value, the plottage value, associated with the corridor having already been assembled. This assembled corridor, or as is the case with the PG&E real property, produces greater utility and higher productivity by maximizing the highest and best use as a power system energy grid.

The ATF indication plus the enhancement factor is the corridor valuation technique employed to determine the fair market value of PG&E's real property interests in this real estate.

In the traditional Sales Comparison Approach, market value is determined by comparing similar properties that have sold, are listed for sale, or are under contract (i.e., recent purchase offers accompanied by a cash or equivalent deposit) a reasonable time before or after the date of value to the Subject Property. A major premise of the Sales Comparison Approach is that the fair market value of a property is directly related to the prices of comparable and competitive properties.

In the ATF Approach, these comparable sales are better treated as "market indicators" and the premise is that the fair market value of a corridor is based upon nearby and adjacent land prices, inherently reflecting the value of the lands to be assembled to create the corridor, and then adjusted for the plottage which promotes and supports the highest and best use as a corridor.

The traditional Sales Comparison Approach focuses on similarities and differences among properties and transactions that affect value. These may include differences in the property rights appraised, the motivations of competing buyers and sellers, financing terms, market conditions at the time of sale, size, location, physical features, and, if the properties produce income, economic characteristics.

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[40] John P. Dolman, MAI, CRE and Charles F. Seymour, MAI, CRE, Valuation of Transportation / Communication Corridors, The Appraisal Journal (October 1978), 518.

[41] Arthur G. Rahn, Across the Fence Methodology for Valuation of Corridors: What Is It and How Is It Used? The Appraisal Journal (July 2001), 271.

In the ATF adjustment construct, the market indicators utilized may have sold within a reasonable time before or after the date of value; they may be located within reasonable proximity to the Subject Property; however, may not be similar in respect to character, size, situation, usability, improvements, and economic characteristics. Unlike the traditional approach, the ATF approach typically does not include adjustments for size, shape, access, and topography. The rationale is that absent corridor use, the land within the corridor would be part of the adjacent parcels and share similar access, shape, and topography. Primary adjustments that *are* considered in the ATF analysis include property interest, conditions of sale, market conditions, location, proximity, and entitlement. Elements of comparison are tested against market evidence to determine which elements are sensitive to change and how they affect value. An enhancement factor is considered and applied only after recognizing the nature and quality of the highest and best use regarding the assembled electric utility corridor/grid.

Comparative analysis can be through a quantitative or qualitative process. Quantitative techniques employ paired data sets, statistical analyses, graphic analyses, trend analyses, cost-related analyses, and secondary data analyses. This method is mathematical in nature. Qualitative techniques employ relative comparison analyses, ranking analyses, and personal interviews.

All market data items have been verified with sources considered reliable and may include direct verifications with buyer, seller or broker involved in the transaction; documentary transfer tax / transaction fee per San Francisco Business and Tax Regulations Code, verifications on public records; and market data reporting systems including CoStar, MLS, and local real estate appraisers.

PG&E's Energy Grid in the CCSF Jurisdiction – Measured by ATF

This power system energy grid is comprised of a collection of land segments forming corridors, owned by and/or under the beneficial interest and control of PG&E, otherwise physically and/or constructively contiguous as it relates to highest and best use, and integrated into a single unified use functioning as a network of utility corridors, with transmission systems, distribution systems and substations forming an energy grid designed to deliver reliable energy to a mix of customers throughout San Francisco.

The Easement Interests have been inventoried and studied with respect to location, neighborhood land use district and zoning, and height, bulk, and density characteristics.

Fee-Owned Segments of the Corridor/ Energy Grid

The Fee-Owned properties include thirty-three (33) fee-owned sites containing a total of 50.352 acres within San Francisco and 36.784 acres in San Mateo County, including the related onsite substation building and site improvements. These thirty-three (33) properties represent individual segments or portions of the PG&E power system energy grid that have been independently analyzed by the Valbridge appraisal firm. Recognizing the non-corridor use of adjacent and nearby properties within the immediate and / or competitive neighborhood, "across-the-fence" land sales have been selected, intended to reflect prices for typical or similar adjacent and nearby properties that shed light on the contributory value of these land segments as a part of the entire energy corridor / grid.

The concluded value for each substation land segment reflects the ATF value either as a measure of the current value contribution of the ATF segment or hypothetically as an equivalent indication of the

cost to create the land component for that segment. The concluded ATF unit rate ($'s per square foot) is then applied to the area content of that segment to arrive at an indication of the ATF contribution for that segment within the corridor / energy grid. Ultimately, the ATF indicated value is adjusted for the corridor / energy grid highest and best use by the substation improvement contribution and the enhancement factor.

The land valuation technique utilized in the appraisal of corridors is the **Across-the-Fence (ATF) Method**. It is a method used to develop a value indication based on a comparison to abutting lands. In the valuation of real estate corridors, the value indicator concluded is based on a comparison with adjacent lands before the consideration of any other adjustment factors. In other words, the ATF value itself is not the fair market value.

Valuation Fee-Owned Properties: Cost Approach

Methodology

The cost approach yields fair market value (of the real property rights and improvements) by adding land value with the depreciated value of improvements, by calculating the costs new to build the property structures and site improvements – in this assignment the substation buildings and site improvements – then by deducting depreciation and obsolescence. Land value added to the depreciated value of the improvements results in the as-is or as-was, fair market value of the subject property(ies) as of the date of value (DOV).

In summary, the iterative steps in the cost approach are:

- Estimate Land Value – the as-was (as of DOV) fair market value of each fee-owned site.
- Estimate "RCN" – the as-was reproduction or replacement costs new ("RCN") of the improvements on each fee-owned site from cost sources, either actual costs or surveyed costs.
- Deduct Depreciation and Obsolescence – estimate and deduct the appropriate forms of depreciation, including obsolescence – i.e., less depreciation ("LD") – to yield reproduction or replacement cost new less depreciation (RCNLD) for the improvements on each fee-owned site.
- Value of Each Fee-Owned Site - add RCNLD of the improvements to the fair market value of the land for each fee-owned site; and,
- Total Value - the fair market value of PG&E's fee-owned properties is the sum of the values for each of the 33 fee-owned sites CCSF proposes to take.

Reproduction cost and *replacement* cost carry distinctly different meanings in appraisal and construction, and therefore in valuation.

- Reproduction cost is: *"The estimated cost to construct, at current prices as of the effective date of the appraisal, a duplicate or replica of the building being appraised, using the same or similar materials, construction standards, design, and quality of workmanship and embodying all the deficiencies, superadequacies, and obsolescence of the subject building."*

- Replacement cost is: *"The estimated cost to construct, at current prices as of a specific date, a substitute for a building or improvements, using modern materials and current standards, design, and layout."* Whereas the former costs the duplicate improvement, the latter costs a substitute improvement.[42]

Modern and modernized PG&E substation building-and-site improvements are specialized improvements in materials, construction standards, design, and quality of workmanship. Three GIS substation buildings (Embarcadero, Potrero, and Larkin) were recently constructed, providing actual and recent reproduction costs. The costs for turnkey building and site improvements for these sites, as constructed, were provided by PG&E.

[42] *The Dictionary of Real Estate Appraisal*, Seventh Edition, Appraisal Institute, Chicago IL, 2022, p. 163

The applicable RCN applied to these latter substations are, then, actual *reproduction costs new*. *Reproduction costs new* are applicable also to (1) the second Embarcadero Substation building constructed about 1974 and situated contiguous to the newer Embarcadero Building and to (2) the Mission Substation remodeled about 2013. *Replacement costs new* are applied from Marshall Swift Valuation Services costs to the remaining substation improvements – both building and site improvements.

The cost approach is based on the premise that a buyer of real property will pay no more for a specific property than the cost to reproduce or replace the improvements as-if new, less any accrued depreciation, plus payment of entrepreneurial incentive and land value. The approach is particularly relevant in valuing *special purpose property,* e.g., PG&E's real estate interests comprising its electrical grid corridor and improvements, where no relevant marketplace exists for same, i.e., where no comparable sales exist.

In summary, the cost approach incorporates five components: direct costs, indirect costs, entrepreneurial incentive, depreciation, and land value. Each component consists of the following elements:

Direct Construction Costs

Direct building costs include the basic labor and materials, equipment costs (not including special purpose equipment) and site improvements such as clearing and grading, landscaping, parking lot paving and marking, sidewalks and curbs, exterior lighting, public works agreements, area connections, and similar items. Direct construction costs are based on actual contracts and/or budgets, costs of comparable projects, or through cost estimating services.

Indirect Costs

Indirect costs include items such as professional fees (accounting, appraisal, architect, legal, engineering), interim financing (construction loan costs including points), points for placing permanent financing, settlement fees including title insurance and stamps, promotion and merchandising, and miscellaneous items including signs, contingencies, out-of-pocket expenses, and overhead. Except for construction financing, these are costs largely expended in the development approval stage, during the "entitlement" stage.

Entrepreneurial Incentive

Entrepreneurial incentive reflects the amount an entrepreneur expects to receive for their contribution to a project. Entrepreneurial incentive is distinguished from entrepreneurial profit (often called developer's profit) in that it is the expectation of future profit as opposed to the profit actually earned on a development or improvement. The applicability of each is considered in the valuation of the project.

Depreciation

Forms of depreciation include physical deterioration, which occurs due to normal wear and tear experienced during a property's life; functional obsolescence, which occurs due to changing market standards such as building materials, design, ceiling height, layout, and similar factors; and external obsolescence, which occurs due to forces external to the property.

Land – Fair Market Value of the Land Sites Being Acquired

The fair market value of the fee simple rights to be acquired in the appraised land, as developed within the land valuation section, is added to the reproduction/replacement cost new less depreciation (RNCLD) of the improvements (building and site). The resulting value is the indicated fair market value of the property.

Land Valuation – Before Enhancement Factor Analysis

The first step in the cost approach is the fair market value estimate of the land. Site value is most often priced or valued, or both, by the sales comparison approach. This approach analyzes closed sales or pending sales of properties similar to the property appraised, with focus and *comparative analysis* on the differences between the subject and the comparable, using the applicable elements of comparison.

The sales comparison approach is based on the economic principles of supply and demand, balance, externalities, and substitution, on the premise that a buyer would pay no more for a specific property than the cost of obtaining a comparable property with similar quality, utility, and perceived benefits of ownership in a competitive marketplace.

As discussed previously, PG&E's San Francisco substation sites aggregate as an integrated operating electric utility corridor comprised of the fee simple sites and easement property rights. The applicable land valuation is ATF, Across the Fence, involving the valuation analysis of nearby lands sales, with emphasis on zoning of adjacent lands, and on location and local market conditions. Other factors such as size and/or shape are not included in the adjustment process, unless the sale is unusually atypical of the sites comprising the corridor.

Unit of Comparison

The applicable unit of comparison reflects land use economics and how buyers and sellers use and buy/sell the property rights. The applicable unit of comparison of the subject and comparable sales is on a price per square foot (of land area) basis.

Elements of Comparison

Elements of comparison are the characteristics or attributes of properties and transactions that cause the prices of real estate to vary. The primary elements of comparison considered in sales comparison analysis are as follows: (A) **Transactional Characteristics** – (1) property rights conveyed; (2) financing terms; (3) conditions of sale; (4) market conditions; and (B) **Property Characteristics** – (5) location, (6) physical characteristics; (7) entitlements/development approvals; (8) zoning/land use; (9) among others.

Comparable Sales Data

To obtain and verify comparable sales of land properties, we conducted a search of public records, field surveys, interviews with knowledgeable real estate professionals in the area, and a review of our internal database. This search included investigations of land sales, listings, and pending transactions found, for example, in our database, and in commercial public databases such as CoStar and the regional Multiple Listing Service (MLS).

Transactions concluded to be the most comparable to the PG&E sites appraised are summarized in the table included on the following page. Sales are Numbered 1 through 72. This table represents the comprehensive list of comparable sales included in the valuation of the 33 PG&E fee sites and 137.57

circuit miles of easements. Comparable sales applicable to each valuation, each specific PG&E fee site and to the easement grid, for example, are selected from this Land Sale Summary. A Location Map follows the Land Sales Summary.

LAND SALE SUMMARY – COMPARABLE SALES 1 THROUGH 37

Comp #	Location	City	APN	COE	Size (sf)	Sale Price	Price per SF	District	Zoning	Height/Bulk	FAR	Entitled at Sale
1	524 Howard Street	San Francisco	3721-013	5/7/2019	12,266	$78,000,000	$6,359.04	SoMA/Rincon Hill	C-3-O (SD)	450-S (450)	30.11 (9.0:1)	Yes
2	325 Fremont Street	San Francisco	3747-012, 013, and 014	2/26/2015	6,434	$28,500,000	$4,429.59	SoMa/Rincon Hill	RH DTR	85/250-R (250)	22.12	Yes
3	525 Harrison Street	San Francisco	3764-063	6/26/2017	12,981	$36,000,000	$2,773.28	SoMa/Rincon Hill	RH DTR	65/250-R (250)	18.01:1	Yes
4	547 Howard Street	San Francisco	3736-110	4/22/2015	2,126	$6,300,000	$2,963.31	SoMa/Transbay	C-3-O (SD)	350-S (350)	9.0:1	No
5	555 Howard Street	San Francisco	3736-086	4/28/2015	8,250	$27,000,100	$3,272.74	SoMa/Transbay	C-3-O (SD)	350-S (350)	9.0:1	No
6	557 Howard Street	San Francisco	3736-107	5/1/2015	4,121	$12,250,000	$2,972.58	SoMa/Transbay	C-3-O (SD)	350-S (350)	9.0:1	No
7	901 Illinois Street	San Francisco	4110-012	2/13/2019	67,988	$24,000,000	$353.00	Bayview/Dogpatch	P70-MU	65-X (65)	5.0:1	Partial/Y
8	790 Pennsylvania Avenue	San Francisco	4167-013 and -011	3/3/2016	119,885	$35,000,000	$291.95	Potrero Hill	UMU (Lot 13)/ PDR-1-G (Lot	40-X (40)	3.0:1	Partial/Y
9	1755 Egbert Avenue	San Francisco	5431A-001-A & 001-Z	1/29/2021	70,446	$16,950,000	$240.61	Produce Market	PDR-2	65-J (65)	5.0:1	No
10	2270 Jerrod Avenue	San Francisco	5230-008	5/9/2022	154,883	$70,070,000	$452.41	Produce Market	PDR-2	65-J (65)	5.0:1	No
11	2150 Oakdale Avenue	San Francisco	5590A-003	5/7/2019	52,098	$13,750,000	$263.93	Produce Market	PDR-2	65-J (65)	5.0:1	No
12	2000 Marin Street	San Francisco	4346-003	4/30/2020	343,688	$63,600,000	$185.05	Central Waterfront	PDR-2	65-J (65)	5.0:1	No
13	430 Eddy Street	San Francisco	0334-0008	11/12/2020	3,578	$3,250,000	$908.33	Tenderloin	RC-4	80-T (80)	4.81:1	Yes
14	199 Turk and 180 Jones Streets	San Francisco	0343-014	11/30/2016	4,744	$4,000,000	$843.17	Tenderloin	RC-4	80-T-120-T (120)	4.81:1	Yes
15	530-540 Turk Street	San Francisco	0741-003, -004	6/27/2022	9,583	$3,850,000	$401.75	Tenderloin	RC-4	80-T (80)	4.81:1	No
16	500 Turk Street	San Francisco	0741-002	12/20/2016	18,906	$12,250,000	$647.94	Tenderloin	RC-4	80-T (80)	4.81:1	No
17	719-725 Larkin Street	San Francisco	0717-003	12/31/2015	5,998	$3,000,000	$500.17	Tenderloin	RC-4	80-T (80)	4.81:1	No
18	1550 Market Street	San Francisco	0836-006 & -007	11/24/2015	12,567	$23,000,000	$1,830.19	Market-Octavia	C-3-G	120-R-2 (120)	6.0:1	Yes
19	72-80 Ellis Street	San Francisco	0327-011	5/13/2015	8,420	$9,900,000	$1,175.77	Union Square	C-3-R	80-130-F (130)	6.0:1	Yes
20	1121-1125 Mission Street	San Francisco	3702-047	5/22/2015	12,402	$19,800,000	$1,596.52	SoMa/Mid-Market	C-3-G	120-X (120)	6.0:1	Partial/Y
21	30 Van Ness St	San Francisco	0835-004	5/5/2017	38,124	$70,000,000	$1,836.11	Market-Octavia	C-3-G	120/400-R-2; 140/520-R-2	6.0:1	No
22	1338-1370 Mission Street	San Francisco	3508-022, 024, 025 & 052	11/20/2015	18,901	$25,000,000	$1,322.68	WSoMa	C-3-G	120-X (120)/150-S (150)	6.0:1	No
23	2100 Mission Street	San Francisco	3576-001	8/22/2019	6,370	$4,800,000	$753.53	Mission	NCT	65-B (65)	1.8:1	Yes
24	1490 Ocean Avenue	San Francisco	3197-010	8/25/2015	10,237	$5,300,000	$517.73	Westwood Park	NCT	45-X (45)	1.8:1	No
25	1455 Irving Street	San Francisco	1770-051 & -052	11/7/2016	4,792	$1,570,000	$327.63	Inner Sunset	NCD	50//85-R-4	1.8:1	No
26	3820 24th Street	San Francisco	3651-079	5/20/2016	2,849	$2,100,000	$737.10	Noe Valley	NCD	1-Story	1.8:1	No
27	2550 Irving Street	San Francisco	1724-038	11/19/2021	19,162	$9,000,000	$469.68	Outer Sunset	NCD	40-X (40)	1.8:1	No
28A	42 & 44 Cook Street	San Francisco	1067-034	3/17/2023	3,000	$3,350,000	$1,116.67	Laurel Heights	RH-2	40-X (40)	1.8:1	Yes
28B	42 & 44 Cook Street	San Francisco	1067-034	2/3/2021	3,000	$1,670,000	$556.67	Laurel Heights	RH-2	40-X (40)	1.8:1	No
29	524 Hickory Street	San Francisco	829-042	7/27/2017	1,250	$1,300,000	$1,040.00	Hayes Valley	RH-3 Hayes Valley	40-X (40)	1.8:1	Yes
30	166 Parker Avenue	San Francisco	1065-032	3/20/2018	2,775	$1,650,000	$594.59	Jordan Park				No
31	2677 Harrison Street	San Francisco	4148-034	9/27/2017	2,304	$1,295,000	$562.07	Mission	RH-3	40-X (40)	1.8:1	No
32	1120 Valencia St	San Francisco	3635-004	10/16/2018	4,134	$3,460,000	$836.96	Mission	NCT	55-X (55)	1.8:1	No
33	1090-1098 Valencia Street	San Francisco	3617-085	11/22/2017	10,114	$11,898,000	$1,176.39	Mission	NCT	55-X (55)	1.8:1	No
34	606 Capp Street	San Francisco	3615-055	7/31/2015	7,350	$3,300,000	$448.98	Mission	RTO-M	40-X (40)	1.8:1	No
35	1526 Powell Street	San Francisco	0130-025	4/14/2022	5,259	$2,900,000	$551.44	North Beach	NCD	40-X (40)	1.8:1	No
36	555 Jackson Street	San Francisco	0195-019	9/27/2019	8,089	$6,500,000	$803.56	Chinatown/Jackson Square	CRNC	40-X (40)	1.0:1	No
37	1198 Columbus Ave/ 2568 Jones St	San Francisco	0043-007	11/26/2018	6,420	$4,500,000	$700.93	North Beach	C-2	40-X (40)	3.61:1	No

LAND SALE SUMMARY – COMPARABLE SALES 38 THROUGH 72

Comp #	Location	City	APN	COE	Size (sf)	Sale Price	Price per SF	District	Zoning	Height/Bulk	FAR	Entitled at Sale
38	425 Broadway	San Francisco	0163-002	5/30/2017	13,641	$11,000,000	$806.39	Broadway	NCD	65-A-1 (65)	2.5 to 1	No
39	1598 Bay Street	San Francisco	0459-007	12/7/2015	12,541	$7,875,000	$627.94	Marina	NC-2	40-X (40)	2.5:1	No
40	1633 Cabrillo Street	San Francisco	1660-044	3/20/2018	2,500	$988,000	$395.20	Inner Sunset	RH-2	40-X (40)	1.8:1	No
41	36 Tehama Street	San Francisco	3736-083A	6/28/2018	2,000	$2,500,000	$1,250.00	SoMa/Yerba Buena	C-3-O (SD)	350-S (350)	9.0:1	No
42	135 Wetmore Street	San Francisco	0212-031	1/4/2017	2,225	$2,700,000	$1,213.48	Nob Hill	RM-3	65-A (65)	3.6 to 1	No
43	361-365 21st Street	San Francisco	1453-013	3/4/2016	2,997	$1,850,000	$617.28	Mission	RH-2	40-X (40)	1.8:1	Yes
44	53 States Street	San Francisco	2623-074	2/7/2017	2,642	$1,920,000	$726.72	Corona Heights	RH-2	40-X (40)	1.8:1	Yes
45	2055 Taraval Street	San Francisco	2395-037	2/4/2020	3,250	$1,260,000	$387.69	Parkside	NCD	50-X (50)		No
46	134 Athens Street	San Francisco	5959-006	6/24/2022	2,495	$713,000	$285.77	Portola	RH-1	40-X (40)	1.8:1	Yes
47	332 Bradford Street	San Francisco	5697-006	2/1/2021	1,751	$563,000	$321.53	Bernal Heights	RH-1	40-X (40)	1.8:1	Yes
48	300 University Street	San Francisco	5991-001	11/15/2019	2,060	$660,000	$320.39	Portola	RH-1	40-X (40)	1.8:1	Yes
49	302 University Street	San Francisco	5991-002	11/15/2019	2,060	$560,000	$271.84	Portola	RH-1	40-X (40)	1.8:1	Yes
50	326 Ganbier Street	San Francisco	5965-005	6/24/2021	2,950	$500,000	$169.49	Portola	RH-1	40-X (40)	1.8:1	No
51	1654 Kirkwood Avenue	San Francisco	5279-17 & -18	4/8/2021	5,000	$1,200,000	$240.00	Baywood	RH-2	40-X (40)	1.8:1	Yes
52A	1782 Quesada Avenue	San Francisco	5327-027	7/30/2020	2,500	$675,000	$270.00	Baywood	RH-2	40-X (40)	1.8:1	Yes
52B	1782 Quesada Avenue	San Francisco	5327-027	1/13/2017	2,500	$380,000	$152.00	Baywood	RH-2	40-X (40)	1.8:1	No
52C	1782 Quesada Avenue	San Francisco	5327-027	9/9/2022	2,500	$400,000	$160.00	Baywood	RH-1	40-X (40)	1.8:1	Yes
53	1750 Oakdale Avenue	San Francisco	5312-014	1/25/2022	2,500	$320,000	$128.00	Baywood	RH-2	40-X (40)	1.8:1	No
54	1528 Hudson Avenue	San Francisco	5254-006A	2/28/2022	2,500	$398,000	$159.20	Baywood	RH-2	40-X (40)	1.8:1	No
55	1390 Oakdale Avenue	San Francisco	4730-018	3/8/2019	2,663	$425,000	$159.59	Baywood	RH-2	40-X (40)	1.8:1	No
56	150 Eureka Street	San Francisco	2692-007	2/4/2015	6,069	$2,325,000	$383.09	Castro	RH-2	40-X (40)	1.8:1	No
57	56 Laussat Street	San Francisco	0858-024A	4/23/2021	750	$428,000	$570.67	Hayes Valley	RTO	40-X (40)	1.8:1	No
58	1 Gull Drive	South San Francisco	015-082-250	12/23/2020	113,256	$10,840,000	$95.71	South San Francisco	BTP-H	N/A	1.0:1	No
59	165 S. Linden Avenue	South San Francisco	014-212-110	6/12/2019	40,946	$4,000,000	$97.69	South San Francisco	MIH	65-C	0.4:2.0	No
60	1030 Brittan Avenue	San Carlos	046-162-070 and 046-162-060	2/16/2016	87,991	$6,800,000	$77.28	San Carlos	GCI	50	2.0:1	No
61	595 Industrial Road & 810-850 E. San Carlos Avenue	San Carlos	046-090-210	2/2/2016	170,755	$13,690,000	$80.17	San Carlos	LC	50	2.0:1	No
62	1401 Shoreway Road	Belmont	040-373-030	3/2/2016	147,668	$12,000,000	$81.26	Belmont	RC	55	1.8:1	No
63	514-580 Minna Street	San Francisco	3726-101	8/14/2020	3,375	$1,700,000	$503.70	SoMa/Mid-Market	MUG	45-X (45)	3.0:1	No
64	1288 Howard Street	San Francisco	3728-19, -24, -25, -26, -87	8/28/2019	37,116	$23,000,000	$619.68	SoMa	RCD; RED-MX; WMUG	45-X; 55-X	1.0:1; 1.0:1; 3.0:1	No
65	230-237 7th Street	San Francisco	3730-004	7/31/2018	12,197	$6,100,000	$500.12	SoMa	WMUG	65-X (65)	5.0:1	No
66	220 9th Street	San Francisco	3518-002	1/12/2018	16,121	$10,350,000	$642.02	SoMa	RCD	55-X (55)	2.5:1	No
67	915 Minna Street	San Francisco	3510-058	6/13/2017	11,617	$6,250,000	$538.00	SoMa	RED-MX	45-X (45)	1.0:1	No
68	292 Arleta Avenue	San Francisco	6234-024	11/30/2022	2,495	$400,000	$160.32	Visitacion Valley	RH-1	40-X (40)	1.8:1	No
69	3338 San Bruno Avenue	San Francisco	6172-036	4/1/2022	1,750	$275,000	$157.14	Visitacion Valley	RH-1	40-X (40)	1.8:1	No
70	666 Hamilton Street	San Francisco	6115-040	9/13/2019	9,960	$1,650,000	$165.66	Portola Valley	RH-1	40-X (40)	1.8:1	No
71	154 Delta Street	San Francisco	6190-015 & -016	7/26/2017	5,000	$590,000	$118.00	Visitacion Valley	RH-1	40-X (40)	1.8:1	No
72	2168 Bayshore Boulevard	San Francisco	5067-011B	1/3/2017	2,195	$300,000	$136.67	Visitacion Valley	RH-1	40-X (40)	1.8:1	No

LAND SALE SUMMARY – WETLAND AND HABITAT LAND SALES (W1 THROUGH W5)

	Location	City	APN	COE	Size (Acres)	Sale Price	Price/Acre	District	General Plan
W1	East of Bayshore Highway	Brisbane	005-223-050	12/21/2004	45.910	$346,000	$7,536	Brisbane	Marsh-Lagoon-Bayfront
W2	Foster City Marina Site	Foster City	096-170-180 and 096-150-230 (Parcel C-3)	12/24/2009	64.400	$2,200,000	$34,161	Foster City	Waterfront Commercial
W3	San Francisco Bay Trail, south of Oyster Point	South San Francisco	015-200-190-5	2/27/2015	108.750	$800,000	$7,356	South San Francisco	Open Space
W4	Mowry Avenue, west of Union Pacific Rail Corridor	Newark	537-0850-003, -004, -005, -006, -007, -011-1 & -011-4	1/16/2007	129.660	$5,647,990	$43,560	Newark - Area 4	Low Density Residential
W5	Los Esteros Road	San Jose	015-30-057 and portion 015-30-059	10/28/2014	21.980	$462,200	$21,028	Alviso	Open Space, Parklands and Habitat

COMPARABLE LAND SALES LOCATION MAP (SAN FRANCISCO)

COMPARABLE LAND SALES LOCATION MAP (SAN MATEO COUNTY)

COMPARABLE WETLAND AND HABITAT LAND SALES – LOCATION MAP

Each of the 33 PG&E fee-owned sites (31 appraised by CCSF, plus 2 not included in the CCSF appraisal) is individually appraised in separate subsections within this section. Comparable sales applicable to each site are taken from the foregoing list and are resummarized in Comparable Land Sale Summary tables. An Adjustment Grid summarizing the respective comparable analysis follows the sale summary table.

A narrative conclusion section summarizes the adjustment process seen in each grid, and concludes to the respective site value opinion. Each site is valued entitled, recognizing that PG&E sites are entitled and that entitled land sells at a premium to unentitled land. Before appraising the multiple subject sites, the comparative analysis and adjustment process are summarized in the following subsection.

Land Valuation - Comparative Analysis

Both quantitative and qualitative adjustments are applied in the valuation. Adjustments are based on market data, experience, and/or judgment. The bases for quantitative factors are discussed and/or are exhibited in the following subsections. Quantitative adjustments are imputed on numeric percentage (%) factors. Qualitative adjustments recognize the comparability of the sale in comparison to the subject, noting it as inferior (+), meaning the sale is inferior to the subject (and the value of the subject is greater in comparison to the sale); or as superior (-), meaning the value of the subject for this factor is less in comparison to the sale. "0" adjustment means no adjustment is warranted.

A summary of the elements of comparison follows.

Transaction Adjustments

These items are applied prior to the application of property adjustments. Transaction adjustments applicable to this assignment include:

1. Real Property Rights Conveyed
2. Financing Terms
3. Conditions of Sale
4. Expenditures After Sale
5. Market Conditions (Price Trends/"Time")

Real Property Rights Conveyed

Real property rights conveyed are the legal interests, the so-called bundle of rights held in real property that sell or can be sold with the property. These are the value interests being appraised or priced. Property rights influence sale prices and value and are considered also when analyzing a comparable sale. Adjustments to the property interests being appraised may be warranted.

If a property is not leased or otherwise encumbered, the rights available for purchase and sale are typically the *fee simple* interests inuring all the rights of "ownership absolute." The rights appraised in each of the 33 PG&E sites are the fee simple. Each comparable sale similarly sold its fee simple interests.

No adjustments for rights conveyed are warranted.

Financing Terms

The transaction price of one property may differ from that of an identical property due to different financial arrangements. Sales involving financing terms that are not at or near market terms require adjustments for cash equivalency to reflect typical market terms. A cash equivalency procedure discounts the atypical mortgage terms to provide an indication of value at cash equivalent terms.

All of the comparable sales involved typical market terms by which the sellers received cash or its equivalent and the buyers paid cash or tendered typical down payments and obtained conventional financing at market terms for the balance. No adjustments for this category are required.

Conditions of Sale

When the conditions of sale are atypical, the result may be a price that is higher or lower than that of a normal transaction. Adjustments for conditions of sale usually reflect the motivations of either a buyer or a seller who is under duress to complete the transaction. Another typical condition of sale involves the downward adjustment required to a comparable property's for-sale listing price, which usually reflects the upper limit of value.

No adjustments are warranted for atypical conditions.

Expenditures After Sale

No adjustments for expenditures after sale are warranted or apply to the comparable sales.

Market Conditions/Time

Market conditions change over time because of inflation, deflation, fluctuations in supply and demand, and other factors. That is, market conditions affect asset pricing, including sales prices and market values on real property and property rights. Changing market conditions create the need for adjustments to comparable sales sold during periods of dissimilar market conditions to the date of valuation of the property appraised. Comparable sales included in the comparative analysis sold from 2015 to 2023.

Prices before the July 2021 valuation date appreciated gradually and steadily in the Bay Area across all CRE (commercial real estate, including residential) property segments; prices trended up. Based on analyses of property sale prices, rents, and/or capitalization rates, price appreciation trended up in all types of residential, retail, office, and industrial over the period, in subject market areas. Retail rents suffered during Covid, then recovered and increased slightly by July 27, 2021.

According to MLS, CoStar, and REIS surveys, as well as other industry publications such as broker newsletters, residential prices increased 3% - 6% year-over-year, depending on San Francisco location and residential product type until a peak about mid-year 2021. Citywide, the average rate of appreciation among residential trended up 5% year-over-year. Thereafter, prices declined to 2020 or pre-2020 price levels.

Commercial retail property price levels declined during Covid, recovered slightly, then similar to residential peaked the second half of 2021. Retail property rents, capitalization rates and sale prices between 2015 and 2021 trended up 2%-4%, or 3%, per year over the period. Office prices levels

between 2015 and 2021 were essentially flat year-over-year, up about 0.50% annually. Industrial property price statistic levels over the same period increased at annual rates of 9%-11%, or 10%.

In summary, comparable sales are adjusted reflecting market trends. By CRE property types, these adjustments are:

Residential:	+5%/year to sales before DOV; +4%/year to sales after DOV
Retail:	+3%/year to sales before DOV; -3%/year to sales after DOV
Office:	+0.50%/year to sales before DOV; -0.50%/year to sales after DOV
Industrial:	+10%/year to sales before DOV; -10%/year to sales after DOV

Reference is made to the comparative analysis and Adjustment Grids that follow.

Property Adjustments

Property adjustments are based on locational and physical characteristics applied after the application of transaction adjustments. Property adjustments reflect market research and analyses, best judgment, and experience in the appraisal of similar properties. Property Adjustments applicable to this assignment are as follows:

1. Location
2. Site Size
3. Site Utility/Shape
4. Building and Site Requirements
5. Zoning, Height-Bulk, Density
6. Entitlements/Development Approvals

Location

Location adjustments are warranted where the sale property is influenced by its superior or inferior location in comparison to the subject property. Location differences may include macro and micro characteristics, off-site and on-site influences. Adjustments as warranted are included in the comparative analyses that follow.

Size

As stated previously, ATF requires adjustment for site size if the sale is not the customary size of lands comprising the corridor. Few adjustments are typically warranted to San Francisco sites, because of the generally uniform site sizes. Fewer are required in ATF. Where adjustments are deemed to be needed, to be consistent with ATF methodology, the adjustment is included in the comparative analyses that follow.

Site Utility/Shape

Similarly, few adjustments are reasonably required in operating corridor valuation. As a practical matter, subject sites are typically readily developable, with comparative average to good shape and utility typical among the sales. The sale properties have comparable site shapes with similar utility as the subjects. Few adjustments are warranted to sales for this element of comparison.

Building and Site Requirements

Sites purchased with building improvements contributing value more than just land value, although with substantially all of the value in the land, or sites with comparatively restrictive requirements on development, may require adjustment. Those sales are adjusted on the Adjustment Grid as warranted.

Zoning, Height-Bulk, Density

City zoning districts are commonly connected with height-and-bulk regulations, also density (FAR) restrictions, potentially affecting highest and best use and pricing. In addition, within some zoning districts and locations, the city provides opportunities to exceed stated maximum limits. More recently, state laws, including well-known density bonus provisions, allow height and densities to be exceeded. Differences between sales and subject sites being appraised are recognized in the adjustment process.

Entitlements

Entitlements in land use can be a somewhat vague and ambiguous term connected with allowable land use, like zoning. It is more directly an industry term of art relating to site development approvals. A site may sell, for example, as "fully entitled" in market brochures, meaning that a specific development has already been approved at the city and county planning (and Board of Supervisors) levels. Site development approvals, aka entitlements, are complex, costly, and valuable in San Francisco when they are consistent with the site's highest and best use.

Paired sales/resales of the same site – first selling without entitlements, then reselling with entitlements – consistently show substantial price premiums are paid for ready-to-build sites with approvals and plans. Double the price levels, "2x" or 100% premiums, for entitled sites is the most frequent value tendency for a variety of development projects in San Francisco, evidenced by the prices paid for entitlements among the paired sales.

Each of PG&E's 32 substation sites is improved on fully entitled land. PG&E's improvements, in turn, are legal and conforming to the land uses and entitlements and are consistent with the sites' highest and best use comprising the electrical power grid special purpose use. Although the CPUC entitlement approval process is a separate process from the City and County process, PG&E cooperates in the city/county process in its effort to comply as a local citizen would be required. Each PG&E substation site is entitled to its highest and best use and is recognized with this value characteristic.

Many of the comparable sales previously summarized sold with "entitlements." In fact, two pairs of sales (28 A and B, and 52 A, B, and C) are among recent and available paired sales reflecting 100% premiums paid (after deducting the effect of price appreciation in the time between the initial sale and the subsequent resale). Although those entitled uses were not for the special purpose use the subject sites are entitled, we find that entitlement value on properties proposed to their highest and best use, whatever that use may be, is consistently about 100%, or 2x, the land value as-if unentitled. Those land sales sold with entitlements are concluded to be comparable in entitlement value characteristic to subjects' highest and best use. No additional adjustments are warranted to those sales in comparison to subject sites. But those land sales sold without development approvals warrant upward adjustment.

Paired land sales are excellent supporting market evidence of the adjustment, both in direction (up) and in magnitude (100%). Additional support is provided in the subject's Egbert Substation site, CCSF-designated site #30, that PG&E recently purchased unentitled. Since purchase, PG&E entitlement costs

have been 55% of its land purchase price, based on itemized cost details provided. The difference between cost (55%) and market price (100%) recognizes the market premium paid for the entrepreneurial know-how and for the risks taken in the process. The indicated adjustment for entitlements is much greater than the 55% entitlement costs: entitlement value typically sells at a substantial earned profit over costs. 100% value (including costs) adjustments for the subject sites being entitled to their highest and best use is concluded to best recognize the price paid in the marketplace for the factor.

The price paid for new development entitlements is on proposed projects that have not yet experienced depreciation, however, or have not yet begun the life-cycle process. Improved and entitled PG&E substation sites are variously dated and aged. The overall remaining age of the substation improvements is 67%, based on our life-cycle analysis of the individual properties, included later in this section of the report. Based on the foregoing, we estimate the quantitative measure of subject's existing entitlements is 65%. Those land sales sold unentitled are adjusted up 65% in the comparative analyses that follow.

Comparable sales sold with entitlements are listed before unentitled sales in the Sale Summary tables and Adjustment Grids that follow in the valuations of individual Substation Sites. Entitled sales more current with the valuation date are listed before other entitled sales. This "ordering" of sales may appear out of Numbering Sequence which, while may appear to be random, are ordered by location relating to clustering around the sequencing and numbering of subject sites adopted by CCSF.

Substation Site Valuations

As noted earlier, these quantitative and qualitative adjustments are based on market research, judgment, and experience in the appraisal of similar properties. These adjustments are annotated in the Adjustment Grids that follow.

Sales are selected for their overall comparability to the PG&E-owned site appraised regarding property type, date of sale, size, physical condition, location, land use constraints, functional utility, and/or economic characteristics, including entitlements. The sales that shed light on the valuation of the subject are selected; these are considered competitive substitutes to the PG&E sites appraised and a component of the necessary cost to create the assembled corridor.

PG&E Substations Site Numbers 1 through 33 are appraised on the following pages. The format of presentation first provides the applicable Land Sale Summary table listing the comparable land sales numbered from the previously provided larger dataset of sales. This Summary is followed by the Adjustment Grid that summarizes the respective comparative analysis. This analysis, in turn, is followed by the conclusion and reconciliations of value for each substation site.

All land values are summarized in a table included at the conclusion of the individual site valuations, before appraising the contributory values of respective substation building and site improvements.

PG&E Property #1 - Substation Z (Embarcadero)

SALE SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
1	524 Howard Street SoMa/Rincon Hill 3721-013	5/7/2019	12,266 0.282	$78,000,000	**$6,359.04**	C-3-O (SD) 450-S (450) 30.11 (9.0:1)	Y	Howard/First Property LLC Ridgegate Apartments, LLC et al. 2019-9K764208-00006
2	325 Fremont Street SoMa/Rincon Hill 3747-012, 013, and 014	2/26/2015	6,434 0.148	$28,500,000	**$4,429.59**	RH DTR 85/250-R (250) 22.12	Y	Fremont 325 Development, LLC Full Energy Properties, LLC 2015-9K026582-00004
3	525 Harrison Street SoMa/Rincon Hill 3764-063	6/26/2017	12,981 0.298	$36,000,000	**$2,773.28**	RH DTR 65/250-R (250) 18.01:1	Y	Guang De CA LLC Hong You Properties, LLC 2017-9K469244-00003
4	547 Howard Street SoMa/Transbay 3736-110	4/22/2015	2,126 0.049	$6,300,000	**$2,963.31**	C-3-O (SD) 350-S (350) 9.0:1	N	547-549 Howard Street Pacific Howard Corporation 2015-9K051061-00003
5	555 Howard Street SoMa/Transbay 3736-086	4/28/2015	8,250 0.189	$27,000,100	**$3,272.74**	C-3-O (SD) 350-S (350) 9.0:1	N	Paul Descalso Trust Pacific Howard Corporation 2015-9K053233-00014
6	557 Howard Street SoMa/Transbay 3736-107	5/1/2015	4,121 0.095	$12,250,000	**$2,972.58**	C-3-O (SD) 350-S (350) 9.0:1	N	Guggie H, LLC Pacific Howard Corporation 2015-9K055129-00003
Subject	Embarcadero Substation (Z) 405 Folsom Street 425 Folsom Street SoMa/Rincon Hill 3748-001, 003, 004, 0050 & 029	---	1) 22,900 1) 0.526 2) 10,310 2) 0.237	---	---	RH-DTR 85/200-R RH-DTR 85/200-R	Y	

ADJUSTMENT GRID

Comparable Number	**Land Sale 1**	**Land Sale 2**	**Land Sale 3**	**Land Sale 4**	**Land Sale 5**	**Land Sale 6**
Location	524 Howard St SoMa/Rincon Hill	325 Fremont St SoMa/Rincon Hill	525 Harrison St SoMa/Rincon Hill	547 Howard SoMa/Transbay	555 Howard St SoMa/Transbay	557 Howard St SoMa/Transbay
Sale Date	5/7/2019	2/26/2015	6/26/2017	4/22/2015	4/28/2015	5/1/2015
Sale Price	$78,000,000	$28,500,000	$36,000,000	$6,300,000	$27,000,100	$12,250,000
Site Size (Acre)	0.282	0.150	0.298	0.050	0.190	0.090
Site Size (SF)	12,266	6,434	12,981	2,126	8,250	4,121
Price Per SF	**$6,359**	**$4,430**	**$2,773**	**$2,963**	**$3,273**	**$2,973**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0	0
Rights Conveyed	0	0	0	0	0	0
Sale Conditions	0	0	0	0	0	0
Price Trends	1.11	1.37	1.22	1.36	1.36	1.36
Adjusted Price (to DOV)						
Price/SF	**$7,059**	**$6,069**	**$3,383**	**$4,030**	**$4,451**	**$4,043**
Location	0	0	Inferior (+)	0	0	0
Site Size	0	0	0	0	0	0
Site Utility/Shape	0	0	Inferior (+)	0	0	0
Building and Site Requirements	0	0	0	0	0	0
Zoning, Height-Bulk/Density	Superior (-)	0	0	Superior (-)	Superior (-)	Superior (-)
Entitlements	0	0	0	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Similar** Similar	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$7,059**	**$6,069**	**$3,383**	**$6,650**	**$7,344**	**$6,670**

Land Value Conclusion – #1 Substation Z (Embarcadero)

PG&E's Embarcadero Substation Site comprises two adjacent sites located at the southwest corner of Fremont and Folsom Street in the Rincon Hill area of South of Market (SoMa). Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 4 through 6. The Embarcadero Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 1 through 3 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including "Location"; "Site Utility/Shape"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether the comparable sales are Superior, Similar, or Inferior to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in PG&E Property #1 is $6,000 per square foot, or $199,278,000, calculated as follows:

33,213 sf x $6,000/sf = $199,278,000

PG&E Property #2 – Substation A (Potrero)

SALE SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
7	901 Illinois Street (Pcl K) Central Waterfront 4110-012	2/13/2019	67,988 1.561	$24,000,000	**$353.00**	PDR-2 65-J (65)	Y Partial	City and County of San Francisco 64 PKN Owner LLC 2019-K731222-00006
8	790 Pennsylvania Avenue Potrero Hill 4167-013 4167-011	3/3/2016	119,885 2.752	$35,000,000	**$291.95**	UMU (Lot 13) PDR-1-G (Lot 11) 40-X (40)	Y Partial	2007 Sherman C. Little and Delaine K. Little Revocable Trust et al. RP Pennyslvania, LLC 2016-9K210708-00008
9	1755 Egbert Avenue Bayview 5431A-001-A & -001-Z	1/29/2021	70,446 1.617	$16,950,000	**$240.61**	PDR-2 65-J (65)	N	Egbert Enterprises LLC Pacific Gas and Electric Company 2021-015848
10	2270 Jerrod Avenue Bayview 5230-008	5/9/2022	154,883 3.556	$70,070,000	**$452.41**	PDR-2 65-J (65)	N	First Student, Inc. GIC San Francisco LLC 2022-047193
11	2150 Oakdale Avenue Bayview 5590A-003	5/7/2019	52,098 1.196	$13,750,000	**$263.93**	PDR-2 65-J (65)	N	MacBeath Hardwood Company Prologis-Exchange 2150 Oakdale LLC 2019-9K764192-00005
12	2000 Marin Street Central Waterfront 4346-003	4/30/2020	343,688 7.890	$63,600,000	**$185.05**	PDR-2 65-J (65)	N	2000 Marin Property, LP City and County of San Francisco 2020-K927582-00007
Subject	Potrero Substation (A) 1101 Illinois Street Central Waterfront/Dogpatch 4715-018	--	293,960 6.748	--	**--**	P70-MU; PPS-MU; M-2 65-PPS/240-PPS; 65-X; 40-X	Y	

ADJUSTMENT GRID

Comparable Number	**Land Sale 7**	**Land Sale 8**	**Land Sale 9**	**Land Sale 10**	**Land Sale 11**	**Land Sale 12**
Location	901 Illinois St Central Waterfront	790 Pennsylvania Ave Potrero Hill	1755 Egbert Ave Bayview	2270 Jerrod Ave Bayview	2150 Oakdale Ave Bayview	2000 Marin St Central Waterfront
Sale Date	2/13/2019	3/3/2016	1/29/2021	5/9/2022	5/7/2019	4/30/2020
Sale Price	$24,000,000	$35,000,000	$16,950,000	$70,070,000	$13,750,000	$63,600,000
Site Size (Acre)	1.561	2.752	1.617	3.556	1.196	7.890
Site Size (SF)	67,988	119,885	70,446	154,883	52,098	343,688
Price Per SF	**$353**	**$292**	**$241**	**$452**	**$264**	**$185**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0	0
Rights Conveyed	0	0	0	0	0	0
Sale Conditions	0	0	0	0	0	0
Price Trends	1.26	1.66	1.05	0.90	1.23	1.13
Adjusted Price (to DOV) **Price/SF**	**$445**	**$485**	**$253**	**$407**	**$325**	**$209**
Location	0	Superior (-)	Inferior (+)	Inferior (+)	Inferior (+)	0
Site Size	0	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0	0
Building and Site Improvements	0	0	0	Superior (-)	0	0
Zoning, Height-Bulk/Density, Site Use Restrictions	Superior (-)	Superior (-)	Superior (-)	Superior (-)	Superior (-)	0
Entitlements	20%	20%	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Sl. Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than	**Similar (~)** Similar to
Indicated Value of Subject ($/sf)	**$534**	**$582**	**$417**	**$672**	**$536**	**$345**

Land Value Conclusion – #2 Substation A (Potrero)

PG&E's Potrero Substation Site comprises adjacent sites located along the east side of Illinois Street, the north and south sides of 22nd Street, and the north side of 23rd Street in the Central Waterfront

area, adjacent to Dogpatch. CCSF proposes to acquire a portion of the site. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale, except for Land Sale 9, warrants adjustment for increasing, or decreasing, land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. CoStar and industrial market segment sources evidence that prices in the competitive market area of subject about 10% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to partially or unentitled land sales. Sale Numbers 7 and 8 sold with entitlement approvals having previously been processed and requiring updating. The rest of the sales – Numbers 9 through 12 – sold unentitled. The Potrero Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 7 and 8 are adjusted 20% for the value of existing approvals. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Zoning, Height-Bulk, Density"; Location; and/or "Building and Site Improvement" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

The Potrero Substation Site can be developed and used for industrial or commercial use, so long as the use encapsulates the site. Uses such as residential or hospitals or healthcare facilities, for example, while permitted under zoning are restricted by site covenants due to soil contamination. No additional clean-up is required of the subject site; the site has certified completion of past-required remedial environmental actions. The site is well-suited to the existing use and to prospective industrial or commercial uses allowed by zoning, but not a use restricted by covenant. This land use restriction is recognized in the valuation, including in the adjustments.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the *unencumbered* fee simple rights in the PG&E Site is $350 per square foot, or $102,886,000, calculated as follows:

293,960 sf x $350/sf = $102,886,000

The site, as discussed in the Site Description section, is to be encumbered by a proposed 50-foot-wide easement to be conveyed to PG&E, extending 25 feet on either side of the centerline of the existing underground gas transmission pipeline and containing 35,175 square feet. To reflect the diminution in value attributable to this encumbrance, we have applied a 50% reduction to the fee value of the easement area, calculated as follows:

35,175 sf x $350/sf x 50% = $6,155,625

Accordingly, the indicated land value of PG&E Property #2, as encumbered by the proposed easement, is $96,730,375, reflecting the unencumbered fee value, *less* the easement deduction, calculated as follows:

$102,886,000 – $6,155,625 = $96,730,375

PG&E Property #3 -Substation P (Hunters Point)

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
7	901 Illinois Street (Pcl K) Central Waterfront 4110-012	2/13/2019	67,988 1.561	$24,000,000	**$353.00**	PDR-2 65-J (65)	Y Partial	City and County of San Francisco 64 PKN Owner LLC 2019-K731222-00006
8	790 Pennsylvania Avenue Potrero Hill 4167-013 4167-011	3/3/2016	119,885 2.752	$35,000,000	**$291.95**	UMU (Lot 13) PDR-1-G (Lot 11) 40-X (40)	Y Partial	2007 Sherman C. Little and Delaine K. Little Revocable Trust et al. RP Pennysivania, LLC 2016-9K210708-00008
9	1755 Egbert Avenue Bayview 5431A-001-A & -001-Z	1/29/2021	70,446 1.617	$16,950,000	**$240.61**	PDR-2 65-J (65)	N	Egbert Enterprises LLC Pacific Gas and Electric Company 2021-015848
10	2270 Jerrod Avenue Bayview 5230-008	5/9/2022	154,883 3.556	$70,070,000	**$452.41**	PDR-2 65-J (65)	N	First Student, Inc. GIC San Francisco LLC 2022-047193
11	2150 Oakdale Avenue Bayview 5590A-003	5/7/2019	52,098 1.196	$13,750,000	**$263.93**	PDR-2 65-J (65)	N	MacBeath Hardwood Company Prologis-Exchange 2150 Oakdale LLC 2019-9K764192-00005
12	2000 Marin Street Central Waterfront 4346-003	4/30/2020	343,688 7.890	$63,600,000	**$185.05**	PDR-2 65-J (65)	N	2000 Marin Property, LP City and County of San Francisco 2020-K927582-00007
Subject	Hunter's Point Substation (P) 1180 Evans Avenue Hunter's Point 4570-024	--	79,680 1.829	--	--	PDR-2 65-J (65)	Y	
	Hunter's Point Substation (P) 1010-1030 Evans Avenue Hunter's Point 4604A-002	--	281,659 6.466	--	--	M-1; M-2 40-X (40)	Y	
	Hunter's Point Substation (P) 1135 Evans Avenue Hunter's Point 4621-014	--	85,747 1.968	--	--	NC-2 40-X (40)	Y	
	Hunter's Point Substation (P) 1059-1075 Evans Avenue Hunter's Point 4603A-005	--	151,588 3.480	--	--	NC-2 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 7	Land Sale 8	Land Sale 9	Land Sale 10	Land Sale 11	Land Sale 12
Location	901 Illinois St Central Waterfront	790 Pennsylvania Ave Potrero Hill	1755 Egbert Ave Bayview	2270 Jerrod Ave Bayview	2150 Oakdale Ave Bayview	2000 Marin St Central Waterfront
Sale Date	2/13/2019	3/3/2016	1/29/2021	5/9/2022	5/7/2019	4/30/2020
Sale Price	$24,000,000	$35,000,000	$16,950,000	$70,070,000	$13,750,000	$63,600,000
Site Size (Acre)	1.561	2.752	1.617	3.556	1.196	7.890
Site Size (SF)	67,988	119,885	70,446	154,883	52,098	343,688
Price Per SF	**$353**	**$292**	**$241**	**$452**	**$264**	**$185**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0	0
Rights Conveyed	0	0	0	0	0	0
Sale Conditions	0	0	0	0	0	0
Price Trends	1.26	1.66	1.05	0.90	1.23	1.13
Adjusted Price (to DOV)						
Price/SF	**$445**	**$485**	**$253**	**$407**	**$325**	**$209**
Location	0	Superior (-)	Inferior (+)	Inferior (+)	Inferior (+)	0
Site Size	0	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0	0
Building and Site Improvements	0	0	0	Superior (-)	0	0
Zoning, Height-Bulk/Density, Site Use Restrictions	Superior (-)	Superior (-)	Superior (-)	Superior (-)	Superior (-)	0
Entitlements	20%	20%	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Sl. Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than	**Similar (~)** Similar to
Indicated Value of Subject ($/sf)	**$534**	**$582**	**$417**	**$672**	**$536**	**$345**

Land Value Conclusion – #3 Substation P (Hunters Point)

PG&E's Hunters Point Substation Site comprises multiple sites located along the waterfront, and generally, at the intersections of Evans Avenue and Jennings Street, and Hunters Point Boulevard at India Basin in Hunters Point. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Land areas to be acquired include uplands and wetland habitat lands – tidal and subtidal adjacent Baylands. These lands, like other PG&E lands to be acquired, have economic highest and best use characteristics and appeal to the marketplace, evidenced by additional comparable land sales Numbers W1 through W5. That is, habitat lands hold marketable value. Property 3.6 is valued based on the contributing lands areas: 0.38 acres in Intertidal and Pond habitat lands and 0.09 acres in Subtidal habitat lands.

Each sale, except for Land Sale 9, warrants adjustment for increasing, or decreasing, land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. CoStar and industrial market segment sources evidence that prices increased in the competitive market area of subject at a rate of about 10% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to partially or unentitled land sales. Sale Numbers 7 and 8 sold with entitlement approvals having previously been processed and requiring updating. The rest of the sales, Numbers 9 through 12, sold unentitled. The Hunters Point Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 7 and 8 are adjusted 20% for the value of existing approvals. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Zoning, Height-Bulk, Density"; Location; and/or "Building and Site Improvement" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

The sales are adjusted to value the level, useable subject lands in this Hunters Point grouping of properties. Portions of Properties 3.3 to 3.5 are steeply sloping and less useable. Portions of Properties 3.2 and 3.6 comprise open space and/or wetlands habitat. Similarly, open space and wetland habitat areas of the site are less "valuable" than level developable lands.

The Hunters Point Substation Site can be developed and used for industrial or commercial use, so long as the use encapsulates the site. Uses such as residential or hospitals or healthcare facilities, for example, while permitted under zoning are restricted by site covenants due to soil contamination. No additional clean-up is required of the subject site; the site has certified completion of past-required remedial environmental actions. The site is well-suited to the existing use and to prospective industrial or commercial uses allowed by zoning, but not a use restricted by covenant. This land use restriction is recognized in the valuation, including in the adjustments.

Based on comparative analysis of the land sales and the subject site, the indicated fee simple market value of the net developable area of the PG&E Site is $340 per square foot of net upland area comprising Property 3.1, which is applied as a base value to Property 3.2 through 3.6. Additional adjustments are warranted to this base value ($340/sf) to recognize lesser valuable features of Property 3.2 through 3.6.

Given the lower contributory value of the wetlands and trail segments, the overall site value across the gross acreage of the six components ranges from $50 to $340 per square foot, averaging $220 per square foot. This indicates a combined site value of $329,520,310, calculated as follows.

3.1	79,680 sf	x $340/sf =	$27,091,200
3.2	281,659 sf	x $250/sf =	$70,414,750
3.3	85,747 sf	x $250/sf =	$21,436,750
3.4	325,709 sf	x $250/sf =	$81,427,250
3.5	13,734 sf	x $50/sf =	$686,700
3.6	713,687 sf	x $180/sf =	$128,463,660
	1,500,216 sf	**x $220/sf =**	**$329,520,310**

PG&E Property #4 - Substation W (Bayshore)

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
7	901 Illinois Street (Pcl K) Central Waterfront 4110-012	2/13/2019	67,988 1.561	$24,000,000	**$353.00**	PDR-2 65-J (65)	Y Partial	City and County of San Francisco 64 PKN Owner LLC 2019-K731222-00006
8	790 Pennsylvania Avenue Potrero Hill 4167-013 4167-011	3/3/2016	119,885 2.752	$35,000,000	**$291.95**	UMU (Lot 13) PDR-1-G (Lot 11) 40-X (40)	Y Partial	2007 Sherman C. Little and Delaine K. Little Revocable Trust et al. RP Pennyslvania, LLC 2016-9K210708-00008
9	1755 Egbert Avenue Bayview 5431A-001-A & -001-Z	1/29/2021	70,446 1.617	$16,950,000	**$240.61**	PDR-2 65-J (65)	N	Egbert Enterprises LLC Pacific Gas and Electric Company 2021-015848
10	2270 Jerrod Avenue Bayview 5230-008	5/9/2022	154,883 3.556	$70,070,000	**$452.41**	PDR-2 65-J (65)	N	First Student, Inc. GIC San Francisco LLC 2022-047193
11	2150 Oakdale Avenue Bayview 5590A-003	5/7/2019	52,098 1.196	$13,750,000	**$263.93**	PDR-2 65-J (65)	N	MacBeath Hardwood Company Prologis-Exchange 2150 Oakdale LLC 2019-9K764192-00005
12	2000 Marin Street Central Waterfront 4346-003	4/30/2020	343,688 7.890	$63,600,000	**$185.05**	PDR-2 65-J (65)	N	2000 Marin Property, LP City and County of San Francisco 2020-K927582-00007
Subject	Bayshore Substation (W) 151-157 Bayshore Boulevard Bayview 5559-004, -005, -006	--	55,930 1.284	--	--	PDR-2 65-J (65)	Y	

ADJUSTMENT GRID

Comparable Number	**Land Sale 7**	**Land Sale 8**	**Land Sale 9**	**Land Sale 10**	**Land Sale 11**	**Land Sale 12**
Location	901 Illinois St Central Waterfront	790 Pennsylvania Ave Potrero Hill	1755 Egbert Ave Bayview	2270 Jerrod Ave Bayview	2150 Oakdale Ave Bayview	2000 Marin St Central Waterfront
Sale Date	2/13/2019	3/3/2016	1/29/2021	5/9/2022	5/7/2019	4/30/2020
Sale Price	$24,000,000	$35,000,000	$16,950,000	$70,070,000	$13,750,000	$63,600,000
Site Size (Acre)	1.561	2.752	1.617	3.556	1.196	7.890
Site Size (SF)	67,988	119,885	70,446	154,883	52,098	343,688
Price Per SF	**$353**	**$292**	**$241**	**$452**	**$264**	**$185**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0	0
Rights Conveyed	0	0	0	0	0	0
Sale Conditions	0	0	0	0	0	0
Price Trends	1.26	1.66	1.05	0.90	1.23	1.13
Adjusted Price (to DOV)						
Price/SF	**$445**	**$485**	**$253**	**$407**	**$325**	**$209**
Location	0	Superior (-)	Inferior (+)	Inferior (+)	Inferior (+)	0
Site Size	0	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0	0
Building and Site Improvements	0	0	0	Superior (-)	0	0
Zoning, Height-Bulk/Density, Site Use Restrictions	Inferior (+)	Inferior (+)	Inferior (+)	Inferior (+)	Inferior (+)	Inferior (+)
Entitlements	20%	20%	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Inferior (+)** Greater Than	**Similar** Similar	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than
Indicated Value of Subject ($/sf)	**$534**	**$582**	**$417**	**$672**	**$536**	**$345**

Land Value Conclusion – #4 Substation W (Bayshore)

PG&E's Bayshore Substation Site is situated along Bayshore Boulevard and Barneveld Avenue at Jerrold Avenue on the Bayview/Produce Market area. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale, except for Land Sale 9, warrants adjustment for increasing, or decreasing, land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. CoStar and industrial market segment sources evidence that prices increased in the competitive market area of subject about 10% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to partially or unentitled land sales. Sale Numbers 7 and 8 sold with entitlement approvals having previously been processed and requiring updating. The rest of the sales – Numbers 9 through 12 – sold unentitled. The Bayshore Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 7 and 8 are adjusted 20% for the value of existing approvals. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Building and Site Improvement"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.
Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $575 per square foot, or $32,159,750, calculated as follows:

55,930 sf x $575/sf: = $32,159,750

PG&E Property #5 - Substation Y (Larkin)

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
13	430 Eddy Street Tenderloin 0334-0008	11/12/2020	3,578 0.082	$3,250,000	**$908.33**	RC-4 80-T (80)	Y MU: Res over Retail	430 Eddy Street Associates LLC et al. SF Eddy Housing Investors, LP 2020-047619
14	199 Turk/180 Jones Sts Tenderloin 0343-014	11/30/2016	4,744 0.109	$4,000,000	**$843.17**	RC-4 80-T-120-T (120)	Y 26 Sty Residential	Jones Development Project, LLC MM 180 Jones LLC 2016-9K364758-00003
15	530-540 Turk Street Tenderloin 0741-003, -004	6/27/2022	9,583 0.220	$3,850,000	**$401.75**	RC-4 80-T (80)	N	Family Bypass Trust et al. 530 Turk Street LLC 2022-063571
16	500 Turk Street Tenderloin 0741-002	12/20/2016	18,906 0.434	$12,250,000	**$647.94**	RC-4 80-T (80)	N	Frederick Rolandi, III Turk 500 Associates, LP 2016-9K377413-00009
17	719-725 Larkin Street Tenderloin 0717-003	12/31/2015	5,998 0.138	$3,000,000	**$500.17**	RC-4 80-T (80)	N	M & M Investments Sean Sullivan 2015-K182908
Subject	Larkin Substation (Y) 538 Eddy Street Tenderloin 0355-037	--	46,875 1.076	--	--	RC-4 80-T (80)	Y	

ADJUSTMENT GRID

Comparable Number	**Land Sale 13**	**Land Sale 14**	**Land Sale 15**	**Land Sale 16**	**Land Sale 17**
Location	430 Eddy St Tenderloin	199 Turk St Tenderloin	530-540 Turk St Tenderloin	500 Turk St Tenderloin	719-725 Larkin St Tenderloin
Sale Date	11/12/2020	11/30/2016	6/27/2022	12/20/2016	12/31/2015
Sale Price	$3,250,000	$4,000,000	$3,850,000	$12,250,000	$3,000,000
Site Size (Acre)	0.082	0.110	0.220	0.434	0.138
Site Size (SF)	3,578	4,792	9,583	18,906	5,998
Price Per SF	**$908**	**$835**	**$402**	**$648**	**$500**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.03	1.26	1.05	1.25	1.31
Adjusted Price (to DOV) **Price/SF**	**$936**	**$1,052**	**$422**	**$810**	**$655**
Location	0	0	0	0	0
Site Size	Inferior (+)	Inferior (+)	0	0	Inferior (+)
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0
Zoning, Height-Bulk/Density	0	Superior (-)	0	0	0
Entitlements	0	0	65%	65%	65%
Total Adjustment ($/Land sf)	**Inferior (+)** Greater Than	**Similar** Similar	**Similar** Similar	**Similar** Similar	**Inferior (+)** Greater Than
Indicated Value of Subject ($/sf)	**$936**	**$1,052**	**$696**	**$1,336**	**$1,081**

Land Value Conclusion – #5 Substation Y (Larkin)

PG&E's Larkin Substation Site is situated at the northeast corner of Larkin and Eddy Streets in the Tenderloin area. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each of the land sales requires adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial market segment sources evidence that prices increased in the competitive market area of subject about 5% per year, a blended (commercial and residential) compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to partially or unentitled land sales. Sale Numbers 13 and 14 sold with entitlement approvals; no adjustments are warranted. The rest of the sales – Numbers 15 through 17 – sold unentitled. The Larkin Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Site Size," and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.
Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $1,000 per square foot, or $46,875,000, calculated as follows:

46,875 sf x $1,000/sf: = $46,875,000

PG&E Property #6 - Substation X (Mission)

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
18	1550 Market Street Civic Center 0836-006 & -007	11/24/2015	12,567 0.288	$23,000,000	**$1,830.19**	C-3-G 120-R-2 (120)	Y	TUP Market LLC Full Bright Properties, LLC 2015-9K159514-00004
19	72-80 Ellis Street Union Square 0327-011	5/13/2015	8,420 0.189	$9,900,000	**$1,175.77**	C-3-R 80-130-F (130)	Y	AGPME Parking Lot, LLC 72 Ellis Owner LP 2015-K060083-00
20	1121-1125 Mission Street Mid-Market 3702-047	5/22/2015	12,402 0.285	$19,800,000	**$1,596.52**	C-3-G 120-X (120)	Partial/Y	1125 Market, LLC Pacific 1125 Market Corporation 2015-9K06618-00004
21	30 Van Ness St Market-Octavia 0835-004	5/5/2017	38,124 0.875	$70,000,000	**$1,836.11**	C-3-G 120/400-R-2 140/520-R-2	N	City and County of San Francisco 30 Van Ness Development LLC 2017-9K447786-00006
22	1338-1370 Mission Street WSoMa 3508-022, 024, 025 & 052	11/20/2015	18,901 0.434	$25,000,000	**$1,322.68**	C-3-G 120-X (120)/ 150-S (150)	N	MCC 1360 LLC SPF2 1370 Mission St, LLC 2015-K158782-00
Subject	Mission Substation (X) 1250 Mission Street Mission 3701-053	--	44,617 1.024	--	--	C-3-G 150-S (150) 180-X (180)	Y	

ADJUSTMENT GRID

Comparable Number	**Land Sale 18**	**Land Sale 19**	**Land Sale 20**	**Land Sale 21**	**Land Sale 22**
Location	1550 Market St Civic Center	72-80 Ellis St Union Square	1121-1125 Market St Mid-Market	30 Van Ness St Market-Octavia	1360 Mission St WSoMa
Sale Date	11/24/2015	5/13/2015	5/22/2015	5/5/2017	11/20/2015
Sale Price	$23,000,000	$9,900,000	$19,800,000	$70,000,000	$25,000,000
Site Size (Acre)	0.288	0.193	0.285	0.875	0.434
Site Size (SF)	12,545	8,420	12,401	38,124	18,901
Price Per SF	**$1,830**	**$1,176**	**$1,597**	**$1,836**	**$1,323**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.31	1.35	1.35	1.23	1.31
Adjusted Price (to DOV) **Price/SF**	**$2,398**	**$1,587**	**$2,155**	**$2,258**	**$1,733**
Location	0	0	Sl. Superior (-)	Superior (-)	0
Site Size	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0
Zoning, Height-Bulk/Density	Inferior (+)	Inferior (+)	Inferior (+)	Superior (-)	Inferior (+)
Entitlements	0	0	65%	65%	65%
Total Adjustment ($/Land sf)	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than	**Similar** Similar	**Superior (-)** Less Than	**Inferior (+)** Greater Than
Indicated Value of Subject ($/sf)	**$2,398**	**$1,587**	**$3,556**	**$3,726**	**$2,859**

Land Value Conclusion – #6 Substation X (Mission)

PG&E's Mission Substation Site is situated at the northwest corner of Mission and 8th Streets in SoMa, between Mid-Market and Civic Center. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 20 through 22. The Embarcadero Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 18 and 19 sold with entitled development approvals, requiring no adjustment. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location" and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $3,500 per square foot, or $156,159,500, calculated as follows:

44,617 sf x $3,500/sf = $156,159,500

PG&E Property #7 - Substation L

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
23	2100 Mission Street Mission 3576-001	8/22/2019	6,370 0.146	$4,800,000	**$753.53**	NCT 65-B (65)	Y	Muller 2005 Trust 2100 Mission Street Impossible LLC 2019-9K818307-00004
24	1490 Ocean Avenue Westwood Park 3197-010	8/25/2015	10,237 0.235	$5,300,000	**$517.73**	NCT 45-X (45)	N	Saint Anthony Real Estate, LLC ISCA Assets 33, LLC 2015-9K11442-00003
25	1455 Irving Street Outer Sunset 1770-051 & -052	11/7/2016	4,792 0.110	$1,570,000	**$327.63**	NCD 40-X (40)	N	Karl Olson and Karen Olson Edward Romanov and Janet Romanov 2016-9K354888-00002
26	3820 24th Street Noe Valley 3651-079	5/20/2016	2,849 0.065	$2,100,000	**$737.10**	NCD 1 Story	N	3820 24th Street LLC Hurwitz-Family Living Trust 2016-9K246774-00004
27	2550 Irving Street Outer Sunset 1724-038	11/19/2021	19,162 0.440	$9,000,000	**$469.68**	NCD 40-X (40)	N	The Police Credit Union of California 2550 Irving Associates LP 2021-172913
Subject	Substation L 2475 Ocean Avenue Inglesides Terraces 6901-001	---	17,076 0.392	--	--	NC-1 26-X (26)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 23	Land Sale 24	Land Sale 25	Land Sale 26	Land Sale 27
Location	2100 Mission St Mission	1490 Ocean Ave Westwood Park	1455 Irving St Outer Sunset	3820 24th St Noe Valley	2550 Irving St Outer Mission
Sale Date	8/22/2019	8/25/2015	11/7/2016	5/20/2016	11/19/2021
Sale Price	$4,800,000	$5,300,000	$1,570,000	$2,100,000	$9,000,000
Site Size (Acre)	0.146	0.235	0.110	0.065	0.440
Site Size (SF)	6,370	10,237	4,792	2,849	19,162
Price Per SF	**$754**	**$518**	**$328**	**$737**	**$470**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.08	1.27	1.20	1.22	1.00
Adjusted Price (to DOV) **Price/SF**	**$814**	**$658**	**$393**	**$899**	**$470**
Location	Superior (-)	Superior (-)	0	Superior (-)	0
Site Size	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	Inferior (+)	0	0
Zoning, Height-Bulk/Density	Superior (-)	Superior (-)	Superior (-)	0	Superior (-)
Entitlements	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Similar** Similar	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$814**	**$1,085**	**$649**	**$1,484**	**$775**

Land Value Conclusion – #7 Substation L

PG&E's Substation L Site is situated on the south side of Ocean Avenue, one parcel east of Junipero Serra Boulevard in the Inglesides Terraces neighborhood. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Sales 23, 24, 25, and 26 warrant adjustments for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 4% per year, a blended (commercial and residential) compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis. No adjustment is made to Sale 27 for land price trends.

Quantitative adjustment is made to unentitled land sales – Numbers 24 through 27. The Substation L Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Number 23 sold with entitled development approvals, requiring no adjustment. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location," "Building or Site Improvements," and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable

to the valuation. The site has good size and shape, though is trapezoidal in shape. It has good overall uniform site dimensions, however, which is recognized in the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $650 per square foot, or $11,099,400, calculated as follows:

17,076 sf x $650/sf: = $11,099,400

PG&E Property #8 - Substation G

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet / Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
28A	42 & 44 Cook Street Laurel Heights 1067-034	3/17/2023	3,000 0.069	$3,350,000	**$1,116.67**	RH-2 40-X (40)	Y	44 Cook LLC Jewish Family and Children's Services 2023-020157
29	524 Hickory Street Hayes Valley 829-042	7/27/2017	1,250 0.029	$1,300,000	**$1,040.00**	RH-3 Hayes Valley 40-X (40)	Y	Reco Investors LLC Gilligan of Lenny Family Trust 2017-9K479111-00003
28B	42 & 44 Cook Street Laurel Heights 1067-034	2/3/2021	3,000 0.069	$1,670,000	**$556.67**	RH-2 40-X (40)	N	DRS Group, LP 44 Cook LLC 2021-018659
30	166 Parker Avenue Jordan Park 1065-032	3/20/2018	2,775 0.064	$1,650,000	**$594.59**	RH-2 40-X (40)	N	Wells Fargo Bank, N.A. Frances Biglieri 2018-9K591558-00003
31	2677 Harrison Street Mission 4148-034	9/27/2017	2,304 0.053	$1,295,000	**$562.07**	RH-3 40-X (40)	N	Fred W & Carolyn Li Deevy Abhishek & Alisha Gupta 2017-9K519306-00002
Subject	Substation G 1200 Broderick Street Pacific Heights 1101-013	--	15,469 0.355	--	--	RM-3 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 28A	Land Sale 29	Land Sale 28B	Land Sale 30	Land Sale 31
Location	42 & 44 Cook St Laurel Heights	524 Hickory St Hayes Valley	42 & 44 Cook St Laurel Heights	166 Parker Ave Jordan Park	2677 Harrison St Mission
Sale Date	3/17/2023	7/27/2017	2/3/2021	3/20/2018	9/27/2017
Sale Price	$3,350,000	$1,300,000	$1,670,000	$1,650,000	$1,295,000
Site Size (Acre)	0.069	0.029	0.069	0.064	0.053
Site Size (SF)	3,000	1,250	3,000	2,775	2,304
Price Per SF	**$1,117**	**$1,040**	**$557**	**$595**	**$562**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.07	1.22	1.00	1.18	1.21
Adjusted Price (to DOV)					
Price/SF	**$1,195**	**$1,269**	**$557**	**$702**	**$680**
Location	Inferior (+)	Inferior (+)	Inferior (+)	Inferior (+)	Inferior (+)
Site Size	Superior (-)	Superior (-)	Superior (-)	Superior (-)	Superior (-)
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0
Zoning, Height-Bulk/Density	Inferior (+)	0	Inferior (+)	Inferior (+)	0
Entitlements	0	0	65%	65%	65%
Total Adjustment ($/Land sf)	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$1,195**	**$1,269**	**$919**	**$1,158**	**$1,122**

Land Value Conclusion – #8 Substation G

PG&E's Substation G Site is located at the northeast corner of Broderick and Ellis Streets in the Anza Vista neighborhood. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale, except for Land Sale 28B, warrants adjustment for increasing, or decreasing, land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time before 2021 then declined about 4% per year. These rates are applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 28B, 30, and 31. The Substation G Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 28A and 29 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Utility/Shape"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or

Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $1,200 per square foot, or $ $18,562,800, calculated as follows:

15,469 sf x $1,200/sf: = $18,562,800

PG&E Property #9 - Substation E

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
23	2100 Mission Street Mission 3576-001	8/22/2019	6,370 0.146	$4,800,000	**$753.53**	NCT 65-B (65)	Y	Muller 2005 Trust 2100 Mission Street Impossible LLC 2019-9K818307-00004
32	1120 Valencia St Mission 3635-004	10/16/2018	4,134 0.095	$3,460,000	**$836.96**	NCT 55-X (55)	N	The Evelyn L. Feno Family LP M3 LLC 2018-9K683199-00005
33	1090-1098 Valencia Street Mission 3617-085	11/22/2017	10,114 0.232	$11,898,000	**$1,176.39**	NCT 55-X (55)	N	Pet Co Properties I Diamond Bay Valencia Corporation 2017-9K541022-00004
34	606 Capp Street Mission 3615-055	7/31/2015	7,350 0.169	$3,300,000	**$448.98**	RTO-M 40-X (40)	N	Winter/Capp Street Family Partnership, LP 606 Capp Sreet LLC 2015-9K100138-00003
Subject	Substation E 205 Lexington Avenue Mission 3596-104	--	13,175 0.302	--	--	RTO-M 55-X (55)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 23	Land Sale 32	Land Sale 33	Land Sale 34
Location	2100 Mission St Mission	1120 Valencia St Mission	1098 Valencia St Mission	606 Capp St Mission
Sale Date	8/22/2019	10/16/2018	11/22/2017	7/31/2015
Sale Price	$4,800,000	$3,460,000	$11,898,000	$3,300,000
Site Size (Acre)	0.146	0.095	0.232	0.169
Site Size (SF)	6,370	4,134	10,114	7,350
Price Per SF	**$754**	**$837**	**$1,176**	**$449**
Expenditures Immediately After Sale (Demo)	0	0	0	0
Rights Conveyed	0	0	0	0
Sale Conditions	0	0	0	0
Price Trends	1.10	1.14	1.20	1.34
Adjusted Price (to DOV)				
Price/SF	**$829**	**$954**	**$1,412**	**$602**
Location	Inferior (+)	0	0	0
Site Size	Inferior (+)	Inferior (+)	0	Inferior (+)
Site Utility/Shape	Inferior (+)	0	0	0
Building and Site Improvements	0	0	0	0
Zoning, Height-Bulk/Density	Superior (-)	0	0	Inferior (+)
Entitlements	0	65%	65%	65%
Total Adjustment ($/Land sf)	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than	**Similar** Similar	**Inferior (+)** Greater Than
Indicated Value of Subject ($/sf)	**$829**	**$1,574**	**$2,329**	**$993**

Land Value Conclusion – #9 Substation E

PG&E's Substation E Site is located at the northeast corner of 19th and Lexington Streets and the corner of San Carlos Street in the Mission District. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time before 2021. These rates are applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 32 through 34. Substation E Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 23 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Size"; "Site Utility/Shape"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $2,300 per square foot, or $30,302,500 calculated as follows:

13,175 sf x $2,300/sf: = $30,302,500

PG&E Property #10 - Substation F (Marina)

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
35	1526 Powell Street North Beach 0130-025	4/14/2022	5,259 0.121	$2,900,000	**$551.44**	NCD 40-X (40)	N	Delucchi Mechanical Inc. Powell Street Partners LLC 2022-038465
36	555 Jackson Street Chinatown 0195-019	9/27/2019	8,089 0.186	$6,500,000	**$803.56**	CRNC 40-X (40)	N	Roman Catholic Archibishop of San Francisco 555 Jackson Ventures LLC 2019-9K837619-00005
37	1198 Columbus Ave/2568 Jones St North Beach 0043-007	11/26/2018	6,420 0.147	$4,500,000	**$700.93**	C-2 40-X (40)	N	1196 Hotel, LLC Linden Station Columbus LLC 2018-K697461-00
38	425 Broadway Jackson Square 0163-002	5/30/2017	13,641 0.313	$11,000,000	**$806.39**	NCD 65-A-1 (65)	N	Michael A Moglia Montgomery Place LLC 2017-9K457063-00008
39	1598 Bay Street Marina 0459-007	12/7/2015	12,541 0.288	$7,875,000	**$627.94**	NC-2 40-X (40)	N	Pacific Coast Homes Bay Street Partners LLC 2015-K165225-00
Subject	Substation F (Marina Substation) 1570 Bay Street Marina 0459-032	--	13,112 0.301	--	--	NC-2/RM-4 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 35	Land Sale 36	Land Sale 37	Land Sale 38	Land Sale 39
Location	1526 Powell Street North Beach	555 Jackson Street Chinatown	1198 Columbus Ave North Beach	425 Broadway North Beach	1598 Bay St Marina
Sale Date	4/14/2022	9/27/2019	11/26/2018	5/30/2017	12/7/2015
Sale Price	$2,900,000	$6,500,000	$4,500,000	$11,000,000	$7,875,000
Site Size (Acre)	0.121	0.186	0.147	0.313	0.288
Site Size (SF)	5,259	8,089	6,420	13,641	12,541
Price Per SF	**$551**	**$804**	**$701**	**$806**	**$628**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.00	1.10	1.13	1.22	1.31
Adjusted Price (to DOV)					
Price/SF	**$551**	**$884**	**$792**	**$984**	**$823**
Location	0	0	0	0	0
Site Size	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0
Zoning, Height-Bulk/Density	Inferior (+)	Superior (-)	0	Superior (-)	0
Entitlements	65%	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Similar** Similar	**Superior (-)** Less Than	**Similar** Similar
Indicated Value of Subject ($/sf)	**$910**	**$1,458**	**$1,307**	**$1,623**	**$1,357**

Land Value Conclusion – #10 Substation F (Marina)

PG&E's Marina Substation Site is located on the north side of Bay Street between Buchanan and Laguna Streets in the Marina District. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 5% per year, a blended (commercial and residential) and compounding rate of price increases with time before 2021. These rates are applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – each of the sales. The Marina Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Property #10, the Marina Substation, is a "flag-shaped" site. The narrow "pole" fronts Bay Street, a local commercial throughfare. The flag-portion of the site sits behind 1598 Bay Street, limiting commercial exposure to Bay Street. While the site is well-suited to most prospective commercial uses, including the subject's actual existing use, the site's functional utility and value are diminished in comparison to a more rectangular- or square-shaped site.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $950 per square foot, or $12,456,400 calculated as follows:

13,112 sf x $950/sf = $12,456,400

PG&E Property #11 - Substation K

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
28A	42 & 44 Cook Street Laurel Heights 1067-034	3/17/2023	3,000 0.069	$3,350,000	**$1,116.67**	RH-2 40-X (40)	Y	44 Cook LLC Jewish Family and Children's Services 2023-020157
29	524 Hickory Street Hayes Valley 829-042	7/27/2017	1,250 0.029	$1,300,000	**$1,040.00**	RH-3 Hayes Valley 40-X (40)	Y	Reco Investors LLC Gilligan of Lenny Family Trust 2017-9K479111-00003
28B	42 & 44 Cook Street Laurel Heights 1067-034	2/3/2021	3,000 0.069	$1,670,000	**$556.67**	RH-2 40-X (40)	N	DRS Group, LP 44 Cook LLC 2021-018659
30	166 Parker Avenue Jordan Park 1065-032	3/20/2018	2,775 0.064	$1,650,000	**$594.59**	RH-2 40-X (40)	N	Wells Fargo Bank, N.A. Frances Biglieri 2018-9K591558-00003
40	1633 Cabrillo Street Inner Richmond 1660-044	11/29/2016	2,500 0.057	$988,000	**$395.20**	RH-2 40-X (40)	N	1643 Cabrillo, LLC 1633-1649 Cabrillo LLC 2016-9K364321-00003
31	2677 Harrison Street Mission 4148-034	9/27/2017	2,304 0.053	$1,295,000	**$562.07**	RH-3 40-X (40)	N	Fred W & Carolyn Li Deevy Abhishek & Alisha Gupta 2017-9K519306-00002
Subject	Substation K 679 24th Avenue Central Richmond 1567-012	---	12,398 0.285	--	--	RH-2 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 28A	Land Sale 29	Land Sale 28B	Land Sale 30	Land Sale 40	Land Sale 31
Location	42 & 44 Cook St Laurel Heights	524 Hickory St Hayes Valley	42 & 44 Cook St Laurel Heights	166 Parker Ave Jordan Park	1633 Cabrillo St Inner Richmond	2677 Harrison St Mission
Sale Date	3/17/2023	7/27/2017	2/3/2021	3/20/2018	3/20/2018	9/27/2017
Sale Price	$3,350,000	$1,300,000	$1,670,000	$1,650,000	$988,000	$1,295,000
Site Size (Acre)	0.069	0.029	0.069	0.064	0.057	0.053
Site Size (SF)	3,000	1,250	3,000	2,775	2,500	2,304
Price Per SF	**$1,117**	**$1,040**	**$557**	**$595**	**$395**	**$562**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0	0
Rights Conveyed	0	0	0	0	0	0
Sale Conditions	0	0	0	0	0	0
Price Trends	1.07	1.22	1.00	1.18	1.18	1.21
Adjusted Price (to DOV)						
Price/SF	**$1,195**	**$1,269**	**$557**	**$702**	**$466**	**$680**
Location	Superior (-)	Superior (-)	Superior (-)	Superior (-)	0	0
Site Size	0	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0	0
Zoning, Height-Bulk/Density	0	Superior (-)	0	0	0	Superior (-)
Entitlements	0	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than	**Similar** Similar	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$1,195**	**$1,269**	**$919**	**$1,158**	**$769**	**$1,122**

Land Value Conclusion – #11 Substation K

PG&E's Substation K Site is located at the northwest corner of 24th Avenue and Balboa Street in the Central Richmond district. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale, except for Land Sale 28B, warrants adjustment for increasing, or decreasing, land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time before 2021 then declined about 4% per year. These rates are applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 28B, 30, 31, and 40. The Substation K Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 28A and 29 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Utility/Shape"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $750 per square foot, or $9,298,500, calculated as follows:

12,398 sf x $750/sf = $9,298,500

PG&E Property #12 - Substation J

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
19	72-80 Ellis Street Union Square 0327-011	5/13/2015	8,240 0.189	$9,900,000	**$1,201.46**	C-3-R 80-130-F (130) 6.0:1	Y	AGPME Parking Lot, LLC 72 Ellis Owner LP 2015-K060083-00
38	425 Broadway Jackson Square 0163-002	5/30/2017	13,639 0.313	$11,000,000	**$806.51**	NCD 65-A-1 (65)	N	Michael A Moglia Montgomery Place LLC 2017-9K457063-00008
41	36 Tehama Street SoMa/Yerba Buena 3736-083A	6/28/2018	2,000 0.046	$2,500,000	**$1,250.00**	C-3-O (SD) 350-S (350) 9.0:1	N	Tehama Partners LLC 36 Tehama Partners LLC 2018-9K633420-00004
35	1526 Powell Street North Beach 0130-025	4/14/2022	5,259 0.121	$2,900,000	**$551.44**	NCD - North Beach 40-X (40)	N	Delucchi Mechanical Inc. Powell Street Partners LLC 2022-038465
42	135 Wetmore Street Nob Hill 0212-031	3/2/2016	2,225 0.051	$2,700,000	**$1,213.48**	RM-3 65-A (65)	N	APF Development LLC Wetmore/Knobhill Partners LLC 2016-K210361-00
Subject	Substation J 530 Sacramento Street North Financial 0228-006	---	8,395 0.193	--	--	C-3-O 75-X (75)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 19	Land Sale 38	Land Sale 41	Land Sale 35	Land Sale 42
Location	72-80 Ellis St Union Square	425 Broadway Jackson Square	36 Tehama St SoMa/Yerba Buena	1526 Powell St North Beach	135 Wetmore St Nob Hill
Sale Date	5/13/2015	5/30/2017	6/28/2018	4/14/2022	1/4/2017
Sale Price	$9,900,000	$11,000,000	$2,500,000	$2,900,000	$2,700,000
Site Size (Acre)	0.193	0.313	0.046	0.121	0.051
Site Size (SF)	8,420	13,641	2,000	5,259	2,225
Price Per SF	**$1,176**	**$806**	**$1,250**	**$551**	**$1,213**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.35	1.22	1.16	1.00	1.25
Adjusted Price (to DOV)					
Price/SF	**$1,587**	**$984**	**$1,450**	**$551**	**$1,517**
Location	Superior (-)	0	Superior (-)	0	Superior (-)
Site Size	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0
Zoning, Height-Bulk/Density	Superior (-)	Inferior (+)	Superior (-)	Inferior (+)	0
Entitlements	0	0	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$1,587**	**$984**	**$2,393**	**$910**	**$2,503**

Land Value Conclusion – #12 Substation J

PG&E's Substation J Site is located at the northeast corner of Leidesdorff and Sacramento Street with the corner of Commercial Street in the Financial District. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Sales 19, 38, 41, and 42 warrant adjustments for increasing land price trends between the respective dates of their land sale and valuation date of the PG&E substation site appraised. No adjustment for market conditions is made to Sale 35. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 35, 41 and 42. Substation J Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 19 and 38 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location" and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $1,000 per square foot, or $8,395,000, calculated as follows:

8,395 sf x $1,000/sf = $8,395,000

PG&E Property #13 - Substation N

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
28A	42 & 44 Cook Street Laurel Heights 1067-034	3/17/2023	3,000 0.069	$3,350,000	**$1,116.67**	RH-2 40-X (40)	Y	44 Cook LLC Jewish Family and Children's Services 2023-020157
29	524 Hickory Street Hayes Valley 829-042	7/27/2017	1,250 0.029	$1,300,000	**$1,040.00**	RH-3 Hayes Valley 40-X (40)	Y	Reco Investors LLC Gilligan of Lenny Family Trust 2017-9K479111-00003
28B	42 & 44 Cook Street Laurel Heights 1067-034	2/3/2021	3,000 0.069	$1,670,000	**$556.67**	RH-2 40-X (40)	N	DRS Group, LP 44 Cook LLC 2021-018659
30	166 Parker Avenue Jordan Park 1065-032	3/20/2018	2,775 0.064	$1,650,000	**$594.59**	RH-2 40-X (40)	N	Wells Fargo Bank, N.A. Frances Biglieri 2018-9K591558-00003
40	1633 Cabrillo Street Inner Richmond 1660-044	11/29/2016	2,500 0.057	$988,000	**$395.20**	RH-2 40-X (40)	N	1643 Cabrillo, LLC 1633-1649 Cabrillo LLC 2016-9K364321-00003
31	2677 Harrison Street Mission 4148-034	9/27/2017	2,304 0.053	$1,295,000	**$562.07**	RH-3 40-X (40)	N	Fred W & Carolyn Li Deevy Abhishek & Alisha Gupta 2017-9K519306-00002
Subject	Substation N 1437-1449 9th Avenue Outer Richmond 1844-053	--	6,492 0.149	--	--	RH-2 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 28A	Land Sale 29	Land Sale 28B	Land Sale 30	Land Sale 40	Land Sale 31
Location	42 & 44 Cook St Laurel Heights	524 Hickory St Hayes Valley	42 & 44 Cook St Laurel Heights	166 Parker Ave Jordan Park	1633 Cabrillo St Inner Richmond	2677 Harrison St Mission
Sale Date	3/17/2023	7/27/2017	2/3/2021	3/20/2018	3/20/2018	9/27/2017
Sale Price	$3,350,000	$1,300,000	$1,670,000	$1,650,000	$988,000	$1,295,000
Site Size (Acre)	0.069	0.029	0.069	0.064	0.057	0.053
Site Size (SF)	3,000	1,250	3,000	2,775	2,500	2,304
Price Per SF	**$1,117**	**$1,040**	**$557**	**$595**	**$395**	**$562**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0	0
Rights Conveyed	0	0	0	0	0	0
Sale Conditions	0	0	0	0	0	0
Price Trends	1.07	1.22	1.00	1.18	1.18	1.21
Adjusted Price (to DOV)						
Price/SF	**$1,195**	**$1,269**	**$557**	**$702**	**$466**	**$680**
Location	Superior (-)	Superior (-)	Superior (-)	Superior (-)	0	0
Site Size	0	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0	0
Zoning, Height-Bulk/Density	0	Superior (-)	0	0	0	Superior (-)
Entitlements	0	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than	**Similar** Similar	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$1,195**	**$1,269**	**$919**	**$1,158**	**$769**	**$1,122**

Land Value Conclusion – #13 Substation N

PG&E's Substation N Site is located on the west side of 9th Avenue between Judah and Kirkham Streets in the Inner Sunset. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale, except for Land Sale 28B, warrants adjustment for increasing, or decreasing, land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time before 2021 then declined about 4% per year. These rates are applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 28B, 30, 31, and 40. The Substation N Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 28A and 29 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Utility/Shape"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $750 per square foot, or $4,869,000, calculated as follows:

6,492 sf x $750/sf = $4,869,000

PG&E Property #14 - Randolph Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
23	2100 Mission Street Mission 3576-001	8/22/2019	6,370 0.146	$4,800,000	**$753.53**	NCT 65-B (65)	Y	Muller 2005 Trust 2100 Mission Street Impossible LLC 2019-9K818307-00004
24	1490 Ocean Avenue Westwood Park 3197-010	8/25/2015	10,237 0.235	$5,300,000	**$517.73**	NCT 45-X (45)	N	Saint Anthony Real Estate, LLC ISCA Assets 33, LLC 2015-9K11442-00003
25	1455 Irving Street Outer Sunset 1770-051 & -052	11/7/2016	4,792 0.110	$1,570,000	**$327.63**	NCD 40-X (40)	N	Karl Olson and Karen Olson Edward Romanov and Janet Romanov 2016-9K354888-00002
26	3820 24th Street Noe Valley 3651-079	5/20/2016	2,849 0.065	$2,100,000	**$737.10**	NCD 1 Story	N	3820 24th Street LLC Hurwitz-Family Living Trust 2016-9K246774-00004
27	2550 Irving Street Outer Sunset 1724-038	11/19/2021	19,162 0.440	$9,000,000	**$469.68**	NCD 40-X (40)	N	The Police Credit Union of California 2550 Irving Associates LP 2021-172913
Subject	Randolph Substation 724 Randolph Street Ingleside Heights 7084-024	--	4,865 0.112	--	--	NC-1 26-X (26)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 23	Land Sale 24	Land Sale 25	Land Sale 26	Land Sale 27
Location	2100 Mission St Mission	1490 Ocean Ave Westwood Park	1455 Irving St Outer Sunset	3820 24th St Noe Valley	2550 Irving St Outer Mission
Sale Date	8/22/2019	8/25/2015	11/7/2016	5/20/2016	11/19/2021
Sale Price	$4,800,000	$5,300,000	$1,570,000	$2,100,000	$9,000,000
Site Size (Acre)	0.146	0.235	0.110	0.065	0.440
Site Size (SF)	6,370	10,237	4,792	2,849	19,162
Price Per SF	**$754**	**$518**	**$328**	**$737**	**$470**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.08	1.27	1.20	1.22	1.00
Adjusted Price (to DOV) **Price/SF**	**$814**	**$658**	**$393**	**$899**	**$470**
Location	Superior (-)	Superior (-)	0	Superior (-)	0
Site Size	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	Inferior (+)	0	0
Zoning, Height-Bulk/Density	Superior (-)	Superior (-)	Superior (-)	0	Superior (-)
Entitlements	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Similar** Similar	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$814**	**$1,085**	**$649**	**$1,484**	**$775**

Land Value Conclusion – #14 Randolph Substation

PG&E's Randolph Substation Site is situated at the northeast corner of Randolph and Byxbee Streets at 19th Avenue in the Ingleside Heights area. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Sales 23, 24, 25, and 26 warrant adjustments for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 4% per year, a blended (commercial and residential) and compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis. No adjustment is made to Sale 27 for land price trends.

Quantitative adjustment is made to unentitled land sales – Numbers 24 through 27. The Randolph Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Number 23 sold with entitled development approvals, requiring no adjustment. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location," "Building or Site Improvements," and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation. The site has good size and shape and corner exposure to Randolph Street, a

neighborhood commercial throughfare, and to Byxbee Street, a residential-oriented street. The site's dimension to its commercial exposure is narrow relative to its length along Byxbee Street. This is recognized in the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $650 per square foot, or $3,162,250 calculated as follows:

4,865 sf x $650/sf = $3,162,250

PG&E Property #15 - Substation M

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
29	524 Hickory Street Hayes Valley 829-042	7/27/2017	1,250 0.029	$1,300,000	**$1,040.00**	RH-3 Hayes Valley 40-X (40)	Y	Reco Investors LLC Gilligan of Lenny Family Trust 2017-9K479111-00003
43	361-365 21st Street Mission 1453-013	3/4/2016	2,997 0.069	$1,850,000	**$617.28**	RH-2 40-X (40)	Y	Kim Wu Woods Family Investments, LP 2016-9K211142-00002
44	53 States Street Corona Heights 2623-074	2/7/2017	2,642 0.061	$1,920,000	**$726.72**	RH-2 40-X (40)	Y	53 States Street, LLC Golden Properties LLC 2017-9K405850-00003
31	2677 Harrison Street Mission 4148-034	9/27/2017	2,304 0.053	$1,295,000	**$562.07**	RH-3 40-X (40)	N	Fred W & Carolyn Li Deevy Abhishek & Alisha Gupta 2017-9K519306-00002
Subject	Substation M 20 Rousseau Street St. Mary's Park 6747-016	---	4,725 0.108	--	--	RH-2 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 29	Land Sale 43	Land Sale 44	Land Sale 31
Location	524 Hickory St Hayes Valley	361-365 21st St Mission	53 States St Corona Heights	2677 Harrison St Mission
Sale Date	7/27/2017	3/4/2016	2/7/2017	9/27/2017
Sale Price	$1,300,000	$1,850,000	$1,920,000	$1,295,000
Site Size (Acre)	0.029	0.069	0.061	0.053
Site Size (SF)	1,250	2,997	2,642	2,304
Price Per SF	**$1,040**	**$617**	**$727**	**$562**
Expenditures Immediately After Sale (Demo)	0	0	0	0
Rights Conveyed	0	0	0	0
Sale Conditions	0	0	0	0
Price Trends	1.22	1.30	1.24	1.21
Adjusted Price (to DOV)				
Price/SF	**$1,269**	**$802**	**$901**	**$680**
Location	Superior (-)	Inferior (+)	Inferior (+)	0
Site Size	0	0	0	0
Site Utility/Shape	0	0	0	0
Building and Site Improvements	0	0	0	0
Zoning, Height-Bulk/Density	Superior (-)	0	0	0
Entitlements	0	0	0	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than	**Similar** Similar
Indicated Value of Subject ($/sf)	**$1,269**	**$802**	**$901**	**$1,122**

Land Value Conclusion – #15 Substation M

PG&E's Substation M Site is located at the northwest corner of Bosworth and Rousseau Streets in the St. Mary's Park neighborhood. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Number 31. Substation M Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 29, 43, and 44 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location" and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $1,100 per square foot, or $5,197,500, calculated as follows:

4,725 sf x $1,100/sf = $5,197,500

PG&E Property #16 - Portola Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
23	2100 Mission Street Mission 3576-001	8/22/2019	6,370 0.146	$4,800,000	**$753.53**	NCT 65-B (65)	Y	Muller 2005 Trust 2100 Mission Street Impossible LLC 2019-9K818307-00004
24	1490 Ocean Avenue Westwood Park 3197-010	8/25/2015	10,237 0.235	$5,300,000	**$517.73**	NCT 45-X (45)	N	Saint Anthony Real Estate, LLC ISCA Assets 33, LLC 2015-9K11442-00003
25	1455 Irving Street Outer Sunset 1770-051 & -052	11/7/2016	4,792 0.110	$1,570,000	**$327.63**	NCD 40-X (40)	N	Karl Olson and Karen Olson Edward Romanov and Janet Romanov 2016-9K354888-00002
26	3820 24th Street Noe Valley 3651-079	5/20/2016	2,849 0.065	$2,100,000	**$737.10**	NCD 1 Story	N	3820 24th Street LLC Hurwitz-Family Living Trust 2016-9K246774-00004
27	2550 Irving Street Outer Sunset 1724-038	11/19/2021	19,162 0.440	$9,000,000	**$469.68**	NCD 40-X (40)	N	The Police Credit Union of California 2550 Irving Associates LP 2021-172913
Subject	Portola Substation 610 Portola Drive Forest Hill Extension 2892-003	--	4,711 0.108	--	--	NC-1 26-X (26)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 23	Land Sale 24	Land Sale 25	Land Sale 26	Land Sale 27
Location	2100 Mission St Mission	1490 Ocean Ave Westwood Park	1455 Irving St Outer Sunset	3820 24th St Noe Valley	2550 Irving St Outer Mission
Sale Date	8/22/2019	8/25/2015	11/7/2016	5/20/2016	11/19/2021
Sale Price	$4,800,000	$5,300,000	$1,570,000	$2,100,000	$9,000,000
Site Size (Acre)	0.146	0.235	0.110	0.065	0.440
Site Size (SF)	6,370	10,237	4,792	2,849	19,162
Price Per SF	**$754**	**$518**	**$328**	**$737**	**$470**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.08	1.27	1.20	1.22	1.00
Adjusted Price (to DOV) **Price/SF**	**$814**	**$658**	**$393**	**$899**	**$470**
Location	Superior (-)	Superior (-)	0	Superior (-)	0
Site Size	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	Inferior (+)	0	0
Zoning, Height-Bulk/Density	Superior (-)	Superior (-)	Superior (-)	0	Superior (-)
Entitlements	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Similar** Similar	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$814**	**$1,085**	**$649**	**$1,484**	**$775**

Land Value Conclusion – #16 Portola Substation

PG&E's Portola Substation Site is situated on the west side Portola Drive between Woodside Avenue and Sydny Way in the Forest Hill extension area. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Sales 23, 24, 25, and 26 warrant adjustments for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 4% per year, a blended (commercial and residential) and compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis. No adjustment is made to Sale 27 for land price trends.

Quantitative adjustment is made to unentitled land sales – Numbers 24 through 27. The Randolph Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Number 23 sold with entitled development approvals, requiring no adjustment. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location," "Building or Site Improvements," and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable

to the valuation. The site has good size and shape, though is trapezoidal in shape with a slightly narrow dimension on one side, which is recognized in the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $625 per square foot, or $2,936,250 calculated as follows:

4,698 sf x $625/sf = $2,936,250

PG&E Property #17 - Beach Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
35	1526 Powell Street North Beach 0130-025	4/14/2022	5,259 0.121	$2,900,000	**$551.44**	NCD 40-X (40)	N	Delucchi Mechanical Inc. Powell Street Partners LLC 2022-038465
36	555 Jackson Street Chinatown 0195-019	9/27/2019	8,089 0.186	$6,500,000	**$803.56**	CRNC 40-X (40)	N	Roman Catholic Archibishop of San Francisco 555 Jackson Ventures LLC 2019-9K837619-00005
37	1198 Columbus Ave/2568 Jones St North Beach 0043-007	11/26/2018	6,420 0.147	$4,500,000	**$700.93**	C-2 40-X (40)	N	1196 Hotel, LLC Linden Station Columbus LLC 2018-K697461-00
38	425 Broadway Jackson Square 0163-002	5/30/2017	13,641 0.313	$11,000,000	**$806.39**	NCD 65-A-1 (65)	N	Michael A Moglia Montgomery Place LLC 2017-9K457063-00008
39	1598 Bay Street Marina 0459-007	12/7/2015	12,541 0.288	$7,875,000	**$627.94**	NC-2 40-X (40)	N	Pacific Coast Homes Bay Street Partners LLC 2015-K165225-00
Subject	Beach Street Substation 330 Beach Street Fisherman's Wharf 0013-010	---	3,750 0.086	--	--	C-2 40-X (40)	N	

ADJUSTMENT GRID

Comparable Number	Land Sale 35	Land Sale 36	Land Sale 37	Land Sale 38	Land Sale 39
Location	1526 Powell Street North Beach	555 Jackson Street Chinatown	1198 Columbus Ave North Beach	425 Broadway North Beach	1598 Bay St Marina
Sale Date	4/14/2022	9/27/2019	11/26/2018	5/30/2017	12/7/2015
Sale Price	$2,900,000	$6,500,000	$4,500,000	$11,000,000	$7,875,000
Site Size (Acre)	0.121	0.186	0.147	0.313	0.288
Site Size (SF)	5,259	8,089	6,420	13,641	12,541
Price Per SF	**$551**	**$804**	**$701**	**$806**	**$628**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.00	1.10	1.13	1.22	1.31
Adjusted Price (to DOV)					
Price/SF	**$551**	**$884**	**$792**	**$984**	**$823**
Location	0	0	0	0	0
Site Size	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0
Zoning, Height-Bulk/Density	Inferior (+)	Superior (-)	0	Superior (-)	0
Entitlements	65%	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Similar** Similar	**Superior (-)** Less Than	**Similar** Similar
Indicated Value of Subject ($/sf)	**$910**	**$1,458**	**$1,307**	**$1,623**	**$1,357**

Land Value Conclusion – #17 Beach Substation

PG&E's Beach Substation Site is located on the north side of Beach Street between Taylor and Mason Streets in the Fisherman's Wharf area. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Four of five sales, Numbers 36 through 39, warrant adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. No adjustment is made to Number 35. MLS and residential sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time before 2021. These rates are applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – each of the sales. The Beach Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation. The site has good size and shape, and commercial frontage, which is recognized in the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $1,350 per square foot, or $5,062,500 calculated as follows:

3,750 sf x $1,350/sf = $5,062,500

PG&E Property #18 - 6th Avenue Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
23	2100 Mission Street Mission 3576-001	8/22/2019	6,370 0.146	$4,800,000	**$753.53**	NCT 65-B (65)	Y	Muller 2005 Trust 2100 Mission Street Impossible LLC 2019-9K818307-00004
24	1490 Ocean Avenue Westwood Park 3197-010	8/25/2015	10,237 0.235	$5,300,000	**$517.73**	NCT 45-X (45)	N	Saint Anthony Real Estate, LLC ISCA Assets 33, LLC 2015-9K11442-00003
25	1455 Irving Street Outer Sunset 1770-051 & -052	11/7/2016	4,792 0.110	$1,570,000	**$327.63**	NCD 40-X (40)	N	Karl Olson and Karen Olson Edward Romanov and Janet Romanov 2016-9K354888-00002
45	2055 Taraval Street Parkside 2395-037	2/4/2020	3,250 0.075	$1,260,000	**$387.69**	NCD 50-X (50)	N	Cynthia D. Hampton Revocable Trust 2055 Taraval Street, LLC 2020-9K898534-00003
27	2550 Irving Street Outer Mission 1724-038	11/19/2021	19,162 0.440	$9,000,000	**$469.68**	NCD 40-X (40)	N	The Police Credit Union of California 2550 Irving Associates LP 2021-172913
Subject	6th Avenue Substation 365 6th Avenue Richmond 1438-014	--	3,000 0.069	--	--	NCD 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 23	Land Sale 24	Land Sale 25	Land Sale 45	Land Sale 27
Location	2100 Mission St Mission	1490 Ocean Ave Westwood Park	1455 Irving St Outer Sunset	2055 Taraval St Parkside	2550 Irving St Outer Mission
Sale Date	8/22/2019	8/25/2015	11/7/2016	2/4/2020	11/19/2021
Sale Price	$4,800,000	$5,300,000	$1,570,000	$1,260,000	$9,000,000
Site Size (Acre)	0.146	0.235	0.110	0.075	0.440
Site Size (SF)	6,370	10,237	4,792	3,250	19,162
Price Per SF	**$754**	**$518**	**$328**	**$388**	**$470**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.08	1.27	1.20	1.07	1.00
Adjusted Price (to DOV)					
Price/SF	**$814**	**$658**	**$393**	**$415**	**$470**
Location	Superior (-)	Superior (-)	0	0	0
Site Size	0	Superior (-)	0	0	Superior (-)
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	Inferior (+)	0	0
Zoning, Height-Bulk/Density	Superior (-)	0	0	Superior (-)	0
Entitlements	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$814**	**$1,085**	**$649**	**$684**	**$775**

Land Value Conclusion – #18 6th Avenue Substation

PG&E's 6th Avenue Substation is located on the west side of 6th Avenue between Clement Street and Geary Boulevard in the Inner Richmond District. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Four of the sales (Numbers 23, 24, 25, and 45) warrant adjustments for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 5% per year, a blended (commercial and residential) and compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis. No adjustment is made to Land Sale Number 27.

Quantitative adjustment is made to unentitled land sales – Numbers 24, 25, 27 and 45. The 6th Avenue Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 23 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Size"; "Building and Site Improvements"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether

Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $675 per square foot, or $2,025,000, calculated as follows:

3,000 sf x $675/sf = $2,025,000

PG&E Property #19 - Silver Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
46	134 Athens Street Portola 5959-006	6/24/2022	2,495 0.057	$713,000	**$285.77**	RH-1 40-X (40)	Y	Leo F Bautista Louis Maxwell Chou Primax Investments LLC 2022-063281
47	332 Bradford Street Bernal Heights 5697-006	2/1/2021	1751 0.040	$563,000	**$321.53**	RH-1 40-X (40)	Y	1948 Quesada Street LLC Chetan Patil 2021-016516
48	300 University Street Portola 5991-001	11/15/2019	2,060 0.047	$660,000	**$320.39**	RH-1 40-X (40)	Y	Zhenliving, LLC Yin Kai Tong and Di Fun Tsang Tong 2019-9K857400-00003
49	302 University Street Portola 5991-002	11/15/2019	2,060 0.047	$560,000	**$271.84**	RH-1 40-X (40)	Y	Zhenliving, LLC Mandy Lee 2019-9K857447-00003
50	326 Gambier Street Portola 5965-005	6/24/2021	2,950 0.068	$500,000	**$169.49**	RH-1 40-X (40)	N	Benton Yiubong Wong, et.al. Jimmy Kin Ho Tam and Averie Xiao Zheng 2021-101636
Subject	Silver Substation 1086 Silver Avenue College Hill 1438-014	---	2,834 0.065	--	--	RH-1 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 46	Land Sale 47	Land Sale 48	Land Sale 49	Land Sale 50
Location	134 Athens St Portola	332 Bradford St Bernal Heights	300 University St Portola	302 University St Portola	326 Gambier St Portola
Sale Date	6/24/2022	2/1/2021	11/15/2019	11/15/2019	6/24/2021
Sale Price	$713,000	$563,000	$660,000	$560,000	$500,000
Site Size (Acre)	0.057	0.040	0.047	0.047	0.068
Site Size (SF)	2,495	1,751	2,060	2,060	2,950
Price Per SF	**$286**	**$322**	**$320**	**$272**	**$169**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.03	1.00	1.09	1.09	1.00
Adjusted Price (to DOV)					
Price/SF	**$294**	**$322**	**$349**	**$296**	**$169**
Location	Inferior (+)	Inferior (+)	0	Inferior (+)	Inferior (+)
Site Size	0	Superior (-)	0	0	0
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0
Zoning, Height-Bulk/Density	0	0	0	0	0
Entitlements	0	0	0	0	65%
Total Adjustment ($/Land sf)	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than	**Similar** Similar	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than
Indicated Value of Subject ($/sf)	**$294**	**$322**	**$349**	**$296**	**$280**

Land Value Conclusion – #19 Silver Substation

PG&E's Silver Substation is located at the southwest corner of Silver Avenue and Colby Street in the Portola neighborhood. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Three of the sales (Numbers 46, 48, and 49) warrant adjustments for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Number 50. The Silver Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 46 through 49 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location" and "Site Size" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the

ATF sales comparison approach applicable to the valuation. Quantitative adjustments are not estimated, however, the magnitude of adjustment for location is greater than the adjustment for size, yielding an overall inferior adjustment to Sale Number 47.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $350 per square foot, or $991,900, calculated as follows:

2,834 sf x $350/sf = $991,900

PG&E Property #20 - Ocean Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
23	2100 Mission Street Mission 3576-001	8/22/2019	6,370 0.146	$4,800,000	**$753.53**	NCT 65-B (65)	Y	Muller 2005 Trust 2100 Mission Street Impossible LLC 2019-9K818307-00004
24	1490 Ocean Avenue Westwood Park 3197-010	8/25/2015	10,237 0.235	$5,300,000	**$517.73**	NCT 45-X (45)	N	Saint Anthony Real Estate, LLC ISCA Assets 33, LLC 2015-9K11442-00003
25	1455 Irving Street Outer Sunset 1770-051 & -052	11/7/2016	4,792 0.110	$1,570,000	**$327.63**	NCD 40-X (40)	N	Karl Olson and Karen Olson Edward Romanov and Janet Romanov 2016-9K354888-00002
45	2055 Taraval Street Parkside 2395-037	2/4/2020	3,250 0.075	$1,260,000	**$387.69**	NCD 50-X (50)	N	Cynthia D. Hampton Revocable Trust 2055 Taraval Street, LLC 2020-9K898534-00003
27	2550 Irving Street Outer Mission 1724-038	11/19/2021	19,162 0.440	$9,000,000	**$469.68**	NCD 40-X (40)	N	The Police Credit Union of California 2550 Irving Associates LP 2021-172913
Subject	Ocean Substation 1155 Ocean Avenue Ingleside 6944-040	---	2,655 0.061	--	--	NCT 45-X (45)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 23	Land Sale 24	Land Sale 25	Land Sale 45	Land Sale 27
Location	2100 Mission St Mission	1490 Ocean Ave Westwood Park	1455 Irving St Outer Sunset	2055 Taraval St Parkside	2550 Irving St Outer Mission
Sale Date	8/22/2019	8/25/2015	11/7/2016	2/4/2020	11/19/2021
Sale Price	$4,800,000	$5,300,000	$1,570,000	$1,260,000	$9,000,000
Site Size (Acre)	0.146	0.235	0.110	0.075	0.440
Site Size (SF)	6,370	10,237	4,792	3,250	19,162
Price Per SF	**$754**	**$518**	**$328**	**$388**	**$470**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.08	1.27	1.20	1.07	1.00
Adjusted Price (to DOV)					
Price/SF	**$814**	**$658**	**$393**	**$415**	**$470**
Location	Superior (-)	Superior (-)	0	0	0
Site Size	0	Superior (-)	0	0	Superior (-)
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	Inferior (+)	0	0
Zoning, Height-Bulk/Density	Superior (-)	0	0	Superior (-)	0
Entitlements	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$814**	**$1,085**	**$649**	**$684**	**$775**

Land Value Conclusion – #20 Ocean Substation

PG&E's Ocean Substation is located on the south side of Ocean Avenue between Brighton and Lee Avenues in the Ingleside neighborhood. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Four of five sales (Numbers 23, 24, 25, and 45) warrant adjustments for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. Sale 27 requires no adjustment for price trends. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 5% per year, a blended (commercial and residential) and compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 24, 25, 27 and 45. The Ocean Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 23 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Size"; "Building and Site Improvements"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether

Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $675 per square foot, or $1,792,125, calculated as follows:

2,655 sf x $675/sf = $1,792,125

PG&E Property #21 - Yosemite Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
51	1654 Kirkwood Avenue Baywood 5279-17 & -18	4/8/2021	5,000 0.115	$1,200,000	**$240.00**	RH-2 40-X (40)	Y	Robert Mendez Lynton LLC 2021-060109
52A	1782 Quesada Avenue Baywood 5327-027	7/30/2020	2,500 0.057	$675,000	**$270.00**	RH-2 40-X (40)	Y	1782 Quesada Partners, LLC Golden Sunset Development LLC 2020-9K962446-00002
52B	1782 Quesada Avenue Baywood 5327-027	1/13/2017	2,500 0.057	$380,000	**$152.00**	RH-2 40-X (40)	N	Melvin Pitre 1782 Quesada Partners, LLC 2017-9K394945-00002
53	1750 Oakdale Avenue Baywood 5312-014	1/25/2022	2,500 0.057	$320,000	**$128.00**	RH-2 40-X (40)	N	1748 Oakdale Avenue, LLC Lynton LLC 2022-007815
54	1528 Hudson Avenue Baywood 5254-006A	2/28/2022	2,500 0.057	$398,000	**$159.20**	RH-1 40-X (40)	N	Ze Qlang Xiao and Ai Ci Zhang Kim M Lam and Angela Y Lam Revocable Trust 2022-020574
55	1390 Oakdale Avenue Baywood 4730-018	3/8/2019	2,663 0.061	$425,000	**$159.59**	RH-1 40-X (40)	N	Charles E and Frances M Jackson Michelle Yip and Peter Suen 2019-9K741017-00004
Subject	Yosemite Substation 1802 Yosemite Avenue Bayview 5417-007	--	2,500 0.057	--	--	RH-1 65-J (65)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 51	Land Sale 52A	Land Sale 52B	Land Sale 53	Land Sale 54	Land Sale 55
Location	1654 Kirkwood Ave Bayview	1782 Quesada Ave Bayview	1782 Quesada Ave Bayview	1750 Oakdale Ave Bayview	1528 Hudson Ave Bayview	1390 Oakdale Ave Bayview
Sale Date	4/8/2021	7/30/2020	1/13/2017	1/25/2022	2/28/2022	3/8/2019
Sale Price	$1,200,000	$675,000	$380,000	$320,000	$398,000	$425,000
Site Size (Acre)	0.115	0.057	0.057	0.057	0.057	0.061
Site Size (SF)	5,000	2,500	2,500	2,500	2,500	2,663
Price Per SF	**$240**	**$270**	**$152**	**$128**	**$159**	**$160**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0	0
Rights Conveyed	0	0	0	0	0	0
Sale Conditions	0	0	0	0	0	0
Price Trends	1.00	1.00	1.00	1.02	1.03	1.00
Adjusted Price (to DOV)						
Price/SF	**$240**	**$270**	**$152**	**$131**	**$164**	**$160**
Location	0	0	0	0	0	0
Site Size	Inferior (+)	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0	0
Zoning, Height-Bulk/Density	0	0	0	0	0	0
Entitlements	0	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Inferior (+)**	**Similar**	**Similar**	**Similar**	**Similar**	**Similar**
	Greater Than	Similar	Similar	Similar	Similar	Similar
Indicated Value of Subject ($/sf)	**$240**	**$270**	**$251**	**$215**	**$271**	**$263**

Land Value Conclusion – #21 Yosemite Substation

PG&E's Yosemite Substation is located adjacent to the south side of Williams Avenue east of Newhall Street in the Bayview district. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each of the sales has direct street frontage, however, and has direct frontage street access. Access to the Yosemite site is through the contiguous site that owns the frontage land directly in front of the subject. It appears the subject site holds dominant tenement access rights through the other site in front of it. This indirect access is a negative impact on highest and best use and value, which is recognized in the value estimate.

No adjustments are made for increasing, or decreasing, land values between the respective dates of the sales and the valuation date of the property appraised. MLS and residential sources evidence that prices were flat year-over-year in the period of sales in the Bayview District. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 52B, 53, 54 and 55. The Yosemite Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 51 and 52A sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to Site Size" characteristics. Adjustment for this factor recognizes the difference between subject and comparable

sale – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $225 per square foot, or $562,500, calculated as follows:

2,500 sf x $225/sf = $562,500

PG&E Property #22 - Taraval Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
23	2100 Mission Street Mission 3576-001	8/22/2019	6,370 0.146	$4,800,000	**$753.53**	NCT 65-B (65)	Y	Muller 2005 Trust 2100 Mission Street Impossible LLC 2019-9K818307-00004
24	1490 Ocean Avenue Westwood Park 3197-010	8/25/2015	10,237 0.235	$5,300,000	**$517.73**	NCT 45-X (45)	N	Saint Anthony Real Estate, LLC ISCA Assets 33, LLC 2015-9K11442-00003
25	1455 Irving Street Outer Sunset 1770-051 & -052	11/7/2016	4,792 0.110	$1,570,000	**$327.63**	NCD 40-X (40)	N	Karl Olson and Karen Olson Edward Romanov and Janet Romanov 2016-9K354888-00002
45	2055 Taraval Street Parkside 2395-037	2/4/2020	3,250 0.075	$1,260,000	**$387.69**	NCD 50-X (50)	N	Cynthia D. Hampton Revocable Trust 2055 Taraval Street, LLC 2020-9K898534-00003
27	2550 Irving Street Outer Mission 1724-038	11/19/2021	19,162 0.440	$9,000,000	**$469.68**	NCD 40-X (40)	N	The Police Credit Union of California 2550 Irving Associates LP 2021-172913
Subject	Taraval Substation 2533 Taraval Street Sunset 2390-044		2,500 0.057	--	--	NCD 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 23	Land Sale 24	Land Sale 25	Land Sale 45	Land Sale 27
Location	2100 Mission St Mission	1490 Ocean Ave Westwood Park	1455 Irving St Outer Sunset	2055 Taraval St Parkside	2550 Irving St Outer Mission
Sale Date	8/22/2019	8/25/2015	11/7/2016	2/4/2020	11/19/2021
Sale Price	$4,800,000	$5,300,000	$1,570,000	$1,260,000	$9,000,000
Site Size (Acre)	0.146	0.235	0.110	0.075	0.440
Site Size (SF)	6,370	10,237	4,792	3,250	19,162
Price Per SF	**$754**	**$518**	**$328**	**$388**	**$470**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.08	1.27	1.20	1.07	1.00
Adjusted Price (to DOV)					
Price/SF	**$814**	**$658**	**$393**	**$415**	**$470**
Location	Superior (-)	Superior (-)	0	0	0
Site Size	0	Superior (-)	0	0	Superior (-)
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	Inferior (+)	0	0
Zoning, Height-Bulk/Density	Superior (-)	0	0	Superior (-)	0
Entitlements	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$814**	**$1,085**	**$649**	**$684**	**$775**

Land Value Conclusion – #22 Taraval Substation

PG&E's Taraval Substation is located on the south side of Taraval Street between 35th and 36th Avenues in the Sunset District. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Four of the sales (Numbers 23, 24, 25, and 45) warrant adjustments for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. Sal Number 27 does not require an adjustment for price trends. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 5% per year, a blended (commercial and residential) and compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 24, 25, 27 and 45. The Taraval Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 23 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Size"; "Building and Site Improvements"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether

Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $675 per square foot, or $1,687,500, calculated as follows:

2,500 sf x $675/sf = $1,687,500

PG&E Property #23 - Judah Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
28A	42 & 44 Cook Street Laurel Heights 1067-034	3/17/2023	3,000 0.069	$3,350,000	**$1,116.67**	RH-2 40-X (40)	Y	44 Cook LLC Jewish Family and Children's Services 2023-020157
29	524 Hickory Street Hayes Valley 829-042	7/27/2017	1,250 0.029	$1,300,000	**$1,040.00**	RH-3 Hayes Valley 40-X (40)	Y	Reco Investors LLC Gilligan of Lenny Family Trust 2017-9K479111-00003
28B	42 & 44 Cook Street Laurel Heights 1067-034	2/3/2021	3,000 0.069	$1,670,000	**$556.67**	RH-2 40-X (40)	N	DRS Group, LP 44 Cook LLC 2021-018659
30	166 Parker Avenue Jordan Park 1065-032	3/20/2018	2,775 0.064	$1,650,000	**$594.59**	RH-2 40-X (40)	N	Wells Fargo Bank, N.A. Frances Biglieri 2018-9K591558-00003
40	1633 Cabrillo Street Inner Richmond 1660-044	11/29/2016	2,500 0.057	$988,000	**$395.20**	RH-2 40-X (40)	N	1643 Cabrillo, LLC 1633-1649 Cabrillo LLC 2016-9K364321-00003
31	2677 Harrison Street Mission 4148-034	9/27/2017	2,304 0.053	$1,295,000	**$562.07**	RH-3 40-X (40)	N	Fred W & Carolyn Li Deevy Abhishek & Alisha Gupta 2017-9K519306-00002
Subject	Judah Substation 2927 Judah Street Outer Sunset 1819-042		2,500 0.057	--	--	RH-3 40-X (40)		

ADJUSTMENT GRID

Comparable Number	Land Sale 28A	Land Sale 29	Land Sale 28B	Land Sale 30	Land Sale 40	Land Sale 31
Location	42 & 44 Cook St Laurel Heights	524 Hickory St Hayes Valley	42 & 44 Cook St Laurel Heights	166 Parker Ave Jordan Park	1633 Cabrillo St Inner Richmond	2677 Harrison St Mission
Sale Date	3/17/2023	7/27/2017	2/3/2021	3/20/2018	3/20/2018	9/27/2017
Sale Price	$3,350,000	$1,300,000	$1,670,000	$1,650,000	$988,000	$1,295,000
Site Size (Acre)	0.069	0.029	0.069	0.064	0.057	0.053
Site Size (SF)	3,000	1,250	3,000	2,775	2,500	2,304
Price Per SF	**$1,117**	**$1,040**	**$557**	**$595**	**$395**	**$562**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0	0
Rights Conveyed	0	0	0	0	0	0
Sale Conditions	0	0	0	0	0	0
Price Trends	1.07	1.22	1.00	1.18	1.18	1.21
Adjusted Price (to DOV)						
Price/SF	**$1,195**	**$1,269**	**$557**	**$702**	**$466**	**$680**
Location	Superior (-)	Superior (-)	Superior (-)	Superior (-)	0	0
Site Size	0	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0	0
Zoning, Height-Bulk/Density	0	Superior (-)	0	0	0	Superior (-)
Entitlements	0	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than	**Similar** Similar	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$1,195**	**$1,269**	**$919**	**$1,158**	**$769**	**$1,122**

Land Value Conclusion – #23 Judah Substation

PG&E's Judah Substation Site is located on the south side of Judah Street between 34th and 35th Avenues in the Outer Sunset district. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale, except for Land Sale 28B, warrants adjustment for increasing, or decreasing, land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential sources evidence that prices increased in the competitive market area of the subject property at about 5% per year. A compounding rate of price increases with time before 2021 then declined about 4% per year. These rates are applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 28B, 30, 31, and 40. The Judah Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 28A and 29 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Utility/Shape"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $750 per square foot, or $1,875,000, calculated as follows:

2,500 sf x $750/sf = $1,875,000

PG&E Property #24 - Plymouth Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
23	2100 Mission Street Mission 3576-001	8/22/2019	6,370 0.146	$4,800,000	**$753.53**	NCT 65-B (65)	Y	Muller 2005 Trust 2100 Mission Street Impossible LLC 2019-9K818307-00004
24	1490 Ocean Avenue Westwood Park 3197-010	8/25/2015	10,237 0.235	$5,300,000	**$517.73**	NCT 45-X (45)	N	Saint Anthony Real Estate, LLC ISCA Assets 33, LLC 2015-9K11442-00003
25	1455 Irving Street Outer Sunset 1770-051 & -052	11/7/2016	4,792 0.110	$1,570,000	**$327.63**	NCD 40-X (40)	N	Karl Olson and Karen Olson Edward Romanov and Janet Romanov 2016-9K354888-00002
45	2055 Taraval Street Parkside 2395-037	2/4/2020	3,250 0.075	$1,260,000	**$387.69**	NCD 50-X (50)	N	Cynthia D. Hampton Revocable Trust 2055 Taraval Street, LLC 2020-9K898534-00003
27	2550 Irving Street Outer Mission 1724-038	11/19/2021	19,162 0.440	$9,000,000	**$469.68**	NCD 40-X (40)	N	The Police Credit Union of California 2550 Irving Associates LP 2021-172913
Subject	Plymouth Substation 214 Plymouth Avenue Oceanview 7112-012A	---	2,500 0.057	--	--	NC-1 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 23	Land Sale 24	Land Sale 25	Land Sale 45	Land Sale 27
Location	2100 Mission St Mission	1490 Ocean Ave Westwood Park	1455 Irving St Outer Sunset	2055 Taraval St Parkside	2550 Irving St Outer Mission
Sale Date	8/22/2019	8/25/2015	11/7/2016	2/4/2020	11/19/2021
Sale Price	$4,800,000	$5,300,000	$1,570,000	$1,260,000	$9,000,000
Site Size (Acre)	0.146	0.235	0.110	0.075	0.440
Site Size (SF)	6,370	10,237	4,792	3,250	19,162
Price Per SF	**$754**	**$518**	**$328**	**$388**	**$470**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.08	1.27	1.20	1.07	1.00
Adjusted Price (to DOV)					
Price/SF	**$814**	**$658**	**$393**	**$415**	**$470**
Location	Superior (-)	Superior (-)	0	0	0
Site Size	0	Superior (-)	0	0	Superior (-)
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	Inferior (+)	0	0
Zoning, Height-Bulk/Density	Superior (-)	0	0	Superior (-)	0
Entitlements	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$814**	**$1,085**	**$649**	**$684**	**$775**

Land Value Conclusion – #24 Plymouth Substation

PG&E's Plymouth Substation is located on the east side of Plymouth Street between Broad and Sadowa Streets in the Oceanview neighborhood. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale, except for Land Sale 27, warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 5% per year, a blended (commercial and residential) and compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 24, 25, 27 and 45. The Plymouth Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 23 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Size"; "Building and Site Improvements"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether

Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $675 per square foot, or $1,687,500, calculated as follows:

2,500 sf x $675/sf = $1,687,500

PG&E Property #25 - Noriega Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
23	2100 Mission Street Mission 3576-001	8/22/2019	6,370 0.146	$4,800,000	**$753.53**	NCT 65-B (65)	Y	Muller 2005 Trust 2100 Mission Street Impossible LLC 2019-9K818307-00004
24	1490 Ocean Avenue Westwood Park 3197-010	8/25/2015	10,237 0.235	$5,300,000	**$517.73**	NCT 45-X (45)	N	Saint Anthony Real Estate, LLC ISCA Assets 33, LLC 2015-9K11442-00003
25	1455 Irving Street Outer Sunset 1770-051 & -052	11/7/2016	4,792 0.110	$1,570,000	**$327.63**	NCD 40-X (40)	N	Karl Olson and Karen Olson Edward Romanov and Janet Romanov 2016-9K354888-00002
45	2055 Taraval Street Parkside 2395-037	2/4/2020	3,250 0.075	$1,260,000	**$387.69**	NCD 50-X (50)	N	Cynthia D. Hampton Revocable Trust 2055 Taraval Street, LLC 2020-9K898534-00003
27	2550 Irving Street Outer Mission 1724-038	11/19/2021	19,162 0.440	$9,000,000	**$469.68**	NCD 40-X (40)	N	The Police Credit Union of California 2550 Irving Associates LP 2021-172913
Subject	Noriega Substation 3819 Noriega Street Outer Sunset 2082-001L		2,325 0.053	--	--	NC-1 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 23	Land Sale 24	Land Sale 25	Land Sale 45	Land Sale 27
Location	2100 Mission St Mission	1490 Ocean Ave Westwood Park	1455 Irving St Outer Sunset	2055 Taraval St Parkside	2550 Irving St Outer Mission
Sale Date	8/22/2019	8/25/2015	11/7/2016	2/4/2020	11/19/2021
Sale Price	$4,800,000	$5,300,000	$1,570,000	$1,260,000	$9,000,000
Site Size (Acre)	0.146	0.235	0.110	0.075	0.440
Site Size (SF)	6,370	10,237	4,792	3,250	19,162
Price Per SF	**$754**	**$518**	**$328**	**$388**	**$470**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.08	1.27	1.20	1.07	1.00
Adjusted Price (to DOV)					
Price/SF	**$814**	**$658**	**$393**	**$415**	**$470**
Location	Superior (-)	Superior (-)	0	0	0
Site Size	0	Superior (-)	0	0	Superior (-)
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	Inferior (+)	0	0
Zoning, Height-Bulk/Density	Superior (-)	0	0	Superior (-)	0
Entitlements	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$814**	**$1,085**	**$649**	**$684**	**$775**

Land Value Conclusion – #25 Noriega Substation

PG&E's Noriega Substation is located on the east side of Noriega Street between 45th and 46th Avenue in the Outer Sunset district. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale, except for Land Sale 27, warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 5% per year, a blended (commercial and residential) and compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 24, 25, 27 and 45. The Noriega Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 23 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Size"; "Building and Site Improvements"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether

Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $675 per square foot, or $1,569,375, calculated as follows:

2,325 sf x $675/sf = $1,569,375

PG&E Property #26 - 18th Street Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
29	524 Hickory Street Hayes Valley 829-042	7/27/2017	1,250 0.029	$1,300,000	**$1,040.00**	RH-3 Hayes Valley 40-X (40)	Y	Howard/First Property LLC Ridgegate Apartments, LLC et al. 2017-9K479111-00003
44	53 States Street Corona Heights 2623-074	2/7/2017	2,642 0.061	$1,920,000	**$726.72**	RH-2 40-X (40)	Y	Kim Wu Woods Family Investments, LP 2017-9K405850-00003
43	361-365 21st Street Mission 1453-013	3/4/2016	2,997 0.069	$1,850,000	**$617.28**	RH-2 40-X (40)	Y	Kim Wu Woods Family Investments, LP 2016-9K211142-00002
56	150 Eureka Street Castro 2692-007	2/4/2015	6,069 0.139	$2,325,000	**$383.09**	RH-2 40-X (40)	N	Metroplitan Community Church of San Francisco 150 Eureka Street 2015-9K016292-00003
31	2677 Harrison Street Mission 4148-034	9/27/2017	2,304 0.053	$1,295,000	**$562.07**	RH-3 40-X (40)	N	Fred W & Carolyn Li Deevy Abhishek & Alisha Gupta 2017-9K519306-00002
57	56 Laussat Street Hayes Valley 0858-024A	4/23/2021	750 0.017	$428,000	**$570.67**	RTO 40-X (40)	N	Leonard Krasowski Martin C and Junyi Li Kellogg 2021-069734
Subject	18th Street Substation 4430 18th Street Castro 2650-020	---	2,250 0.052	--	--	RH-3 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 29	Land Sale 44	Land Sale 43	Land Sale 56	Land Sale 31	Land Sale 57
Location	524 Hickory St Hayes Valley	53 States St Corona Heights	361-365 21st St Mission	150 Eureka St Castro	2677 Harrison St Mission	56 Laussat St Hayes Valley
Sale Date	7/27/2017	2/7/2017	3/4/2016	2/4/2015	9/27/2017	4/23/2021
Sale Price	$1,300,000	$1,920,000	$1,850,000	$2,325,000	$1,295,000	$428,000
Site Size (Acre)	0.029	0.061	0.069	0.139	0.053	0.017
Site Size (SF)	1,250	2,642	2,997	6,069	2,304	750
Price Per SF	**$1,040**	**$727**	**$617**	**$383**	**$562**	**$571**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0	0
Rights Conveyed	0	0	0	0	0	0
Sale Conditions	0	0	0	0	0	0
Price Trends	1.21	1.25	1.31	1.37	1.21	1.00
Adjusted Price (to DOV)						
Price/SF	**$1,258**	**$908**	**$809**	**$525**	**$680**	**$571**
Location	Superior (-)	0	0	0	0	Superior (-)
Site Size	0	0	0	0	0	Inferior (+)
Site Utility/Shape	0	0	0	0	0	Inferior (+)
Building and Site Improvements	0	0	0	Inferior (+)	0	0
Zoning, Height-Bulk/Density	0	Inferior (+)	Inferior (+)	Inferior (+)	0	0
Entitlements	0	0	0	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than	**Similar** Similar	**Inferior (+)** Greater Than
Indicated Value of Subject ($/sf)	**$1,258**	**$908**	**$809**	**$866**	**$1,122**	**$942**

Land Value Conclusion – #26 18th Street Substation

PG&E's 18th Street Substation is located on the north side of 18th Street between Douglass and Eureka Street in the Eureka Valley area. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale, except for Land Sale 57, warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 31, 56, and 57. The 18th Street Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 29, and 43 and 44 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Size"; "Site Utility/Shape; "Building and Site Improvements"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $1,100 per square foot, or $2,475,000, calculated as follows:

2,250 sf x $1,100/sf = $2,475,000

PG&E Property #27 - Acton Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
23	2100 Mission Street Mission 3576-001	8/22/2019	6,370 0.146	$4,800,000	**$753.53**	NCT 65-B (65)	Y	Muller 2005 Trust 2100 Mission Street Impossible LLC 2019-9K818307-00004
24	1490 Ocean Avenue Westwood Park 3197-010	8/25/2015	10,237 0.235	$5,300,000	**$517.73**	NCT 45-X (45)	N	Saint Anthony Real Estate, LLC ISCA Assets 33, LLC 2015-9K11442-00003
25	1455 Irving Street Outer Sunset 1770-051 & -052	11/7/2016	4,792 0.110	$1,570,000	**$327.63**	NCD 40-X (40)	N	Karl Olson and Karen Olson Edward Romanov and Janet Romanov 2016-9K354888-00002
45	2055 Taraval Street Parkside 2395-037	2/4/2020	3,250 0.075	$1,260,000	**$387.69**	NCD 50-X (50)	N	Cynthia D. Hampton Revocable Trust 2055 Taraval Street, LLC 2020-9K898534-00003
27	2550 Irving Street Outer Mission 1724-038	11/19/2021	19,162 0.440	$9,000,000	**$469.68**	NCD 40-X (40)	N	The Police Credit Union of California 2550 Irving Associates LP 2021-172913
Subject	Acton Substation 5889 Mission Street Outer Mission 6472-021D	--	2,250 0.052	--	--	NCD 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 23	Land Sale 24	Land Sale 25	Land Sale 45	Land Sale 27
Location	2100 Mission St Mission	1490 Ocean Ave Westwood Park	1455 Irving St Outer Sunset	2055 Taraval St Parkside	2550 Irving St Outer Mission
Sale Date	8/22/2019	8/25/2015	11/7/2016	2/4/2020	11/19/2021
Sale Price	$4,800,000	$5,300,000	$1,570,000	$1,260,000	$9,000,000
Site Size (Acre)	0.146	0.235	0.110	0.075	0.440
Site Size (SF)	6,370	10,237	4,792	3,250	19,162
Price Per SF	**$754**	**$518**	**$328**	**$388**	**$470**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.08	1.27	1.20	1.07	1.00
Adjusted Price (to DOV)					
Price/SF	**$814**	**$658**	**$393**	**$415**	**$470**
Location	Superior (-)	Superior (-)	0	0	0
Site Size	0	Superior (-)	0	0	Superior (-)
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	Inferior (+)	0	0
Zoning, Height-Bulk/Density	Superior (-)	0	0	Superior (-)	0
Entitlements	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$814**	**$1,085**	**$649**	**$684**	**$775**

Land Value Conclusion – #27 Acton Substation

PG&E's Acton Substation is located on the south side of Mission Street between Acton and Oliver Streets in the Outer Mission district. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale, except for Land Sale 27, warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 5% per year, a blended (commercial and residential) and compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 24, 25, 27 and 45. The Acton Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 23 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Size"; "Building and Site Improvements"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether

Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $675 per square foot, or $1,518,750, calculated as follows:

2,250 sf x $675/sf = $1,518,750

PG&E Property #28 - Castro Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
29	524 Hickory Street Hayes Valley 829-042	7/27/2017	1,250 0.029	$1,300,000	**$1,040.00**	RH-3 Hayes Valley 40-X (40)	Y	Howard/First Property LLC Ridgegate Apartments, LLC et al. 2017-9K479111-00003
43	361-365 21st Street Mission 1453-013	3/4/2016	2,997 0.069	$1,850,000	**$617.28**	RH-2 40-X (40)	Y	Kim Wu Woods Family Investments, LP 2016-9K211142-00002
44	53 States Street Corona Heights 2623-074	2/7/2017	2,642 0.061	$1,920,000	**$726.72**	RH-2 40-X (40)	Y	53 States Street, LLC Golden Properties LLC 2017-9K405850-00003
31	2677 Harrison Street Mission 4148-034	9/27/2017	2,304 0.053	$1,295,000	**$562.07**	RH-3 40-X (40)	N	Fred W & Carolyn Li Deevy Abhishek & Alisha Gupta 2017-9K519306-00002
Subject	Castro Substation 1510-1512 Castro Street Noe Valley 6546-004	--	2,000 0.046	--	--	RH-2 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 29	Land Sale 43	Land Sale 44	Land Sale 31
Location	524 Hickory St Hayes Valley	361-365 21st St Mission	53 States St Corona Heights	2677 Harrison St Mission
Sale Date	7/27/2017	3/4/2016	2/7/2017	9/27/2017
Sale Price	$1,300,000	$1,850,000	$1,920,000	$1,295,000
Site Size (Acre)	0.029	0.069	0.061	0.053
Site Size (SF)	1,250	2,997	2,642	2,304
Price Per SF	**$1,040**	**$617**	**$727**	**$562**
Expenditures Immediately After Sale (Demo)	0	0	0	0
Rights Conveyed	0	0	0	0
Sale Conditions	0	0	0	0
Price Trends	1.21	1.31	1.25	1.21
Adjusted Price (to DOV)				
Price/SF	**$1,258**	**$809**	**$908**	**$680**
Location	Superior (-)	Inferior (+)	Inferior (+)	Inferior (+)
Site Size	0	0	0	0
Site Utility/Shape	0	0	0	0
Building and Site Improvements	0	0	0	0
Zoning, Height-Bulk/Density	Superior (-)	0	0	0
Entitlements	0	0	0	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than	**Inferior (+)** Greater Than
Indicated Value of Subject ($/sf)	**$1,258**	**$809**	**$908**	**$1,122**

Land Value Conclusion – #28 Castro Substation

PG&E's Castro Substation is located on the west side of Castro Street between 25th and Clipper Streets in Noe Valley. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential sources evidence that prices increased in the competitive market area of subject about 5% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Number 31. The Castro Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 29, 43, and 44 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales, which was made to Land Sale Number 31.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location" and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $1,150 per square foot, or $2,300,000, calculated as follows:

2,000 sf x $1,150/sf = $2,300,000

PG&E Property #29 - 21st Avenue Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
23	2100 Mission Street Mission 3576-001	8/22/2019	6,370 0.146	$4,800,000	**$753.53**	NCT 65-B (65)	Y	Muller 2005 Trust 2100 Mission Street Impossible LLC 2019-9K818307-00004
24	1490 Ocean Avenue Westwood Park 3197-010	8/25/2015	10,237 0.235	$5,300,000	**$517.73**	NCT 45-X (45)	N	Saint Anthony Real Estate, LLC ISCA Assets 33, LLC 2015-9K11442-00003
25	1455 Irving Street Outer Sunset 1770-051 & -052	11/7/2016	4,792 0.110	$1,570,000	**$327.63**	NCD 40-X (40)	N	Karl Olson and Karen Olson Edward Romanov and Janet Romanov 2016-9K354888-00002
45	2055 Taraval Street Parkside 2395-037	2/4/2020	3,250 0.075	$1,260,000	**$387.69**	NCD 50-X (50)	N	Cynthia D. Hampton Revocable Trust 2055 Taraval Street, LLC 2020-9K898534-00003
27	2550 Irving Street Outer Mission 1724-038	11/19/2021	19,162 0.440	$9,000,000	**$469.68**	NCD 40-X (40)	N	The Police Credit Union of California 2550 Irving Associates LP 2021-172913
Subject	21st Avenue Substation 1340 Noriega Street 2029-025	---	1,875 0.043	--	--	NCD 40-X (40)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 23	Land Sale 24	Land Sale 25	Land Sale 45	Land Sale 27
Location	2100 Mission St Mission	1490 Ocean Ave Westwood Park	1455 Irving St Outer Sunset	2055 Taraval St Parkside	2550 Irving St Outer Mission
Sale Date	8/22/2019	8/25/2015	11/7/2016	2/4/2020	11/19/2021
Sale Price	$4,800,000	$5,300,000	$1,570,000	$1,260,000	$9,000,000
Site Size (Acre)	0.146	0.235	0.110	0.075	0.440
Site Size (SF)	6,370	10,237	4,792	3,250	19,162
Price Per SF	**$754**	**$518**	**$328**	**$388**	**$470**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.08	1.27	1.20	1.07	1.00
Adjusted Price (to DOV)					
Price/SF	**$814**	**$658**	**$393**	**$415**	**$470**
Location	Superior (-)	Superior (-)	0	0	0
Site Size	0	Superior (-)	0	0	Superior (-)
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	Inferior (+)	0	0
Zoning, Height-Bulk/Density	Superior (-)	0	0	Superior (-)	0
Entitlements	0	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Inferior (+)** Greater Than	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$814**	**$1,085**	**$649**	**$684**	**$775**

Land Value Conclusion – #29 21st Avenue Substation

PG&E's 21st Avenue Substation is located on the north side of Noriega Street between 20th and 21st Avenues in the Outer Sunset district. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale, except for Land Sale 27, warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 5% per year, a blended (commercial and residential) and compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – Numbers 24, 25, 27, and 45. The 21st Avenue Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Number 23 sold with entitled development approvals, requiring no adjustment for this value characteristic. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Location"; "Site Size"; "Building and Site Improvements"; and/or "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether

Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $675 per square foot, or $1,265,625, calculated as follows:

1,875 sf x $675/sf = $1,265,625

PG&E Property #30 - Egbert Switching Station

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
7	901 Illinois Street (Pcl K) Central Waterfront 4110-012	2/13/2019	67,988 1.561	$24,000,000	**$353.00**	PDR-2 65-J (65)	Y Partial	City and County of San Francisco 64 PKN Owner LLC 2019-K731222-00006
8	790 Pennsylvania Avenue Potrero Hill 4167-013 4167-011	3/3/2016	119,885 2.752	$35,000,000	**$291.95**	UMU (Lot 13) PDR-1-G (Lot 11) 40-X (40)	Y Partial	2007 Sherman C. Little and Delaine K. Little Revocable Trust et al. RP Pennyslvania, LLC 2016-9K210708-00008
9	1755 Egbert Avenue Bayview 5431A-001-A & -001-Z	1/29/2021	70,446 1.617	$16,950,000	**$240.61**	PDR-2 65-J (65)	N	Egbert Enterprises LLC Pacific Gas and Electric Company 2021-015848
10	2270 Jerrod Avenue Bayview 5230-008	5/9/2022	154,883 3.556	$70,070,000	**$452.41**	PDR-2 65-J (65)	N	First Student, Inc. GIC San Francisco LLC 2022-047193
11	2150 Oakdale Avenue Bayview 5590A-003	5/7/2019	52,098 1.196	$13,750,000	**$263.93**	PDR-2 65-J (65)	N	MacBeath Hardwood Company Prologis-Exchange 2150 Oakdale LLC 2019-9K764192-00005
12	2000 Marin Street Central Waterfront 4346-003	4/30/2020	343,688 7.890	$63,600,000	**$185.05**	PDR-2 65-J (65)	N	2000 Marin Property, LP City and County of San Francisco 2020-K927582-00007
Subject	Egbert Switching Station 1755 Egbert Avenue Bayview 5431A-001-A & -001-Z	---	70,446 1.617	--	--	PDR-2 65-J (65)	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 7	Land Sale 8	Land Sale 9	Land Sale 10	Land Sale 11	Land Sale 12
Location	901 Illinois St Central Waterfront	790 Pennsylvania Ave Potrero Hill	1755 Egbert Ave Bayview	2270 Jerrod Ave Bayview	2150 Oakdale Ave Bayview	2000 Marin St Central Waterfront
Sale Date	2/13/2019	3/3/2016	1/29/2021	5/9/2022	5/7/2019	2/4/2020
Sale Price	$24,000,000	$35,000,000	$16,950,000	$70,070,000	$13,750,000	$63,600,000
Site Size (Acre)	1.561	2.752	1.617	3.556	1.196	7.890
Site Size (SF)	67,988	119,885	70,446	154,883	52,098	343,688
Price Per SF	**$353**	**$292**	**$241**	**$452**	**$264**	**$185**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0	0
Rights Conveyed	0	0	0	0	0	0
Sale Conditions	0	0	0	0	0	0
Price Trends	1.27	1.65	1.00	0.90	1.21	1.16
Adjusted Price (to DOV) Price/SF	**$448**	**$482**	**$241**	**$407**	**$319**	**$215**
Location	Superior (-)	Superior (-)	0	0	0	0
Site Size	0	0	0	0	0	Inferior (+)
Site Utility/Shape	0	0	0	0	0	0
Parking/Construction Requirements	0	0	0	0	0	0
Building and Site Improvements	0	0	0	Superior (-)	0	0
Zoning, Height-Bulk/Density, Site Use Restrictions	Superior (-)	Superior (-)	0	Superior (-)	Superior (-)	0
Entitlements	-15%	-15%	0	0	0	0
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Similar** Similar	**Superior (-)** Less Than	**Superior (-)** Less Than	**Inferior (+)** Greater Than
Indicated Value of Subject ($/sf)	**$381**	**$409**	**$241**	**$407**	**$319**	**$215**

Land Value Conclusion – #30 Egbert Switching Station

PG&E's Egbert Switching Station Site is situated on the southside Egbert Avenue east of Highway 101 in the Bayview area. The site was purchased by PG&E to develop a 230 kV switching station. As of the DOV, the project development was unentitled. Since purchase and after DOV, extensive entitlement work has been completed. The site is appraised in the existing physical and legal conditions as of DOV, as requested.

Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property. Each sale warrants adjustment for increasing, or decreasing, land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. CoStar and industrial market segment sources evidence that prices increased over the period in the competitive market area of subject about 10% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to partially or unentitled land sales. Sale Numbers 7 and 8 sold with entitlement approvals having previously been processed and requiring updating. The rest of the sales – Numbers 9 through 12 – sold unentitled. The Egbert Switching Station Site is entitled for the existing developed use, similar to land sales selling with development entitlements. Land Sale Numbers 7 and 8 are adjusted down 15% for the value of existing approvals.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Zoning, Height-Bulk, Density"; Location; and/or "Building and Site Improvement" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is its recent purchase price, $240.61 per square foot, or $16,950,000, calculated as follows:

70,446 sf x $240.61/sf = $16,950,000

PG&E Property #31 - Martin Substation

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
58	1 Gull Drive South San Francisco 015-082-250	12/23/2020	113,256 2.60	$10,840,000	**$95.71**	BTP-H N/A	N	SMPO ELS, LLC SRE SSF Innovation, LLC 2021-151604
59	165 S. Linden Avenue South San Francisco 014-212-110	6/12/2019	40,946 0.94	$4,000,000	**$97.69**	MIH 65'	N	Wui Fung, LLC Pacific Coast Capital Investors, LLC 2019-045013
60	1030 Brittan Avenue San Carlos 046-162-070 and 046-162-060	2/16/2016	87,991 2.02	$6,800,000	**$77.28**	GCI 50	N	L-3 Communications Corporation 1030 Brittan, LLC 2016-013533
61	595 Industrial Road & 810-850 E. San Carlos Avenue 046-090-210	2/2/2016	170,755 3.92	$13,690,000	**$80.17**	LC 50	N	City of San Carlos, California SC Landmark Hotels, LLC 2016-009441
62	1401 Shoreway Road Belmont 040-373-030	3/2/2016	147,668 3.39	$12,000,000	**$81.26**	M-1/HC 55'	N	Nikon Precision Inc. Blemont Hotels, LLC 2016-018790
Subject	Martin Substation 3150 Geneva Avenue Brisbane 005-141-999 (ptn)	---	1) 631,310 1) 14.49 2) 300,940 2) 6.91 3) 0.00	--	--	C/P-U Not Applicable	Y	

ADJUSTMENT GRID

Comparable Number	Land Sale 58	Land Sale 59	Land Sale 60	Land Sale 61	Land Sale 62
Location	1 Gull Drive South San Francisco	165 S. Linden Avenue South San Francisco	1030 Brittan Avenue San Carlos	595 Industrial Road San Carlos	1401 Shoreway Road Belmont
Sale Date	12/23/2020	6/12/2019	2/16/2016	2/2/2016	3/2/2016
Sale Price	$10,840,000	$4,000,000	$6,800,000	$13,690,000	$12,000,000
Site Size (Acre)	2.60	0.940	2.020	3.920	3.390
Site Size (SF)	113,256	40,946	87,991	170,755	147,668
Price Per SF	**$96**	**$98**	**$77**	**$80**	**$81**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.05	1.20	1.50	1.50	1.50
Adjusted Price (to DOV)					
Price/SF	**$100**	**$117**	**$116**	**$120**	**$122**
Location	0	0	0	0	0
Site Size	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0
Zoning, Site Use Restrictions	Superior (-)	Superior (-)	Superior (-)	Superior (-)	Superior (-)
Entitlements	65%	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than	**Superior (-)** Less Than
Indicated Value of Subject ($/sf)	**$166**	**$193**	**$191**	**$198**	**$201**

Land Value Conclusion – #31 Martin Substation

PG&E's Martin Substation Site is situated at the southwest corner of Bayshore Boulevard and Geneva Avenue in Brisbane about 0.25 mile from the San Francisco city and county border. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. CoStar and industrial market segment sources evidence that prices increased in the competitive market area of subject about 10% per year, a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to partially or unentitled land sales. Each of the sales – Numbers 58 through 62 – sold unentitled. The Martin Substation Site is entitled for the existing developed use, similar to land sales selling with development entitlements. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid, including to "Zoning, Height-Bulk, Density" characteristics. Adjustments for these factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Martin Substation Site is soil contaminated, allowing both the existing uses and prospective industrial or commercial uses that encapsulate the soil. Sales permit comparable uses by zoning. But land uses are not otherwise restricted.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the *unencumbered* fee simple rights in the PG&E Site is $120 per square foot, or $192,277,560, calculated as follows:

1,602,313 sf x $120.00/sf = $192,277,560

The site, as discussed in the Site Description section, is to be encumbered by a proposed 50-foot-wide easement to be conveyed to PG&E, extending 25 feet on either side of the centerline of the existing underground gas transmission pipeline and containing 53,475.50 square feet. To reflect the diminution in value attributable to this encumbrance, we have applied a 50% reduction to the fee value of the easement area, calculated as follows:

53,475.50 sf x $120/sf x 50% = $3,208,530

Accordingly, the indicated land value of the Martin Substation (PG&E Property #31), as encumbered by the proposed easement, is $189,060,030, reflecting the unencumbered fee value, *less* the easement deduction, calculated as follows:

$192,277,560 – $3,208,530 = $189,069,030

PG&E Property #32 - Beeman Lane

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
68	292 Arleta Avenue Visitacion Valley 6234-024	11/30/2022	2,495 0.057	$400,000	**$160.32**	RH-1 40-X	N	Shue Family Trust Massoudi Development LLC 2022-107765
69	3338 San Bruno Avenue Visitacion Valley 6172-036	4/1/2022	1,750 0.040	$275,000	**$157.14**	RH-1 40-X	N	Ray A. Peralta and Carmelita H. Peralta Quintin Edward Donnelly & Sandy Tran Donnelly 2022-033643
70	666 Hamilton Street Visitacion Valley 6115-040	9/13/2019	9,960 0.229	$1,650,000	**$165.66**	RH-1 40-X	N	Valerie J. Hogan CarlMai, LLC 2019-9K830895-0004
71	154 Delta Street Visitacion Valley 6190-015 & -016	7/26/2017	5,000 0.115	$590,000	**$118.00**	RH-1 40-X	N	Wing On Chan Kenneth Cui and Chi Hung Chu 2017-9K4830888-00002
72	2168 Bayshore Boulevard Visitacion Valley 5067-011B	1/3/2017	2,195 0.050	$300,000	**$136.67**	RH-1 40-X	N	Alan K.L. and Adrianne B. Scoggie Revocable Trust Eddie Y. Law and Wendy Law 2017-9K390731-00003
Subject	Beeman Lane Visitacion Valley (Vacant Lot - 5067-001A)	-----	4,721 0.108	-----	-----	RH-1 40-X	-----	-----

ADJUSTMENT GRID

Comparable Number	Land Sale 68	Land Sale 69	Land Sale 70	Land Sale 71	Land Sale 72
Location	292 Arleta Avenue Visitacion Valley	3338 San Bruno Avenue Visitacion Valley	666 Hamilton Street Visitacion Valley	154 Delta Street Visitacion Valley	2168 Bayshore Boulevard Visitacion Valley
Sale Date	11/30/2022	4/1/2022	9/13/2019	7/26/2017	1/3/2017
Sale Price	$400,000	$275,000	$1,650,000	$295,000	$300,000
Site Size (Acre)	0.057	0.040	0.229	0.057	0.050
Site Size (SF)	2,495	1,750	9,960	2,500	2,195
Price Per SF	**$160**	**$157**	**$166**	**$118**	**$137**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.00	1.00	1.00	1.02	1.03
Adjusted Price (to DOV)					
Price/SF	**$160**	**$157**	**$166**	**$120**	**$141**
Location	0	0	0	0	0
Site Size	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0
Zoning, Height-Bulk/Density	0	0	0	0	0
Entitlements	65%	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Similar**	**Similar**	**Similar**	**Similar**	**Similar**
	Similar	Similar	Similar	Similar	Similar
Indicated Value of Subject ($/sf)	**$265**	**$259**	**$273**	**$199**	**$232**

Land Value Conclusion – #32 Beeman Lane

PG&E's Beeman Lane Site is located on the north side of Wabash Terrace and the south side of San Bruno Avenue in the Visitacion Valley. Land sales summarized and analyzed above are similarly located and are selected as comparables partly for this reason.

Each sale warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential sources evidence that prices were flat over the sales period in the market area. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – each sale, Numbers 68 through 72. The Beeman Lane Site is entitled for the existing developed use, similar to land sales selling with development entitlements. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid. Adjustments for factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.
Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $260 per square foot, or $1,227,460, calculated as follows:

4,721 sf x $260/sf = $1,227,460

PG&E Property #33 - Substation I

SALES SUMMARY

Comp No.	Location/APN	Sale Date (COE)	Site Area: Square Feet/ Acres	Sale Price	Price/SF	Zoning Height/Bulk	Entitled on Sale (Y/N)	Grantor / Grantee/ Recording No.
63	514-580 Minna Street SoMa/Mid-Market 3726-101	8/14/2020	3,375 0.077	$1,700,000	**$503.70**	MUG 45-X (X)	N	Christopher Joseph Harney and Christina Marina Harney Revocable Living Trust 1948 Quesada Street, LLC 2020-004604
64	1288 Howard Street SoMa 3728-19, -24, -25, -26, -87	8/28/2019	37,116 0.852	$23,000,000	**$619.68**	RCD 55-X (X)	N	1288 Howard LP 1288 Howard Owner LP 2019-K820923
65	230-237 7th Street SoMa 3730-004	7/31/2018	12,197 0.280	$6,100,000	**$500.12**	WMUG 65-X (65)	N	South Beach Partners, LLC 230 7th Street LLC 2018-9K647074-00006
66	220 9th Street SoMA 3518-002	1/12/2018	16,121 0.370	$10,350,000	**$642.02**	RCD 55-X	N	Kiner Family Partners LP LMT Home Corporation 2018-K566300
67	915 Minna Street SoMA 3510-058	6/13/2017	11,617 0.267	$6,250,000	**$538.00**	RED-MX 45-X (X)	N	Alta Investors 915 Minna, LLC 2017-K462591
Subject	Substation I 117 8th Street SoMA 3727-135	---	10,000 0.230	--	--	WMUG/MUO 65-X (65)	Y	

ADJUSTMENT GRID

Comparable Number	**Land Sale 63**	**Land Sale 64**	**Land Sale 65**	**Land Sale 66**	**Land Sale 67**
Location	514-580 Minna Street SoMa	1288 Howard Street SoMa	230-237 7th Street SoMa	220 9th Street SoMa	915 Minna Street SoMa
Sale Date	8/14/2020	8/28/2019	7/31/2018	1/12/2018	6/13/2017
Sale Price	$1,700,000	$23,000,000	$6,100,000	$10,530,000	$6,250,000
Site Size (Acre)	0.077	0.852	0.280	0.370	0.270
Site Size (SF)	3,375	37,116	12,197	16,121	11,761
Price Per SF	**$504**	**$620**	**$500**	**$653**	**$531**
Expenditures Immediately After Sale (Demo)	0	0	0	0	0
Rights Conveyed	0	0	0	0	0
Sale Conditions	0	0	0	0	0
Price Trends	1.05	1.10	1.15	1.19	1.22
Adjusted Price (to DOV)					
Price/SF	**$529**	**$682**	**$575**	**$777**	**$648**
Location	0	0	0	0	0
Site Size	0	0	0	0	0
Site Utility/Shape	0	0	0	0	0
Building and Site Improvements	0	0	0	0	0
Zoning, Height-Bulk/Density, Site Use Restrictions	0	0	0	0	0
Entitlements	65%	65%	65%	65%	65%
Total Adjustment ($/Land sf)	**Similar** Similar	**Similar** Similar	**Similar** Similar	**Similar** Similar	**Similar** Similar
Indicated Value of Subject ($/sf)	**$873**	**$1,125**	**$949**	**$1,283**	**$1,070**

Land Value Conclusion – #33 Substation I

PG&E's Substation I is located on the north side of 8th Street between Mission and Minna Streets in SoMa, between Mid-Market and Civic Center. Land sales summarized and analyzed above were selected for their comparable locations and overall comparability to the subject property.

Each sale warrants adjustment for increasing land price trends between the respective dates of each land sale and the valuation date of the PG&E substation site appraised. MLS and residential and commercial sources evidence that prices increased in the competitive market area of subject about 5% per year; a compounding rate of price increases with time. This rate is applied as the quantitative adjustment basis.

Quantitative adjustment is made to unentitled land sales – each land sale, Numbers 63 through 67. The Substation I Site is entitled for the existing developed use, similar to land sales selling with development entitlements. As previously discussed, the applicable quantitative adjustment is 65% to unentitled sales.

Qualitative adjustments are made to sales, as shown on the Adjustment Grid. Adjustments for factors recognize differences between subject and comparable sales – whether Superior, Similar, or Inferior – to the PG&E site, consistent with the ATF sales comparison approach applicable to the valuation.

Based on comparative analysis of the comparable sales and the subject site, the indicated fair market value of the fee simple rights in the PG&E Site is $1,050 per square foot, or $10,500,000, calculated as follows:

10,000 sf x $1,050/sf = $10,500,000

FAIR MARKET VALUE (FMV) – LAND ONLY
BEFORE ENHANCEMENT FACTOR

No.	PG&E Substation	Site Size (SF)	Site Size (AC)	$/SF	FMV Land As-Is (DOV)
1	Substation Z (Embarcadero)	33,213	0.762	$6,000.00	$199,278,000
2	Substation A (Portrero)	293,960	6.748	$350.00	$96,730,375
3.1	Substation P (Hunter's Point)	79,680	1.829	$340.00	$27,091,200
3.2	Substation P (Hunter's Point)	281,659	6.466	$250.00	$70,414,750
3.3	Substation P (Hunter's Point)	85,747	1.968	$250.00	$21,436,750
3.4	Substation P (Hunter's Point)	325,709	7.477	$250.00	$81,427,250
3.5	Substation P (Hunter's Point)	13,734	0.315	$50.00	$686,700
3.6	Substation P (Hunter's Point)	713,687	16.384	$180.00	$128,463,660
4	Substation W (Bayshore)	55,930	1.284	$575.00	$32,159,750
5	Substation Y (Larkin)	46,875	1.076	$1,000.00	$46,875,000
6	Substation X (Mission)	44,617	1.024	$3,500.00	$156,159,500
7	Substation L	17,076	0.392	$650.00	$11,099,400
8	Substation G	15,469	0.355	$1,200.00	$18,562,800
9	Substation E	13,175	0.302	$2,300.00	$30,302,500
10	Substation F (Marina)	13,112	0.301	$950.00	$12,456,400
11	Substation K	12,398	0.285	$750.00	$9,298,500
12	Substation J	8,395	0.193	$1,000.00	$8,395,000
13	Substation N	6,492	0.149	$750.00	$4,869,000
14	Randolph Substation	4,865	0.112	$650.00	$3,162,250
15	Substation M	4,725	0.108	$1,100.00	$5,197,500
16	Portola Substation	4,698	0.108	$625.00	$2,936,250
17	Beach Substation	3,750	0.086	$1,350.00	$5,062,500
18	6th Avenue	3,000	0.069	$675.00	$2,025,000
19	Silver Substation	2,834	0.065	$350.00	$991,900
20	Ocean Substation	2,655	0.061	$675.00	$1,792,125
21	Yosemite Substation	2,500	0.057	$225.00	$562,500
22	Taraval Substation	2,500	0.057	$675.00	$1,687,500
23	Judah Substation	2,500	0.057	$750.00	$1,875,000
24	Plymouth Substation	2,500	0.057	$675.00	$1,687,500
25	Noriega Substation	2,325	0.053	$675.00	$1,569,375
26	18th Street Substation	2,250	0.052	$1,100.00	$2,475,000
27	Acton Substation	2,250	0.052	$675.00	$1,518,750
28	Castro Substation	2,000	0.046	$1,150.00	$2,300,000
29	21st Avenue Substation	1,875	0.043	$675.00	$1,265,625
30	Egbert Switching Station	70,446	1.617	$240.61	$16,950,000
32	Beeman Lane	4,721	0.108	$260.00	$1,227,460
33	Substation I	10,000	0.230	$1,050.00	$10,500,000
		2,193,322	**50.352**		**$1,020,492,770**
31	Martin Substation	**1,602,313**	**36.784**	$120.00	**$189,069,030**
Total Land and Improvements		**3,795,635**			**$1,209,561,800**

Substation Building and Site Improvements Valuation

The next step in the cost approach is the valuation of the improvements. This involves determining RCNLD – Reproduction/Replacement Cost New Less Depreciation. The building improvements (i.e., structures) are valued separately from site improvements (i.e., grading, paving, drainage, etc.) for each property.

PG&E provided actual costs for three recently constructed substation buildings and sites: Embarcadero Substation Z (Building 1.2); Potrero GIS Substation A (Building 2.2); and Larkin GIS Substation Y (Building 5.2). The actual costs are used to estimate the reproduction cost new for these buildings and structures, and the summary tables below refer to the costs for these buildings as "Actual" costs. Cost escalators are applied for increasing costs between the dates of construction new to the valuation date as of July 2021 reflecting the State of California Department of General Service California Construction Cost Index (DGS CCCI)

In addition, these recent Actual costs are also applied to estimate the reproduction cost new of three similar PG&E substations and buildings: Embarcadero Substation Z (Building 1.1); Larkin Substation Y (Building 5.1); and to Mission Substation X (Building 6). The summary table below refer to the costs for these similar substations and buildings as "PG&E Costs." DGS CCCI cost escalators are also applied to PG&E Costs for these substations and buildings.

Perimeter fencing improvements are deducted/excluded from all RCN and RCNLD, as they have been valued by other experts. The deduction for perimeter fencing improvements is also applied to the Embarcadero, Potrero, Larkin, and Mission Substation properties to reach the Subtotal Base Cost for these properties.

Marshall Valuation Service (MVS) is sourced for all other building and site costs to estimate replacement cost new. The direct building cost estimate starts with a base cost and refinements applied to the base cost, as necessary. Refinements include various multipliers that are applied from MVS. These include multipliers to respective base costs for "current" (cost escalator), "local" (County of San Francisco), "Floor Area to Perimeter," "Story/Height to Floor Area" also known as "Average Wall Height," and "Shape."

MVS cost escalators are specific to MVS's cost bases. For this reason, MVS escalators from its index are applied to MVS costs bases, rather than the DGS CCCI, which is specific to non-MVS general cost levels statewide, based on costs in San Francisco and Los Angeles metro areas. Indirect costs included in RCN, connected securing approvals to develop the property – i.e., with entitlements, such as architectural and engineering, consultants, and studies, etc. – are deducted as the costs are market reflected in the contributory value of land value.

Entrepreneurial incentive is added as a value step in RCN. As previously discussed, incentive is the economic cost added for the coordination of building, in this current example, the real property improvements necessary to support the electronic distribution and transmission grid system that is the subject. Over the years, we have analyzed profit, overhead, and anticipated incentives expected for developments projects. A low of 15%, to a high of 25% or greater, direct and indirect costs is a normal

range under market conditions comparable to the DOV. Considering that entitlement costs and value are captured in land value, 10% entrepreneurial incentive to RCN before depreciation is applicable.

With RCN calculated for building and structures (site improvements are valued subsequently), depreciation is valued next. Depreciation in this analysis is based on life-cycle depreciation and tables, wherein the economic life of buildings and structures, the effective age of each improvement, and its/their remaining economic life are estimated based on property inspections and on property- and market-life cycles. The life-cycle table applied in this analysis is available in MSV (Section 97, Page 24, Dated: December 2020, current in the July 2021 MSV published handbook).

Importantly, life-cycle tables index the improvement's economic life with its effective age on market-based pricing, not on a mathematical calculation of straight-line depreciation, for example, or on other depreciation methods. The life cycle yields expected remaining economic life based on market pricing and experience. A building's estimated Effective Age may be 65 years and its Economic Life 70 years, but its Remaining Economic Life (life cycle) in the marketplace has shown similar buildings to be 9 years (not 5 years, for example), based on the life-cycle table on Page 24, Section 97. In our experience, life-cycle depreciation more accurately reflects market pricing of real property improvements than does straight-line, for example.

Depreciation derives in three forms: physical deterioration, functional obsolescence, and external obsolescence. Life-Cycle Depreciation (aka Age-Life) analysis imputes physical depreciation and functional obsolescence. We find no additional depreciation or functional obsolescence not captured in the Depreciation table and analysis. Additionally, we find no external obsolescence affecting the value(s) of subject improvements.

Structures/Buildings Improvements

The table included on the following three pages shows the step-by-steps valuation of buildings and substation buildings.

REPRODUCTION/REPLACEMENT COST ANALYSIS – BUILDING IMPROVEMENTS (TABLE 1)

CCSF No.	PG&E Substation/ Property Name	Address	Year Built/ Renovated	GBA (SF)	Building Height (Ft) (Interior Floor Levels, NIC Bsmt)	Average Wall Height/ Interior Floors	Construction Type	Construction Quality
1.1	Z Embarcadero	405 Folsom Street	1974	119,080	114' (5)	22.5	Concrete/Steel	Excellent
1.2	Z Embarcadero (GIS)	425 Folsom Street	2016	13,688	30' (2)	15	Concrete/Steel	Excellent
2.1	A Potrero	1101 Illinois Street	1961	5,787	32' (1) - 20' Clear	20-32	Metal	Good
2.2	A Potrero (GIS)	1101 Illinois Street	2016	16,932	32' (1)	32	Concrete/Steel	Excellent
3.1	P Hunter's Point	1030 Evans Avenue	1925	306	12' (1)	12	Poured-in-Place Concrete	Good
3.2	P Hunter's Point	1030 Evans Avenue	1965	763	13' (1)	13	Metal	Good
3.3	P Hunter's Point	1030 Evans Avenue	1965	314	12' (1)	12	Metal	Good
4	W Bayshore	151-157 Bayshore Street	1971	770	13' (1)	13	Concrete Block	Average
5.1	Y Larkin	538 Eddy Street	1962	95,400	30' (2) - 46' (2)	15-23	Concrete/Steel	Excellent
5.2	Y Larkin (GIS)	538 Eddy Street	2018	13,780	40' (2)	20	Concrete/Steel	Excellent
6	X Mission	66 8th Street	1948/2013	89,100	61' (3)	20	Concrete/Steel	Excellent
7.1	L	2475 Ocean Street	1925	3,356	37' (1+)	37	Poured-in-Place Concrete	Good
7.2	L	2475 Ocean Street	1925	1,825	18' (1)	18	Poured-in-Place Concrete	Good
8	G	1200 Broderick Street	1935	23,304	32' (2)	16	Poured-in-Place Concrete	Good
9	E	205 Lexington Street	1930	16,750	37' (2); 50' (2); 56' (2)	18.50-28	Poured-in-Place Concrete	Good
11	K	679 24th Avenue	1915	10,956	33' (2)	16.5	Poured-in-Place Concrete	Good
12	J	222 Leidesdorff Street	1925	26,250	33' (3) - 65' (4)	10-60	Poured-in-Place Concrete	Good
15	M - Brick	20 Rousseau Street	1925	1,680	15' (1)	15	Poured-in-Place/Masonry	Good
15	M - Metal Lean-To	20 Rousseau Street	2007	1,068	16'-23'	16-23	Metal Lean-To	Good
33	Substation I	117 8th Street	1925	10,950	33' (2) - 39' (2)	16-20	Poured-in-Place Concrete	Good
	Total Within San Francisco			**452,059**				
31	Martin Substation	E 3150 Geneva Avenue, Brisbane	1925/1947	9,144	34'	34	Poured-in-Place Concrete	Good
		F 2850 Bayshore Road, Brisbane	1960	17,608	16'	16	Poured-in-Place Concrete	Good
		G N/A Geneva Avenue, Brisbane	1983	11,700	20'	20	Metal	Good
		H 3150 Bayshore Blvd, Brisbane	2019	12,800	22'	22	Metal "Butler" Type	Good
	Total Within Brisbane			**51,252**				
	Total Buildings San Francisco & Brisbane			**503,311**				

REPRODUCTION/REPLACEMENT COST ANALYSIS – BUILDING IMPROVEMENTS (TABLE 2)

CCSF No.	PG&E Substation/ Property Name	Cost Source (Marshall Swift)/Actual	If MSV Section/Page	Base Unit Cost (SF)	Sprinklers	Subtotal Base Cost (SF)	Current	Local	Floor Area Perimeter	Story/ Height	Shape	RCN per SF	RCN/SF Less 5%*	Entreprenerial Incentive	GBA (SF)	RCN Total
1.1	Z Embarcadero	PG&E Costs	--	$1,305	0.00	$1,285	1.24	1.00	0.950	1.500	1.00	$2,271	$2,157.07	10%	119,080	$282,549,663
1.2	Z Embarcadero (GIS)	Actual	--	$1,305	0.00	$1,285	1.24	1.00	1.000	1.000	1.00	$1,593	$1,513.73	10%	13,688	$22,791,930
2.1	A Potrero	Marshall Swift Valuation	14/14	$68.50	7.12	$76	1.15	1.47	1.000	1.000	1.00	$128	$127.84	10%	5,787	$813,763
2.2	A Potrero (GIS)	Actual	--	$1,305	0.00	$1,270	1.24	1.00	1.000	1.000	1.00	$1,575	$1,496.06	10%	16,932	$27,864,417
3.1	P Hunter's Point	Marshall Swift Valuation	14/15	$164	8.09	$172	1.16	1.50	1.000	1.000	1.00	$299	$299.44	10%	306	$100,790
3.2	P Hunter's Point	Marshall Swift Valuation	14/14	$68.50	8.09	$77	1.15	1.47	1.000	1.000	1.00	$129	$129.48	10%	763	$108,669
3.3	P Hunter's Point	Marshall Swift Valuation	14/14	$68.50	8.09	$77	1.15	1.47	1.000	1.000	1.00	$129	$129.48	10%	314	$44,721
4	W Bayshore	Marshall Swift Valuation	14/14	$39.50	8.09	$48	1.16	1.50	1.000	1.000	1.00	$82.81	$82.81	10%	770	$70,137
5.1	Y Larkin	PG&E Costs	--	$1,305	0.00	$1,285	1.24	1.00	0.910	1.000	1.00	$1,450	$1,377.49	10%	95,400	$144,554,252
5.2	Y Larkin (GIS)	Actual	--	$1,370	0.00	$1,360	1.18	1.00	1.000	1.000	1.00	$1,605	$1,524.56	10%	13,780	$23,109,280
6	X Mission	PG&E Costs	--	$1,305	0.00	$1,285	1.24	1.00	1.000	1.000	1.00	$1,593	$1,513.73	10%	89,100	$148,360,677
7.1	L	Marshall Swift Valuation	14/15	$164	0.00	$164	1.16	1.50	1.107	1.515	1.00	$479	$478.58	10%	3,356	$1,766,721
7.2	L	Marshall Swift Valuation	14/15	$164	0.00	$164	1.16	1.50	1.324	1.086	1.00	$410	$410.15	10%	1,825	$823,384
8	G	Marshall Swift Valuation	14/15	$164	5.35	$169	1.16	1.50	1.170	1.041	1.00	$359	$358.74	10%	23,304	$9,196,203
9	E	Marshall Swift Valuation	14/15	$164	5.75	$170	1.16	1.50	0.943	1.520	1.00	$423	$423.27	10%	16,750	$7,798,834
11	K	Marshall Swift Valuation	14/15	$164	0.00	$164	1.16	1.50	1.000	1.041	1.00	$297	$297.06	10%	10,956	$3,580,045
12	J	Marshall Swift Valuation	14/15	$164	5.22	$169	1.16	1.50	1.059	1.382	1.00	$431	$430.77	10%	26,250	$12,438,544
15	M - Brick	Marshall Swift Valuation	14/15	$164	8.09	$172	1.16	1.50	1.000	1.000	1.00	$299	$299.44	10%	1,680	$553,359
15	M - Metal Lean-To	Marshall Swift Valuation	17/27	$14.50	0.00	$15	1.15	1.47	1.000	1.000	1.00	$25	$24.51	10%	1,068	$28,797
33	Substation I	Marshall Swift Valuation	14/15	$164	0.00	$164	1.16	1.50	1.324	1.086	1.00	$410	$410.15	10%	10,950	$4,940,304
	Total Within San Francisco															
31	Martin Substation	Marshall Swift Valuation	14/15	$164	0.00	$164	1.16	1.50	1.087	1.484	1.00	$460	$460.10	10%	9,144	$4,627,918
		Marshall Swift Valuation	14/15	$164	0.00	$164	1.16	1.50	1.000	1.000	1.00	$285	$285.36	10%	17,608	$5,527,081
		Marshall Swift Valuation	14/14	$69	8.09	$77	1.15	1.47	1.000	1.000	1.00	$129	$129.48	10%	11,700	$1,666,348
		Marshall Swift Valuation	14/15	$69	8.09	$77	1.15	1.47	1.000	1.000	1.00	$129	$129.48	10%	12,800	$1,823,014
	Total Within Brisbane															
	Total Buildings San Francisco & Brisbane															

** Indirect Costs in architectural & engineering studies connected with design and development approval, etc. are deducted 5% from RCN; the contributory value of entitlements is included with FMV Land Value.*

REPRODUCTION/REPLACEMENT COST ANALYSIS – BUILDING IMPROVEMENTS (TABLE 3)

CCSF No.	PG&E Substation/ Property Name	Plus Basement and Freight Elevators & Cranes	Expected Life	Chron. Age	Effective Age	Remaining Economic Life	Age/Life Depreciation (%)	RCN Total	RCNLD Building Improvements
1.1	Z Embarcadero	Included in Actual Costs	70	47	45	25	33%	$282,549,663	$189,308,274
1.2	Z Embarcadero (GIS)	Included in Actual Costs	70	6	5	64	1%	$22,791,930	$22,564,011
2.1	A Potrero		50	60	35	15	45%	$800,742	$447,570
2.2	A Potrero (GIS)	Included in Actual Costs	70	6	5	65	1%	$27,864,417	$27,585,773
3.1	P Hunter's Point		60	96	50	11	58%	$100,790	$42,332
3.2	P Hunter's Point		50	56	45	7	72%	$108,669	$30,427
3.3	P Hunter's Point		50	56	45	7	72%	$44,721	$12,522
4	W Bayshore	--	45	50	35	10	58%	$66,350	$29,458
5.1	Y Larkin	Included in Actual Costs	70	59	50	20	38%	$144,554,252	$89,623,636
5.2	Y Larkin (GIS)	Included in Actual Costs	70	3	2	68	1%	$23,109,280	$22,878,188
6	X Mission	Included in Actual Costs	70	73	35	35	16%	$148,360,677	$124,622,969
7.1	L		70	96	70	7	71%	$1,766,721	$512,349
7.2	L		70	96	80	4	78%	$823,384	$181,144
8	G	$353,250	70	86	65	9	65%	$9,097,426	$3,218,671
9	E		70	91	65	9	65%	$7,798,834	$2,729,592
11	K		70	106	55	16	48%	$3,580,045	$1,861,624
12	J		70	96	60	12	57%	$12,305,472	$5,348,574
15	M - Brick		60	96	45	15	50%	$553,359	$276,679
15	M - Metal Lean-To		45	14	10	35	8%	$28,797	$26,494
33	Substation I		70	96	80	4	78%	$4,940,304	$1,086,867
	Total Within San Francisco								**$492,387,153**
31	Martin Substation		60	96	70	3	80%	$4,627,918	$925,585
			70	61	50	20	38%	$5,493,180	$3,426,790
			50	38	30	20	34%	$1,719,757	$1,099,790
			50	2	2	48	1%	$1,823,014	$1,804,783
	Total Within Brisbane								**$7,256,948**
	Total Buildings San Francisco & Brisbane								**$499,644,101**

Site Improvements

Site improvements include rough and finished site grading; site infrastructure, such as drainage and utilities; lighting and wiring; and surface covers – gravel, or asphalt, or concrete. Differences in base unit costs applied on the Fair Market Value of Site Improvements table below reflect differences, primarily, with surface cover. $11.00 per square foot, for example, are sites with gravel cover; $12.75 per square foot are sites with asphalt cover; $21.50 per square foot is concrete; and $17.25 per square foot values asphalt and concrete improvements. Substation P, Hunter's Point 3.3, is mostly ungraded hillside sloping land improved with graded-and-improved pad areas and circulation estimated to cover in asphalt about 25% of the site; this site is valued at $3.19/sf ($12.75 at 25%). Depreciation on site improvements RCN is estimated based on onsite inspection or aerial review by Google Earth, or both.

As in the buildings' valuations, fencing and walls are excluded, and site improvements are valued on RCNLD.

The following table (*next page*) shows the step-by-step valuation of the substation site improvements.

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FAIR MARKET VALUE OF SITE IMPROVEMENTS

No.	PG&E Substation	Address	Assessor Parcel No.	SBE Parcel No.	Site Size (SF)	Site Improvements Description	Improved Site Area (SF;LF)	RCN per SF (or LF)	Entreprenerial (%)	RCN Total	%	FMV Site Improvements
1.1	Substation Z (Embarcadero)	405 Folsom Street	3748-001, -003, -004, -005	135-38-033A-1	22,900	Included in Building Costs	Incl in Building Costs	$0.00	10%	$0	--	$0
1.2	Substation Z (Embarcadero)	425 Folsom Street	3748-029	135-38-033A-2	10,313	Included in Building Costs	Incl in Building Costs	$0.00	10%	$0	--	$0
2	Substation A (Portrero)	1101 Ilinois Street	4175-018 (ptn)	135-38-024D-2, D-3 (ptn)	293,960	Included in Building Costs	Incl in Building Costs	$0.00	10%	$0	--	$0
3.1	Substation P (Hunter's Point)	1180 Evans Avenue	4570-024	135-38-018D-1	79,680	Grading, Paving, Drainage, Lighting	79,680	$12.75	10%	$1,117,512	50%	$558,756
3.2	Substation P (Hunter's Point)	1010-1030 Evans Avenue	4604-002	135-38-018E-1	281,659	Grading, Paving, Drainage, Lighting	150,000	$21.50	10%	$3,547,500	50%	$1,773,750
3.3	Substation P (Hunter's Point)	1135 Evans Avenue	4621-014	135-38-026A-1	85,747	Grading, Paving, Drainage, Lighting	85,747	$3.19	10%	$300,650	50%	$150,325
3.4	Substation P (Hunter's Point)	1059-1075 Evans Avenue	4603A-002,-005, 4647A-010	135-38-026A-2	325,709	Grading, Paving, Drainage, Lighting	126,850	$12.75	10%	$1,779,071	50%	$889,536
3.5	Substation P (Hunter's Point)	5000 Hunter's Point Blvd	4229A-012	135-38-026A-3	14,345	Grading, Gravel, Gate, Lighting	7,000	$12.75	10%	$98,175	50%	$49,088
3.6	Substation P (Hunter's Point)	1000 Evans Avenue	4580-002	135-018A-2	713,687	Grading, Paving, Bulkheads, Shore Amoring	434,558	$21.50	10%	$10,277,297	50%	$5,138,648
4	Substation W (Bayshore)	151-157 Bayshore Boulevard	5559-004,-005,-006	135-38-031-1	55,930	Grading, Paving, Drainage, Lighting	54,470	$12.75	10%	$763,942	50%	$381,971
5	Substation Y (Larkin)	538 Eddy Street	0335-037	135-38-030A-1, -2, & -3	46,875	Included in Building Costs	Incl in Building Costs	$0.00	10%	$0	--	$0
6	Substation X (Mission)	66 8th Street	3701-053	135-38-015A-2	44,617	Included in Building Costs	Incl in Building Costs	$0.00	10%	$0	--	$0
7	Substation L	2475 Ocean Avenue	6901-001	135-38-001-19	17,076	Grading, Paving, Drainage, Lighting	12,486	$11.00	10%	$151,081	50%	$75,540
8	Substation G	1200 Broderick Street	1101-013	135-38-002-4	15,469	Grading, Paving, Drainage, Lighting	2,970	$21.50	10%	$70,241	50%	$35,120
9	Substation E	205 Lexington Avenue	3596-104	135-38-003-6	13,175	Landscaping	1,075	$41.00	10%	$48,483	25%	$36,362
10	Substation F (Marina)	1570 Bay Street	0459-032	135-38-001D-1	13,112	Grading, Paving, Drainage, Lighting	13,112	$21.50	10%	$310,089	25%	$232,567
11	Substation K	679 24th Avenue	1567-012	135-38-002-5	12,398	Grading, Paving, Drainage, Lighting	5,707	$12.75	10%	$80,041	50%	$40,020
12	Substation J	530 Sacramento Street	0228-006	135-38-004-6	8,395	No Site Improvements	0	$0.00	10%	$0	--	$0
13	Substation N	1437-1449 9th Avenue	1844-053	135-38-02A-1	6,492	Grading, Paving, Drainage, Lighting	6,492	$21.50	10%	$153,536	25%	$115,152
14	Randolph Substation	724 Randolph Street	7084-024	135-38-019A-1	4,865	Grading, Paving, Drainage, Lighting	4,865	$12.75	10%	$68,232	50%	$34,116
15	Substation M	20 Rousseau Street	6747-016	135-38-005B-1	4,725	Grading, Paving, Drainage, Lighting	1,977	$21.50	10%	$46,756	50%	$23,378
16	Portola Substation	610 Portola Drive	2892-003	135-38-023-1	4,698	Grading, Paving, Drainage, Lighting	4,698	$21.50	10%	$111,108	50%	$55,554
17	Beach Substation	330 Beach Street	0013-010	135-38-018B-1	3,750	Grading, Paving, Drainage, Lighting	3,750	$21.50	10%	$88,688	50%	$44,344
18	6th Avenue	365 6th Avenue	1438-014	135-38-015-3	3,000	Grading, Paving, Drainage, Lighting	3,000	$11.00	10%	$36,300	50%	$18,150
19	Silver Substation	1086 Silver Avenue	5915-001	135-38-025-1	2,834	Grading, Paving, Drainage, Lighting	2,834	$11.00	10%	$34,291	50%	$17,146
20	Ocean Substation	1155 Ocean Avenue	6944-040	135-38-020-1	2,655	Grading, Paving, Drainage, Lighting	2,655	$11.00	10%	$32,126	50%	$16,063
21	Yosemite Substation	1802 Yosemite Avenue	5417-007	135-38-011-1	2,500	Grading, Paving, Drainage, Lighting	2,500	$11.00	10%	$30,250	50%	$15,125
22	Taraval Substation	2533 Taraval Street	2390-044	135-38-010-2	2,500	Grading, Paving, Drainage, Lighting	2,500	$11.00	10%	$30,250	50%	$15,125
23	Judah Substation	2927 Judah Street	1819-042	135-38-010-1	2,500	Grading, Paving, Drainage, Lighting	2,500	$11.00	10%	$30,250	50%	$15,125
24	Plymouth Substation	214 Plymouth Avenue	7112-012A	135-38-025-2	2,500	Grading, Paving, Drainage, Lighting	2,500	$11.00	10%	$30,250	50%	$15,125
25	Noriega Substation	3819 Noriega Street	2082-001L	135-38-013-1	2,325	Grading, Paving, Drainage, Lighting	2,325	$12.75	10%	$32,608	50%	$16,304
26	18th Street Substation	4430 18th Street	2650-020	135-38-008-1	2,250	Grading, Paving, Drainage, Lighting	2,250	$11.00	10%	$27,225	50%	$13,613
27	Acton Substation	5009 Mission Street	6472-021D	135-38-013-5	2,250	Grading, Paving, Drainage, Lighting	2,250	$11.00	10%	$27,225	50%	$13,613
28	Castro Substation	1510-1512 Castro Street	6546-004	135-38-014-1	2,000	Grading, Paving, Drainage, Lighting	2,000	$11.00	10%	$24,200	75%	$6,050
29	21st Avenue Substation	1340 Noriega Street	2029-025	135-38-013-2	1,875	Grading, Paving, Drainage, Lighting	1,875	$11.00	10%	$22,688	75%	$5,672
30	Egbert Switching Station	1755 Egbert Avenue	5431-001A	135-38-057-1 & -2	70,446	Site Improvements Inc Land Value	70,446	$0.00	10%	$0	--	$0
32	Beeman Lane	3789 San Bruno Avenue	5067-001A	135-38-018-7	4,721	Fence, Gate	4,721	6.50	10%	$33,755	50%	$16,878
33	Substation I	117 8th Street	3727-135	135-38-003A-1	10,000	Grading, Paving, Darinage, Lighting	905	$12.75	10%	$12,693	50%	$6,346
	Subtotal - San Francisco				**2,193,933**		**1,100,698**			**$19,416,509**		**$9,824,560**
31	Martin Substation	3150 Geneva Avenue, Brisbane, CA	005-141-999 (ptn)	135-41-28B-3 (ptn)	**1,602,313**	Partial Paving, Partial Gravel	**1,237,841**	$11.00	10%	**$14,977,876**	50%	**$7,488,938**
	San Francisco and San Mateo County Totals				**3,796,246**		**2,338,539**			**$34,394,385**		**$17,313,498**

Cost Approach Valuation Summary

Valuation by the cost approach is the sum of the fair market value of building and site improvements plus land; it is the aggregation of PG&E substation property and property rights – site-by-site and easement-miles-by-easement-miles – comprising the operating electric grid system in San Francisco.

The table included on the following page lists and aggregates PG&E substation and site values included within the scope of assignment. The valuations of easement property rights are subsequently valued in this appraisal.

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COST APPROACH VALUATION SUMMARY TABLE—BEFORE ENHANCEMENT FACTOR

					RCNLD Improvements			Land Value - Before Enhancement Factor				
No.	PG&E Substation	Address	Assessor Parcel No.	SBE Parcel No.	FMV Structural Improvements	FMV Site Improvements	Total FMV Improvements (Bldg + Site)	Site Size (SF)	Site Size (AC)	$/SF	FMV Land As-Is (DOV)	FMV Conclusion (RCNLD + Land)
1	Substation Z (Embarcadero)	405 & 425 Folsom Street	3748-001, -003, -004, -005 & -029	135-38-033A-1 & A-2	$211,872,285	$0	$211,872,285	33,213	0.762	$6,000.00	$199,278,000	$411,150,285
2	Substation A (Portrero)	1101 Ilinois Street	4175-018 (ptn)	135-38-024D-2, D-3 (ptn)	$28,033,342	$0	$28,033,342	293,960	6.748	$350.00	$96,730,375	$124,763,717
3.1	Substation P (Hunter's Point)	1180 Evans Avenue	4570-024	135-38-018D-1	$42,332	$558,756	$601,088	79,680	1.829	$340.00	$27,091,200	$27,692,288
3.2	Substation P (Hunter's Point)	1010-1030 Evans Avenue	4604A-002	135-38-018E-1	$30,427	$1,773,750	$1,804,177	281,659	6.466	$250.00	$70,414,750	$72,218,927
3.3	Substation P (Hunter's Point)	1135 Evans Avenue	4602A-014	135-38-026A-1	$12,522	$150,325	$162,847	85,747	1.968	$250.00	$21,436,750	$21,599,597
3.4	Substation P (Hunter's Point)	1059-1075 Evans Avenue	4603A-002, -005; 4647A-013	135-38-026A-2	$0	$889,536	$889,536	325,709	7.477	$250.00	$81,427,250	$82,316,786
3.5	Substation P (Hunter's Point)	5000 Hunter's Point Boulevard	4629A-012	135-38-026A-3	$0	$49,088	$49,088	13,734	0.315	$50.00	$686,700	$735,788
3.6	Substation P (Hunter's Point)	1000 Evans Avenue	4580-002	135-38-018A-2	$0	$5,138,648	$5,138,648	713,687	16.384	$180.00	$128,463,660	$133,602,308
4	Substation W (Bayshore)	151-157 Bayshore Boulevard	5559-004,-005,-006	135-38-031-1	$29,458	$381,971	$411,428	55,930	1.284	$575.00	$32,159,750	$32,571,178
5	Substation Y (Larkin)	538 Eddy Street	0335-037	135-38-030A-1, -2, & -3	$112,501,824	$0	$112,501,824	46,875	1.076	$1,000.00	$46,875,000	$159,376,824
6	Substation X (Mission)	66 8th Street	3701-053	135-38-015A-2	$124,622,969	$0	$124,622,969	44,617	1.024	$3,500.00	$156,159,500	$280,782,469
7	Substation L	2475 Ocean Avenue	6901-001	135-38-001-19	$693,494	$75,540	$769,034	17,076	0.392	$650.00	$11,099,400	$11,868,434
8	Substation G	1200 Broderick Street	1101-013	135-38-002-4	$3,218,671	$35,120	$3,253,791	15,469	0.355	$1,200.00	$18,562,800	$21,816,591
9	Substation E	205 Lexington Avenue	3596-104	135-38-003-6	$2,729,592	$36,362	$2,765,954	13,175	0.302	$2,300.00	$30,302,500	$33,068,454
10	Substation F (Marina)	1570 Bay Street	0459-032	135-38-001D-1	$0	$232,567	$232,567	13,112	0.301	$950.00	$12,456,400	$12,688,967
11	Substation K	679 24th Avenue	1567-012	135-38-002-5	$1,861,624	$40,020	$1,901,644	12,398	0.285	$750.00	$9,298,500	$11,200,144
12	Substation J	530 Sacramento Street	0228-006	135-38-004-6	$5,348,574	$0	$5,348,574	8,395	0.193	$1,000.00	$8,395,000	$13,743,574
13	Substation N	1437-1449 9th Avenue	1844-053	135-38-02A-1	$0	$115,152	$115,152	6,492	0.149	$750.00	$4,869,000	$4,984,152
14	Randolph Substation	724 Randolph Street	7084-024	135-38-019A-1	$0	$34,116	$34,116	4,865	0.112	$650.00	$3,162,250	$3,196,366
15	Substation M	20 Rousseau Street	6747-016	135-38-005B-1	$303,174	$23,378	$326,552	4,725	0.108	$1,100.00	$5,197,500	$5,524,052
16	Portola Substation	610 Portola Drive	2892-003	135-38-023-1	$0	$55,554	$55,554	4,698	0.108	$625.00	$2,936,250	$2,991,804
17	Beach Substation	330 Beach Street	0013-010	135-38-018B-1	$0	$44,344	$44,344	3,750	0.086	$1,350.00	$5,062,500	$5,106,844
18	6th Avenue	365 6th Avenue	1438-014	135-38-015-3	$0	$18,150	$18,150	3,000	0.069	$675.00	$2,025,000	$2,043,150
19	Silver Substation	1086 Silver Avenue	5915-001	135-38-025-1	$0	$17,146	$17,146	2,834	0.065	$350.00	$991,900	$1,009,046
20	Ocean Substation	1155 Ocean Avenue	6944-040	135-38-020-1	$0	$16,063	$16,063	2,655	0.061	$675.00	$1,792,125	$1,808,188
21	Yosemite Substation	1802 Yosemite Avenue	5417-007	135-38-011-1	$0	$15,125	$15,125	2,500	0.057	$225.00	$562,500	$577,625
22	Taraval Substation	2533 Taraval Street	2390-044	135-38-010-2	$0	$15,125	$15,125	2,500	0.057	$675.00	$1,687,500	$1,702,625
23	Judah Substation	2927 Judah Street	1819-042	135-38-010-1	$0	$15,125	$15,125	2,500	0.057	$750.00	$1,875,000	$1,890,125
24	Plymouth Substation	214 Plymouth Avenue	7112-012A	135-38-025-2	$0	$15,125	$15,125	2,500	0.057	$675.00	$1,687,500	$1,702,625
25	Noriega Substation	3819 Noriega Street	2082-001L	135-38-013-1	$0	$16,304	$16,304	2,325	0.053	$675.00	$1,569,375	$1,585,679
26	18th Street Substation	4430 18th Street	2650-020	135-38-008-1	$0	$13,613	$13,613	2,250	0.052	$1,100.00	$2,475,000	$2,488,613
27	Acton Substation	5889 Mission Street	6472-021D	135-38-013-5	$0	$13,613	$13,613	2,250	0.052	$675.00	$1,518,750	$1,532,363
28	Castro Substation	1510-1512 Castro Street	6546-004	135-38-014-1	$0	$6,050	$6,050	2,000	0.046	$1,150.00	$2,300,000	$2,306,050
29	21st Avenue Substation	1340 Noriega Street	2029-025	135-38-013-2	$0	$5,672	$5,672	1,875	0.043	$675.00	$1,265,625	$1,271,297
30	Egbert Switching Station	1755 Egbert Avenue	5431-001A	135-38-057-1 & -2	$0	$0	$0	70,446	1.617	$240.61	$16,950,000	$16,950,000
32	Beeman Lane	3789 San Bruno Avenue	5067-001A	135-38-018	$0	$16,878	$16,878	4,721	0.108	$260.00	$1,227,460	$1,244,338
33	Substation I	117 8th Street	3727-135	135-38-003A-1	$1,086,867	$6,346	$1,093,213	10,000	0.230	$1,050.00	$10,500,000	$11,593,213
				Subtotal Land & Improvements - San Francisco	**$492,387,154**	**$9,824,560**	**$502,211,713**	**2,193,322**	**50.352**		**$1,020,492,770**	**$1,522,704,483**
31	Martin Substation	3150 Geneva Avenue, Brisbane, CA	005-141-999 (ptn)	135-41-28B-3 (ptn)	**$7,256,948**	**$7,488,938**	**$14,745,886**	**1,602,313**	**36.784**	**$120.00**	**$189,069,030**	**$203,814,916**
				Total Land and Improvements	**$499,644,102**	**$17,313,498**	**$516,957,599**	**3,795,635**			**$1,209,561,800**	**$1,726,519,399**

The fair market value of the fee simple rights in the PG&E sites appraised (PG&E Properties 1 to 33, which includes the Martin Substation in Brisbane, San Mateo County), land and improvements before an added enhancement factor, is, as of July 27, 2021, summarized in the following table.

FAIR MARKET VALUE: LAND AND IMPROVEMENTS—BEFORE ENHANCEMENT FACTOR

San Francisco Fee Owned Properties	$1,522,704,483
Plus: Brisbane, San Mateo Co. Property (Martin Substation)	$203,814,916
Total:	**$1,726,519,399**

Valuation – PG&E's Private Easement Interests

Easement Interest Segments of the Corridor/ Energy Grid

The Easement Interests include over 2,400 unique easements. These easements were acquired over time, dating back to an era around PG&E's beginning in 1905 and the CPUC's forming in 1911. Prices paid, terms, and conditions for these acquisitions are unknown with many reflecting "no consideration" on the face of the recording documents. These land rights, by way of easement grants, represent an assemblage and an improvement of the operating electrical grid over time.

While these easement rights may have been acquired without a documented transfer price or cost to PG&E, these land rights were clearly exchanged for considerable value.

Furthermore, enumeration of the true consideration may not have been monetized in dollars, however the value in exchange was a quid pro quo between the utility purveyor and the beneficiary of electrical distribution and service, i.e. the provider/grantor of the easement. There was considerable value in the exchange of easement land rights for electrical service, allowing the user of this commodity to enhance the value of its real property.

Any historical consideration memorialized through transfer tax conversion, or any other means, is not time relevant to today's task of determining the fair market value of PG&E's electrical grid as of July 27, 2021. Additionally, these fragmented transactions are not comparable to the Larger Parcel's highest and best use as a network of assembled corridors operating as an electric grid.

In summary, these historical easement transactions are not relevant in this analysis.

Easement documents provided by PG&E were randomly selected to determine type, purpose, rights, length, width, area content and location. Due to the significant number of easements requiring research and examination by PG&E, PG&E determined that in the best interest of the company and its customers, a complete, detailed, and exhaustive review of over 2,400 unique easements was not financially practical, would require an undue consumption of time and cost, and that a reasonable alternative method, a circuit mile analysis, would adequately define and allow valuation of these easement interests.

PG&E utilized the San Francisco FF Electric Master dated 12-31-2021 to identify total "circuit miles". There are 137.56 net private circuit miles containing 175.883 acres or 7,661,472 square feet of private easement area. These represent segments or portions of the PG&E power system energy grid that have been analyzed by the Waldron appraisal firm.

The circuit miles are expressed as a linear distance. PG&E has defined the locations for each of the five types of easements. These circuit miles are further separated into "Private" circuit miles. This appraisal assignment excludes all "Public" circuit miles (interests derived from franchises, licenses, agreements, service extensions or other forms of use and occupancy) and focuses only on "Private" circuit miles for each of the five types of easements. Any "Private" circuit miles situated within PG&E Fee-Owned parcels were removed from the inventory to avoid value duplication.

There are five categories of easements including Electric Transmission – Underground (ET-UG), Electric Transmission – Overhead (ET-OH), Electric Distribution - Underground Facilities Management (ED-UFM), Electric Distribution - Underground (ED-UG), and Electric Distribution - Overhead (ED-OH).

Each category of easement was reviewed, inventoried, and analyzed utilizing the PG&E GIS mapping of "Private" circuit miles and the zoning overlays. PG&E also provided assumed physical widths for Transmission and Distribution easements which were relied upon for valuation purposes.

The assumed widths are reported as ten (10) feet for Distribution easements and forty-five (45) feet for Transmission easements. PG&E notes that the widths of easements have varied and changed with operational and maintenance needs throughout the years. With technology and design changes, PG&E's current practice is to acquire a 30-foot-wide easement for Distribution Overhead and a 10-foot-wide easement for Distribution Underground. So, the overall assumed width for Distribution, either Overhead or Underground at ten (10) feet is considered conservative.

Valuation Steps - Easement Interests

After concluding to the highest and best use as a network of utility corridors forming an energy grid delivering reliable energy to its customers in the city and county of San Francisco, the next step is to determine the market value of the underlying fee simple interest, collectively for each easement type.

This is determined based on a study of comparable land sales or market indicators consistent with the ATF methodology. These land sales are compared and contrasted on an unadjusted and adjusted basis. Refer to sub-heading "**Market Data – Land**" on Page 277.

For analytical purposes, two (2) separate valuation analyses are conducted. All land sales are relevant and considered in the application of each valuation study.

Following the market data – land sales discussion, the first study prioritizes the easement's unique location within San Francisco. The city and county were divided into sixteen (16) relatively equal-sized physical grids (2miles by 2 miles). Specific easement areas are calculated within each grid for each easement type.

Land sales or market indicators are then compared to the subject easements, which share a common location or proximity within their respective grid. Refer to sub-heading "**ATF – 16-Grid Quadrants**" on Page 279.

An overall weighted average rate per square foot of the fee simple interest for each easement type is determined by the following steps: 1) calculating the percentage of easement area within each quadrant; 2) multiply the percentage of easement area within each quadrant by the land rate within the quadrant; 3) resulting in a weighted land rate within the respective grid; 4) the weighted land rate within each of the 16 grids are totaled, which results in the overall weighted average rate for the respective easement type.

The second study prioritizes the easements unique zoning or permitted uses. The zoning is summarized for each easement type. Refer to sub-heading "**ATF – Zoning Use District**" on Page 290.

Land sales or market indicators are then compared to the subject easements, which share a common or similar zoning/use district.

An overall weighted average rate per square foot of the fee simple interest for each easement type is determined by the following steps: 1) calculating the percentage of easement area for each zoning designation; 2) multiply the percentage of easement area for each zoning designation by the land rate within the quadrant; 3) resulting in a weighted land rate within the respective zoning designation; 4) the weighted land rates with each zoning designation are totaled, which results in the overall weighted average rate for the respective easement type.

Each of the two (2) value studies, one focusing on the easement's location (16-Grid) and the other focusing on the easement's zoning (Zoning/Use District), are then carried into an easement analysis. For each easement type, the land area is multiplied by the weighted land rate, resulting in an indicated ATF value for the fee simple interest. The next step is to determine the easement contribution. Here the 100% fee simple interest is adjusted for the inherent land rights for each easement type. Refer to heading "**Easement Valuation**" on Page 296.

After adjusting the underlying fee simple value for the easement rights unique to each easement type, the two (2) indicators (16-Grid and Zoning/Use District) are reconciled into a single indicator of the ATF Easement Interest, prior to adjusting upward for the enhancement factor.

Market Data - Land Sales

Informative market data, specifically land transactions occurring before and after the date of valuation were gathered, researched, field inspected or aerially inspected, and verified. Like the geographic overlay of the private circuit miles for each of the five easement types, the land transactions representing market indicators in each section were overlaid in the relative geographic location as they may reside in each section.

The results of the search for land sales transactions, i.e., market indicators, in the CCSF environs generated 109 sales transactions and five (5) additional wetland sales identified as W1 through W5. The 109 supporting land sales are contained in ***Exhibit "W-3" (Land Sales Summary & Adjustments)***, which is included in the ***Appendices*** section. Also included in the ***Appendices*** section is a Market Data map identifying the location of the land sales. Wetland sales were not utilized by Waldron & Associates, Inc.

The 109 land sales are identified as Sale Nos. 1 through 27, 28A, 28B, 29 through 51, 52A, 52B, 52C, and 53 through 106. Sale Numbers 1 through 72 are being utilized by the Valbridge appraisal team for valuing the PG&E fee properties. The Waldron appraisal team expanded the land sales search to include additional transactions within the 16-quadrant overlay and additional transactions corresponding with the zoning use districts. For the valuation of the Easement Interests, the sales relied upon include Sale Nos. 1 through 57 and Sale Nos. 63 through 109. Sale Nos. 58 through 62 are being utilized by the Valbridge appraisal team for the Martin Substation valuation analysis, which is in San Mateo County.

All but five (5) of the sales are located within San Francisco. Sale Nos. 58 through 62 are located south of San Francisco; two (2) are in South San Francisco, two (2) are in San Carlos, and one (1) is in Belmont.

Land Sales - Unadjusted

Excluding the five sales located outside the CCSF jurisdiction (Sale Nos. 58 through 62), the 104 land sale transactions located in CCSF are summarized below:

- Sale dates range from February 2015 to March 2023. Of the 104 land sales, 84 occurred prior to July 27, 2021, the date of value; the remaining 20 sales occurred after the date of value.

- Land areas range from 750 square feet (0.17 acres) to 343,588 square feet (7.89 acres), averaging 15,834 square feet (0.364 acres). The median site area is 4,501 square feet, or 0.103 acres.

- The 104 land sales are located within the following Zoning Use Districts:

No. of Sales	Zoning Use District
47	Residential, House Character
8	Residential, Mixed
5	Residential-Commercial Combined
1	Residential, Transit Oriented
2	Downtown Residential
11	Commercial
8	Neighborhood Commercial
5	Neighborhood Commercial Transit
1	Chinatown Mixed Use
3	Eastern Neighborhoods Mixed Use
9	Production, Distribution & Repair
2	Industrial
1	Two Designations: Eastern Neighborhoods Mixed Use/ Production, Distribution & Repair
1	Two Designations: Eastern Neighborhoods Mixed Use/ Neighborhood Commercial

- Reported sales ranged from $275,000 to $78,000,000, with an average of $8,042,451 and a median at $1,937,500.
- Unadjusted, on a per square foot basis, the indicated land rates range from $89.74 per square foot to $6,359.04 per square foot with an average of $701.15 per square foot and a median at $450.69 per square foot.
- Overall, among the 104 land transactions, the unadjusted aggregate sale prices total $836,414,950 and the aggregate land areas total 1,646,724 square feet or 37.804 acres. The weighted average land rate indicator is $507.93 per square foot ($836,414,950 / 1,646,724 sf = $507.93 PSF).

Land Sales – Adjusted (Market Conditions and Entitlement)

The market data items were analyzed, and quantitative adjustments were applied for market conditions and entitlement status at the time of sale.

Market Conditions Adjustment

To determine an appropriate adjustment to the land transactions for market conditions, historical price trends have been analyzed among improved sales/rents within general use categories, including detached residential sales; attached residential sales; retail building sales; retail rental rates; office rental rates; industrial building sales; and industrial rental rates. Reported historical data price trends were not available for land transactions. For the period covering 2015 to 2021 (July 27, 2021, date of value), the trends are summarized below:

Use	Period	Annual Rate
Detached Residential - Average Sale Prices	2015 – 2021	7.63%
Detached Residential - Median Sale Prices	2015 – 2021	8.13%
Attached Residential - Average Sale Prices	2015 – 2021	2.28%
Attached Residential - Median Sale Prices	2015 – 2021	2.12%
Retail Building Sales (PSF)	Q1 2015 – Q2 2021	3.99%
Retail Rents	Q1 2015 – Q2 2021	2.31%
Office Rents	Q1 2015 – Q2 2021	0.96%
Industrial Building Sales (PSF)	Q1 2015 – Q2 2021	15.03%
Industrial Rents	Q1 2015 – Q2 2021	6.97%
Average		**5.49%**

The Valbridge appraisal team has also analyzed market conditions. This analysis coincides with the Waldron appraisal team. The discussion is detailed in the section **Valuation: Fee Owned Properties**, on pages 204 and 205.

In summary, comparable sales are adjusted as follows:

Residential:	+5%/year to sales before and +4%/year after DOV
Commercial:	+3%/year to sales before DOV; -3%/year to sales after DOV
Office:	+0.50%/year to sales before DOV; -0.50%/year to sales after DOV
Industrial:	+10%/year to sales before DOV; -10%/year to sales after DOV

The adjustments are detailed in ***Exhibit "W-3" (Land Sales Summary & Adjustments)***, located in the ***Appendices*** section. The transactions occurring after the date of value with a residential land use designation are highlighted in green in the market conditions column, since the adjustment is positive after the date of value. For all other transactions with closing dates after the date of value, the adjustment was downward.

Entitlement Adjustment

The Subject Property Easement Interests are spread throughout the urbanized jurisdiction of CCSF. For the most part, these easement segments are situated within improved properties, where entitlements are already in place, which permit their respective existing uses. The existing entitlements enhance the

value, and consequently, the cost to create the electric grid corridor reflects the contribution of PG&E's easement.

The permitted usability and adaptability of real estate require an additional cost of time, expenses, risk and uncertainty to secure the ultimate government approvals for a specific use.

In the context of real property ownership and the permitted usability and adaptability of real estate for development to an existing or proposed use, entitlement is the potential added value increment associated with government approvals. These approvals include, but are not limited to use, zoning, development density, height, bulk/massing, building areas, parking, architectural style/materials, approvals, grading permits, building permits, and use or occupancy permits.

Market evidence supports a substantial upward adjustment for entitled properties as compared to unentitled properties, at levels of two (2) to three (3) times the underlying, unentitled land rates. Two sets of market data items, Land Sale 28A/28B and Land Sale 52A/52B, represent examples among the data sets demonstrating the premium for entitled land compared to unentitled land, whereby the property sells first as unentitled, then re-sells as entitled.

Where easements are situated within older, historically developed, established neighborhoods, and obtaining entitlements were less complex, and required little, if any, City discretion, essentially with more "by-right" zoning permissibility, the entitlement adjustment is tempered downward. Where unentitled market indicators require an adjustment for entitlements, an upward adjustment of 20% has been applied.

Summary – Land Sales Adjusted for Market Conditions and Entitlement

Considering adjustments for market conditions and entitlement, the 104 land sale transactions located in CCSF are summarized below:

- The adjusted sale prices range from $339,900 to $94,920,000, with an average of $10,367,672 and a median at $2,350,750.
- Adjusted, on a per square foot basis, the indicated land rates range from $112.78 per square foot to $6,804.17 per square foot with an average of $891.89 per square foot and a median at $578.45 per square foot.
- Overall, on an adjusted basis, among the 104 land transactions, the aggregate sale prices total $1,078,237,852, and the aggregate land areas total 1,646,724 square feet or 37.80 acres. The weighted average land rate indicator is $654.78 per square foot ($1,078,237,852 / 1,646,724 sf = $654.78 PSF).

ATF – 16-Grid Quadrants

After eliminating all "Private" circuit miles on PG&E fee-owned properties within the GIS mapping tools, the remaining "Private" circuit miles were identified for each of the five Subject Property corridor easement categories within the CCSF jurisdiction. Equal-sized geographic sections were laid over the physical and jurisdictional boundaries of CCSF. These sections were approximately distributed as two-mile squares and totaled sixteen (16) section quadrants, identifying the location of the PG&E private

easements, and formulating geographic ATF districts. These sixteen (16) quadrants represent the framework for a proximity zone of value analysis in the ATF methodology.

Informative market data, specifically land transactions occurring before and after the date of valuation were gathered, researched, field inspected or aerially inspected, and verified. Like the geographic overlay of the private circuit miles for each of the five easement types, the land transactions representing market indicators in each section were overlaid in the relative geographic location as they may reside in each section quadrant.

Recognizing the non-corridor use of adjacent and nearby properties within each of the "across-the-fence" land sales within the ATF district were selected. These land sales reflect prices for typical or similar proximate, adjacent, and nearby properties that shed light on the contributory value of these land segments within the ATF identified section quadrant / district as a part of the entire energy corridor / grid.

Each zone of value section quadrant or district was studied based upon the observed ranges in prices over land area, including the average price per square foot, the median price per square foot and the weighted average price per square foot. The price rate per square foot was then reconciled and applied as the ATF indicator for that specific easement category in that specific ATF district. Each easement, depending upon the nature and scope of PG&E's easement rights, was analyzed by recognizing the division of property rights by way of (1) a "before and after" easement analysis and (2) a direct summation analysis, two easement valuation methodologies. These analyses are discussed later, in more detail, in the Easement Valuation section.

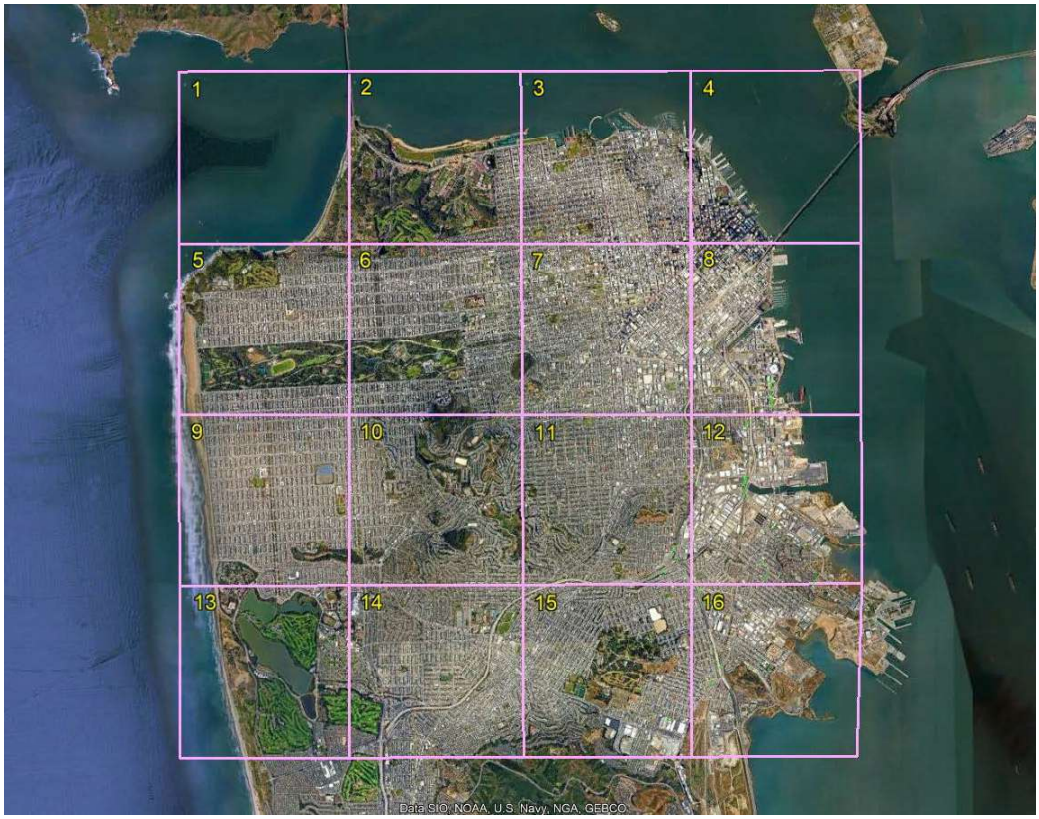
The concluded value for each 16-zone quadrant reflects the ATF value either as a measure of the current value contribution of the ATF segment or hypothetically as an indication of the cost to create the land component for that segment. The concluded ATF unit rate ($'s per square foot) is then applied to the area content of that combined private circuit mile easement segment to arrive at an indication of the ATF contribution for that easement category within the corridor / energy grid. Ultimately, the ATF indicated easement value is adjusted for the corridor / energy grid highest and best use by the enhancement factor.

The 16-quadrant overlays for each easement type (ET-UG, ET-OH, ED-UFM, ED-UG, ED-OH), are presented in the following aerial exhibits.

PRIVATE ELECTRIC TRANSMISSION - UNDERGROUND (ET-UG)

CITY AND COUNTY OF SAN FRANCISCO

CIRCUIT MILES:	2.157	miles
LINEAR FEET:	11,387	linear feet
LAND AREA:	512,428	square feet
	11.764	acres
RIGHT-OF-WAY WIDTH:	45	feet



Quadrant	Linear Feet	Land Area	% of Total
1	0.00 lf	0 sf	0.00%
2	0.00 lf	0 sf	0.00%
3	0.00 lf	0 sf	0.00%
4	0.00 lf	0 sf	0.00%
5	0.00 lf	0 sf	0.00%
6	0.00 lf	0 sf	0.00%
7	10.61 lf	477 sf	0.09%
8	1,895.22 lf	85,285 sf	16.64%
9	0.00 lf	0 sf	0.00%
10	0.00 lf	0 sf	0.00%
11	1,833.31 lf	82,499 sf	16.10%
12	4,795.17 lf	215,782 sf	42.11%
13	0.00 lf	0 sf	0.00%
14	0.00 lf	0 sf	0.00%
15	552.51 lf	24,863 sf	4.85%
16	2,300.47 lf	103,521 sf	20.20%
Overall	**11,387.28 lf**	**512,428 sf**	**100.00%**

PRIVATE ELECTRIC TRANSMISSION - OVERHEAD (ET-OH)

CITY AND COUNTY OF SAN FRANCISCO

CIRCUIT MILES:	0.000	miles
LINEAR FEET:	0	linear feet
LAND AREA:	0	square feet
	0.000	acres
RIGHT-OF-WAY WIDTH:	45	feet

Quadrant	Linear Feet	Land Area	% of Total
1	0.00 lf	0 sf	0.00%
2	0.00 lf	0 sf	0.00%
3	0.00 lf	0 sf	0.00%
4	0.00 lf	0 sf	0.00%
5	0.00 lf	0 sf	0.00%
6	0.00 lf	0 sf	0.00%
7	0.00 lf	0 sf	0.00%
8	0.00 lf	0 sf	0.00%
9	0.00 lf	0 sf	0.00%
10	0.00 lf	0 sf	0.00%
11	0.00 lf	0 sf	0.00%
12	0.00 lf	0 sf	0.00%
13	0.00 lf	0 sf	0.00%
14	0.00 lf	0 sf	0.00%
15	0.00 lf	0 sf	0.00%
16	0.00 lf	0 sf	0.00%
Overall	**0.00 lf**	**0 sf**	**0.00%**

PRIVATE ELECTRIC DISTRIBUTION - UNDERGROUND FACILITIES MANAGEMENT (ED-UFM)

CITY AND COUNTY OF SAN FRANCISCO

CIRCUIT MILES:	54.020	miles
LINEAR FEET:	285,225	linear feet
LAND AREA:	2,852,250	square feet
	65.479	acres
RIGHT-OF-WAY WIDTH:	10	feet

Quadrant	Linear Feet	Land Area	% of Total
1	0.00 lf	0 sf	0.00%
2	3,385.35 lf	33,854 sf	1.19%
3	17,260.97 lf	172,610 sf	6.05%
4	7,655.38 lf	76,554 sf	2.68%
5	1,289.35 lf	12,893 sf	0.45%
6	9,793.28 lf	97,933 sf	3.43%
7	40,474.15 lf	404,741 sf	14.19%
8	39,018.51 lf	390,185 sf	13.68%
9	9,116.96 lf	91,170 sf	3.20%
10	53,106.68 lf	531,067 sf	18.62%
11	12,443.17 lf	124,432 sf	4.36%
12	30,633.42 lf	306,334 sf	10.74%
13	10,616.75 lf	106,167 sf	3.72%
14	36,858.65 lf	368,587 sf	12.92%
15	7,048.74 lf	70,487 sf	2.47%
16	6,523.63 lf	65,236 sf	2.29%
Overall	**285,224.99 lf**	**2,852,250 sf**	**100.00%**

PRIVATE ELECTRIC DISTRIBUTION - UNDERGROUND (ED-UG)

CITY AND COUNTY OF SAN FRANCISCO

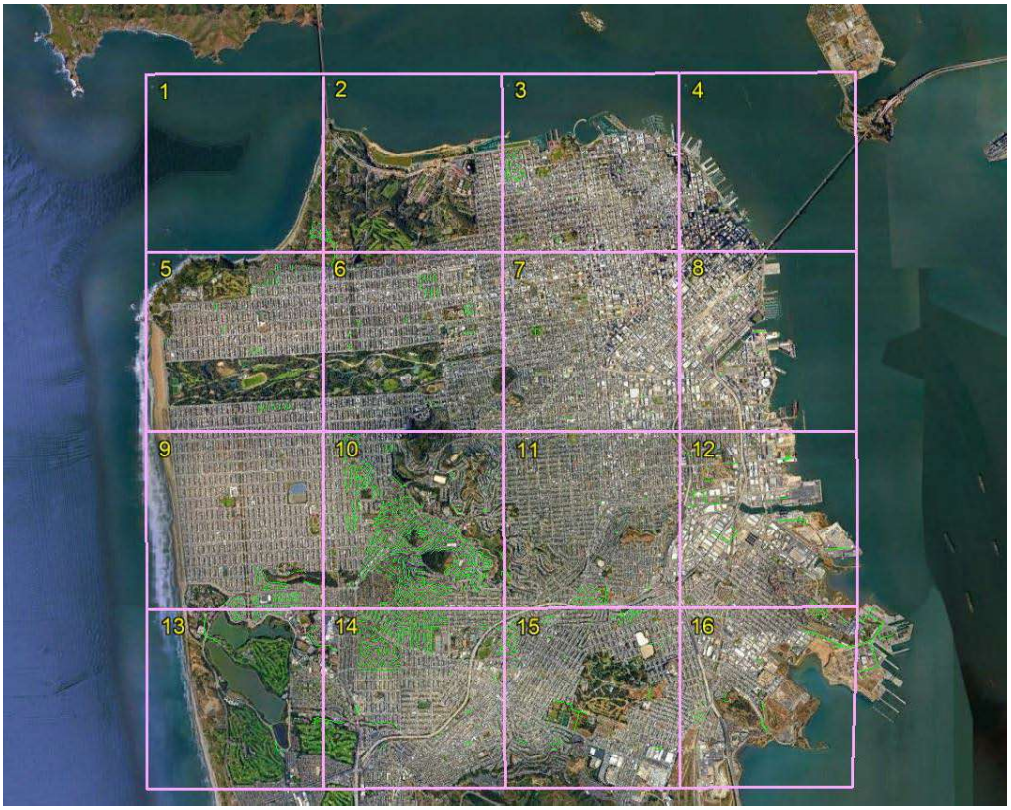
CIRCUIT MILES:	20.874	miles
LINEAR FEET:	110,216	linear feet
LAND AREA:	1,102,163	square feet
	25.302	acres
RIGHT-OF-WAY WIDTH:	10	feet

Quadrant	Linear Feet	Land Area	% of Total
1	33.72 lf	337 sf	0.03%
2	6,785.81 lf	67,858 sf	6.16%
3	1,755.14 lf	17,551 sf	1.59%
4	0.00 lf	0 sf	0.00%
5	12,752.11 lf	127,521 sf	11.57%
6	10,432.69 lf	104,327 sf	9.47%
7	693.51 lf	6,935 sf	0.63%
8	16,974.31 lf	169,743 sf	15.40%
9	11,044.45 lf	110,444 sf	10.02%
10	7,531.95 lf	75,319 sf	6.83%
11	1,847.71 lf	18,477 sf	1.68%
12	9,673.77 lf	96,738 sf	8.78%
13	8,515.22 lf	85,152 sf	7.73%
14	6,411.20 lf	64,112 sf	5.82%
15	5,723.29 lf	57,233 sf	5.19%
16	10,041.42 lf	100,414 sf	9.11%
Overall	**110,216.29 lf**	**1,102,163 sf**	**100.00%**

PRIVATE ELECTRIC DISTRIBUTION - OVERHEAD (ED-OH)

CITY AND COUNTY OF SAN FRANCISCO

CIRCUIT MILES:	60.504	miles
LINEAR FEET:	319,463	linear feet
LAND AREA:	3,194,632	square feet
	73.339	acres
RIGHT-OF-WAY WIDTH:	10	feet



Quadrant	Linear Feet	Land Area	% of Total
1	7,070.53 lf	70,705 sf	2.21%
2	145.79 lf	1,458 sf	0.05%
3	8,042.53 lf	80,425 sf	2.52%
4	74.72 lf	747 sf	0.02%
5	8,510.33 lf	85,103 sf	2.66%
6	8,660.93 lf	86,609 sf	2.71%
7	2,552.71 lf	25,527 sf	0.80%
8	2,687.21 lf	26,872 sf	0.84%
9	21,417.84 lf	214,178 sf	6.70%
10	117,906.87 lf	1,179,069 sf	36.91%
11	11,225.94 lf	112,259 sf	3.51%
12	21,001.35 lf	210,014 sf	6.57%
13	11,923.01 lf	119,230 sf	3.73%
14	55,041.52 lf	550,415 sf	17.23%
15	22,051.15 lf	220,512 sf	6.90%
16	21,150.72 lf	211,507 sf	6.62%
Overall	**319,463.15 lf**	**3,194,632 sf**	**100.00%**

Land Sales Application – 16 Quadrants

As previously discussed, equal-sized geographic sections were laid over the physical and jurisdictional boundaries of CCSF. These sections were approximately distributed as two-mile squares and totaled sixteen (16) section quadrants, identifying the location of the PG&E private easements, and formulating geographic ATF districts. These sixteen (16) quadrants represent the framework for a proximity zone of value analysis in the ATF methodology.

Each zone of value section quadrant or district was studied based upon the observed ranges in prices over land area, including the average price per square foot, the median price per square foot and the weighted average price per square foot. The price per square foot indicators were analyzed and reconciled, resulting in a concluded rate per square foot to be applied as the ATF indicator for each specific easement category in each specific ATF district.

The 104 land transactions were analyzed by their respective locations within each quadrant and are summarized in ***Exhibit "W-4" (Land Sales Summary & Adjustments – By Quadrant)***, which is included in the ***Appendices*** section.

The following exhibit provides a quadrant-by-quadrant summary, identifying the total number of sales in each quadrant, the total sale price, total land area, average land area, the indicated rate per square foot on a weighted average basis, the lowest and highest price per square foot land rate indicator, along with the average, median and midpoint of the weighted average and median. The concluded land rate per square foot for the respective quadrant is depicted in the final column to the right.

Quadrants with the higher number of sales are more reliable. For quadrants with limited sales or no sales, indicated rates within adjoining quadrants were also considered when reconciling to a concluded rate for each quadrant. The reconciled rates are within a reasonable range of the weighted average and median land rate per square foot for each quadrant.

The following exhibit also provides a quadrant-by-quadrant summary, focusing rate per square foot indicators for the average, weighted average, median, and midpoint of the weighted average. The concluded land rate per square foot for the respective quadrant is depicted in the last row of each quadrant. The 16-quadrant grid coincides with the 16-grid aerial overlay depicting the circuit miles within each of the five (5) easement types.

LAND SALES INDICATORS AND CONCLUSIONS - BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

	Quadrant 1	Quadrant 2	Quadrant 3	Quadrant 4
Items	0	1	6	2
Land Rate - PSF				
Average	---	$2,195.61	$915.62	$1,067.42
Weighted Average	---	$2,195.61	$875.65	$1,071.61
Median	---	$2,195.61	$797.81	$1,067.42
Midpoint - Weighted Average & Median	---	$2,195.61	$836.73	$1,069.52
Conclusion	**$575.00**	**$850.00**	**$850.00**	**$1,100.00**

	Quadrant 5	Quadrant 6	Quadrant 7	Quadrant 8
Items	6	7	19	8
Land Rate - PSF				
Average	$610.37	$745.64	$1,152.90	$3,905.70
Weighted Average	$715.46	$715.46	$1,368.96	$2,284.07
Median	$599.99	$681.36	$909.10	$4,238.23
Midpoint - Weighted Average & Median	$589.88	$698.41	$1,139.03	$3,261.15
Conclusion	**$575.00**	**$680.00**	**$1,150.00**	**$2,350.00**

	Quadrant 9	Quadrant 10	Quadrant 11	Quadrant 12
Items	1	7	10	15
Land Rate - PSF				
Average	$483.84	$240.12	$819.44	$301.43
Weighted Average	$483.84	$211.38	$863.51	$354.83
Median	$483.84	$262.99	$759.93	$244.80
Midpoint - Weighted Average & Median	$483.84	$237.18	$811.72	$299.82
Conclusion	**$480.00**	**$250.00**	**$800.00**	**$290.00**

	Quadrant 13	Quadrant 14	Quadrant 15	Quadrant 16
Items	1	5	8	9
Land Rate - PSF				
Average	$411.40	$382.27	$252.89	$231.65
Weighted Average	$411.40	$505.48	$233.94	$210.56
Median	$411.40	$313.36	$255.12	$201.73
Midpoint - Weighted Average & Median	$411.40	$409.42	$244.53	$206.15
Conclusion	**$400.00**	**$400.00**	**$245.00**	**$200.00**

Conclusion – ATF Land Rate Market Indicators – By Quadrant

The concluded weighted average rate per square foot is determined in two (2) steps: first, multiplying the percentage of easement area within each of the 16 quadrants by the concluded land rate for the respective quadrant; second, the contributory rates for the respective quadrants are totaled, accounting for 100% of the easements' area within each of the five (5) easement types. The application for each easement type is presented in the exhibit on the following page.

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LAND RATE AND WEIGHTED RATE PER SQUARE FOOT - BY QUADRANT - BY EASEMENT TYPE
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - OVERHEAD AND UNDERGROUND
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		ELECTRIC TRANSMISSION					ELECTRIC DISTRIBUTION											
Description		Transmission - Underground				Transmission - Overhead	Distribution - UFM				Distribution - Underground				Distribution - Overhead			
PG&E Easement Interest																		
Linear Feet		11,387.28 lf				0.00 lf	285,224.99 lf				110,216.29 lf				319,463.15 lf			
Circuit Miles		2.157 miles				0.000 miles	54.020 miles				20.874 miles				60.504 miles			
Average Easement Width		45 feet				45 feet	10 feet				10 feet				10 feet			
Land Area																		
Square Feet		512,428 sf				0 sf	2,852,250 sf				1,102,163 sf				3,194,632 sf			
Acres		11.764 acres				0.000 acres	65.479 acres				25.302 acres				73.339 acres			
Quadrant	Land Rate Within Quadrant	% of Easement Area Within Quadrant	Land Rate Within Quadrant	Land Rate - Weighted Average (PSF)		% of Easement Area Within Quadrant	% of Easement Area Within Quadrant	Land Rate Within Quadrant	Land Rate - Weighted Average (PSF)		% of Easement Area Within Quadrant	Land Rate Within Quadrant	Land Rate - Weighted Average (PSF)		% of Easement Area Within Quadrant	Land Rate Within Quadrant	Land Rate - Weighted Average (PSF)	
1	$575.00	0.00% x	$575.00 =	$0.00		0.00%	0.00% x	$575.00 =	$0.00		0.03% x	$575.00 =	$0.18		2.21% x	$575.00 =	$12.72	
2	$850.00	0.00% x	$850.00 =	$0.00		0.00%	1.19% x	$850.00 =	$10.09		6.16% x	$850.00 =	$52.33		0.05% x	$850.00 =	$0.39	
3	$850.00	0.00% x	$850.00 =	$0.00		0.00%	6.05% x	$850.00 =	$51.44		1.59% x	$850.00 =	$13.53		2.52% x	$850.00 =	$21.40	
4	$1,100.00	0.00% x	$1,100.00 =	$0.00		0.00%	2.68% x	$1,100.00 =	$29.52		0.00% x	$1,100.00 =	$0.00		0.02% x	$1,100.00 =	$0.25	
5	$575.00	0.00% x	$575.00 =	$0.00		0.00%	0.45% x	$575.00 =	$2.60		11.57% x	$575.00 =	$66.53		2.66% x	$575.00 =	$15.32	
6	$680.00	0.00% x	$680.00 =	$0.00		0.00%	3.43% x	$680.00 =	$23.35		9.47% x	$680.00 =	$64.37		2.71% x	$680.00 =	$18.43	
7	$1,150.00	0.09% x	$1,150.00 =	$1.04		0.00%	14.19% x	$1,150.00 =	$163.19		0.63% x	$1,150.00 =	$7.23		0.80% x	$1,150.00 =	$9.19	
8	$2,350.00	16.64% x	$2,350.00 =	$391.04		0.00%	13.68% x	$2,350.00 =	$321.48		15.40% x	$2,350.00 =	$361.92		0.84% x	$2,350.00 =	$19.76	
9	$480.00	0.00% x	$480.00 =	$0.00		0.00%	3.20% x	$480.00 =	$15.34		10.02% x	$480.00 =	$48.10		6.70% x	$480.00 =	$32.18	
10	$250.00	0.00% x	$250.00 =	$0.00		0.00%	18.62% x	$250.00 =	$46.55		6.83% x	$250.00 =	$17.09		36.91% x	$250.00 =	$92.27	
11	$800.00	16.10% x	$800.00 =	$128.80		0.00%	4.36% x	$800.00 =	$34.90		1.68% x	$800.00 =	$13.41		3.51% x	$800.00 =	$28.11	
12	$290.00	42.11% x	$290.00 =	$122.12		0.00%	10.74% x	$290.00 =	$31.15		8.78% x	$290.00 =	$25.45		6.57% x	$290.00 =	$19.06	
13	$400.00	0.00% x	$400.00 =	$0.00		0.00%	3.72% x	$400.00 =	$14.89		7.73% x	$400.00 =	$30.90		3.73% x	$400.00 =	$14.93	
14	$400.00	0.00% x	$400.00 =	$0.00		0.00%	12.92% x	$400.00 =	$51.69		5.82% x	$400.00 =	$23.27		17.23% x	$400.00 =	$68.92	
15	$245.00	4.85% x	$245.00 =	$11.88		0.00%	2.47% x	$245.00 =	$6.05		5.19% x	$245.00 =	$12.72		6.90% x	$245.00 =	$16.91	
16	$200.00	20.20% x	$200.00 =	$40.40		0.00%	2.29% x	$200.00 =	$4.57		9.11% x	$200.00 =	$18.22		6.62% x	$200.00 =	$13.24	
Total / Weighted Average		100.00%		$695.28		0.00%	100.00%		$806.81		100.00%		$755.25		100.00%		$383.08	

The concluded weighted fee interest land rate for each easement type utilizing the "**ATF – 16-Grid Quadrants**" methodology is as follows:

Easement Type	Land Rate
Electric Transmission	
Underground (ET-UG)	$695.28
Overhead (ET-OH)	N/Appl.
Electric Distribution	
Underground Facilities Management (ED-UFM)	$806.81
Underground (ED-UG)	$755.25
Overhead (ED-OH)	$383.08

ATF – Zoning Use District

Land Sales Application – Zoning Use District

As an additional analysis, each linear reach for each category of easement type was inventoried as it relates to the underlying Zoning Use District – Zoning designation. The overall private easement acreage associated within each Use District was quantified. Sales of similarly zoned land, proximate to the private easement type, were studied. Based upon the observed ranges in prices over land area, including the average price per square foot, the median price per square foot and the weighted average price per square foot, a rate for that particular use district was determined. The price per square foot indicators were analyzed and reconciled, resulting in a concluded rate per square foot to be applied to each easement reach / segment as the ATF indicator for that specific easement category in that specific Use District.

The land area within each zoning use district for the five (5) easement categories (ET-UG, ET-OH, ED-UFM, ED-UG, ED-OH) is summarized in the following exhibit. When considering all five (5) easement categories, approximately 58% of the land area is located within "Residential" zoned districts, therefore, the focus for market data selection is residential land sales.

ZONING ALLOCATION - BY USE DISTRICT
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

ZONING USE DISTRICT	ELECTRIC TRANSMISSION ("ET")			ELECTRIC DISTRIBUTION ("ED")				TOTAL
	ET - UG	ET - OH	ET - TOTAL	ED - UFM	ED - UG	ED - OH	ED - TOTAL	
Land Area Allocation								
Residential, House Character	120,617 sf	0 sf	120,617 sf	981,755 sf	318,001 sf	2,324,524 sf	3,624,280 sf	**3,744,897 sf**
Residential, Mixed (Houses & Apartments)	33,978 sf	0 sf	33,978 sf	267,411 sf	72,085 sf	116,185 sf	455,681 sf	**489,659 sf**
Residential-Commercial Combined	0 sf	0 sf	0 sf	60,456 sf	291 sf	84 sf	60,831 sf	**60,831 sf**
Residential Transit Oriented	0 sf	0 sf	0 sf	67,314 sf	0 sf	2,757 sf	70,071 sf	**70,071 sf**
Downtown Residential	0 sf	0 sf	0 sf	54,298 sf	0 sf	182 sf	54,480 sf	**54,480 sf**
Commercial	0 sf	0 sf	0 sf	223,723 sf	39,704 sf	5,649 sf	269,076 sf	**269,076 sf**
Neighborhood Commercial	11,712 sf	0 sf	11,712 sf	168,649 sf	30,444 sf	32,560 sf	231,653 sf	**243,365 sf**
Neighborhood Commercial Transit	0 sf	0 sf	0 sf	103,247 sf	0 sf	10,856 sf	114,103 sf	**114,103 sf**
Eastern Neighborhoods Mixed Use	54,612 sf	0 sf	54,612 sf	156,551 sf	0 sf	6,574 sf	163,125 sf	**217,737 sf**
Chinatown Mixed Use	0 sf	0 sf	0 sf	4,240 sf	0 sf	261 sf	4,501 sf	**4,501 sf**
Parkmerced Use	0 sf	0 sf	0 sf	56,764 sf	2,789 sf	13,319 sf	72,871 sf	**72,871 sf**
Miscellaneous	39,005 sf	0 sf	39,005 sf	210,708 sf	178,657 sf	160,782 sf	550,147 sf	**589,152 sf**
Industrial	1,198 sf	0 sf	1,198 sf	21,228 sf	65,354 sf	56,646 sf	143,229 sf	**144,427 sf**
Production, Distribution & Repair	109,204 sf	0 sf	109,204 sf	174,933 sf	17,168 sf	90,192 sf	282,293 sf	**391,497 sf**
Public	142,102 sf	0 sf	142,102 sf	300,971 sf	377,670 sf	374,060 sf	1,052,701 sf	**1,194,803 sf**
Total - Square Feet	512,428 sf	0 sf	512,428 sf	2,852,248 sf	1,102,163 sf	3,194,631 sf	7,149,042 sf	**7,661,470 sf**
Total - Acres	11.764 acres	0.000 acres	11.764 acres	65.479 acres	25.302 acres	73.339 acres	164.119 acres	**175.883 acres**
Circuit Miles	2.16 miles	0.00 miles	2.16 miles	54.02 miles	20.87 miles	60.50 miles	135.40 miles	**137.56 miles**
Allocation Percentage								
Residential, House Character	23.54%	0.00%	23.54%	34.42%	28.85%	72.76%	50.70%	**48.88%**
Residential, Mixed (Houses & Apartments)	6.63%	0.00%	6.63%	9.38%	6.54%	3.64%	6.37%	**6.39%**
Residential-Commercial Combined	0.00%	0.00%	0.00%	2.12%	0.03%	0.00%	0.85%	**0.79%**
Residential Transit Oriented	0.00%	0.00%	0.00%	2.36%	0.00%	0.09%	0.98%	**0.91%**
Downtown Residential	0.00%	0.00%	0.00%	1.90%	0.00%	0.01%	0.76%	**0.71%**
Commercial	0.00%	0.00%	0.00%	7.84%	3.60%	0.18%	3.76%	**3.51%**
Neighborhood Commercial	2.29%	0.00%	2.29%	5.91%	2.76%	1.02%	3.24%	**3.18%**
Neighborhood Commercial Transit	0.00%	0.00%	0.00%	3.62%	0.00%	0.34%	1.60%	**1.49%**
Eastern Neighborhoods Mixed Use	10.66%	0.00%	10.66%	5.49%	0.00%	0.21%	2.28%	**2.84%**
Chinatown Mixed Use	0.00%	0.00%	0.00%	0.15%	0.00%	0.01%	0.06%	**0.06%**
Parkmerced Use	0.00%	0.00%	0.00%	1.99%	0.25%	0.42%	1.02%	**0.95%**
Miscellaneous	7.61%	0.00%	7.61%	7.39%	16.21%	5.03%	7.70%	**7.69%**
Industrial	0.23%	0.00%	0.23%	0.74%	5.93%	1.77%	2.00%	**1.89%**
Production, Distribution & Repair	21.31%	0.00%	21.31%	6.13%	1.56%	2.82%	3.95%	**5.11%**
Public	27.73%	0.00%	27.73%	10.55%	34.27%	11.71%	14.73%	**15.59%**
Total - Square Feet	100.00%	0.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**

Each easement category, depending upon the nature and scope of PG&E's easement rights, was analyzed by recognizing the primary and secondary rights and the division of property rights by way of a "before and after" easement analysis and a direct summation analysis.

Ultimately, the ATF indicated easement value is adjusted for the corridor / energy grid highest and best use by the enhancement factor.

The 104 land transactions were analyzed by their zoning uses district designation and are summarized in ***Exhibit "W-5" (Land Sales Summary & Adjustments – By Zoning Use District)***, which is included in the ***Appendices*** section.

The following exhibit provides a summary by "Zoning Use District", identifying the total number of sales in each zoning use district, the total sale price, total land area, average land area, the indicated rate per square foot on a weighted average basis, the lowest and highest price per square foot land rate indicator, along with the average, median and midpoint of the weighted average and median. For instances where the land sales were limited within a particular zoning use district, data was combined with a similar zoning use district.

- "Residential-Commercial Combined" and "Residential, Transit Oriented" were merged as one data set,
- "Neighborhood Commercial" was combined with "Neighborhood Commercial Transit", and
- "Chinatown Mixed Use" was combined with “Eastern Neighborhoods Mixed Use".

The concluded land rate per square foot for each respective zoning use district depicted in the final column to the right.

LAND SALES SUMMARY AND CONCLUSIONS - BY ZONING USE DISTRICT - ADJUSTED FOR MARKET CONDITIONS AND ENTITLEMENT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

					Land Rate - Per Square Foot						
ZONING USE DISTRICT	Sale Items	Total Sale Price	Total Land Area (SF)	Average Land Area (SF)	Weighted Average (PSF)	Low	High	Average	Median	Midpoint Weighted Avg. & Median	Conclusion
Residential, House Character	47	$76,499,281	178,595	3,800	$428.34	$112.78	$2,195.61	$462.68	$297.20	$362.77	$400.00
Residential, Mixed	8	$26,042,400	72,138	9,017	$361.01	$211.19	$1,791.10	$693.15	$634.29	$497.65	$550.00
Residential-Commercial Combined / Residential, Transit Oriented	6	$40,941,800	50,159	8,360	$816.24	$501.39	$1,037.10	$818.03	$856.46	$836.35	$850.00
Downtown Residential	2	$80,820,000	19,415	9,708	$4,162.76	$3,327.94	$5,847.06	$4,587.50	$4,587.50	$4,375.13	$4,500.00
Commercial	11	$354,766,743	125,417	11,402	$2,828.70	$908.41	$6,804.17	$2,973.32	$2,342.64	$2,585.67	$2,700.00
Neighborhood Commercial / Neighborhood Commercial Transit	13	$115,783,188	148,348	11,411	$780.48	$196.37	$1,665.77	$814.74	$817.98	$799.23	$815.00
Chinatown Mixed Use / Eastern Neighborhoods Mixed Use	3	$87,757,000	165,090	55,030	$531.57	$407.85	$1,051.06	$758.96	$817.98	$674.77	$800.00
Production, Distribution & Repair	10	$337,359,820	991,253	99,125	$340.34	$113.08	$499.46	$337.12	$344.83	$342.58	$340.00
Industrial	2	$3,232,020	10,000	5,000	$323.20	$288.30	$358.10	$323.20	$323.20	$323.20	$325.00
Overall	104	$1,078,237,852	1,646,724 37.80 acres	15,834	$654.78	$112.78	$6,804.17	$891.89	$578.45	$616.61	

Conclusion – ATF Land Rate Market Indicators – By Zoning Use District

The concluded weighted average rate per square foot is determined in two (2) steps: first, multiplying the percentage of easement area within each of the "Zoning Use Districts" by the concluded land rate for the respective "Zoning Use Districts"; second, the contributory rates for the respective "Zoning Use Districts" are totaled, accounting for 100% of the easements' area within each of the five (5) easement types.

The application for each easement type is presented in the exhibit on the following page.

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LAND RATE AND WEIGHTED RATE PER SQUARE FOOT - BY ZONING USE DISTRICT - BY EASEMENT TYPE
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - OVERHEAD AND UNDERGROUND
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		ELECTRIC TRANSMISSION						ELECTRIC DISTRIBUTION											
Description		**Transmission - Underground**					**Transmission - Overhead**	**Distribution - UFM**				**Distribution - Underground**				**Distribution - Overhead**			
PG&E Easement Interest																			
Linear Feet		**11,387.28 lf**					**0.00 lf**	**285,224.99 lf**				**110,216.29 lf**				**319,463.15 lf**			
Circuit Miles		**2.157 miles**					**0.000 miles**	**54.020 miles**				**20.874 miles**				**60.504 miles**			
Average Easement Width		**45 feet**					**45 feet**	**10 feet**				**10 feet**				**10 feet**			
Land Area																			
Square Feet		**512,428 sf**					**0 sf**	**2,852,250 sf**				**1,102,163 sf**				**3,194,632 sf**			
Acres		**11.764 acres**					**0.000 acres**	**65.479 acres**				**25.302 acres**				**73.339 acres**			
Zoning Designation	**Land Rate - Zoning**	**% of Easement Area Within Zone**		**Land Rate Within Zone**		**Land Rate - Weighted Average (PSF)**	**% of Easement Area Within Zone**	**% of Easement Area Within Zone**		**Land Rate Within Zone**		**Land Rate - Weighted Average (PSF)**	**% of Easement Area Within Zone**		**Land Rate Within Zone**		**Land Rate - Weighted Average (PSF)**	**% of Easement Area Within Zone**		**Land Rate Within Zone**		**Land Rate - Weighted Average (PSF)**
Residential, House Character	$400.00	23.54%	x	$400.00	=	$94.15	0.00%	34.42%	x	$400.00	=	$137.68	28.85%	x	$400.00	=	$115.41	72.76%	x	$400.00	=	$291.05
Residential, Mixed (Houses & Apartment	$550.00	6.63%	x	$550.00	=	$36.47	0.00%	9.38%	x	$550.00	=	$51.56	6.54%	x	$550.00	=	$35.97	3.64%	x	$550.00	=	$20.00
Residential-Commercial Combined	$850.00	0.00%	x	$850.00	=	$0.00	0.00%	2.12%	x	$850.00	=	$18.02	0.03%	x	$850.00	=	$0.22	0.00%	x	$850.00	=	$0.02
Residential Transit Oriented	$850.00	0.00%	x	$850.00	=	$0.00	0.00%	2.36%	x	$850.00	=	$20.06	0.00%	x	$850.00	=	$0.00	0.09%	x	$850.00	=	$0.73
Downtown Residential	$4,500.00	0.00%	x	$4,500.00	=	$0.00	0.00%	1.90%	x	$4,500.00	=	$85.67	0.00%	x	$4,500.00	=	$0.00	0.01%	x	$4,500.00	=	$0.26
Commercial	$2,700.00	0.00%	x	$2,700.00	=	$0.00	0.00%	7.84%	x	$2,700.00	=	$211.78	3.60%	x	$2,700.00	=	$97.26	0.18%	x	$2,700.00	=	$4.77
Neighborhood Commercial	$815.00	2.29%	x	$815.00	=	$18.63	0.00%	5.91%	x	$815.00	=	$48.19	2.76%	x	$815.00	=	$22.51	1.02%	x	$815.00	=	$8.31
Neighborhood Commercial Transit	$815.00	0.00%	x	$815.00	=	$0.00	0.00%	3.62%	x	$815.00	=	$29.50	0.00%	x	$815.00	=	$0.00	0.34%	x	$815.00	=	$2.77
Eastern Neighborhoods Mixed Use	$800.00	10.66%	x	$800.00	=	$85.26	0.00%	5.49%	x	$800.00	=	$43.91	0.00%	x	$800.00	=	$0.00	0.21%	x	$800.00	=	$1.65
Chinatown Mixed Use	$800.00	0.00%	x	$800.00	=	$0.00	0.00%	0.15%	x	$800.00	=	$1.19	0.00%	x	$800.00	=	$0.00	0.01%	x	$800.00	=	$0.07
Parkmerced Use	$325.00	0.00%	x	$325.00	=	$0.00	0.00%	1.99%	x	$325.00	=	$6.47	0.25%	x	$325.00	=	$0.82	0.42%	x	$325.00	=	$1.35
Miscellaneous	$325.00	7.61%	x	$325.00	=	$24.74	0.00%	7.39%	x	$325.00	=	$24.01	16.21%	x	$325.00	=	$52.68	5.03%	x	$325.00	=	$16.36
Industrial	$325.00	0.23%	x	$325.00	=	$0.76	0.00%	0.74%	x	$325.00	=	$2.42	5.93%	x	$325.00	=	$19.27	1.77%	x	$325.00	=	$5.76
Production, Distribution & Repair	$340.00	21.31%	x	$340.00	=	$72.46	0.00%	6.13%	x	$340.00	=	$20.85	1.56%	x	$340.00	=	$5.30	2.82%	x	$340.00	=	$9.60
Public	$400.00	27.73%	x	$400.00	=	$110.92	0.00%	10.55%	x	$400.00	=	$42.21	34.27%	x	$400.00	=	$137.07	11.71%	x	$400.00	=	$46.84
Total / Weighted Average		100.00%				$443.39	0.00%	100.00%				$743.52	100.00%				$486.51	100.00%				$409.54

The concluded weighted fee interest land rate for each easement type utilizing the "**ATF – Zoning Use District**" methodology is as follows:

Easement Type	Land Rate
Electric Transmission	
Underground (ET-UG)	$443.39
Overhead (ET-OH)	N/Appl.
Electric Distribution	
Underground Facilities Management (ED-UFM)	$743.52
Underground (ED-UG)	$468.51
Overhead (ED-OH)	$409.54

Easement Valuation

Easement Types

PG&E identifies five (5) categories of easement types: Electric Transmission – Underground (ET-UG), Electric Transmission – Overhead (ET-OH), Electric Distribution - Underground Facilities Management (ED-UFM), Electric Distribution - Underground (ED-UG), and Electric Distribution - Overhead (ED-OH). PG&E easement documents were randomly selected and studied to assist in understanding and confirming the primary and secondary property rights being conveyed to PG&E.

Assumed Easement Widths

PG&E reports the typical physical widths for Transmission and Distribution easements. The assumed historical widths are reported as forty-five (45) feet for Transmission easements and ten (10) feet for Distribution easements. PG&E notes that the widths of easements have varied and changed with operational and maintenance needs throughout the years. With technology and design changes, PG&E's current practice is to acquire a 30-foot-wide easement for Distribution Overhead and a 10-foot-wide easement for Distribution Underground. So, the overall assumed width for Distribution, Overhead at ten (10) feet is considered conservative compared to thirty (30) feet for current practices.

Assumed Easement Rights

PG&E reports the typical easement rights to include a variety of specific rights both primary and secondary, together benefiting the easement holder and burdening the servient estate. The primary rights relate directly to the use and purpose, whether for transmission or distribution, underground or overhead. Additionally, secondary rights allow PG&E to manage vegetation and prohibit buildings from being built within the easement area. Additional rights provide for general access to-and-from the easement parcel, regardless of whether it is for overhead or underground facilities.

Each easement category, depending upon the nature and scope of PG&E's easement rights, was analyzed by recognizing the primary and secondary rights and the division of property rights by way of a "before and after" easement analysis and a direct summation analysis.

Limited Easement Market

A search was conducted for the sales of easements in the local jurisdiction of CCSF. The search was expanded to include the entire California region. The Client was also interviewed with assistance sought for any meaningful easement market data. We were unsuccessful in locating sales of easements that may assist in the valuation of the Subject Property easements. There is, however, general information

available as to the prices paid by government or quasi-government entities who are exercising their eminent domain authority to acquire various types of easements. Typically, these are acquisitions from private property owners under the threat of condemnation.

The prices paid vary depending upon the scope and nature of the easement rights being acquired. The valuation emphasis should be on the specific rights acquired from the fee interest or under a before and after analysis, the value impact to the remaining property as burdened by the easement.

Easement Rights as a Percentage of Fee & Before & After Consideration

Donnie Sherwood, SR/WA, MAI, FRICS published an article titled The Valuation of Easements in the Right of Way magazine in November/December 2014. He discusses standard easement valuation methodologies, including the "Before and After Methodology" and the "Summation Method". He also presents an "Easement Valuation Matrix" as a ".... general guide to assess the effect an easement may have on the total bundle of rights"[43] A review of this Matrix shows that regardless of the type of easement the percentage of fee for any surface use ranges from 50% to 100%. Overhead easements are valued at a higher percentage of fee value than underground easements; strictly subsurface uses appear to be 50% or less, depending upon type of easement. Where the easement holder enjoys a subsurface easement with minimal ancillary or secondary surface rights, the percentage of fee appears to be 25% and greater as the surface rights become more burdensome.

EASEMENT VALUATION MATRIX

90% - 100%	• Severe impact on surface use • Conveyance of future uses	Overhead electric, flowage easements, railroad right of way, irrigation canals, exclusive access easements
75% - 89%	• Major impact on surface use • Conveyance of future uses	Overhead electric, pipelines, drainage easements, railroad right of way, flowage easements
51% - 74%	• Some impact on surface use • Conveyance of ingress/egress rights	Pipelines, scenic easements
50%	• Balanced use by both owner and easement holder	Water or sewer lines, cable lines, telecommunications
26% - 49%	• Location along a property line • Location along non-usable land area	Water or sewer line, cable lines
11% - 25%	• Subsurface or air rights with minimal effect on use and utility • Location with a setback	Air rights, water, or sewer line
0% - 10%	• Nominal effect on use and utility	Small subsurface easement

[43] Donnie Sherwood, SR/WA, MAI, FRICS, The Valuation of Easements, Right of Way Magazine (November/ December 2014), 36-39.

In the textbook Condemnation Appraiser's Handbook by George L. Schmutz, he presents a vertical percentage of value diagram. He reports that, "It was compiled from factual data and from opinions of well-informed persons dealing with this kind of value segregation. It is here presented, not as a rule, but rather to show what has happened in the past, and with the hope that it may prove useful in suggesting a solution to future problems."[44] Strictly subsurface rights, with no consideration to secondary rights, would approximate 18% of the fee interest while strictly surface and above would approximate 82% of the fee interest.

Also noteworthy in the Schmutz treaty are a few contemporaneous comments in the 1930's timeframe regarding the assembling and construction of a corridor/energy grid. He states, "Experience in acquiring rights of way for steel tower power transmission lines in the United States indicates that the acquisition cost ranges from 30 per cent to 100 per cent of the fee value of the land in the right-of-way area, as contrasted with 220 per cent, on the average, for the acquisition of railroad rights of way. Difference appears reasonable in view of the fact that the grantor in a power line easement usually has the full use of the land and can cross it at will, whereas with a railroad right of way he loses the use of the land and cannot cross it except at intervals."

Additionally, Schmutz writes: "For example, the experience of the Southern California Edison Company in acquiring land for a 265-foot right of way through orange groves in Orange County, California, indicated a cost from 33 per cent to 50 per cent of the fee value, with no claim for severance damage. **The City of San Francisco, and also the Pacific Gas and Electric Company, operating out of that city in northern California, indicate a cost of 100 per cent of the fee value with no claim for severance damage**.[45] [*emphasis added*].

License to Use – SF Port Commission & PG&E – Across-the-Fence / Zones of Value / % of Fee

We were able to obtain a relatively meaningful license agreement by and between the City and County of San Francisco acting by and through the San Francisco Port Commission and Pacific Gas and Electric Company, a subsidiary of PG&E Corporation, dated June 10, 2014.

In this instance, the license conveys government permission to conduct an activity on the government's property, without obtaining an interest in the real property. A license is not an easement or a property right, however this non-exclusive license to use Port Property is informative in several ways.

The license agreement is by and between the City and County of San Francisco ("City") acting by and through the San Francisco Port Commission ("Port") and Pacific Gas and Electric Company, a subsidiary of PG&E Corporation ("PG&E" or "Licensee"), dated June 10, 2014. Generally, the Licensee intends to install, operate, and maintain a new single circuit, 230 kV transmission line between the PG&E Embarcadero Substation and its Potrero Switchyard (the "ZA-1 Line") to increase reliability of electric service to downtown San Francisco and provide operational flexibility ("the Project"). This Project involves both transmission line work and substation work.

A portion of the Project includes the construction of an approximately 3.5-mile, 230 kV submarine and underground cable route (for three cables) between PG&E's Embarcadero and Potrero Substations.

[44] George L. Schmutz, Valuation Engineer, Condemnation Appraiser's Handbook (1938), 214-215.

[45] George L. Schmutz, Valuation Engineer, Condemnation Appraiser's Handbook (1938), 210.

The combined license area includes rights in approximately 508,992 square feet, including submerged land (435,600 square feet), underground rights (52,272 square feet as "Onshore/Offshore Transition Area") and above-ground rights (21,120 square feet). The submerged land is divided into two areas, "Submarine Portion Exclusive Zone" and "Submarine Portion Compatible Use Zone".

Commencing on the Effective Date of the License, the License term is forty (40) years with one option to extend the term for a period of twenty-six (26) years.

The "Method of Calculation" provision includes the manner in which the annual license fee was calculated. First, it is apparent that this Port Property is quite unique. The majority of the License Area is submerged land representing about 96% (435,600 sf + 52,272 sf = 487,872 sf; 487,872 sf / 508,992 sf = 96%) of the entire License Area. This underwater, underground area is divided into an exclusive area and a compatible use area as it relates to the location of the actual cable within this underwater strip of land.

The analysis begins with identifying an appropriate base land rate to compare the submerged lands. The parties utilize an "upland industrial sale value" rate. Certainly, with the absence of sales of submerged land, as is the case with the absence of transmission / distribution / substation energy corridors / grids land sales or improved sales, the parties sought an across-the-fence construct to measure the underlying base value, i.e., upland industrial land sales.

The parties appear to also acknowledge zones of value based upon the character of the use within this submerged strip of land. The "Submarine Portion Exclusive Zone" is assigned a rate of 50% of the base rate for this category of use, i.e. reflecting a greater degree of exclusive utilization by the licensee The "Submarine Portion Compatible Use Zone" is assigned a rate of 25% of the base rate for this category of use, i.e. reflecting a lesser degree of utilization by the licensee due potential shared uses by the licensor within this area. The weighted blended rate calculates to approximately 30% for the limited license rights associated with this submerged land.

Overall, this terminable, non-permanent, license to use, subject to many limitations and restrictions, is considered inferior to the property rights conferred by an easement. It does assist in providing support for an across-the-fence methodology in the absence of comparable sales, and for a unique special purpose property where there is no relevant comparable market. It also supports recognition of a zone of value application and an assignment of use rights ranging from 25% to 50% for the ATF underlying land rate for subsurface (underwater) uses for electric transmission uses similar to the Subject Property.

Conclusion – Assignment of % of Fee for Easement Types

Based upon the foregoing review and study, it is apparent that there is support for easement values ranging from approximately twenty-five percent (25%) to one hundred percent (100%) of the underlying fee simple unit rate indicator. It is also evident that this percentage varies depending upon the nature of the easement as surface, subsurface and / or aerial. More importantly, the purpose of the easement and the associated rights acquired will shape the appropriate percentage of fee to be applied.

PG&E owns and/or has the beneficial use and control of five (5) easement categories. Each of these easements enjoys assumed associated primary and secondary rights inherent in each easement type.

The transmission and distribution **overhead easements are concluded to contribute at a rate of fifty percent (50%) of the estimated base fee simple unit rate**, while the transmission and distribution **underground easements are concluded to contribute at a rate of thirty-three percent (33%) of the estimated base fee simple unit rate.**

Valuation – Easement Interest – By Quadrant

The application for the Easement Interest – By Quadrant is presented in the following exhibit (*next two pages*). The concluded land rate for each easement type is multiplied by the respective land area resulting in the ATF fee interest value, which is then multiplied by the easement contribution, 50% of the fee rate for Overhead Easements and 33% for Underground Easements, before consideration of an adjustment for the corridor enhancement factor.

PG&E ATF EASEMENT INTEREST VALUATION - BY QUADRANT
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - OVERHEAD AND UNDERGROUND
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

Description	Easement Land Area							Valuation								
	Linear Feet		Average Width		Land Area (Sq. Ft.)	Land Area (Acres)		Land Area		Weighted Land Rate		ATF - Fee @ 100%		Easement Contribution		ATF - Easement Interest
Transmission - Underground	11,387.28	x	45 feet	=	512,428 sf	11.764 acres		512,428 sf	x	$695.28 psf	=	$356,280,940	x	33.33%	=	$118,748,437
Transmission - Overhead	0.00	x	45 feet	=	0 sf	0.000 acres		0 sf	x	$0.00 psf	=	$0	x	50.00%	=	$0
Distribution - UFM	285,224.99	x	10 feet	=	2,852,250 sf	65.479 acres		2,852,250 sf	x	$806.81 psf	=	$2,301,223,823	x	33.33%	=	$766,997,900
Distribution - Underground	110,216.29	x	10 feet	=	1,102,163 sf	25.302 acres		1,102,163 sf	x	$755.25 psf	=	$832,408,606	x	33.33%	=	$277,441,788
Distribution - Overhead	319,463.15	x	10 feet	=	3,194,632 sf	73.339 acres		3,194,632 sf	x	$383.08 psf	=	$1,223,799,627	x	50.00%	=	$611,899,814
Total	726,291.71				7,661,473 sf	175.884 acres		7,661,473 sf		$615.25 psf		$4,713,712,996				$1,775,087,939
								175.883 acres		(Weighted Average)						
Allocation - Indicated Rate per Square Foot - ATF Fee Interest																
Electric Transmission						11.764 acres		512,428 sf		$695.28 psf		$356,280,940				$231.74
Electric Distribution						164.120 acres		7,149,045 sf		$609.51 psf		$4,357,432,056				$231.69
Total / Overall						175.884 acres		7,661,473 sf		$615.25 psf		$4,713,712,996				$231.69

Valuation – Easement Interest – By Zoning Use District

The application for the Easement Interest – By Zoning Use District is presented in the following exhibit (*next two pages*). The concluded land rate for each easement type is multiplied by the respective land area resulting in the ATF fee interest value, which is then multiplied by the easement contribution, 50% of the fee rate for Overhead Easements and 33% for Underground Easements, before consideration of an adjustment for the corridor enhancement factor.

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PG&E ATF EASEMENT INTEREST VALUATION - BY ZONING USE DISTRICT
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - OVERHEAD AND UNDERGROUND
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

Description	Easement Land Area							Valuation								
	Linear Feet		Average Width		Land Area (Sq. Ft.)	Land Area (Acres)		Land Area		Weighted Land Rate		ATF - Fee @ 100%		Easement Contribution		ATF - Easement Interest
Transmission - Underground	11,387.28	x	45 feet	=	512,428 sf	11.764 acres		512,428 sf	x	$443.39 psf	=	$227,205,451	x	33.33%	=	$75,727,577
Transmission - Overhead	0.00	x	45 feet	=	0 sf	0.000 acres		0 sf	x	$0.00 psf	=	$0	x	50.00%	=	$0
Distribution - UFM	285,224.99	x	10 feet	=	2,852,250 sf	65.479 acres		2,852,250 sf	x	$743.52 psf	=	$2,120,704,920	x	33.33%	=	$706,830,950
Distribution - Underground	110,216.29	x	10 feet	=	1,102,163 sf	25.302 acres		1,102,163 sf	x	$486.51 psf	=	$536,213,321	x	33.33%	=	$178,719,900
Distribution - Overhead	319,463.15	x	10 feet	=	3,194,632 sf	73.339 acres		3,194,632 sf	x	$409.54 psf	=	$1,308,329,589	x	50.00%	=	$654,164,795
Total	726,291.71				7,661,473 sf	175.884 acres		7,661,473 sf		$547.21 psf		$4,192,453,281				$1,615,443,222
								175.883 acres		(Weighted Average)						
Allocation - Indicated Rate per Square Foot - ATF Fee Interest																
Electric Transmission						11.764 acres		512,428 sf		$443.39 psf		$227,205,451				$147.78
Electric Distribution						164.120 acres		7,149,045 sf		$554.65 psf		$3,965,247,830				$215.37
Total / Overall						175.884 acres		7,661,473 sf		$547.21 psf		$4,192,453,281				$210.85

Valuation – ATF Easement Interest – Reconciliation

The "By Quadrant" ATF analysis focuses on proximity, influenced more heavily upon the adjacent and nearby market indicators.

The "By Zoning Use District" ATF analysis focuses on permitted uses within the respective zoning use districts, influenced more heavily upon specific zoning of the market indicators, rather than proximity. Each analysis is equally weighted in the ATF conclusion of the Easement Interests before consideration of an enhancement factor adjustment.

PG&E ATF EASEMENT INTEREST VALUATION
PRIOR TO ENHANCEMENT FACTOR
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

PG&E ATF EASEMENT INTEREST VALUATION	INDICATED VALUE
PG&E ATF EASEMENT - BY QUADRANT	$1,775,087,939
PG&E ATF EASEMENT - BY ZONING USE DISTRICT	$1,615,443,222
ATF EASEMENT INTEREST - PRIOR TO ENHANCEMENT FACTOR	$1,700,000,000

Valuation - Corridor Enhancement Factor

Enhancement Synergy Factor

Once the ATF value is determined, a corridor factor or enhancement factor is a potential additional adjustment to reflect the inherent increment of value, the plottage value, associated with the corridor having already been assembled. This assembled corridor supports and promotes a higher and better use by maximizing the highest and best use as a power system energy grid. PG&E's real property, a collection of land segments, is assembled into a functioning energy grid. These segments are integrated into a single unified use functioning as a network of utility corridors and substations forming an energy grid and delivering reliable energy to a mix of customers throughout San Francisco.

The ATF indication plus the enhancement factor is the corridor valuation technique employed to determine the fair market value of PG&E's real property interests in this real estate. As part of the corridor valuation trilogy, Dolman and Seymour opine:

> *The concept of an enhancement factor speaks to the question: "How much more or less than ATF value is the entire corridor worth because of its ability to connect the end points?" It expresses the relationship between ATF value and value for corridor use.*[46]

Dolman and Seymour also note in their research and investigation:

> *We found then, as we do today, that the "continuity" (or "enhancement") factor tended regarding electrical transmission lines, we heard comments that their right-of-way assemblies cost "two to three times" the prevailing price of farmland acreage through which the corridor passed. A higher multiplier was reflected in urban areas, where the leverage for severance damage was increased not only by higher land values, but also by extensive building takes or damages.*[47]

Likewise, Arthur G. Rahn recognizes the cost elements in creating a transportation corridor:

> *With regard to transportation corridors, it is the land and not the improvements that is unique and constitutes the special use. Long, narrow strips of land that provide continuity between desired end points are not ordinarily available in the usual categorization of land uses.*
>
> *The normal process of creating a transportation corridor is through assemblage, and the cost approach analysis would include both the acquisitions of the necessary properties to create the corridor and the normal project costs to make it useable. The costs that can reasonably be anticipated in creating a corridor would include land, acquisition and removal of existing improvements, severance damages, relocation assistance, right-of-way clearance, legal and*

[46] John P. Dolman, MAI, CRE and Charles F. Seymour, MAI, CRE, Valuation of Transportation / Communication Corridors, The Appraisal Journal (October 1978), 518.

[47] John P. Dolman, MAI, CRE and Charles F. Seymour, MAI, CRE, Valuation of Transportation / Communication Corridors, The Appraisal Journal (October 1978), 513.

> *litigation fees, project and overhead costs, and, lastly, that giant project killer, environmental impact and mitigation.*[48]

An existing corridor can certainly provide substantial savings in time and cost as contrasted with the cost of developing a new corridor. But the focus is on the inherent physical and financial attributes that flow from this unique integrated network as an electric corridor / power grid. The assemblage premium / period and the plottage increment are components of the enhancement factor.

> *"When a group of parcels is put together to form a corridor, synergism results, because the value of the whole exceeds the sum of values of the parts."*[49]

> *"The concept of "plottage" illustrates this synergism: it is the increase in unit value resulting from improved usability when small lots are combined into larger ones. It is not the cost assembly alone that is responsible for plottage value. For a plottage increment to be realized, there must be the basis of a superior operation in use after assembly. In order to enjoy a plottage increment, the character of use must change; a new highest and best use must be created."*[50]

This plottage increment is created through the enhanced and superior highest and best use generated by the unique assemblage of lands which support PG&E's energy grid.

Research of the time necessary to plan, assemble and construct a new transportation corridor, an inherent value component consideration in the enhancement factor, has been studied.

Century Freeway (105) Project

For instance, the Century Freeway (I-105) was a Caltrans project that commenced around 1968 when the route was added to the Interstate Highway System. This planned freeway corridor would eventually connect the Los Angeles International Airport to the (I-605) in the city of Norwalk, California. It is a 17-mile reach / corridor, that following design, engineering, environmental, litigation, funding, acquisition and assembly, and construction, opened to use and travel around 1993-1994. In total, this project took twenty-six (26) years to complete a 17-mile reach, a rate of 1.53 miles per year. The initial cost of $190 million eventually grew to $2.3 billion at completion or over $135M per mile, even after a reduction in right-of-way width and elimination of other mitigation requirements, a cost increase factor of over 12 times the original estimate.

Foothill (SR-210) Freeway Project

The Foothill (SR-210) Freeway has two segments, a western segment and eastern segment. This project originally commenced during the 1970's. The western segment is a Caltrans project that commenced more formally around 1997 with advanced project design and planning. The western segment of the planned freeway corridor would eventually connect Alder Avenue in Rialto, California to California Highway 30 in San Bernardino, California. It is a 7.25- mile reach / corridor that following design, engineering, environmental, funding, acquisition and assembly, and construction (starting in 2003), the

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[48] Arthur G. Rahn, Gary Valentine, MAI, AI-GRS, SR/WA, CCIM, Valuation of Corridors, Corridor Valuation, An Overview and New Alternatives, Appraisal Institute, (2019), 101.

[49] John P. Dolman, MAI, CRE and Charles F. Seymour, MAI, CRE, Valuation of Transportation / Communication Corridors, The Appraisal Journal (October 1978), 515.

[50] Ibid.

freeway corridor was opened to use and travel around 2007. In total, this project took ten (10) years to complete a 7.25-mile reach after its advance planning commencement, a rate of 1.38 miles per year.

Los Angeles Westside Subway Extension Project

The Los Angeles County Metropolitan Transportation Authority (MTA) is currently undertaking the Los Angeles Westside Subway Extension Project. This project originally commenced in the early 1980's, extending westward from the Los Angeles Central Business District to Santa Monica, California. In the early 1990's construction was underway from the Los Angeles downtown area. The project encountered methane gas in the Fairfax District and in 1998 the corridor was suspended for lack of funding. In October 2005, planning studies concluded that it was safe to continue subsurface tunnel construction and operation along Wilshire Boulevard due to improved construction methods. A Draft EIR was prepared and approved in 2009 by the MTA Board. A component of the overall project is the MTA Purple (D Line) Extension Transit Project, a 9.0-mile segment, constructed in three phases, extending from the intersection of Wilshire Boulevard and Western Avenue in Los Angeles, California to the San Diego (I-405) Freeway near UCLA. Construction commenced around 2019 and is estimated to be completed in 2027. In total, this project will take over eighteen (18) years to complete a 9.0-mile reach following the Draft EIR in 2009, a rate of 2.00 miles per year. Much of the corridor is situated within public right-of-way. The cost for this portion alone is estimated to be $9.5 billion, over $1.05B per mile.

High-Speed Rail Authority Project

In 1994 as part of the High-Speed Development Act, California was identified as suitable to support a high-speed rail project. The High-Speed Rail Authority in California was created in 1996. The Project will include about 700-miles of corridor between San Francisco, California and San Diego, California with up to twenty-four (24) stations. Total cost was estimated at $33 billion. The FEIR was completed in 2001.

In 2008, voters approved a $9.95 billion bond to authorize construction of the nation's first high-speed railway. The plan was to utilize an electric train to provide service throughout the route. The first groundbreaking ceremony occurred in Fresno, California in 2015.

The project focus has been on developing and constructing the corridor between Los Angeles and San Francisco, which is about 500 miles of the total 700 miles of corridor initially planned. The most recent cost update for this segment is $88 billion to $128 billion to complete the entire system from Los Angeles to San Francisco, a factor of 3.9 times greater for this portion as compared to the original estimate of $33 billion for the entire project. About $9.8 billion has already been spent. As of 2023, there is not even a single mile of track laid yet.

As of today, the Merced / Fresno / Bakersfield corridor, which is 171 miles in length, is anticipated to be complete and operational by 2033, thirty-two (32) years from the approval of the FEIR, a rate of 5.34 miles per year, or twenty-five (25) years from the initial voter funding approval, for only 24% of the total planned route. Note that much of this corridor is situated within a more rural setting. The current (2023 Project Update Report) per mile cost estimate, including contingency, to deliver the Merced to Bakersfield segment, is approximately $192M per mile. This project is now on hold.

Hawaii Area Rapid Transit Project

The Honolulu High-Capacity Transit Corridor project is a twenty-mile (20) corridor. The corridor extends from the University of Hawaii at West Oahu to Ala Moana Center in Honolulu, Hawaii. There were originally 21 stations. The project has since been revised, postponing the last two station stops, reducing the overall corridor reach to 18.9 miles with 19 stations. This project commenced around 2005 with the notice of intent to prepare an EIS. The FEIS was published in 2010. Groundbreaking began in February 2011 in Kualaka'i Station in East Kapolei. The corridor will transport riders via an elevated fixed guideway rail system. This project has continued to suffer from funding problems and delays. Project completion is currently estimated at 2023 for portions of the railway and 2031 for the balance of the project. In total, from 2005, this project will take over eighteen (18) years to complete a 20-mile reach, a rate of 0.90 miles per year. The initial cost estimate went from $5.12 billion to over $12.45 billion ($622,500,000 per mile) and has been delayed by about eleven (11) years, a cost increase factor of 2.4 times the original estimate.

New Transportation Corridor Summation

Other projects were also investigated, including Southern California Edison's ("SCE") Tehachapi Renewable Transmission Project ("TRTP"). This project included a series of new and upgraded high-voltage electric transmission lines and substations along approximately 173 miles of new and existing right-of-way with the capability of carrying 4,500 megawatts of electricity from renewable and other generators in Kern County south to San Bernardino County. SCE completed construction of the 173-mile TRTP electric transmission line and energized the line in the fourth quarter of 2016. The overall Project, Segments 1 through 11, commenced in the fall of 2004 and was completed twelve (12) years later in December 2016. Very little new right-of-way was required to complete this project.

Except for the High-Speed Rail Authority project, most of these corridor projects are located within suburban and urban environments. These five (5) examples of planned and or completed transportation corridors reflect a period of ten (10) to thirty-two (32) years to complete the planning, design, engineering, environmental, permits, approvals, financing, acquisition, and construction of a new transportation corridor, ranging from 7.25 miles to 171 miles in length. The rate of completion ranges from 0.90 miles per year to 5.34 miles per year, averaging 2.23 miles per year or 1.64 miles per year, excluding the high and low indicators. Also noteworthy is the fact that due to the substantial period to complete these massive transportation corridor projects, it is not uncommon for the estimated cost to break budget by a multiple of 2.4 times to 12 times the original cost estimate and meet unforeseen increased environmental and litigation exposure.

The entire PG&E power system energy grid is comprised of an assemblage of land (fee-owned) and strips of land (easements, licenses, franchises, leases, and other agreements) improved, utilized, and operating for electrical transmission and distribution purposes, i.e., an "assembled corridor". It is a collection of integrated properties, subsequently improved with various facilities, forming an electronic transmission and distribution network / corridors laid out into an energy grid.

Based upon the average rate per mile of corridor completion at 2.23 miles per year, the PG&E energy network of corridors would take several hundred years to complete. The Private circuit mile network of corridors would likely take over sixty (60) years to complete. Any project cost estimate would also likely be exceeded simply due to the changes in market conditions and the general nature of cost increases over time. Applying safe real estate yield rates / discount rates to this development horizon

would result in a substantial upward adjustment for the time-savings and reduced risk and uncertainty that is inherent in the acquisition of this already-assembled corridor.

These are the considerations that market participants would evaluate in acquiring lands already assembled. It reflects why assemblage premiums occur and why plottage value exists as the basis for the enhancement factor.

Enhancement Factor Comparable Sales

Comparable sales additionally provide basis and market evidence that enhancement factor premiums or discounts are paid by participants to purchase assembled, integrated operating corridors, showing that corridors hold intrinsic market value greater or less than ATF value. Factors can be greater or less than 1.0 – i.e., greater than "ATF par" valuation, for example.

Analysis of corridor sales data indicate that transportation or utility corridors situated in urban and suburban locations – where few to no substitute corridors are available, where proven demand exists, and likely future demand – sell at premiums to ATF par value. The eight (8) comparable sales summarized, in the following study below, consist of corridor purchases of both (1) fee simple property rights in land and improvements and (2) subsurface or overhead easement rights within operating corridors. Each of these sales is compared to its respective ATF value opinion. Sales are dated; however, comparable corridors rarely sell. These are, in our experience, sufficiently recent and comparable for valuation purposes and together with the actual history of assembling and constructing transportation corridors, shed light on the application of enhancement factor ratios in determining the value of the PG&E property rights being appraised.

CORRIDOR SALES SUMMARY TABLE

No	Location	Sale Date	Distance Miles	Sale Price ATF Value	Enhancement Factor	Use
1	Los Angeles	2000	3.5	$2,087,461 $1,889,600	**1.10**	Longitudinal overhead easement in existing corridor
2	RT South Line, Phase 1 Sacramento	1999	6.1	$8,400,000 $5,140,000	**1.63**	Segement of existing UPRR corridor for use in light rail project
3	Downey	1996	9.1	$8,874,073 $7,716,585	**1.15**	Longitudinal overhead easement in existing corridor
4	Fruitvaridge Rd to Union Creek Sacramento	1995	3.67	$500,000 $306,373	**1.63**	Longitudinal subsurface easement in existing rail corridor
5	Alameda County	1994	18.3	$193,000,000 $165,000,000	**1.17**	Future use as a freight rail corridor
6	Santa Ana/Costa Mesa	1990	3.6	$3,983,000 $3,463,000	**1.15**	Electrical transmission easement in existing rail corridor
7	So Sacramento County	1987	4.57	$380,000 $253,000	**1.50**	Non-contiguous easements sold for transmission lines in UPRR Corridor
8	Butterfield Line Sacramento	1985	7.28	$6,500,000 $5,625,000	**1.16**	Existing UPRR corridor sold for light rail project
				Average	**1.31**	
				Median	**1.17**	

As studied, assembled operating corridors sell at price multipliers – i.e., at enhancement synergy factors – 1.10 to 1.63 times respective ATF values, at an average of 1.31 times, and a median of 1.17 times. Considering PG&E's highly urbanized location and its fully integrated connection systems – parcel-by-parcel, property-to-property – a 1.30 factor is concluded to be a reasonable measure of the plottage premium enhancing the intrinsic fair market value of the property rights proposed to be acquired.

Applying 1.30 to the subject's property rights in the land and easement rights (excluding the building and site improvements) results in the following fair market value:

Land and Easement Valuation Scenarios (Not Including Building & Site Improvements)	Total Corridor Value Before Enhancement Factor Land (Fee) + Easement Interests	Corridor Enhancement Factor	FMV
Substation Sites (Properties1 thru 33)	$1,209,561,800	1.30	$1,572,430,340
ATF Easement Interests	$1,700,000,000	1.30	$2,210,000,000

Total Fair Market Value Conclusion

The total fair market value of the property interests appraised is the aggregation of all property rights appraised – of the fee simple and easement interests. Total fair market value includes substation building and site improvements, and total fair market value of the land and easement rights.

TOTAL FAIR MARKET VALUE CONCLUSION

FMV Land *	FMV Easements *	Plus: Building & Site Improvements	FMV Total
$1,572,430,340	$2,210,000,000	516,957,599	**$4,299,387,939**
$414/SF	$288/SF		

** Includes Corridor Enhancement Factor of 1.30x*

Reconciliation

Fair Market Value – Fee Simple Properties and Easement Interests

We have concluded to our opinion of the fair market value of PG&E's real property interest in the land and building improvements which it owns in San Francisco, as well as the Martin Substation in San Mateo County. PG&E's real property includes a mix of properties (land, and land and building/site improvements) owned in fee simple and other properties owned as transmission and distribution easement interests (subsurface, surface, and aerial).

These properties are integrated into a single unified use and function as a network of transmission and distribution utility corridors and substations forming an energy grid, delivering reliable energy to a mix of customers throughout San Francisco.

In summary, this appraisal report now reconciles the values of PG&E fee-owned properties, improved sites with substation buildings, and PG&E easements over additional private properties. Fee-owned properties number thirty-three (33) in total; these are identified as Property Numbers 1 through 33. Thirty-two (32) of the 33 properties (Subject Properties 1-30 and 32-33) are situated in San Francisco. Subject Property 31, Martin Substation, is situated in San Mateo County, adjacent to San Francisco.

The 32 San Francisco located properties contain ±50.352 acres. The San Mateo situated property contains ±36.784 acres. These include thirty-one (31) improved substation sites, plus two (2) vacant sites. One of the two vacant sites, Egbert (Subject Property 30), is a proposed 230 kV switching site. The other vacant site, Beeman Lane (Subject Property 32), is improved with substantial underground electrical transmission improvements.

Combined, these 33 properties total 87.136 acres in land area. The properties are improved with 503,311 square feet of building area. Additionally, 137.56 net private circuit miles of easement rights and grid improvements, containing 175.883 acres of property rights, are included as part of the proposed taking.

The total of these value components, adjusted for the enhancement factor consistent with its highest and best use, reflects the line-item for "FMV – Land", which will be utilized in the Cost Approach ("RCNLD") prepared by other experts, assisting in providing an indication of the fair market value of the total Parts Taken.

Excluded cost components and values to be prepared by others, include but are not limited to, fixtures, equipment and system improvements (poles, electrical lines, towers, transformers, substation fixtures, conduits, and vaults), intangible assets, and severance damages.

The fair market value of the fee simple and easement property interests appraised are summarized as follows:

TOTAL FAIR MARKET VALUE CONCLUSION

FMV Land *	FMV Easements *	Plus: Building & Site Improvements	FMV Total
$1,572,430,340	$2,210,000,000	$516,957,599	$4,299,387,939

* *Includes* Corridor *Enhancement Factor of 1.30x*

Any additional value associated with PG&E's non-real property interests are not included in this real property appraisal.

The value opinions reported herein are subject to the definitions, general assumptions and limiting conditions, and certifications contained in this report. The findings and conclusions are further contingent upon the following extraordinary assumptions and/or hypothetical conditions, the use of which might effect the assignment results.

Extraordinary Assumptions:

- Title Reports for the individual fee-owned properties were not provided for review and consideration. It is assumed the property owner has clear and marketable title to the property rights appraised and that there are no adverse easements, encumbrances, covenants, and/or land use restrictions, other than those noted in this appraisal report, which would affect the marketability and utility of the subject properties.
- Information provided and relied upon by the Client is assumed to be accurate.
- Four (4) of the subject properties – Potrero Substation (Subject Property 2), Hunters Point Substation (Subject Property 3), Marina Substation (Subject Property 10), and Martin Substation (Subject Property 31) – are environmentally contaminated sites.

  Based on our review of public-sourced information, along with information provided by the Client, the property owner (PG&E) has encapsulated the contamination and is continuing to use the sites as a part of its operations. Potrero, Hunters Point and Martin are encumbered with restrictive Land Use Conditions (LUC's), recognized in the appraisal.

  It is assumed that the remaining 29 properties (Subject Properties 1, 4 to 9, 11 to 30, 32, and 33) are not environmentally contaminated. These are appraised as environmentally clean.

  It is assumed that all private easement interests are environmentally clean.
- The proposed PG&E easements to encumber Subject Property #2 and Subject Property #31 have not been finalized as of the effective date of this appraisal. Based on information provided by the City and County of San Francisco (CCSF), we have assumed each easement will be 50 feet in width, extending 25 feet on either side of the centerline of the existing underground gas transmission pipeline, and will encumber 35,175.00 square feet of Subject Property #2 and 53,475.50 square feet of Subject Property #31. A revision to the appraisal may be warranted should the final easement language differ materially from that described or valued herein.

- It is assumed that PG&E's GIS mapping overlays accurately identified the inventory of fee-owned properties and electrical utility easement interests proposed to be acquired by CCSF.
- PG&E determined that in the best interest of the company and its customers, a complete, detailed, and exhaustive inventory of over 2,400 unique easements was not financially practical, would require an undue consumption of time and cost, and that a reasonable and accurate alternative method would adequately define these easement interests. It is assumed that PG&E's alternative measure of identifying easements, utilizing the San Francisco FF Electric Master dated 12-31-2021 to identify total "circuit miles" is accurate, fair, and reasonable.
- It is assumed that PG&E's use of the algorithmically defined locations for each of the five types of electric corridor segments, utilizing the circuit mile analyses expressed as a linear distance as being equivalent to the various easement types, is accurate, fair, and reasonable. This appraisal assignment focuses only on "Private" circuit miles assumed to reflect each of the five types of easements.
- PG&E's separate identification and inventory of each category of private easements as Electric Transmission – Underground (ET-UG), Electric Transmission – Overhead (ET-OH), Electric Distribution - Underground Facilities Management (ED-UFM), Electric Distribution - Underground (ED-UG), Electric Distribution - Overhead (ED-OH), is accurate, fair, and reasonable.
- It is assumed that PG&E's reported typical easement rights, both primary and secondary, together benefiting the easement holder and burdening the servient estate are accurate, fair, and reasonable.
- PG&E's assumed physical widths for Transmission and Distribution easements are reported as ten (10) feet for Distribution easements and forty-five (45) feet for Transmission easements are assumed to be accurate, fair, and reasonable. PG&E notes that the widths of easements have varied and changed with operational and maintenance needs throughout the years. With technology and design changes, PG&E's current practice is to acquire a 30-foot-wide easement for Distribution Overhead and a 10-foot-wide easement for Distribution Underground. So, the overall assumed width for Distribution, either Overhead or
- Underground at ten (10) feet is considered conservative.

Hypothetical Conditions:

- Subject Properties 2, 3.5, and 31 are proposed to be encumbered by a pipeline easement (Properties #s 2 and 31) and subterranean electric transmission easement (Property #3.5) to be granted in favor of Pacific Gas and Electric Company (PG&E). As of the effective date of this appraisal, these easements have not been granted and do not encumber the subject properties. The value conclusions for these three properties are predicated on the hypothetical condition that the proposed PG&E easements are in place as described herein.
- We are informed that Subject Property 32 (Beeman Lane) is improved with subsurface electrical transmission improvements that run the length of the property and nearly its width. PG&E easement rights for the use, and these improvements are not recorded. That is, the subsurface is improved with transmission lines, burdening subsurface, surface, and air rights on the property. At the request of the Client, the fee simple rights in the property are appraised as if the parcel is not burdened by the improvements or by the rights to construct, maintain,

operate, etc. the improvements. Instead, the fee simple rights in the property are appraised as if the subsurface improvements do not exist. At the same time, to avoid any duplication, the contributory value of easement rights through this private property and to the larger grid are not additionally or separately valued.

Exposure Time and Marketing Period

The value conclusion in this appraisal is fair market value as defined in California Code of Civil Procedure §1263.320. That definition does not include or require the measure of exposure time of the property to the open market, or a reasonable time to find a purchaser, as a component of value. For this reason, no opinion of exposure time is developed. The scope of work does not require a measure of exposure time.

Marketing time is an opinion of the time that might be required to sell a property interest at the appraised value after the effective date. CCP §1263.320 also does not include or require marketing time opinion, and none was requested by the client or required by the scope of work. No marketing time opinion is developed.

The subject is valued using the Across the Fence method. Under the method, the corridor's land value is estimated by reference to the fair market value of the adjoining land, consistent with §1263.320(a). It is also consistent with §1263.320(b), which provides that property for which there is no relevant, comparable market may be valued by any method that is just and equitable. Omitting exposure and marketing time opinions is consistent with the applicable definition of value.
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General Assumptions and Limiting Conditions:

VALBRIDGE PROPERTY ADVISORS | NORTHERN CALIFORNIA

This appraisal is subject to the following general assumptions and limiting conditions:

1. The legal description – if furnished to us – is assumed to be correct.
2. No responsibility is assumed for legal matters, questions of survey or title, soil or subsoil conditions, engineering, availability or capacity of utilities, or other similar technical matters. The appraisal does not constitute a survey of the property appraised. All existing liens and encumbrances have been disregarded and the property is appraised as though free and clear, under responsible ownership and competent management unless otherwise noted.
3. Unless otherwise noted, the appraisal will value the property as though free of contamination. Valbridge Property Advisors | Northern California will conduct no hazardous materials or contamination inspection of any kind. It is recommended that the client hire an expert if the presence of hazardous materials or contamination poses any concern.
4. The stamps and/or consideration placed on deeds used to indicate sales are in correct relationship to the actual dollar amount of the transaction.
5. Unless otherwise noted, it is assumed there are no encroachments, zoning violations or restrictions existing in the subject property.
6. The appraiser is not required to give testimony or attendance in court by reason of this appraisal, unless previous arrangements have been made.
7. Unless expressly specified in the engagement letter, the fee for this appraisal does not include the attendance or giving of testimony by Appraiser at any court, regulatory or other proceedings, or any conferences or other work in preparation for such proceeding. If any partner or employee of Valbridge Property Advisors | Northern California is asked or required to appear and/or testify at any deposition, trial, or other proceeding about the preparation, conclusions or any other aspect of this assignment, client shall compensate Appraiser for the time spent by the partner or employee in appearing and/or testifying and in preparing to testify according to the Appraiser's then current hourly rate plus reimbursement of expenses.
8. The values for land and/or improvements, as contained in this report, are constituent parts of the total value reported and neither is (or are) to be used in making a summation appraisal of a combination of values created by another appraiser. Either is invalidated if so used, unless otherwise stated in this report (including in the Purpose of Appraisal section).
9. The dates of value to which the opinions expressed in this report apply are set forth in this report. We assume no responsibility for economic or physical factors occurring at some point at a later date, which may affect the opinions stated herein. The forecasts, projections, or operating estimates contained herein are based on current market conditions and anticipated short-term supply and demand factors and are subject to change with future conditions. The appraiser is not responsible for determining whether the date of value requested by Client is appropriate for Client's intended use.
10. The sketches, maps, plats, and/or exhibits in this report are included to assist the reader in visualizing the property. The appraiser has made no survey of the property and assumed no responsibility in connection with such matters.
11. The information, estimates and opinions which were obtained from sources outside of this office, are considered reliable. However, no liability for them can be assumed by the appraiser.

12. Possession of this report, or a copy thereof, does not carry with it the right to publication. Neither all, nor any part of the content of the report, or copy thereof (including conclusions as to property value, the identity of the appraisers, professional designations, reference to any professional appraisal organization or the firm with which the appraisers are connected), shall be disseminated to the public through advertising, public relations, news, sales, or other media without prior written consent and approval.
13. No claim is intended to be expressed for matters of expertise that would require specialized investigation or knowledge beyond that ordinarily employed by real estate appraisers. We claim no expertise in areas such as, but not limited to, legal, survey, structural, environmental, pest control, mechanical, etc.
14. This appraisal was prepared for the sole and exclusive use of the client for the function outlined herein. Any party who is not the client or intended user identified in the appraisal or engagement letter is not entitled to rely upon the contents of the appraisal without express written consent of Valbridge Property Advisors | Northern California and Client. The Client shall not include partners, affiliates, or relatives of the party addressed herein. The appraiser assumes no obligation, liability or accountability to any third party.
15. Distribution of this report is at the sole discretion of the client, but third-parties not listed as an intended user on the face of the appraisal or the engagement letter may not rely upon the contents of the appraisal. In no event shall client give a third-party a partial copy of the appraisal report. We will make no distribution of the report without the specific direction of the client.
16. This appraisal shall be used only for the function outlined herein, unless expressly authorized by Valbridge Property Advisors | Northern California.
17. This appraisal shall be considered in its entirety. No part thereof shall be used separately or out of context.
18. Unless otherwise noted in the body of this report, this appraisal assumes that the subject property does not fall within the areas where mandatory flood insurance is effective. Unless otherwise noted, we have not completed nor have we contracted to have completed an investigation to identify and/or quantify the presence of non-tidal wetland conditions on the subject property. Because the appraiser is not a surveyor, he or she makes no guarantees, express or implied, regarding this determination.
19. The flood maps are not site specific. We are not qualified to confirm the location of the subject property in relation to flood hazard areas based on the FEMA Flood Insurance Rate Maps or other surveying techniques. It is recommended that the client obtain a confirmation of the subject property's flood zone classification from a licensed surveyor.
20. If the appraisal is for mortgage loan purposes 1) we assume satisfactory completion of improvements if construction is not complete, 2) no consideration has been given for rent loss during rent-up unless noted in the body of this report, and 3) occupancy at levels consistent with our "Income and Expense Projection" are anticipated.
21. It is assumed that there are no hidden or unapparent conditions of the property, subsoil, or structures which would render it more or less valuable. No responsibility is assumed for such conditions or for engineering which may be required to discover them.

22. Our inspection included an observation of the land and improvements thereon only. It was not possible to observe conditions beneath the soil or hidden structural components within the improvements. We inspected the buildings involved, and reported damage (if any) by termites, dry rot, wet rot, or other infestations as a matter of information, and no guarantee of the amount or degree of damage (if any) is implied. Condition of heating, cooling, ventilation, electrical and plumbing equipment is considered to be commensurate with the condition of the balance of the improvements unless otherwise stated. Should the client have concerns in these areas, it is the client's responsibility to order the appropriate inspections. The appraiser does not have the skill or expertise to make such inspections and assumes no responsibility for these items.
23. This appraisal does not guarantee compliance with building code and life safety code requirements of the local jurisdiction. It is assumed that all required licenses, consents, certificates of occupancy or other legislative or administrative authority from any local, state or national governmental or private entity or organization have been or can be obtained or renewed for any use on which the value conclusion contained in this report is based unless specifically stated to the contrary.
24. When possible, we have relied upon building measurements provided by the client, owner, or associated agents of these parties. In the absence of a detailed rent roll, reliable public records, or "as-built" plans provided to us, we have relied upon our own measurements of the subject improvements. We follow typical appraisal industry methods; however, we recognize that some factors may limit our ability to obtain accurate measurements including, but not limited to, property access on the day of inspection, basements, fenced/gated areas, grade elevations, greenery/shrubbery, uneven surfaces, multiple story structures, obtuse or acute wall angles, immobile obstructions, etc. Professional building area measurements of the quality, level of detail, or accuracy of professional measurement services are beyond the scope of this appraisal assignment.
25. We have attempted to reconcile sources of data discovered or provided during the appraisal process, including assessment department data. Ultimately, the measurements that are deemed by us to be the most accurate and/or reliable are used within this report. While the measurements and any accompanying sketches are considered to be reasonably accurate and reliable, we cannot guarantee their accuracy. Should the client desire more precise measurement, they are urged to retain the measurement services of a qualified professional (space planner, architect or building engineer) as an alternative source. If this alternative measurement source reflects or reveals substantial differences with the measurements used within the report, upon request of the client, the appraiser will submit a revised report for an additional fee.
26. In the absence of being provided with a detailed land survey, we have used assessment department data to ascertain the physical dimensions and acreage of the property. Should a survey prove this information to be inaccurate, upon request of the client, the appraiser will submit a revised report for an additional fee.
27. If only preliminary plans and specifications were available for use in the preparation of this appraisal, and a review of the final plans and specifications reveals substantial differences upon request of the client the appraiser will submit a revised report for an additional fee.

28. Unless otherwise stated in this report, the value conclusion is predicated on the assumption that the property is free of contamination, environmental impairment or hazardous materials. Unless otherwise stated, the existence of hazardous material was not observed by the appraiser and the appraiser has no knowledge of the existence of such materials on or in the property. The appraiser, however, is not qualified to detect such substances. The presence of substances such as asbestos, urea-formaldehyde foam insulation or other potentially hazardous materials may affect the value of the property. No responsibility is assumed for any such conditions, or for any expertise or engineering knowledge required for discovery. The client is urged to retain an expert in this field, if desired.
29. The Americans with Disabilities Act ("ADA") became effective January 26, 1992. We have not made a specific compliance survey of the property to determine if it is in conformity with the various requirements of the ADA. It is possible that a compliance survey of the property, together with an analysis of the requirements of the ADA, could reveal that the property is not in compliance with one or more of the requirements of the Act. If so, this could have a negative effect on the value of the property. Since we have no direct evidence relating to this issue, we did not consider possible noncompliance with the requirements of ADA in developing an opinion of value.
30. This appraisal applies to the land and building improvements only. The value of trade fixtures, furnishings, and other equipment, or subsurface rights (minerals, gas, and oil) were not considered in this appraisal unless specifically stated to the contrary.
31. No changes in any federal, state or local laws, regulations or codes (including, without limitation, the Internal Revenue Code) are anticipated, unless specifically stated to the contrary.
32. Any income and expense estimates contained in the appraisal report are used only for the purpose of estimating value and do not constitute prediction of future operating results. Furthermore, it is inevitable that some assumptions will not materialize and that unanticipated events may occur that will likely affect actual performance.
33. Any estimate of insurable value, if included within the scope of work and presented herein, is based upon figures developed consistent with industry practices. However, actual local and regional construction costs may vary significantly from our estimate and individual insurance policies and underwriters have varied specifications, exclusions, and non-insurable items. As such, we strongly recommend that the Client obtain estimates from professionals experienced in establishing insurance coverage. This analysis should not be relied upon to determine insurance coverage and we make no warranties regarding the accuracy of this estimate.
34. The data gathered in the course of this assignment (except data furnished by the Client) shall remain the property of the Appraiser. The appraiser will not violate the confidential nature of the appraiser-client relationship by improperly disclosing any confidential information furnished to the appraiser. Notwithstanding the foregoing, the Appraiser is authorized by the client to disclose all or any portion of the appraisal and related appraisal data to appropriate representatives of the Appraisal Institute if such disclosure is required to enable the appraiser to comply with the Bylaws and Regulations of such Institute now or hereafter in effect.

35. You and Valbridge Property Advisors | Northern California both agree that any dispute over matters in excess of $5,000 will be submitted for resolution by arbitration. This includes fee disputes and any claim of malpractice. The arbitrator shall be mutually selected. If Valbridge Property Advisors | Northern California and the client cannot agree on the arbitrator, the presiding head of the Local County Mediation & Arbitration panel shall select the arbitrator. Such arbitration shall be binding and final. In agreeing to arbitration, we both acknowledge that, by agreeing to binding arbitration, each of us is giving up the right to have the dispute decided in a court of law before a judge or jury. In the event that the client, or any other party, makes a claim against Valbridge Property Advisors | Northern California or any of its employees in connections with or in any way relating to this assignment, the maximum damages recoverable by such claimant shall be the amount actually received by Valbridge Property Advisors | Northern California for this assignment, and under no circumstances shall any claim for consequential damages be made.
36. Valbridge Property Advisors | Northern California shall have no obligation, liability, or accountability to any third party. Any party who is not the "client" or intended user identified on the face of the appraisal or in the engagement letter is not entitled to rely upon the contents of the appraisal without the express written consent of Valbridge Property Advisors | Northern California. "Client" shall not include partners, affiliates, or relatives of the party named in the engagement letter. Client shall hold Valbridge Property Advisors | Northern California and its employees harmless in the event of any lawsuit brought by any third party, lender, partner, or part-owner in any form of ownership or any other party as a result of this assignment. The client also agrees that in case of lawsuit arising from or in any way involving these appraisal services, client will hold Valbridge Property Advisors | Northern California harmless from and against any liability, loss, cost, or expense incurred or suffered by Valbridge Property Advisors | Northern California in such action, regardless of its outcome.
37. The Valbridge Property Advisors office responsible for the preparation of this report is independently owned and operated by San Francisco Bay Area | Silicon Valley | San Jose. Neither Valbridge Property Advisors, Inc., nor any of its affiliates has been engaged to provide this report. Valbridge Property Advisors, Inc. does not provide valuation services, and has taken no part in the preparation of this report.
38. If any claim is filed against any of Valbridge Property Advisors, Inc., a Florida Corporation, its affiliates, officers or employees, or the firm providing this report, in connection with, or in any way arising out of, or relating to, this report, or the engagement of the firm providing this report, then (1) under no circumstances shall such claimant be entitled to consequential, special or other damages, except only for direct compensatory damages, and (2) the maximum amount of such compensatory damages recoverable by such claimant shall be the amount actually received by the firm engaged to provide this report.
39. This report and any associated work files may be subject to evaluation by Valbridge Property Advisors, Inc., or its affiliates, for quality control purposes.
40. Acceptance and/or use of this appraisal report constitutes acceptance of the foregoing general assumptions and limiting conditions.
41. The global outbreak of a "novel coronavirus" (known as COVID-19) was officially declared a pandemic by the World Health Organization (WHO). It is currently unknown what direct, or indirect, effect, if any, this event may have on the national economy, the local economy or the market in which the subject property is located. The reader is cautioned, and reminded that the conclusions presented in this appraisal report apply only as of the effective date(s) indicated. The appraiser makes no representation as to the effect on the subject property of this event, or any event, subsequent to the effective date of the appraisal.

General Assumptions and Limiting Conditions:

WALDRON & ASSOCIATES, INC.

This report is made expressly subject to the contingent and limiting conditions, factors, and assumptions herewith:

1. This is an Appraisal Report and is intended to comply with the reporting requirements set forth under Standard Rule 2-2(a) of the Uniform Standards of Professional Appraisal Practice for an Appraisal Report. The information contained in this report is specific to the needs of the Client and for the intended use stated in this report. The appraiser is not responsible for unauthorized use of this report. No part of this report shall be used separately or out of context.

2. No responsibility is assumed for legal or title considerations. Any legal description provided is assumed to be correct. Title to the property is assumed good and marketable unless otherwise stated in this report.

3. The property is appraised free and clear of any or all liens and encumbrances unless otherwise stated in this report.

4. Responsible ownership and competent property management are assumed unless otherwise stated in this report.

5. That no guarantee is made as to the correctness of estimates or opinions furnished by others, which have been used in making this appraisal and that no liabilities are assumed because of inaccuracies in such estimates or opinions.

6. The documentary transfer tax stamps and/or consideration placed on deeds used to indicate sales are in correct relationship to the actual dollar amount of the transaction.

7. That this appraisal is subject to review upon presentation of data, which might be later made available, undisclosed, or not available during the preparation of this report.

8. That the appraiser herein, by reason of this appraisal, is not required to give testimony or attendance in court or any governmental hearing with reference to the property in question, unless arrangements have previously been made, therefore.

9. All engineering is assumed correct. Any plot plans and illustrative material in this report are included only to assist the reader in visualizing the property.

10. It is assumed that there are no hidden, unreported, or unapparent conditions of the property, including availability or capacity of utilities, soil, subsoil, flooding, flood hazards, flood designations, or structures that render it more or less valuable. No responsibility is assumed for such conditions or for arranging for engineering studies, surveys or other experts that may be required to discover them.

GENERAL ASSUMPTIONS AND LIMITING CONDITIONS (Continued)

11. It is assumed that there is full compliance with all applicable federal, state, and local environmental regulations and laws unless otherwise stated in this report.

12. It is assumed that all applicable zoning and use regulations and restrictions, development standards, and building codes, have been complied with or have proper permits and approvals, unless nonconformity has been stated, defined, and considered in this appraisal report.

13. It is assumed that all required licenses, certificates of occupancy or other legislative or administrative authority from any local, state, or national governmental or private entity or organization have been or can be obtained or renewed for any use on which the value estimates contained in this report are based.

14. Any sketch in this report may show approximate dimensions and is included to assist the reader in visualizing the property. Maps and exhibits found in this report are provided for reader reference purposes only. No guarantee as to accuracy is expressed or implied unless otherwise stated in this report. No survey has been conducted for the purpose of this report.

15. It is assumed that the utilization of the land and improvements is within the boundaries or property lines of the property described and that there is no encroachment or trespass unless otherwise stated in this report.

16. The appraiser is not qualified to detect hazardous waste and/or toxic materials. Unless otherwise noted, the appraisal will value the property as though free and clear of any contamination or environmental impairment. Waldron & Associates, Inc. will not conduct any hazardous materials or contamination inspection of any kind. It is recommended that the Client retain an expert if the presence of hazardous materials or contamination poses any concern.

17. Any comment by the appraiser that might suggest the possibility of the presence of such substances should not be taken as confirmation of the presence of hazardous waste and/or toxic materials. Such a determination would require investigation by a qualified expert in the field of environmental assessment. The presence of substances such as asbestos, urea-formaldehyde foam insulation or other potentially hazardous materials may affect the value of the property. The appraiser's value estimate is predicated on the assumption that there is no such material on or within the property that would cause a loss in value unless otherwise stated in this report. No responsibility is assumed for any environmental conditions or for any expertise or engineering knowledge required to discover them. The appraiser's descriptions and resulting comments are the result of the routine observations made during the appraisal process. No responsibility is assumed by the appraiser either for the existence of any hazardous or toxic waste nor for the determination of the costs of removal and/or disposal thereof.

GENERAL ASSUMPTIONS AND LIMITING CONDITIONS (Continued)

18. Unless otherwise stated in this report, the Subject Property is appraised without a specific compliance survey having been conducted to determine if the property is or is not in conformance with the requirements of the Americans with Disabilities Act. The presence of architectural and communications barriers that are structural in nature that would restrict access by disabled individuals may adversely affect the property's value, marketability, or utility.

19. Any proposed improvements are assumed to be completed in a good workmanlike manner in accordance with the submitted plans and specifications.

20. The distribution, if any, of the total valuation in this report between land and improvements applies only under the stated program of utilization. The separate allocations for land and buildings must not be used in conjunction with any other appraisal and are invalid if so used, unless otherwise stated in this report (including in the Purpose of Appraisal section).

21. Possession of this report, or a copy thereof, does not carry with it the right of publication. The appraiser assumes no obligation, liability, or accountability to any third party. This appraisal report was prepared for the sole and exclusive use of the Client for the purpose, function, and intended use outlined herein. It may not be used for any purpose by any person other than the party to whom it is addressed without the written consent of the appraiser and, in any event, only with proper written qualification and only in its entirety. Any party who is not the Client or intended user identified in the appraisal or engagement letter is not entitled to rely upon the appraisal without express written consent of Waldron & Associates, Inc.

22. No part of the contents of this report (especially any conclusions as to value, the identity of the appraiser, the firm with which the appraiser is connected, any professional designations, or any reference to any professional appraisal organization) shall be disseminated to the public through advertising, public relations, news, sales, or other media without prior written consent and approval of the appraiser and appraisal firm.

23. All information gathered during this assignment (except data furnished by the Client) shall remain the property of Waldron & Associates, Inc. The Appraiser will not violate the confidential nature of the appraiser-client relationship by improperly disclosing any confidential information furnished to the appraiser. Notwithstanding the foregoing, the Appraiser is authorized by the Client to disclose all or any portion of the appraisal and related appraisal data to appropriate representatives of the Appraisal Institute if such disclosure is required to enable the appraiser to comply with the Bylaws and Regulations of the Appraisal Institute.

24. The Contingent and Limiting Conditions, if changed, will influence the assignment results.

25. The appraiser reserves the right to amend the opinions expressed herein should any Project changes, Court rulings and/or additional information become available.

Certification of Appraisers

Certification of Appraisal

Walter D. Carney, MAI

I certify that, to the best of my knowledge and belief:

1. The statements of fact contained in this report are true and correct.
2. The reported analyses, opinions, and conclusions are limited only by the reported assumptions and limiting conditions and are my personal, impartial, and unbiased professional analyses, opinions, and conclusions.
3. I have no present or prospective interest in the property that is the subject of this report and no personal interest with respect to the parties involved.
4. I have not performed services, as an appraiser or in any other capacity, regarding the property that is the subject of this report within the three-year period immediately preceding acceptance of this assignment.
5. I have no bias with respect to the property that is the subject of this report or to the parties involved with this assignment.
6. My engagement in this assignment was not contingent upon developing or reporting predetermined results.
7. My compensation for completing this assignment is not contingent upon the development or reporting of a predetermined value or direction in value that favors the cause of the client, the amount of value opinion, the attainment of a stipulated result, or the occurrence of a subsequent event directly related to the intended use of this appraisal.
8. My analyses, opinions and conclusions were developed, and this report has been prepared, in conformity with the Uniform Standards of Professional Appraisal Practice.
9. Walter D. Carney, MAI has made a personal inspection of 33 of the 33 PG&E fee-owned properties that are the subject of this appraisal; an inspection of the interior building improved on the Randolph Substation (PG&E Site #14) was not available to inspect. Some easement areas were additionally inspected.
10. Neil N. Shah provided significant real property assistance to the person signing this certification.
11. The reported analyses, opinions and conclusions were developed, and this report has been prepared, in conformity with the requirements of the Code of Professional Ethics and Standards of Professional Practice of the Appraisal Institute.
12. The use of this report is subject to the requirements of the Appraisal Institute relating to review by its duly authorized representatives.
13. Neither all nor any part of the contents of this report (especially any conclusions as to value, the identity of the consultant or the firm with which he is connected, or any reference to the Appraisal Institute or the MAI designation) shall be disseminated to the public through advertising media, public relations media, news media, sales media, or any other public means of communication without the prior written consent and approval of the undersigned.

14. As of the date of this report, I, Walter D. Carney, MAI, have completed the continuing education program for Designated Members of the Appraisal Institute.

Walter D. Carney, MAI
Valbridge Property Advisors | Northern California
Senior Managing Director
California Certified License #AG003413

DATE: October 13, 2026

Certification and Restriction Upon Disclosure and Use for this Appraisal Report

Michael F. Waldron, MAI
Christer Fiege-Kollmann, MAI

I certify that, to the best of my knowledge and belief:

1. The statements of fact contained in this report are true and correct.

2. The reported analyses, opinions, and conclusions are limited only by the reported assumptions and limiting conditions and are my personal, impartial, and unbiased professional analyses, opinions, and conclusions.

3. I have no present or prospective interest in the property that is the subject of this report and no personal interest with respect to the parties involved.

4. I have performed no services, as an appraiser or in any other capacity, regarding the property that is the subject of this report within the three-year period immediately preceding acceptance of this assignment.

5. I have no bias with respect to the property that is the subject of this report or to the parties involved with this assignment.

6. My engagement in this assignment was not contingent upon developing or reporting predetermined results.

7. My compensation for completing this assignment is not contingent upon the development or reporting of a predetermined value or direction in value that favors the cause of the client, the amount of the value opinion, the attainment of a stipulated result, or the occurrence of a subsequent event directly related to the intended use of this appraisal.

8. My analyses, opinions, and conclusions were developed, and this report has been prepared, in conformity with the *Uniform Standards of Professional Appraisal Practice*.

9. Michael F. Waldron and Christer Fiege-Kollmann have not made a personal inspection of the 33 PG&E fee-owned properties that are the subject of this appraisal. Neighborhood areas of the easement properties were inspected.

CERTIFICATION AND RESTRICTION UPON DISCLOSURE AND USE FOR THIS APPRAISAL REPORT (Continued)

10. Mr. Walter D. Carney, MAI, Mr. Neil N. Shah, Senior Appraisal Analyst, both with Valbridge Property Advisors, and Mr. Kevin R. Waldron, Research Appraiser and Mr. Petros Berhane, Senior Appraiser, both with Waldron & Associates, Inc. provided significant real property appraisal assistance to the persons signing this certification.

11. The reported analyses, opinions, and conclusions were developed, and this report has been prepared in conformity with the requirements of the Code of Professional Ethics and Standards of Professional Practice of the Appraisal Institute.

12. The use of this report is subject to the requirements of the Appraisal Institute relating to review by its duly authorized representatives.

13. Neither all nor any part of the contents of this report (especially any conclusions as to value, the identity of the consultant or the firm with which he is connected, or any reference to the Appraisal Institute or to the MAI designation) shall be disseminated to the public through advertising media, public relations media, news media, sales media or any other public means of communication without the prior written consent and approval of the undersigned.

14. As of the date of this report, Michael F. Waldron has completed the continuing education program for Designated Members of the Appraisal Institute.

15. As of the date of this report, Christer Fiege-Kollmann has completed the continuing education program for Designated Members of the Appraisal Institute.

Michael F. Waldron, MAI
CA #AG011796

DATE: October 13, 2026

Christer Fiege-Kollmann, MAI
CA #AG015749

DATE: October 13, 2026

Addendum

Additional Exhibits

- PG&E Electrical System – Illustration from PG&E Website
- Exhibit W-1 -Zoning Description Summary
- Exhibit W-2 – Zoning Designation and Use District Summary
- Exhibit W-3 – Land Sales Summary & Adjustments
- Exhibit W-4 – Land Sales Summary & Adjustments - By Quadrant
- Exhibit W-5 – Land Sales Summary & Adjustments - By Zoning Use District
- Market Data Maps

Qualifications of Appraiser

- Walter D. Carney, MAI, Senior Managing Director, Valbridge Property Advisors
- Michael F. Waldron, MAI, President and Principal Appraiser, Waldron & Associates, Inc.
- Christer Fiege-Kollmann, MAI, Senior Appraiser, Waldron & Associates, Inc.

PG&E's Electric System (Illustration)

PG&E's electric system

PG&E's electric system is designed and built to deliver safe, reliable power to customers in Northern and Central California. PG&E produces or buys its power from a mix of conventional and renewable generating sources, which travel through our electric transmission and distribution systems to reach our customers.

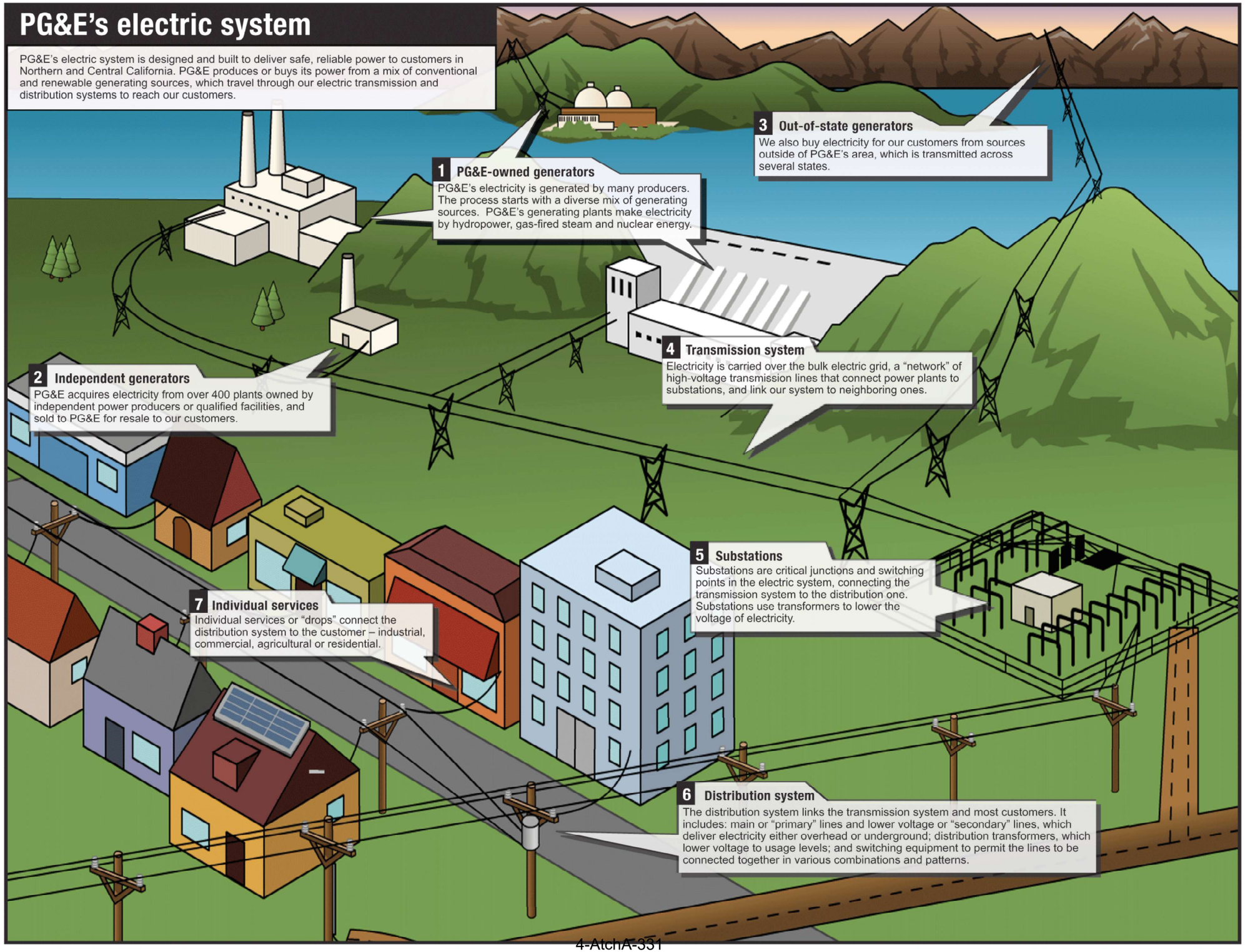

Exhibit W-1: Zoning Description Summary

EXHIBIT "W - 1"
ZONING DESCRIPTION SUMMARY
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID
DATE OF VALUE: JULY 27, 2021

Zoning Designation		Zoning Use District	Zoning Descriptions
RH-1	Residential, House-One Family	Residential, House Character	These Districts are occupied almost entirely by single-family houses on lots 25 feet in width, without side yards. Floor sizes and building styles vary, but tend to be uniform within tracts developed in distinct time periods. Though built on separate lots, the structures have the appearance of small-scale row housing, rarely exceeding 35 feet in height. Front setbacks are common, and ground level open space is generous. In most cases the single-family character of these Districts has been maintained for a considerable time.
RH-1(D)	Residential, House-One Family(Detached Dwelling)	Residential, House Character	These Districts are characterized by lots of greater width and area than in other parts of the City, and by single-family houses with side yards. The structures are relatively large, but rarely exceed 35 feet in height. Ground level open space and landscaping at the front and rear are usually abundant. Much of the development has been in sizable tracts with similarities of building style and narrow streets following the contours of hills. In some cases private covenants have controlled the nature of development and helped to maintain the street areas.
RH-1(S)	Residential, House-One Family with Minor Second Unit	Residential, House Character	These Districts are similar in character to RH-1 Districts, except that a small second dwelling unit has been installed in many structures, usually by conversion of a ground-story space formerly part of the main unit or devoted to storage. The second unit remains subordinate to the owner's unit, and may house one or two persons related to the owner or be rented to others. Despite these conversions, the structures retain the appearance of single-family dwellings.
RH-2	Residential, House-Two-Family	Residential, House Character	These Districts are devoted to one-family and two-family houses, with the latter commonly consisting of two large flats, one occupied by the owner and the other available for rental. Structures are finely scaled and usually do not exceed 25 feet in width or 40 feet in height. Building styles are often more varied than in historically single-family areas, but certain streets and tracts are quite uniform. Considerable ground-level open space is available, and it frequently is private for each unit. The Districts may have easy access to shopping facilities and transit lines. In some cases, Group Housing and institutions are found in these areas, although nonresidential uses tend to be quite limited.
RH-3	Residential, House-Three Family	Residential, House Character	These Districts have many similarities to RH-2 Districts, but structures with three units are common in addition to one-family and two-family houses. The predominant form is large flats rather than apartments, with lots 25 feet wide, a fine or moderate scale, and separate entrances for each unit. Building styles tend to be varied but complementary to one another. Outdoor space is available at ground level, and also on decks and balconies for individual units. Nonresidential uses are more common in these areas than in RH-2 Districts.
RM-1	Residential, Mixed-Low Density	Residential, Mixed (Houses & Apartments)	These Districts contain a mixture of the dwelling types found in RH Districts, but in addition have a significant number of apartment buildings that broaden the range of unit sizes and the variety of structures. A pattern of 25-foot to 35-foot building widths is retained, however, and structures rarely exceed 40 feet in height. The overall density of units remains low, buildings are moderately scaled and segmented, and units or groups of units have separate entrances. Outdoor space tends to be available at ground and upper levels regardless of the age and form of structures. Shopping facilities and transit lines may be found within a short distance of these districts. Nonresidential uses are often present to provide for the needs of residents.
RM-2	Residential, Mixed-Moderate Density	Residential, Mixed (Houses & Apartments)	These Districts are generally similar to RM-1 Districts, but the overall density of units is greater and the mixture of building types and unit sizes is more pronounced. Building widths and scales remain moderate, and considerable outdoor space is still available. The unit density permitted requires careful design of new structures in order to provide adequate amenities for the residents. Where nonresidential uses are present, they tend to offer services for wider areas than in RM-1 Districts.
RM-3	Residential, Mixed-Medium Density	Residential, Mixed (Houses & Apartments)	These Districts have some smaller structures, but are predominantly devoted to apartment buildings of six, eight, 10 or more units. Most of these districts are close to downtown and have been developed in this manner for some time. The units vary in size, but tend to be smaller than in RM-1 and RM-2 Districts. Many buildings exceed 40 feet in height, and in some cases additional buildings over that height may be accommodated without disruption of the district character. Although lots and buildings wider than 25 or 35 feet are common, the scale often remains moderate through sensitive facade design and segmentation. Open spaces are smaller, but decks and balconies are used to advantage for many units. Supporting nonresidential uses are often found in these areas.
RM-4	Residential, High Density	Residential, Mixed (Houses & Apartments)	These Districts are devoted almost exclusively to apartment buildings of high density, usually with smaller units, close to downtown. Buildings over 40 feet in height are very common, and other tall buildings may be accommodated in some instances. Despite the intensity of development, distinct building styles and moderation of facades are still to be sought in new development, as are open areas for the residents. Group housing is especially common in these districts, as well as supporting nonresidential uses.
RC-3	Residential-Commercial-Medium Density	Residential-Commercial Combined	These Districts provide for a mixture of medium-density Dwellings similar to those in RM-3 Districts, with supporting Commercial uses. Open spaces are required for Dwellings in the same manner as in RM-3 Districts, except that rear yards need not be at ground level and front setback areas are not required.
RC-4	Residential-Commercial-High Density	Residential-Commercial Combined	These Districts provide for a mixture of high-density Dwellings similar to those in RM-4 Districts with supporting Commercial uses. Open spaces are required for Dwellings in the same manner as in RM-4 Districts, except that rear yards need not be at ground level and front setback areas are not required.

EXHIBIT "W - 1"
ZONING DESCRIPTION SUMMARY
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID
DATE OF VALUE: JULY 27, 2021

Zoning Designation		Zoning Use District	Zoning Descriptions
RTO	Residential, Transit-Oriented Neighborhood	Residential Transit Oriented	These Districts are intended to recognize, protect, conserve, and enhance areas characterized by a mixture of houses and apartment buildings, covering a range of densities and building forms. RTO and RTO-M Districts are composed of multi-family moderate-density areas, primarily areas formerly designated RM and RH-3, and are well served within short walking distance, generally less than one-quarter mile, of transit and neighborhood commercial areas. Transit available on nearby streets is frequent and/or provides multiple lines serving different parts of the City or region. Limited small-scale neighborhood-oriented retail and services is common and permitted throughout the neighborhood on Corner Lots only to provide goods and services to residents within walking distance, but the districts are otherwise residential. Only retail compatible with housing, generally those permitted in NC-1 Districts, is permitted and auto-oriented uses are not permitted. Hours of operation are restricted and off-street parking is not permitted for these very locally-oriented uses.
RTO-M	Residential, Transit-Oriented Mission Neighborhood	Residential Transit Oriented	These Districts are intended to recognize, protect, conserve, and enhance areas characterized by a mixture of houses and apartment buildings, covering a range of densities and building forms. RTO and RTO-M Districts are composed of multi-family moderate-density areas, primarily areas formerly designated RM and RH-3, and are well served within short walking distance, generally less than one-quarter mile, of transit and neighborhood commercial areas. Transit available on nearby streets is frequent and/or provides multiple lines serving different parts of the City or region. Limited small-scale neighborhood-oriented retail and services is common and permitted throughout the neighborhood on Corner Lots only to provide goods and services to residents within walking distance, but the districts are otherwise residential. Only retail compatible with housing, generally those permitted in NC-1 Districts, is permitted and auto-oriented uses are not permitted. Hours of operation are restricted and off-street parking is not permitted for these very locally-oriented uses.
RH DTR	Rincon Hill Downtown Residential	Downtown Residential	The RH-DTR District is adjacent to the southern edge of the downtown, generally bounded by Folsom Street, the Bay Bridge, the Embarcadero, and Essex Street. High-density residential uses and supporting commercial and institutional uses are allowed and encouraged within the limits set by height, bulk, and tower spacing controls. Folsom Street is intended to develop as the neighborhood commercial heart of the Rincon Hill and Transbay neighborhoods, and pedestrian-oriented uses are required on the ground floor. Individual townhouse dwelling units with ground floor entries directly to the street are required on streets that will become primarily residential, including First, Fremont, Beale, Main, and Spear Streets.
SB-DTR	South Beach Downtown Residential	Downtown Residential	The SB-DTR District is adjacent to the southern edge of the downtown, generally bounded by the Bay Bridge, Bryant Street, the Embarcadero, and 2nd Street, and is primarily comprised of the former South Beach Redevelopment Area. High-density residential uses and supporting commercial and institutional uses are allowed and encouraged within the limits set by height, bulk, and tower spacing controls. Individual townhouse dwelling units with ground floor entries directly to the street are generally required on streets.
TB DTR	Transbay Downtown Residential	Downtown Residential	The Transbay Downtown Residential District, which is wholly within the Transbay Redevelopment Project Area, comprises mostly publicly owned parcels containing infrastructure or underutilized land related to the Transbay Terminal and former Embarcadero Freeway. This district generally extends along the north side of Folsom Street from Spear to Essex Streets, and between Main and Beale Streets to the north side of Howard Street. Laid out in the Transbay Redevelopment Plan and its companion documents, including the Design for the Development and the Development Controls and Design Guidelines for the Transbay Redevelopment Project, is the comprehensive vision for this underutilized area as a high-density, predominantly residential, district within walking distance of the downtown core, transit facilities, and the waterfront. The plan for the district includes: a mix of widely-spaced high-rises, mixed with a street-defining base of low- and mid-rise buildings with ground floor townhouses; a public open space on part of the block bounded by Folsom, Beale, Howard, and Main Streets; ground-floor retail along Folsom Street; and several new alleyways to break up the size of the blocks. (a) Basic Controls. Development controls for this district are established in the Transbay Redevelopment Plan as approved by the Planning Commission on December 9, 2004, and January 13, 2005, specifically the Development Controls and Design Guidelines for the Transbay Redevelopment Project. On matters to which these Redevelopment documents are silent, controls in this Code pertaining to the C-3-O District shall apply. The C-3-O District permits construction of Accessory Dwelling Units pursuant to Section 207(c)(4) of this Code.
C-2	Community Business	Commercial	These districts serve several functions. They provide convenience goods and services to Residential areas of the City, both in outlying sections and in closer-in, more densely built communities. In addition, some C-2 Districts provide comparison shopping goods and services on a general or specialized basis to a Citywide or a regional market area, complementing the main area for such types of trade in downtown San Francisco. The extent of these districts varies from smaller clusters of stores to larger concentrated areas, including both shopping centers and strip developments along major thoroughfares, and in each case the character and intensity of commercial development are intended to be consistent with the character of other uses in the adjacent areas. The emphasis in C-2 Districts is upon compatible retail uses, but the district also allows a wider variety of goods and services to suit the longer-term needs of customers and a greater latitude is given for the provision of automobile-oriented uses.
C-3-G	Downtown General	Commercial	This District covers the western portions of downtown and is composed of a variety of uses: Retail, offices, hotels, entertainment, clubs and institutions, and high-density residential. Many of these uses have a Citywide or regional function, although the intensity of development is lower here than in the downtown core area. As in the case of other downtown districts, no off-street parking is required for individual commercial buildings. In the vicinity of Market Street, the configuration of this District reflects easy accessibility by rapid transit.
C-3-O(SD)	Downtown Office Special Development	Commercial	This area south of Market Street and east of 3rd Street comprises the southern side of the core central business district, and is similar to and generally indistinguishable from the C-3-O District in terms of uses and character. The area is centered on the Transbay Transit Center. This District permits densities that exceed those in the C-3-O District and contains the tallest height limits in the City, reflecting its unparalleled public transportation access and geographically central position in the downtown.

EXHIBIT "W - 1"
ZONING DESCRIPTION SUMMARY
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID
DATE OF VALUE: JULY 27, 2021

Zoning Designation		Zoning Use District	Zoning Descriptions
C-3-R	Downtown Retail	Commercial	This District is a regional center for comparison shopper retailing and direct consumer services. It covers a compact area with a distinctive urban character, consists of uses with cumulative customer attraction and compatibility, and is easily traversed by foot. Like the adjacent Downtown Office District, this District is well-served by City and regional transit, with automobile parking best located at its periphery. Within the District, continuity of retail and consumer service uses is emphasized, with encouragement of pedestrian interest and amenities and minimization of conflicts between shoppers and motor vehicles. A further merging of this District with adjacent, related Districts is anticipated, partially through development of buildings which combine retailing with other functions.
C-3-S	Downtown Support	Commercial	This District encompasses Yerba Buena Gardens, which includes San Francisco's Convention Center, hotels, museums and cultural facilities, housing, retail, and offices arranged around public gardens and plazas. The District continues to accommodate important supporting functions such as wholesaling, printing, building services, and secondary office space. It also contains unique housing resources. The District is within walking distance of rapid transit on Market Street, and is served by transit lines on Third, Fourth, Mission and Folsom streets.
NC-1	Neighborhood Commercial Cluster (1 Commercial Story)	Neighborhood Commercial	NC-1 Districts are intended to serve as local neighborhood shopping districts, providing convenience retail goods and services for the immediately surrounding neighborhoods primarily during daytime hours. These NC-1 Districts are characterized by their location in residential neighborhoods, often in outlying areas of the City. The commercial intensity of these districts varies. Many of these districts have the lowest intensity of commercial development in the City, generally consisting of small clusters with three or more commercial establishments, commonly grouped around a corner; and in some cases short linear commercial strips with low-scale, interspersed mixed-use (residential-commercial) development.
NC-2	Neighborhood Commercial Small-Scale (2 Commercial Stories)	Neighborhood Commercial	The NC-2 District is intended to serve as the City's Small-Scale Neighborhood Commercial District. These districts are linear shopping streets which provide convenience goods and services to the surrounding neighborhoods as well as limited comparison shopping goods for a wider market. The range of comparison goods and services offered is varied and often includes specialty retail stores, restaurants, and neighborhood-serving offices. NC-2 Districts are commonly located along both collector and arterial streets which have transit routes. These districts range in size from two or three blocks to many blocks, although the commercial development in longer districts may be interspersed with housing or other land uses. Buildings typically range in height from two to four stories with occasional one-story commercial buildings.
NC-3	Neighborhood Commercial Moderate-Scale (3+ Commercial Stories)	Neighborhood Commercial	NC-3 Districts are intended in most cases to offer a wide variety of comparison and specialty goods and services to a population greater than the immediate neighborhood, additionally providing convenience goods and services to the surrounding neighborhoods. NC-3 Districts are linear districts located along heavily trafficked thoroughfares which also serve as major transit routes. NC-3 Districts include some of the longest linear commercial streets in the City, some of which have continuous retail development for many blocks. Large-scale lots and buildings and wide streets distinguish the districts from smaller-scaled commercial streets, although the districts may include small as well as moderately scaled lots. Buildings typically range in height from two to four stories with occasional taller structures
NCD	Neighborhood Commercial Districts	Neighborhood Commercial	(1) **Neighborhood Commercial Districts.** Neighborhood Commercial Districts are low to high density mixed-use neighborhoods of varying scale established around historical neighborhood commercial centers. The Neighborhood Commercial Districts are intended to support neighborhood-serving uses on the lower floors and housing above. These Districts tend to be linear commercial corridors, but may also include small clusters of commercial activity in Residential Districts. Individually named Neighborhood Commercial Districts are intended to provide for more targeted residential and commercial controls to fit the needs of their respective neighborhoods.
NC-S	Neighborhood Commercial Shopping Center	Neighborhood Commercial	NC-S Districts are intended to serve as small shopping centers or supermarket sites which provide retail goods and services for primarily car-oriented shoppers. They commonly contain at least one anchor store or supermarket, and some districts also have small medical office buildings. The range of services offered at their retail outlets usually is intended to serve the immediate and nearby neighborhoods. These districts encompass some of the most recent (post-1945) retail development in San Francisco's neighborhoods and serve as an alternative to the linear shopping street. Shopping centers and supermarket sites contain mostly one-story buildings which are removed from the street edge and set in a parking lot. Outdoor pedestrian activity consists primarily of trips between the parking lot and the stores on-site. Ground and second stories are devoted to retail sales and some personal services and offices.
NCT	Hayes-Gough Neighborhood Commercial Transit District	Neighborhood Commercial Transit	The Hayes-Gough Neighborhood Commercial Transit District is located within walking distance of the Civic Center, lying west of Franklin Street and east of Laguna Street, with its southern edge generally at Lily Street, with an extension south along both sides of Octavia Boulevard to Market Street. This mixed-use commercial district contains a limited range of retail commercial activity, which primarily caters to the immediate need of the neighborhood. The few comparison goods that it does provide attract clientele from a wider area outside its neighborhood, mostly the Performing Arts and Civic Center workers and visitors. There are a number of restaurants and art galleries, but other types of retail activity are limited.

EXHIBIT "W - 1"
ZONING DESCRIPTION SUMMARY
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID
DATE OF VALUE: JULY 27, 2021

Zoning Designation		Zoning Use District	Zoning Descriptions
NCT-1	Neighborhood Commercial Transit Cluster	Neighborhood Commercial Transit	NCT-1 Districts are intended to serve as local neighborhood shopping districts, providing convenience retail goods and services for the immediately surrounding neighborhoods primarily during daytime hours. NCT-1 Districts are located near major transit services. They are small mixed-use clusters, generally surrounded by residential districts, with small-scale neighborhood-serving commercial uses on lower floors and housing above. Housing density is limited not by lot area, but by the regulations on the built envelope of buildings, including height, bulk, setbacks, and lot coverage, and standards for residential uses, including open space and exposure, and urban design guidelines. There are prohibitions on access (i.e. driveways, garage entries) to off-street parking and loading on critical stretches of commercial and transit street frontages to preserve and enhance the pedestrian-oriented character and transit function. Residential parking is not required and generally limited. Commercial establishments are discouraged from building excessive accessory off-street parking in order to preserve the pedestrian-oriented character of the district and prevent attracting auto traffic.
NCT-2	Small-Scale Neighborhood Commercial Transit	Neighborhood Commercial Transit	NCT-2 Districts are transit-oriented mixed-use neighborhoods with small scale commercial uses near transit services. The NCT-2 Districts are mixed use districts that support neighborhood-serving commercial uses on lower floors and housing above. These Districts are well-served by public transit and aim to maximize residential and commercial opportunities on or near major transit services. The District's form is generally linear along transit-priority corridors, though may be concentric around transit stations or in broader areas where multiple transit services criss-cross the neighborhood. Housing density is limited not by lot area, but by the regulations on the built envelope of buildings, including height, bulk, setbacks, and lot coverage, and standards for residential uses, including open space and exposure, and urban design guidelines. There are prohibitions on access (e.g., driveways, garage entries) to off-street parking and loading on critical stretches of commercial and transit street frontages to preserve and enhance the pedestrian-oriented character and transit function. Residential parking is not required and generally limited. Commercial establishments are discouraged from building excessive accessory off-street parking in order to preserve the pedestrian-oriented character of the district and prevent attracting auto traffic.
NCT-3	Moderate-Scale Neighborhood Commercial Transit	Neighborhood Commercial Transit	(a) NCT-3 Districts are walkable and transit-oriented moderate- to high-density mixed-use neighborhoods of varying scale concentrated near transit services. The NCT-3 Districts are mixed use districts that support neighborhood-serving Commercial Uses on lower floors and housing above. These districts are well-served by public transit and aim to maximize residential and commercial opportunities on or near major transit services. The district's form can be either linear along transit-priority corridors, concentric around transit stations, or broader areas where transit services criss-cross the neighborhood. Housing density is limited not by lot area, but by the regulations on the built envelope of buildings, including height, bulk, setbacks, and lot coverage, and standards for Residential Uses, including open space and exposure, and urban design guidelines. Residential parking is not required and generally limited. Commercial establishments are discouraged or prohibited from building accessory off-street parking in order to preserve the pedestrian-oriented character of the district and prevent attracting auto traffic. There are prohibitions on access (i.e. driveways, garage entries) to off-street parking and loading on critical stretches of NC and transit streets to preserve and enhance the pedestrian-oriented character and transit function. (b) NCT-3 Districts are intended in most cases to offer a wide variety of comparison and specialty goods and services to a population greater than the immediate neighborhood, additionally providing convenience goods and services to the surrounding neighborhoods. NCT-3 Districts include some of the longest linear commercial streets in the City, some of which have continuous retail development for many blocks. Large-scale lots and buildings and wide streets distinguish the districts from smaller-scaled commercial streets, although the districts may include small as well as moderately scaled lots. Buildings may range in height, with height limits varying from four to eight stories.
RCD	Regional Commercial	Neighborhood Commercial Transit	The Regional Commercial District (RCD) is located along the 9th Street and 10th Street corridors, generally running from Mission Street to Harrison Street, and provides for a wide variety of commercial uses and services to a population greater than the immediate neighborhood. While providing convenience goods and services to the surrounding neighborhood, the RCD corridors are also heavily trafficked thoroughfares into and out of the City that serve shoppers from other neighborhoods and cities. Large-scale lots and buildings and wide streets distinguish the RCD from smaller-scaled neighborhood commercial streets, although the district also includes small as well as moderately scaled lots. Buildings typically range in height from two to four stories with occasional taller structures.
CMUO	Central SoMa Mixed Use Office	Eastern Neighborhoods Mixed Use	The Central SoMa Mixed Use-Office (CMUO) extends predominantly between 2nd Street and 6th Street in the South of Market area. The CMUO is designed to encourage a mix of residential and non-residential uses, including office, retail, light manufacturing, arts activities, nighttime entertainment, and tourist hotels.
MUG	Mixed Use General	Eastern Neighborhoods Mixed Use	The Mixed Use-General (MUG) District is largely comprised of the low-scale, production, distribution, and repair (PDR) uses mixed with housing and small-scale retail. The MUG is designed to maintain and facilitate the growth and expansion of small-scale light manufacturing, wholesale distribution, arts production and performance/exhibition activities, general commercial and neighborhood-serving retail and personal service activities while protecting existing housing and encouraging the development of housing at a scale and density compatible with the existing neighborhood. Housing is encouraged over ground floor commercial and PDR uses. New residential or mixed use developments are encouraged to provide as much mixed-income family housing as possible. Existing group housing and dwelling units would be protected from demolition or conversion to nonresidential use by requiring conditional use review. Accessory Dwelling Units are permitted within the district pursuant to subsection 207(c)(4) of this Code.

EXHIBIT "W - 1"
ZONING DESCRIPTION SUMMARY
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID
DATE OF VALUE: JULY 27, 2021

Zoning Designation		Zoning Use District	Zoning Descriptions
MUO	Mixed Use Office	Eastern Neighborhoods Mixed Use	The Mixed Use-Office (MUO) is designed to encourage office uses and housing, as well as small-scale light manufacturing and arts activities. Nighttime entertainment and small tourist hotels are permitted as a conditional use. Large tourist hotels are permitted as a conditional use in certain height districts. Dwelling units and group housing are permitted, while demolition or conversion of existing dwelling units or group housing requires conditional use authorization. Family-sized housing is encouraged. Accessory Dwelling Units are permitted within the district pursuant to subsection 207(c)(4) of this Code. Office, general commercial, most retail, production, distribution, and repair uses are also principal permitted uses. Adult entertainment and heavy manufacturing uses are not permitted.
MUR	Mixed Use Residential	Eastern Neighborhoods Mixed Use	The Mixed Use-Residential District (MUR) is intended to facilitate the development of high-density, mid-rise housing, including family-sized housing and residential hotels. The district is also designed to encourage the expansion of retail, business service and commercial and cultural arts activities. Accessory Dwelling Units are permitted within the district pursuant to subsection 207(c)(4) of this Code. Continuous ground floor commercial frontage with pedestrian-oriented retail activities along major thoroughfares is encouraged. Hotels, nighttime entertainment, adult entertainment and heavy manufacturing uses are not permitted. Office is limited by residential-to-non residential ratio in new construction.
RED	Residential Enclave District	Eastern Neighborhoods Mixed Use	Residential Enclave Districts (RED) encompass many of the clusters of low-scale, medium density, predominantly residential neighborhoods located along the narrow side streets of the South of Market area. Within these predominantly residential enclaves lie a number of vacant parcels, parking lots and other properties in open storage use. These properties are undeveloped or underdeveloped and are viewed as opportunity sites for new, moderate-income, in-fill housing.
RED-MX	Residential Enclave District-Mixed	Eastern Neighborhoods Mixed Use	Residential Enclave-Mixed Districts (RED-MX) encompass some of the clusters of low-scale, medium density, predominantly residential neighborhoods located along the narrow side streets of the Western SoMa area. Many parcels in these residential enclaves are underdeveloped and represent opportunities for new residential and low-intensity commercial uses.
SALI	Service/Arts/Light Industrial	Eastern Neighborhoods Mixed Use	The Service/Arts/Light Industrial (SALI) District is largely comprised of low-scale buildings with production, distribution, and repair uses. The district is designed to protect and facilitate the expansion of existing general commercial, manufacturing, home and business service, and light manufacturing activities, with an emphasis on preserving and expanding arts activities. Nighttime Entertainment is permitted although limited by buffers around RED and RED-MX districts. Residential Uses, Offices, Hotels, and Adult Entertainment uses are not permitted, except that certain Affordable Housing Projects are permitted within the district pursuant to Section 846.24 of this Code, and Accessory Dwelling Units are permitted within the district pursuant to subsection 207(c)(4) of this Code.
SPD	South Park	Eastern Neighborhoods Mixed Use	South Park is an attractive affordable mixed-use neighborhood. The South Park District (SPD) is intended to preserve the scale, density and mix of commercial and residential activities within this unique neighborhood. The district is characterized by small-scale, continuous-frontage warehouse, retail and residential structures built in a ring around an oval-shaped, grassy park. Retention of the existing structures is encouraged, as is a continued mix of uses, family-sized housing units, and in-fill development which contributes positively to the neighborhood scale and use mix. Accessory Dwelling Units are permitted within the district pursuant to subsection 207(c)(4) of this Code. Most retail, general commercial, office, service/light industrial, arts, live/work and residential activities are permitted. Group housing, social services, and other institutional uses are conditional uses. Hotels, motels, movie theaters, adult entertainment and nighttime entertainment are not permitted.
UMU	Urban Mixed Use	Eastern Neighborhoods Mixed Use	The Urban Mixed Use (UMU) District is intended to promote a vibrant mix of uses while maintaining the characteristics of this formerly industrially-zoned area. It is also intended to serve as a buffer between residential districts and PDR districts in the Eastern Neighborhoods. Within the UMU, allowed uses include production, distribution, and repair uses such as light manufacturing, home and business services, arts activities, warehouse, and wholesaling. Additional permitted uses include retail, educational facilities, and nighttime entertainment. Housing is also permitted, but is subject to higher affordability requirements. Family-sized dwelling units are encouraged. Within the UMU, office uses are generally prohibited in the Mission Area Plan and elsewhere are restricted to the upper floors of multiple story buildings. In considering any new land use not contemplated in this District, the Zoning Administrator shall take into account the intent of this District as expressed in this Section 843 1 and in the General Plan. Accessory Dwelling Units are permitted within the district pursuant to subsections 207(c)(4) and (c)(6) of this Code.
WMUG	Western SoMa Mixed Use-General	Eastern Neighborhoods Mixed Use	The WSoMa Mixed Use-General (WMUG) District is largely comprised of the low-scale, production, distribution, and repair uses mixed with housing and small-scale retail. The WMUG is designed to maintain and facilitate the growth and expansion of small-scale light manufacturing, wholesale distribution, arts production and performance/exhibition activities, and general commercial and neighborhood-serving retail and personal service activities, while protecting existing housing and encouraging the development of housing at a scale and density compatible with the existing neighborhood. Housing is encouraged over ground floor commercial and production, distribution, and repair uses. New residential or mixed use developments are encouraged to provide as much mixed-income family housing as possible. Existing group housing and dwelling units will be protected from demolition or conversion to nonresidential use by requiring conditional use review. Accessory Dwelling Units are permitted within the district pursuant to subsection 207(c)(4) of this Code

EXHIBIT "W - 1"
ZONING DESCRIPTION SUMMARY
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID
DATE OF VALUE: JULY 27, 2021

Zoning Designation		Zoning Use District	Zoning Descriptions
WMUO	Western SoMa Mixed Use-Office	Eastern Neighborhoods Mixed Use	The WSoMa Mixed Use-Office (WMUO) runs predominantly along the Townsend Street corridor between 4th Street and 7th Street and on 11th Street, from Harrison Street to the north side of Folsom Street. The WMUO is designed to encourage office uses along with small-scale light manufacturing, entertainment, cultural, and arts activities. Office, general commercial, most retail, production, distribution, and repair uses are also principally permitted uses. Residential uses, large hotels, adult entertainment and heavy manufacturing uses are not permitted.
CCB	Chinatown Community Business	Chinatown Mixed Use	Generally, this district has more potential for added retail and commercial development than other parts of Chinatown. This zoning district is intended to protect existing housing, encourage new housing and to accommodate modest expansion of Chinatown business activities as well as street-level retail uses. The size of individual professional or business office use is limited in order to prevent these areas from being used to accommodate larger office uses spilling over from the financial district.
CRNC	Chinatown Residential/Neighborhood Commercial	Chinatown Mixed Use	The Chinatown Residential Neighborhood Commercial District extends along Stockton Street between Sacramento and Broadway and along Powell Street between Washington Street and Broadway. It is generally west and uphill from Grant Avenue and is close to the relatively intensely developed residential areas of lower Nob and Russian Hills. Stockton Street is a major transit corridor which serves as "Main Street" for the Chinatown neighborhood. Both Stockton and Powell Streets contain a significant amount of housing as well as major community institutions supportive to Chinatown and the larger Chinese community. This daytime-oriented district provides local and regional specialty food shopping for fresh vegetables, poultry, fish, and meat. Weekends are this area's busiest shopping days. Because Stockton Street is intended to remain principally in its present character, the Stockton Street controls are designed to preserve neighborhood-serving uses and protect the residential livability of the area. The controls promote new residential development compatible with existing small-scale mixed-use character of the area. Consistent with the residential character of the area, commercial development is directed to the ground story. Daytime-oriented use is protected and tourist-related uses and financial services are limited.
CVR	Chinatown Visitor Retail	Chinatown Mixed Use	The Chinatown Visitor Retail Neighborhood Commercial District extends along Grant Avenue between California and Jackson Streets. This district contains a concentration of shopping bazaars, art goods stores, and restaurants, which attract visitors and shoppers and contribute to the City's visual and economic diversity. Grant Avenue provides an important link between Downtown retail shopping and the Broadway, North Beach, and Fisherman's Wharf areas. This district is intended to preserve the street's present character and scale and to accommodate uses primarily appealing to visitors (e.g. tourist gifts shops, jewelry stores, art goods, large restaurants). In order to promote continuous retail frontage, entertainment, financial services, health service, automotive, and drive-up uses are restricted. Most commercial uses, except financial services, are permitted on the first two stories. Administrative services (those not serving the public) are prohibited in order to prevent encroachment from downtown office uses. There are also special controls on restaurants and tourist hotels. Building standards protect and complement the existing small-scale development and the historic character of the area
PM-MU1	Parkmerced - Mixed Use-Social Heart District	Parkmerced Use	All uses permitted in PM-R; locally serving Retail Sales and Service uses not larger than 15,000 occupied square feet per business establishment; one General Grocery Store not larger than 50,000 occupied square feet; and Business Service, Design Professional, and Non-Retail Professional Service Uses, provided such Non-Retail Uses shall not exceed 10,000 occupied square feet per business if located on the ground floor of any building;
PM-MU2	Parkmerced - Mixed Use-Neighborhood Commons	Parkmerced Use	All uses permitted in PM-R; locally serving Retail Sales and Service Uses not larger than 5,000 occupied square feet per business establishment; and Business Service, Design Professional, and Non- Retail Professional Service Uses not larger than 5,000 occupied square feet per business, provided that such use does not occupy more than 2,000 occupied square feet per business establishment on the ground floor;
PM-OS	Parkmerced - Open Space District	Parkmerced Use	Publicly-accessible open space and other open space amenities as specifically established in the Parkmerced Design Standards and Guidelines, including: neighborhood commons; parks and passive open space; plazas; recreational space including playgrounds and sports fields; Large-Scale Urban Agriculture or Neighborhood Agriculture; one Restaurant or Limited Restaurant not exceeding 3,500 occupied square feet on Block 23 (as designated in the Parkmerced Design Standards and Guidelines); farmer's markets; and farm support uses and food sales accessory to on-site agriculture. Up to three retail kiosks are permitted on each of Juan Bautista Circle and the land designated as a farm on Block 23 (each as designated and described in Parkmerced Design Standards and Guidelines), provided each such kiosk does not exceed 200 square feet. Up to four retail kiosks not exceeding 500 square feet each and an aggregate total of 1,000 square feet, along with a retail bicycle shop not exceeding 3,200 square feet are permitted on Block 17 (as designated in the Parkmerced Design Standards and Guidelines and also referred to as the "Transit Plaza").
PM-R	Parkmerced - Residential	Parkmerced Use	Dwelling Units; Live/Work Units, provided any such Live/Work Unit is intended for small home business; community gathering spaces such as community rooms and kitchens, business centers, recreation facilities, and art facilities; and Child Care Facilities not larger than 5,000 occupied square feet;
HP-RA	Hunter's Point-Redevelopment Area	Miscellaneous	https://sfocii.org/completed-project-areas/hunters-point

EXHIBIT "W - 1"
ZONING DESCRIPTION SUMMARY
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID
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Zoning Designation		Zoning Use District	Zoning Descriptions
MB-O	Mission Bay - Office	Miscellaneous	The MB-O District is located on either side of King Street. This district is to be developed with large floor plate and smaller structures for office uses. The buildings are expected to occupy most of the development parcel and will vary in height from four to eight stories. Permitted parking will be located beneath the office buildings and in above grade parking structures. Some convenience retail and other uses will be located at the base of office buildings and parking structures. Usable open space will be provided in a variety of forms, including at grade plazas and courtyards
MB-RA	Mission Bay - Redevelopment	Miscellaneous	https://sfocii.org/sites/default/files/inline-files/Mission%20Bay%20South%20Redevelopment%20Plan_2.pdf
MR-MU	Mission Rock Mixed Use	Miscellaneous	(a) Purpose and Boundaries. A Special Use District entitled the Mission Rock Special Use District (SUD), the boundaries of which are shown on Sectional Map SU08 of the Zoning Maps of the City and County of San Francisco, is hereby established to facilitate the City's long-term goal of development of a new Mission Rock neighborhood. The purpose of this SUD is to implement the Mission Rock Affordable Housing, Parks, Jobs and Historic Preservation Initiative approved by City voters on November 3, 2015 (Proposition D), and give effect to the Development Agreement (DA), Disposition and Development Agreement (DDA) and related transactional documents as approved by the Board of Supervisors in ordinances in File Nos. 171313 and 180092, which will provide benefits to the City such as, among other things, development of a mixed-use, transit-oriented community on the waterfront near public transit, major new housing, including a significant amount of affordable housing, increased public access and open spaces, extensive infrastructure improvements, shops, restaurants, cafes, neighborhood-serving retail, community spaces, commercial/office and light industrial/production space, preservation and renovation of historic Pier 48, job creation, responsiveness to climate change and resulting sea level rise, and the generation of revenue to fund public improvements.
P70-MU	Pier 70 Special Use - Mixed Use	Miscellaneous	(a) Purpose and Boundaries. To facilitate the City's long-term goal of redevelopment and revitalization of a portion of Pier 70, a Special Use District entitled the "Pier 70 Special Use District" (SUD) is hereby established. The boundaries of the SUD are shown on Sectional Map SU08 of the Zoning Map. The purpose of this SUD is to give effect to the Development Agreement (DA) and Disposition and Development Agreement (DDA) for the Pier 70 Mixed-Use Project (Project), as approved by the Board of Supervisors in the Ordinance contained in Board File No. 170863. The Project will provide several benefits to the City, such as a significant amount of affordable housing (through the inclusionary housing requirements of this SUD, and through additional inclusionary requirements, provision of land, and funding for affordable housing as provided for in the Affordable Housing Exhibit of the DDA), increased public access and open space, facilities for small-scale manufacturing, extensive infrastructure improvements, and replacement space for Noonan Building tenants, while creating jobs, housing, and a vibrant community as contemplated under California Assembly Bill 418 (AB 418) (Stats. 2011, ch. 477), which made Pier 70-specific amendments to the Burton Act (Stats. 1969, ch. 1333).
PPS-MU	Potrero Power Station Special Use District	Miscellaneous	(a) **Purpose and Boundaries.** A Special Use District entitled the "Potrero Power Station Special Use District" (the SUD) is hereby established, generally bounded by 22nd Street and the southern portion of the newly created Craig Lane to the north, the San Francisco Bay to the east, 23rd Street to the south, and Illinois Street to the west, in the southeast part of San Francisco. The precise boundaries of the SUD are shown on Sectional Map SU08 of the Zoning Map. The purpose of the SUD is to implement the land use controls for the Potrero Power Station Mixed-Use Project, which is subject to a Development Agreement, approved by the Board of Supervisors in the ordinance contained in Board File No. 200040. The Project will provide several benefits to the City, such as a significant amount of publicly accessible open space and Community Facilities, increased public access to the waterfront, neighborhood-serving retail, extensive infrastructure improvements, and affordable housing, while creating jobs, housing, and a vibrant community.
M-1	Light Industrial	Industrial	In general, the M-1 Districts are more suitable for smaller industries dependent upon truck transportation, while the M-2 Districts are more suitable for larger industries served by rail and water transportation and by large utility lines. In M-1 Districts, most industries are permitted, but some with particularly noxious characteristics are excluded. The permitted industries have certain requirements as to enclosure, screening, and minimum distance from Residential Districts.
M-2	Heavy Industrial	Industrial	These Districts are the least restricted as to use and are located at the eastern edge of the City, separated from residential and commercial areas. The heavier industries are permitted, with fewer requirements as to screening and enclosure than in M-1 Districts, but many of these uses are permitted only as conditional uses or at a considerable distance from Residential Districts. Most of the land zoned M-2 is controlled by the Port of San Francisco.

EXHIBIT "W - 1"
ZONING DESCRIPTION SUMMARY
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID
DATE OF VALUE: JULY 27, 2021

Zoning Designation		Zoning Use District	Zoning Descriptions
PDR-1-B	Production, Distribution & Repair-Light Industrial Buffer	Production, Distribution & Repair	The intent of this District is to create a buffer area between residential neighborhoods and light industrial areas, primarily in the Bayview Hunters Point neighborhood. Thus, this District prohibits residential uses and limits Office, Retail, and Institutional uses. Generally, all other uses are permitted. This zone allows for less intensive production, distribution, and repair activities that will not compromise the quality of life of nearby residents. These uses generate less external noise, odors, and vibrations and engage in fewer trucking activities than those permitted in PDR-2 Districts. Uses in this District are generally conducted completely within enclosed structures. Small-scale Retail and Office uses are permitted, as are other activities that may serve well to buffer existing residential neighborhoods from areas of concentrated industrial operations. In considering any new land use not contemplated in this District, the Zoning Administrator shall take into account the intent of this District as expressed in this Section and in the General Plan.
PDR-1-D	Production, Distribution & Repair-Design	Production, Distribution & Repair	The intention of this District is to retain and encourage less-intensive production, distribution, and repair businesses, especially the existing clusters of design-related businesses. Thus, this District prohibits Residential and Office uses, and limits Retail and Institutional uses. Additionally, this District prohibits heavy industrial uses, which generate external noise, odors, and vibrations and engage in frequent trucking activities. Generally, all other uses are permitted. In considering any new land use not contemplated in this District, the Zoning Administrator shall take into account the intent of this District as expressed in this Section and in the General Plan.
PDR-1-G	Production, Distribution & Repair-General	Production, Distribution & Repair	The intention of this District is to retain and encourage existing production, distribution, and repair activities and promote new business formation. Thus, this District prohibits Residential and Office uses, and limits Retail and Institutional uses. Additionally, this District allows for more intensive production, distribution, and repair activities than PDR-1-B and PDR-1-D but less intensive than PDR-2. Generally, all other uses are permitted. In considering any new land use not contemplated in this District, the Zoning Administrator shall take into account the intent of this District as expressed in this Section and in the General Plan.
PDR-2	Production, Distribution & Repair Core Production, Distribution & Repair	Production, Distribution & Repair	The intent of this District is to encourage the introduction, intensification, and protection of a wide range of light and contemporary industrial activities. Thus, this District prohibits new housing, large office developments, large-scale retail, and the heaviest of industrial uses, such as incinerators. Generally, all other uses are permitted. The conservation of existing flexible industrial buildings is also encouraged. This District permits certain non-industrial, non-residential uses, including small-scale Retail and Office, Entertainment, certain institutions, and similar uses that would not create conflicts with the primary industrial uses or are compatible with the operational characteristics of businesses in the area. Light industrial uses in this District may be conducted entirely within an enclosed structure, partly within enclosed structures, or some functions may occur entirely in open areas. These uses may require trucking activity multiple times per day, including trucks with up to 18 wheels or more, and occurring at any time of the day or night. As part of their daily operations, PDR activities in these areas may emit noises, vibrations, odors, and other emissions, as permitted by law. Within the requirements of local, state, and federal health and safety regulations, and within the stipulation of this Code, which may impose additional use size maximums and minimum distance requirements on certain activities, raw materials used for production, manufacturing, repair, storage, research, and distribution may be stored on site and may include chemical, biological, and other hazardous, explosive, or flammable materials. In considering any new land use not contemplated in this District, the Zoning Administrator shall take into account the intent of this District as expressed in this Section and in the General Plan.
P	Public	Public	(a) In addition to the use districts otherwise established by this Code, there shall also be in the City a Public Use District herein referred to as a "P District," to apply to land that is owned by a governmental agency and in some form of public use, including open space. (b) The purpose of designating such land as a P District on the Zoning Map is to relate the Zoning Map to actual land use and to the General Plan with respect to such land. Any lot in a P District may be occupied by a principal use listed in Section 211.1, or by a conditional use listed in Section 211.2, subject to applicable regulations of this Code. Principal uses not identified under Sections 211.1 or 211.2 of this Code are not permitted in any P District.

Exhibit W-2: Zoning Designation and Use District Summary

EXHIBIT "W - 2"
ZONING DESIGNATION AND USE DISTRICT SUMMARY
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - PRIVATE EASEMENTS
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

ZONING DESCRIPTION			ELECTRIC TRANSMISSION ("ET")						ELECTRIC DISTRIBUTION ("ED")												TOTAL	
			ET - UG			ET - OH	ET - TOTAL		ED - UFM			ED - UG			ED - OH			ED - TOTAL			Land Area	% of Total
Zoning Designation		Zoning Use District	Linear Feet	Land Area	% of Total	Land Area	Land Area	% of Total	Linear Feet	Land Area	% of Total	Linear Feet	Land Area	% of Total	Linear Feet	Land Area	% of Total	Linear Feet	Land Area	% of Total		
RH -1	Residential, House-One Family	Residential, House Character	1,983 lf	89,257 sf	17.42%		93,691 sf	18.13%	22,356 lf	223,559 sf	7.84%	9,360 lf	93,601 sf	8.49%	62,405 lf	624,050 sf	19.53%	94,121 lf	941,210 sf	13.17%	**1,034,901 sf**	**13.50%**
RH-1(D)	Residential, House-One Family(Detached Dwelling)	Residential, House Character			0.00%		0 sf	0.00%	62,285 lf	622,852 sf	21.84%	13,968 lf	139,683 sf	12.67%	156,626 lf	1,566,264 sf	49.03%	232,880 lf	2,328,800 sf	32.57%	**2,328,800 sf**	**30.38%**
RH-1(S)	Residential, House-One Family with Minor Second Unit	Residential, House Character			0.00%		0 sf	0.00%			0.00%			0.00%	23 lf	229 sf	0.01%	23 lf	229 sf	0.00%	**229 sf**	**0.00%**
RH-2	Residential, House-Two-Family	Residential, House Character	697 lf	31,360 sf	6.12%		31,360 sf	6.07%	9,973 lf	99,732 sf	3.50%	6,974 lf	69,736 sf	6.33%	10,024 lf	100,243 sf	3.14%	26,971 lf	269,711 sf	3.77%	**301,071 sf**	**3.93%**
RH-3	Residential, House-Three Family	Residential, House Character			0.00%		0 sf	0.00%	3,561 lf	35,612 sf	1.25%	1,498 lf	14,980 sf	1.36%	3,374 lf	33,738 sf	1.06%	8,433 lf	84,330 sf	1.18%	**84,330 sf**	**1.10%**
RM-1	Residential, Mixed-Low Density	Residential, Mixed (Houses & Apartments)	755 lf	33,978 sf	6.63%		33,978 sf	6.57%	12,976 lf	129,755 sf	4.55%	5,341 lf	53,413 sf	4.85%	8,355 lf	83,547 sf	2.62%	26,671 lf	266,715 sf	3.73%	**300,693 sf**	**3.92%**
RM-2	Residential, Mixed-Moderate Density	Residential, Mixed (Houses & Apartments)			0.00%		0 sf	0.00%	3,764 lf	37,644 sf	1.32%	998 lf	9,980 sf	0.91%	1,514 lf	15,137 sf	0.47%	6,276 lf	62,761 sf	0.88%	**62,761 sf**	**0.82%**
RM-3	Residential, Mixed-Medium Density	Residential, Mixed (Houses & Apartments)			0.00%		0 sf	0.00%	6,735 lf	67,353 sf	2.36%	394 lf	3,945 sf	0.36%	767 lf	7,673 sf	0.24%	7,897 lf	78,970 sf	1.10%	**78,970 sf**	**1.03%**
RM-4	Residential, High Density	Residential, Mixed (Houses & Apartments)			0.00%		0 sf	0.00%	3,266 lf	32,659 sf	1.15%	475 lf	4,747 sf	0.43%	983 lf	9,828 sf	0.31%	4,723 lf	47,235 sf	0.66%	**47,235 sf**	**0.62%**
RC-3	Residential-Commercial-Medium Density	Residential-Commercial Combined			0.00%		0 sf	0.00%	771 lf	7,709 sf	0.27%	29 lf	291 sf	0.03%			0.00%	800 lf	8,000 sf	0.11%	**8,000 sf**	**0.10%**
RC-4	Residential-Commercial-High Density	Residential-Commercial Combined			0.00%		0 sf	0.00%	5,275 lf	52,747 sf	1.85%			0.00%	8 lf	84 sf	0.00%	5,283 lf	52,831 sf	0.74%	**52,831 sf**	**0.69%**
RTO	Residential, Transit-Oriented Neighborhood	Residential Transit Oriented			0.00%		0 sf	0.00%	5,089 lf	50,893 sf	1.78%			0.00%	208 lf	2,076 sf	0.06%	5,297 lf	52,969 sf	0.74%	**52,969 sf**	**0.69%**
RTO-M	Residential, Transit-Oriented Mission Neighborhood	Residential Transit Oriented			0.00%		0 sf	0.00%	1,642 lf	16,421 sf	0.58%			0.00%	68 lf	681 sf	0.02%	1,710 lf	17,102 sf	0.24%	**17,102 sf**	**0.22%**
RH DTR	Rincon Hill Downtown Residential	Downtown Residential			0.00%		0 sf	0.00%	897 lf	8,970 sf	0.31%			0.00%	18 lf	182 sf	0.01%	915 lf	9,152 sf	0.13%	**9,152 sf**	**0.12%**
SB-DTR	South Beach Downtown Residential	Downtown Residential			0.00%		0 sf	0.00%	4,213 lf	42,131 sf	1.48%			0.00%			0.00%	4,213 lf	42,131 sf	0.59%	**42,131 sf**	**0.55%**
TB DTR	Transbay Downtown Residential	Downtown Residential			0.00%		0 sf	0.00%	320 lf	3,197 sf	0.11%			0.00%			0.00%	320 lf	3,197 sf	0.04%	**3,197 sf**	**0.04%**
C-2	Community Business	Commercial			0.00%		0 sf	0.00%	12,801 lf	128,009 sf	4.49%	3,970 lf	39,704 sf	3.60%	564 lf	5,636 sf	0.18%	17,335 lf	173,349 sf	2.42%	**173,349 sf**	**2.26%**
C-3-G	Downtown General	Commercial			0.00%		0 sf	0.00%	2,815 lf	28,151 sf	0.99%			0.00%			0.00%	2,815 lf	28,151 sf	0.39%	**28,151 sf**	**0.37%**
C-3-O	Downtown Office	Commercial			0.00%		0 sf	0.00%	2,107 lf	21,074 sf	0.74%			0.00%			0.00%	2,107 lf	21,074 sf	0.29%	**21,074 sf**	**0.27%**
C-3-O(SD)	Downtown Office Special Development	Commercial			0.00%		0 sf	0.00%	1,986 lf	19,861 sf	0.70%			0.00%			0.00%	1,986 lf	19,861 sf	0.28%	**19,861 sf**	**0.26%**
C-3-R	Downtown Retail	Commercial			0.00%		0 sf	0.00%	922 lf	9,217 sf	0.32%			0.00%	1 lf	13 sf	0.00%	923 lf	9,230 sf	0.13%	**9,230 sf**	**0.12%**
C-3-S	Downtown Support	Commercial			0.00%		0 sf	0.00%	1,741 lf	17,411 sf	0.61%			0.00%			0.00%	1,741 lf	17,411 sf	0.24%	**17,411 sf**	**0.23%**
NC-1	Neighborhood Commercial Cluster (1 Commerical Story)	Neighborhood Commercial	21 lf	946 sf	0.18%		946 sf	0.18%	654 lf	6,540 sf	0.23%	676 lf	6,759 sf	0.61%	494 lf	4,942 sf	0.15%	1,824 lf	18,240 sf	0.26%	**19,186 sf**	**0.25%**
NC-2	Neighborhood Commercial Small-Scale (2 Commerical Stories)	Neighborhood Commercial			0.00%		0 sf	0.00%	342 lf	3,418 sf	0.12%	43 lf	434 sf	0.04%	444 lf	4,435 sf	0.14%	829 lf	8,287 sf	0.12%	**8,287 sf**	**0.11%**
NC-3	Neighborhood Commercial Moderate-Scale (3+ Commerical Stories)	Neighborhood Commercial	12 lf	536 sf	0.10%		536 sf	0.10%	2,721 lf	27,211 sf	0.95%	44 lf	440 sf	0.04%	116 lf	1,163 sf	0.04%	2,881 lf	28,813 sf	0.40%	**29,349 sf**	**0.38%**
NCD	Neighborhood Commercial Districts	Neighborhood Commercial	5 lf	244 sf	0.05%		244 sf	0.05%	6,691 lf	66,907 sf	2.35%	1,058 lf	10,582 sf	0.96%	1,551 lf	15,505 sf	0.49%	9,299 lf	92,994 sf	1.30%	**93,238 sf**	**1.22%**
NC-S	Neighborhood Commercial Shopping Center	Neighborhood Commercial	222 lf	9,986 sf	1.95%		9,986 sf	1.93%	6,457 lf	64,573 sf	2.26%	1,223 lf	12,230 sf	1.11%	652 lf	6,515 sf	0.20%	8,332 lf	83,318 sf	1.17%	**93,304 sf**	**1.22%**
NCT	Hayes-Gough Neighborhood Commercial Transit District	Neighborhood Commercial Transit			0.00%		0 sf	0.00%	8,992 lf	89,920 sf	3.15%			0.00%	1,052 lf	10,517 sf	0.33%	10,044 lf	100,437 sf	1.40%	**100,437 sf**	**1.31%**
NCT-1	Neighborhood Commercial Transit Cluster	Neighborhood Commercial Transit			0.00%		0 sf	0.00%	6 lf	58 sf	0.00%			0.00%			0.00%	6 lf	58 sf	0.00%	**58 sf**	**0.00%**

EXHIBIT "W - 2"
ZONING DESIGNATION AND USE DISTRICT SUMMARY
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - PRIVATE EASEMENTS
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

ZONING DESCRIPTION			ELECTRIC TRANSMISSION ("ET")						ELECTRIC DISTRIBUTION ("ED")												TOTAL	
			ET - UG			ET - OH	ET - TOTAL		ED - UFM			ED - UG			ED - OH			ED - TOTAL			Land Area	% of Total
Zoning Designation		Zoning Use District	Linear Feet	Land Area	% of Total	Land Area	Land Area	% of Total	Linear Feet	Land Area	% of Total	Linear Feet	Land Area	% of Total	Linear Feet	Land Area	% of Total	Linear Feet	Land Area	% of Total		
NCT-2	Small-Scale Neighborhood Commercial Transit	Neighborhood Commercial Transit			0.00%		0 sf	0.00%	20 lf	196 sf	0.01%			0.00%			0.00%	20 lf	196 sf	0.00%	**196 sf**	**0.00%**
NCT-3	Moderate-Scale Neighborhood Commercial Transit	Neighborhood Commercial Transit			0.00%		0 sf	0.00%	963 lf	9,634 sf	0.34%			0.00%	34 lf	339 sf	0.01%	997 lf	9,973 sf	0.14%	**9,973 sf**	**0.13%**
RCD	Regional Commercial	Neighborhood Commercial Transit			0.00%		0 sf	0.00%	344 lf	3,439 sf	0.12%			0.00%			0.00%	344 lf	3,439 sf	0.05%	**3,439 sf**	**0.04%**
CMUO	Central SoMa Mixed Use Office	Eastern Neighborhoods Mixed Use	7 lf	311 sf	0.06%		311 sf	0.06%	2,652 lf	26,516 sf	0.93%			0.00%	3 lf	31 sf	0.00%	2,655 lf	26,547 sf	0.37%	**26,858 sf**	**0.35%**
MUG	Mixed Use General	Eastern Neighborhoods Mixed Use			0.00%		0 sf	0.00%	479 lf	4,792 sf	0.17%			0.00%	15 lf	150 sf	0.00%	494 lf	4,942 sf	0.07%	**4,942 sf**	**0.06%**
MUO	Mixed Use Office	Eastern Neighborhoods Mixed Use			0.00%		0 sf	0.00%	1,183 lf	11,827 sf	0.41%			0.00%	10 lf	97 sf	0.00%	1,192 lf	11,924 sf	0.17%	**11,924 sf**	**0.16%**
MUR	Mixed Use Residential	Eastern Neighborhoods Mixed Use	222 lf	9,972 sf	1.95%		9,972 sf	1.93%	1,774 lf	17,743 sf	0.62%			0.00%	8 lf	85 sf	0.00%	1,783 lf	17,828 sf	0.25%	**27,800 sf**	**0.36%**
RED	Residential Enclave District	Eastern Neighborhoods Mixed Use			0.00%		0 sf	0.00%	157 lf	1,566 sf	0.05%			0.00%			0.00%	157 lf	1,566 sf	0.02%	**1,566 sf**	**0.02%**
RED-MX	Residential Enclave District-Mixed	Eastern Neighborhoods Mixed Use			0.00%		0 sf	0.00%	251 lf	2,511 sf	0.09%			0.00%			0.00%	251 lf	2,511 sf	0.04%	**2,511 sf**	**0.03%**
SALI	Service/Arts/Light Industrial	Eastern Neighborhoods Mixed Use			0.00%		0 sf	0.00%	1,071 lf	10,708 sf	0.38%			0.00%	81 lf	811 sf	0.03%	1,152 lf	11,519 sf	0.16%	**11,519 sf**	**0.15%**
SPD	South Park	Eastern Neighborhoods Mixed Use			0.00%		0 sf	0.00%	22 lf	220 sf	0.01%			0.00%	0 lf	2 sf	0.00%	22 lf	222 sf	0.00%	**222 sf**	**0.00%**
UMU	Urban Mixed Use	Eastern Neighborhoods Mixed Use	985 lf	44,329 sf	8.65%		44,329 sf	8.58%	6,436 lf	64,363 sf	2.26%			0.00%	512 lf	5,118 sf	0.16%	6,948 lf	69,481 sf	0.97%	**113,810 sf**	**1.48%**
WMUG	Western SoMa Mixed Use-General	Eastern Neighborhoods Mixed Use			0.00%		0 sf	0.00%	1,320 lf	13,197 sf	0.46%			0.00%			0.00%	1,320 lf	13,197 sf	0.18%	**13,197 sf**	**0.17%**
WMUO	Western SoMa Mixed Use-Office	Eastern Neighborhoods Mixed Use			0.00%		0 sf	0.00%	311 lf	3,108 sf	0.11%			0.00%	28 lf	281 sf	0.01%	339 lf	3,389 sf	0.05%	**3,389 sf**	**0.04%**
CCB	Chinatown Community Business	Chinatown Mixed Use			0.00%		0 sf	0.00%	109 lf	1,090 sf	0.04%			0.00%			0.00%	109 lf	1,090 sf	0.02%	**1,090 sf**	**0.01%**
CRNC	Chinatown Residential/Neighborhood Commercial	Chinatown Mixed Use			0.00%		0 sf	0.00%	241 lf	2,409 sf	0.08%			0.00%	26 lf	261 sf	0.01%	267 lf	2,670 sf	0.04%	**2,670 sf**	**0.03%**
CVR	Chinatown Visitor Retail	Chinatown Mixed Use			0.00%		0 sf	0.00%	74 lf	741 sf	0.03%			0.00%			0.00%	74 lf	741 sf	0.01%	**741 sf**	**0.01%**
PM-MU1	Parkmerced - Mixed Use-Social Heart District	Parkmerced Use			0.00%		0 sf	0.00%	72 lf	724 sf	0.03%	142 lf	1,422 sf	0.13%	1,332 lf	13,319 sf	0.42%	1,547 lf	15,465 sf	0.22%	**15,465 sf**	**0.20%**
PM-MU2	Parkmerced - Mixed Use-Neighborhood Commons	Parkmerced Use			0.00%		0 sf	0.00%	379 lf	3,789 sf	0.13%			0.00%			0.00%	379 lf	3,789 sf	0.05%	**3,789 sf**	**0.05%**
PM-OS	Parkmerced - Open Space District	Parkmerced Use			0.00%		0 sf	0.00%	918 lf	9,178 sf	0.32%			0.00%			0.00%	918 lf	9,178 sf	0.13%	**9,178 sf**	**0.12%**
PM-R	Parkmerced - Residential	Parkmerced Use			0.00%		0 sf	0.00%	4,307 lf	43,073 sf	1.51%	137 lf	1,367 sf	0.12%			0.00%	4,444 lf	44,440 sf	0.62%	**44,440 sf**	**0.58%**
HP-RA	Hunter's Point-Redevelopment Area	Miscellaneous			0.00%		0 sf	0.00%			0.00%	1,066 lf	10,657 sf	0.97%	14,306 lf	143,063 sf	4.48%	15,372 lf	153,720 sf	2.15%	**153,720 sf**	**2.01%**
MB-O	Mission Bay - Office	Miscellaneous			0.00%		0 sf	0.00%	130 lf	1,301 sf	0.05%	16,800 lf	168,000 sf	15.24%	269 lf	2,692 sf	0.08%	17,199 lf	171,993 sf	2.41%	**171,993 sf**	**2.24%**
MB-RA	Mission Bay - Redevelopment	Miscellaneous	867 lf	39,005 sf	7.61%		39,005 sf	7.55%	20,198 lf	201,980 sf	7.08%			0.00%	547 lf	5,466 sf	0.17%	20,745 lf	207,446 sf	2.90%	**246,451 sf**	**3.21%**
MR-MU	Mission Rock Mixed Use	Miscellaneous			0.00%		0 sf	0.00%	190 lf	1,899 sf	0.07%			0.00%	950 lf	9,500 sf	0.30%	1,140 lf	11,399 sf	0.16%	**11,399 sf**	**0.15%**
P70-MU	Pier 70 Special Use - Mixed Use	Miscellaneous			0.00%		0 sf	0.00%			0.00%			0.00%	6 lf	62 sf	0.00%	6 lf	62 sf	0.00%	**62 sf**	**0.00%**
PPS-MU	Potrero Power Station Special Use District	Miscellaneous			0.00%		0 sf	0.00%	553 lf	5,528 sf	0.19%			0.00%			0.00%	553 lf	5,528 sf	0.08%	**5,528 sf**	**0.07%**
M-1	Light Industrial	Industrial	27 lf	1,198 sf	0.23%		1,198 sf	0.23%	766 lf	7,664 sf	0.27%	1,052 lf	10,521 sf	0.95%	12 lf	115 sf	0.00%	1,830 lf	18,300 sf	0.26%	**19,498 sf**	**0.25%**
M-2	Heavy Industrial	Industrial			0.00%		0 sf	0.00%	1,356 lf	13,564 sf	0.48%	5,483 lf	54,834 sf	4.98%	5,653 lf	56,531 sf	1.77%	12,493 lf	124,929 sf	1.75%	**124,929 sf**	**1.63%**

EXHIBIT "W - 2"
ZONING DESIGNATION AND USE DISTRICT SUMMARY
PG&E ELECTRIC TRANSMISSION AND DISTRIBUTION GRID - PRIVATE EASEMENTS
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

ZONING DESCRIPTION			ELECTRIC TRANSMISSION ("ET")						ELECTRIC DISTRIBUTION ("ED")												TOTAL	
			ET - UG			ET - OH	ET - TOTAL		ED - UFM			ED - UG			ED - OH			ED - TOTAL			Land Area	% of Total
Zoning Designation		Zoning Use District	Linear Feet	Land Area	% of Total	Land Area	Land Area	% of Total	Linear Feet	Land Area	% of Total	Linear Feet	Land Area	% of Total	Linear Feet	Land Area	% of Total	Linear Feet	Land Area	% of Total		
PDR-1-B	Production, Distribution & Repair-Light Industrial Buffer	Production, Distribution & Repair			0.00%		0 sf	0.00%	191 lf	1,905 sf	0.07%	38 lf	375 sf	0.03%			0.00%	228 lf	2,280 sf	0.03%	**2,280 sf**	**0.03%**
PDR-1-D	Production, Distribution & Repair-Design	Production, Distribution & Repair			0.00%		0 sf	0.00%	496 lf	4,965 sf	0.17%			0.00%	20 lf	196 sf	0.01%	516 lf	5,161 sf	0.07%	**5,161 sf**	**0.07%**
PDR-1-G	Production, Distribution & Repair-General	Production, Distribution & Repair	264 lf	11,882 sf	2.32%		11,882 sf	2.30%	4,249 lf	42,492 sf	1.49%			0.00%	1,752 lf	17,516 sf	0.55%	6,001 lf	60,008 sf	0.84%	**71,890 sf**	**0.94%**
PDR-2	Production, Distribution & Repair Core Production, Distribution & Repair	Production, Distribution & Repair	2,163 lf	97,322 sf	18.99%		97,322 sf	18.83%	12,557 lf	125,571 sf	4.40%	1,679 lf	16,792 sf	1.52%	7,248 lf	72,479 sf	2.27%	21,484 lf	214,843 sf	3.01%	**312,165 sf**	**4.07%**
P	Public	Public	3,158 lf	142,102 sf	27.73%		142,102 sf	27.49%	30,097 lf	300,971 sf	10.55%	37,767 lf	377,670 sf	34.27%	37,406 lf	374,060 sf	11.71%	105,270 lf	1,052,701 sf	14.73%	**1,194,803 sf**	**15.59%**
Total			11,387 lf	512,428 sf	100.00%		516,862 sf	100.00%	285,225 lf	2,852,248 sf	100.00%	110,216 lf	1,102,163 sf	100.00%	319,463 lf	3,194,631 sf	100.00%	714,904 lf	7,149,042 sf	100.00%	**7,665,904 sf**	**100.00%**
ALLOCATION BY ZONING USE DISTRICT																						
Zoning Use District																						
Residential, House Character			2,680 lf	120,617 sf	23.54%		125,051 sf	24.19%	98,176 lf	981,755 sf	34.42%	31,800 lf	318,001 sf	28.85%	232,452 lf	2,324,524 sf	72.76%	362,428 lf	3,624,280 sf	50.70%	**3,749,331 sf**	**48.91%**
Residential, Mixed (Houses & Apartments)			755 lf	33,978 sf	6.63%		33,978 sf	6.57%	26,741 lf	267,411 sf	9.38%	7,208 lf	72,085 sf	6.54%	11,619 lf	116,185 sf	3.64%	45,568 lf	455,681 sf	6.37%	**489,659 sf**	**6.39%**
Residential-Commercial Combined			0 lf	0 sf	0.00%		0 sf	0.00%	6,046 lf	60,456 sf	2.12%	29 lf	291 sf	0.03%	8 lf	84 sf	0.00%	6,083 lf	60,831 sf	0.85%	**60,831 sf**	**0.79%**
Residential Transit Oriented			0 lf	0 sf	0.00%		0 sf	0.00%	6,731 lf	67,314 sf	2.36%	0 lf	0 sf	0.00%	276 lf	2,757 sf	0.09%	7,007 lf	70,071 sf	0.98%	**70,071 sf**	**0.91%**
Downtown Residential			0 lf	0 sf	0.00%		0 sf	0.00%	5,430 lf	54,298 sf	1.90%	0 lf	0 sf	0.00%	18 lf	182 sf	0.01%	5,448 lf	54,480 sf	0.76%	**54,480 sf**	**0.71%**
Commercial			0 lf	0 sf	0.00%		0 sf	0.00%	22,372 lf	223,723 sf	7.84%	3,970 lf	39,704 sf	3.60%	565 lf	5,649 sf	0.18%	26,907 lf	269,076 sf	3.76%	**269,076 sf**	**3.51%**
Neighborhood Commercial			260 lf	11,712 sf	2.29%		11,712 sf	2.27%	16,865 lf	168,649 sf	5.91%	3,044 lf	30,444 sf	2.76%	3,256 lf	32,560 sf	1.02%	23,165 lf	231,653 sf	3.24%	**243,365 sf**	**3.17%**
Neighborhood Commercial Transit			0 lf	0 sf	0.00%		0 sf	0.00%	10,325 lf	103,247 sf	3.62%	0 lf	0 sf	0.00%	1,086 lf	10,856 sf	0.34%	11,410 lf	114,103 sf	1.60%	**114,103 sf**	**1.49%**
Eastern Neighborhoods Mixed Use			1,214 lf	54,612 sf	10.66%		54,612 sf	10.57%	15,655 lf	156,551 sf	5.49%	0 lf	0 sf	0.00%	657 lf	6,574 sf	0.21%	16,313 lf	163,125 sf	2.28%	**217,737 sf**	**2.84%**
Chinatown Mixed Use			0 lf	0 sf	0.00%		0 sf	0.00%	424 lf	4,240 sf	0.15%	0 lf	0 sf	0.00%	26 lf	261 sf	0.01%	450 lf	4,501 sf	0.06%	**4,501 sf**	**0.06%**
Parkmerced Use			0 lf	0 sf	0.00%		0 sf	0.00%	5,676 lf	56,764 sf	1.99%	279 lf	2,789 sf	0.25%	1,332 lf	13,319 sf	0.42%	7,287 lf	72,871 sf	1.02%	**72,871 sf**	**0.95%**
Miscellaneous			867 lf	39,005 sf	7.61%		39,005 sf	7.55%	21,071 lf	210,708 sf	7.39%	17,866 lf	178,657 sf	16.21%	16,078 lf	160,782 sf	5.03%	55,015 lf	550,147 sf	7.70%	**589,152 sf**	**7.69%**
Industrial			27 lf	1,198 sf	0.23%		1,198 sf	0.23%	2,123 lf	21,228 sf	0.74%	6,535 lf	65,354 sf	5.93%	5,665 lf	56,646 sf	1.77%	14,323 lf	143,229 sf	2.00%	**144,427 sf**	**1.88%**
Production, Distribution & Repair			2,427 lf	109,204 sf	21.31%		109,204 sf	21.13%	17,493 lf	174,933 sf	6.13%	1,717 lf	17,168 sf	1.56%	9,019 lf	90,192 sf	2.82%	28,229 lf	282,293 sf	3.95%	**391,497 sf**	**5.11%**
Public			3,158 lf	142,102 sf	27.73%		142,102 sf	27.49%	30,097 lf	300,971 sf	10.55%	37,767 lf	377,670 sf	34.27%	37,406 lf	374,060 sf	11.71%	105,270 lf	1,052,701 sf	14.73%	**1,194,803 sf**	**15.59%**
Total			**11,387 lf**	**512,428 sf**	**100.00%**		**516,862 sf**	**100.00%**	**285,225 lf**	**2,852,248 sf**	**100.00%**	**110,216 lf**	**1,102,163 sf**	**100.00%**	**319,463 lf**	**3,194,631 sf**	**100.00%**	**714,904 lf**	**7,149,042 sf**	**100.00%**	7,665,904 sf	100.00%

Exhibit W-3: Land Sales Summary & Adjustments

EXHIBIT "W - 3"
LAND SALES & ADJUSTMENTS
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

Comp #	Location	Buyer (Grantee)	Seller (Grantor)	Document No.	COE	Size (sf)	Size (ac)	Sale Price	Price per SF	District	Zoning	Zoning Use District
1	524 Howard Street	Ridgegate Apartments, LLC et al.	Howard/First Property LLC	2019-9K764208-00006	05/07/19	12,266	0.282	$78,000,000	$6,359.04	SoMa/Rincon Hill	C-3-O (SD)	Commercial
2	325 Fremont Street	Full Energy Properties, LLC	Fremont 325 Development, LLC	2015-9K026582-00004	02/26/15	6,434	0.150	$28,500,000	$4,429.59	SoMa/Rincon Hill	RH DTR	Downtown Residential
3	525 Harrison Street	Hong You Properties, LLC	Guang De CA LLC	2017-9K469244-00003	06/26/17	12,981	0.298	$36,000,000	$2,773.28	SoMa/Rincon Hill	RH DTR	Downtown Residential
4	547 Howard Street	Pacific Howard Corporation	547-549 Howard Street	2015-9K051061-00003	04/22/15	2,126	0.049	$6,300,000	$2,963.31	SoMa/Transbay	C-3-O (SD)	Commercial
5	555 Howard Street	Pacific Howard Corporation	Paul Descalso Trust	2015-9K053233-00014	04/28/15	8,250	0.189	$27,000,100	$3,272.74	SoMa/Transbay	C-3-O (SD)	Commercial
6	557 Howard Street	Pacific Howard Corporation	Guggie H, LLC	2015-9K055129-00003	05/01/15	4,121	0.095	$12,250,000	$2,972.58	SoMa/Transbay	C-3-O (SD)	Commercial
7	901 Illinois Street	64 PKN Owner LLC	City and County of San Francisco	2019-K731222-00006	02/13/19	67,988	1.561	$24,000,000	$353.00	Bayview/Dogpatch	PDR-2	Production, Distribution & Repair
8	790 Pennsylvania Avenue	RP Pennsylvania, LLC	2007 Sherman C. Little and Delaine K. Little Revocable Trust et al.	216-9K210708-00008	03/03/16	119,885	2.752	$35,000,000	$291.95	Potrero Hill	UMU (Lot 13)/ PDR-1-G (Lot 11)	Eastern Neighborhoods Mixed Use / Production, Distribution & Repair
9	1755 Egbert Avenue	Pacific Gas and Electric Company	Egbert Enterprises LLC	2021-015848	01/29/21	70,446	1.617	$16,950,000	$240.61	Produce Market	PDR-2	Production, Distribution & Repair
10	2270 Jerrod Avenue	GIC San Francisco LLC	First Student, Inc.	2022-047193	05/09/22	154,883	3.556	$70,070,000	$452.41	Produce Market	PDR-2	Production, Distribution & Repair
11	2150 Oakdale Avenue	Prologis-Exchange 2150 Oakdale LLC	MacBeath Hardwood Company	2019-9K764192-00005	05/07/19	52,085	1.196	$13,750,000	$263.99	Produce Market	PDR-2	Production, Distribution & Repair
12	2000 Marin Street	City and County of San Francisco	2000 Marin Property, LP	2020-K927582-00007	04/30/20	343,688	7.890	$63,600,000	$185.05	Central Waterfront	PDR-2	Production, Distribution & Repair
13	430 Eddy Street	SF Eddy Housing Investors, LP	430 Eddy Street Associates LLC et al.	2020-047619	11/12/20	3,578	0.082	$3,250,000	$908.33	Tenderloin	RC-4	Residential-Commercial Combined
14	199 Turk and 180 Jones Streets	MM 180 Jones LLC	Jones Development Project, LLC	2016-9K364758-00003	11/30/16	4,744	0.109	$4,000,000	$843.17	Tenderloin	RC-4	Residential-Commercial Combined
15	530-540 Turk Street	530 Turk Street LLC	Family Bypass Trust et al.	2022-063571	06/26/22	9,583	0.220	$3,850,000	$401.75	Tenderloin	RC-4	Residential-Commercial Combined
16	500 Turk Street	Turk 500 Associates, LP	Frederick Rolandi, III	2016-9K377413-00009	12/20/16	18,906	0.434	$12,250,000	$647.94	Tenderloin	RC-4	Residential-Commercial Combined
17	719-725 Larkin Street	Sean Sullivan	M & M Investments	---	12/31/15	5,998	0.138	$3,000,000	$500.17	Tenderloin	RC-4	Residential-Commercial Combined
18	1550 Market Street	Full Bright Properties, LLC	TUP Market LLC	2015-9K159514-00004	11/24/15	12,567	0.288	$23,000,000	$1,830.19	Market-Octavia	C-3-G	Commercial
19	72-80 Ellis Street	72 Ellis Owner LP	AGPME Parking Lot, LLC	2015-K060083-00	05/13/15	8,240	0.189	$9,900,000	$1,201.46	Union Square	C-3-R	Commercial
20	1121-1125 Mission Street	Pacific 1125 Market Corporation	1125 Market, LLC	2015-9K06618-00004	05/22/15	12,402	0.285	$19,800,000	$1,596.52	SoMa/Mid-Market	C-3-G	Commercial
21	30 Van Ness St	30 Van Ness Development LLC	City and County of San Francisco	2017-9K447786-00006	05/05/17	38,124	0.875	$70,000,000	$1,836.11	Market-Octavia	C-3-G	Commercial
22	1338-1370 Mission Street	SPF2 1370 Mission St, LLC	MCC 1360 LLC	2015-K158782-00	11/20/15	18,901	0.434	$25,000,000	$1,322.68	WSoMa	C-3-G	Commercial
23	2100 Mission Street	2100 Mission Street Impossible LLC	Muller 2005 Trust	2019-9K818307-00004	08/22/19	6,370	0.146	$4,800,000	$753.53	Mission	NCT	Neighborhood Commercial Transit
24	1490 Ocean Avenue	ISCA Assets 33, LLC	Saint Anthony Real Estate, LLC	2015-9K11442-00003	08/25/15	10,237	0.235	$5,300,000	$517.73	Westwood Park	NCT	Neighborhood Commercial Transit
25	1455 Irving Street	Edward Romanov and Janet Romanov	Karl Olson and Karen Olson	2016-9K354888-00002	11/07/16	4,792	0.110	$1,570,000	$327.63	Outer Sunset	NCD	Neighborhood Commercial
26	3820 24th Street	Hurwitz-Family Living Trust	3820 24th Street LLC	2016-9K246774-00004	05/20/16	2,849	0.065	$2,100,000	$737.10	Noe Valley	NCD	Neighborhood Commercial
27	2550 Irving Street	2550 Irving Associates LP	The Police Credit Union of California	2021-172913	11/19/21	19,162	0.440	$9,000,000	$469.68	Outer Sunset	NCD	Neighborhood Commercial
28A	42 & 44 Cook Street	Jewish Family and Children's Services	44 Cook LLC	2023-020157	03/17/23	3,000	0.069	$3,350,000	$1,116.67	Laurel Heights	RH-2	Residential, House Character
28B	42 & 44 Cook Street	44 Cook LLC	DRS Group, LP	2021-018659	02/03/21	3,000	0.069	$1,670,000	$556.67	Laurel Heights	RH-2	Residential, House Character
29	524 Hickory Street	Gilligan of Lenny Family Trust	Reco Investors LLC	2017-9K479111-00003	07/27/17	1,250	0.029	$1,300,000	$1,040.00	Hayes Valley	RH-3 Hayes Valley	Residential, House Character
30	166 Parker Avenue	Frances Biglieri	Wells Fargo Bank, N.A.	2018-9K591558-00003	03/20/18	2,775	0.064	$1,650,000	$594.59	Laurel Heights	RH-2	Residential, House Character
31	2677 Harrison Street	Abhishek & Alisha Gupta	Fred W & Carolyn Li Deevy	2017-9K519306-00002	09/27/17	2,304	0.053	$1,295,000	$562.07	Mission	RH-3	Residential, House Character
32	1120 Valencia St	M3 LLC	The Evelyn L. Feno Family LP	2018-9K683199-00005	10/16/18	4,134	0.095	$3,460,000	$836.96	Mission	NCT	Neighborhood Commercial Transit
33	1090-1098 Valencia Street	Diamond Bay Valencia Corporation	Pet Co Properties I	2017-9K541022-00004	11/22/17	10,114	0.232	$11,898,000	$1,176.39	Mission	NCT	Neighborhood Commercial Transit
34	606 Capp Street	606 Capp Street LLC	Winter/Capp Street Family Partnership, LP	2015-9K100138-00003	07/31/15	7,350	0.169	$3,300,000	$448.98	Mission	RTO-M	Residential, Transit Oriented
35	1526 Powell Street	Powell Street Partners LLC	Delucchi Mechanical Inc.	2022-038465	04/14/22	5,259	0.121	$2,900,000	$551.44	North Beach	NCD - North Beach	Neighborhood Commercial
36	555 Jackson Street	555 Jackson Ventures LLC	Roman Catholic Archbishop of San Francisco	2019-9K837619-00005	09/27/19	8,089	0.186	$6,500,000	$803.56	Chinatown/Jackson Square	CRNC	Chinatown Mixed Use
37	1198 Columbus Ave/2568 Jones St	Linden Station Columbus LLC	1196 Hotel, LLC	2018-K697461-00	11/26/18	6,420	0.147	$4,500,000	$700.93	North Beach	C-2	Commercial
38	425 Broadway Street	Montgomery Place LLC	Michael A Moglia	2017-9K457063-00008	05/30/17	13,641	0.313	$11,000,000	$806.39	Jackson Square/North Beach	NCD	Neighborhood Commercial
39	1598 Bay Street	Bay Street Partners LLC	Pacific Coast Homes	2015-K165225-00	12/07/15	12,541	0.288	$7,875,000	$627.94	Marina	NC-2	Neighborhood Commercial
40	1633 Cabrillo Street	1633-1649 Cabrillo LLC	1643 Cabrillo, LLC	2016-9K364321-00003	03/20/18	2,775	0.064	$1,650,000	$594.59	Inner Sunset	RH-2	Residential, House Character
41	36 Tehama Street	36 Tehama Partners LLC	Tehama Partners LLC	2018-9K633420-00004	06/28/18	2,000	0.046	$2,500,000	$1,250.00	SoMa/Yerba Buena	C-3-O (SD)	Commercial
42	135 Wetmore Street	Wetmore/Knobhill Partners LLC	APF Development LLC	2016-K210361-00	01/04/17	2,225	0.051	$2,700,000	$1,213.48	Nob Hill	RM-3	Residential, Mixed
43	361-365 21st Street	Woods Family Investments, LP	Kim Wu	2016-9K211142-00002	03/04/16	2,997	0.069	$1,850,000	$617.28	Mission	RH-2	Residential, House Character
44	53 States Street	Golden Properties LLC	53 States Street, LLC	2017-9K405850-00003	02/27/17	2,642	0.061	$1,920,000	$726.72	Corona Heights	RH-2	Residential, House Character
45	2055 Taraval Street	2055 Taraval Street, LLC	Cynthia D. Hampton Revocable Trust	2020-9K898534-00003	02/04/20	3,250	0.075	$1,260,000	$387.69	Parkside	NCD	Neighborhood Commercial
46	134 Athens Street	Louis Maxwell Chou Primax Investments LLC	Leo F Bautista	2022-063281	06/24/22	2,495	0.057	$713,000	$285.77	Portola	RH-1	Residential, House Character
47	332 Bradford Street	Chetan Patil	1948 Quesada Street LLC	2021-016516	02/01/21	1,751	0.040	$563,000	$321.53	Bernal Heights	RH-1	Residential, House Character
48	300 University Street	Yin Kai Tong and Di Fun Tsang Tong	Zhenliving, LLC	2019-9K857400-00003	11/15/19	2,060	0.047	$660,000	$320.39	Portola	RH-1	Residential, House Character
49	302 University Street	Mandy Lee	Zhenliving, LLC	2019-9K857447-00003	11/15/19	2,060	0.047	$560,000	$271.84	Portola	RH-1	Residential, House Character
50	326 Gambier Street	Jimmy Kin Ho Tam and Averie Xiao Zheng	Benton Yiubong Wong, Roland Au-Yeung, and Lisa H. Wong	2021-101636	06/24/21	2,950	0.068	$500,000	$169.49	Portola	RH-1	Residential, House Character
51	1654 Kirkwood Avenue	Lynton LLC	Robert Mendez	2021-060109	04/08/21	5,000	0.115	$1,200,000	$240.00	Baywood	RH-2	Residential, House Character
52A	1782 Quesada Avenue	Golden Sunset Development LLC	1782 Quesada Partners, LLC	2020-9K962446-00002	07/30/20	2,500	0.057	$675,000	$270.00	Baywood	RH-2	Residential, House Character
52B	1782 Quesada Avenue	1782 Quesada Partners, LLC	Melvin Pitre	2017-9K394945-00002	01/13/17	2,500	0.057	$380,000	$152.00	Baywood	RH-2	Residential, House Character
52C	1782 Quesada Avenue	Vincent Gerard Cosgrove and Gerard Gallagher	Golden Sunset Development LLC	2022-087033	09/09/22	2,500	0.057	$400,000	$160.00	Baywood	RH-1	Residential, House Character
53	1750 Oakdale Avenue	Lynton LLC	1748 Oakdale Avenue, LLC	2022-007815	01/25/22	2,500	0.057	$320,000	$128.00	Baywood	RH-2	Residential, House Character
54	1528 Hudson Avenue	Kim M Lam and Angela Y Lam Revocable Trust	Ze Qlang Xiao and Ai Ci Zhang	2022-020574	02/28/22	2,500	0.057	$398,000	$159.20	Baywood	RH-2	Residential, House Character
55	1390 Oakdale Avenue	Michelle Yip and Peter Suen	Charles E and Frances M Jackson	2019-9K741017-00004	03/08/19	2,663	0.061	$425,000	$159.59	Baywood	RH-2	Residential, House Character

EXHIBIT "W - 3"
LAND SALES & ADJUSTMENTS
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

Comp #	Location	Buyer (Grantee)	Seller (Grantor)	Document No.	COE	Size (sf)	Size (ac)	Sale Price	Price per SF	District	Zoning	Zoning Use District
56	150 Eureka Street	150 Eurkea Street	Metropolitan Community Church of San Francisco	2015-9K016292-00003	02/04/15	6,069	0.139	$2,325,000	$383.09	Castro	RH-2	Residential, House Character
57	56 Laussat Street	Martin C and Junyi Li Kellogg	Leonard Krasowski	2021-069734	04/23/21	750	0.017	$428,000	$570.67	Hayes Valley	RTO	Residential, House Character
58	1 Gull Drive	Not applicable	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	South San Francisco	N/Appl.	N/Appl.
59	165 S. Linden Avenue	Not applicable	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	South San Francisco	N/Appl.	N/Appl.
60	1030 Brittan Avenue	Not applicable	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	San Carlos	N/Appl.	N/Appl.
61	595 Industrial Road & 810-850 E. San Carlos Avenue	Not applicable	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	San Carlos	N/Appl.	N/Appl.
62	1401 Shoreway Road	Not applicable	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	N/Appl.	Belmont	N/Appl.	N/Appl.
63	514-580 Minna Street	1948 Quesada Street, LLC	Christopher Joseph Harney and Christina Marina Harney Revocable Living Trust	2020-004604	08/14/20	3,375	0.077	$1,700,000	$503.70	SoMa/Mid-Market	MUG	Eastern Neighborhoods Mixed Use
64	1288 Howard Street	1288 Howard Owner LP	1288 Howard LP	2019-K820923	08/28/19	37,116	0.852	$23,000,000	$619.68	SoMa	Eastern Neighborhoods Mixed Use / Neighborhood Commercial	
65	230-237 7th Street	230 7th Street LLC	South Beach Partners, LLC	2018-9K647074-00006	07/31/18	12,197	0.280	$6,100,000	$500.12	SoMa	WMUG	Eastern Neighborhoods Mixed Use
66	220 9th Street	LMT Home Corporation	Kiner Family Partners LP	2018-K566300	01/12/18	16,121	0.370	$10,350,000	$642.02	SoMa	RCD	Neighborhood Commercial Transit
67	915 Minna Street	915 Minna, LLC	Alta Investors	2017-K462591	06/13/17	11,617	0.267	$6,250,000	$538.00	SoMa	RED-MX	Eastern Neighborhoods Mixed Use
68	292 Arleta Avenue	Massoudi Development LLC	Shue Family Trust	2022-107765	11/30/22	2,495	0.057	$400,000	$160.32	Visitacion Valley	RH-1	Residential, House Character
69	3338 San Bruno Avenue	Quintin Edward Donnelly and Sandy Tran Donne	Ray A. Peralta and Carmelita H. Peralta	2022-033643	04/01/22	1,750	0.040	$275,000	$157.14	Visitacion Valley	RH-1	Residential, House Character
70	666 Hamilton Street	CarlMai, LLC	Valerie J. Hogan	2019-9K830895-0004	09/13/19	9,962	0.229	$1,650,000	$165.63	Portola Valley	RH-1	Residential, House Character
71	154 Delta Street	Kenneth Cui and Chi Hung Chu	Wing On Chan	2017-9K4830888-00002	07/26/17	5,000	0.115	$590,000	$118.00	Visitacion Valley	RH-1	Residential, House Character
72	2168 Bayshore Boulevard	Eddie Y. Law and Wendy Law	Alan K.L. and Adrianne B. Scoggie, Revocable Trust	2017-9K390731-00003	01/03/17	2,195	0.050	$300,000	$136.67	Visitacion Valley	RH-1	Residential, House Character
73	342 22nd Avenue	Elyria Pioneer Construction LLC	Richmond Partners LLC	20026	03/17/23	3,000	0.069	$1,800,000	$600.00	Central Richmond	RM-1	Residential, Mixed
74	347 5th Avenue	McMahon Family Trust	Daniel A. Sheahan, et al	56389	06/03/22	3,000	0.069	$1,825,000	$608.33	Inner Richmond	RM-1	Residential, Mixed
75	112 Kensington Way	K. Jenkins & L. Chandrasekher, H/W	O'Toole Construction Inc.	51445	05/20/22	4,100	0.094	$1,046,850	$255.33	Forest Hills Extension	RH-1(D)	Residential, House Character
76	1713 Yosemite Avenue	Golden East Invt. Group LLC	Zhi Y. Zheng & Yu L. Xie, H/W	32746	03/30/22	5,000	0.115	$1,550,000	$310.00	Bayview	M-1	Industrial
77	448 Valley Street	448 Valley, LLC	Colm Brennan	1153163	10/12/21	2,642	0.061	$1,925,000	$728.61	Noe Valley	RH-2	Residential, House Character
78	47 Montclair Terrace	418 Ventures LLC	Elina Yermian 2013 Living Trust	149228	09/24/21	2,644	0.061	$1,200,000	$453.86	Russian Hill	RH-1	Residential, House Character
79	1133 S. Van Ness Avenue	1133 SVN LLC	Brezzo Properties III, LLC	135212	08/23/21	11,500	0.264	$4,600,000	$400.00	Inner Mission	RH-3	Residential, House Character
80	1450 Marin Street	Mariela Delatorre	Seosamh O,Briain	105849	07/02/21	14,125	0.324	$2,495,000	$176.64	Bayview	PRD-2	Production, Distribution & Repair
81	552 Ortega Street	552 Ortega LLC	Joseph Slamovich Irrev. Trust, et al	91037	06/04/21	3,458	0.079	$940,000	$271.83	Inner Sunset	RH-1	Residential, House Character
82	1 Castenada Avenue	Stachan and Melissa Forgan Tr.	Forest Hill Christian Church	59128	04/07/21	8,140	0.187	$750,000	$92.14	Forest Hill	RH-1 (D)	Residential, House Character
83	39 Santa Rosa Avenue	Ruo Wu Chen & HonJaun Wang, H/W	Mario Gentile	42308	03/05/21	2,495	0.057	$600,000	$240.48	Mission Terrace	RH-1	Residential, House Character
84	1251 Thomas Avenue	Joseph O'Brian, et al	Antonio & Henrietta Ruiz, H/W	35818	02/23/21	9,600	0.220	$1,950,000	$203.13	Bayview	PDR-2	Production, Distribution & Repair
85	1245 Van Dyke Avenue	Silverstone Ventures, LLC	Garza Property Living Trust, et al	32766	02/02/21	78,556	1.803	$7,050,000	$89.74	Bayview	PDR-2	Production, Distribution & Repair
86	7 Edgar Place	T.K. Abib & I.R. Akhbiriq, H/W	Tak Wing, Inc.	952405	07/16/20	4,258	0.098	$699,000	$164.16	Ingleside	RH-1	Residential, House Character
87	2011 Filbert Street	Filbert Partners, LLC	F.R. & A.M. Petuya 1994 Rev. Trust	950391	07/10/20	1,650	0.038	$935,000	$566.67	Cow Hollow	RH-2	Residential, House Character
88	5222-5250 3rd Street	5250 Third Street LLC	Ratti Family Trust, et al	950103	07/10/20	18,883	0.433	$3,000,000	$158.87	Bayview	NCD	Neighborhood Commercial
89	1230 - 1240 Twin Peaks Boulevard	Trust of William & Patrica Mandel	Michael Chung Living Trust	936719	06/01/20	10,723	0.246	$1,506,000	$140.45	Midtown Terrace	RH-1	Residential, House Character
90	4512 23rd Street	Paramount Estate LLC	Richard Ruhland Rev. Living Trust, et al	817093	08/19/19	3,027	0.069	$800,000	$264.29	Twin Peaks	RM-1	Residential, Mixed
91	2921 Vallejo Street	2921 Vallejo Street, LLC	Stein Ting Rev. Trust	796804	07/23/19	4,008	0.092	$8,000,000	$1,996.01	Pacific Heights	RH-1(D)	Residential, House Character
92	923 Kansas Street	939 Kansas, LLC	945 Kansas Street, LLC	786296	06/25/19	12,500	0.287	$7,150,000	$572.00	Potrero Hill	RH-2	Residential, House Character
93	1713 Yosemite Avenue	Zhi Y. Zheng & Yu L. Xie, H/W	Yosemite Partners SF, LLC	658514	08/23/18	5,000	0.115	$1,388,000	$277.60	Bayview	M-1	Industrial
94	287 Minerva Street	Zhou Wen & Rui Zhen Zhao, H/W	R. & Y.C. Cayabyab Family Trust	619766	05/29/18	3,125	0.072	$425,000	$136.00	Oceanview	RH-1	Residential, House Character
95	95 Santa Cruz Avenue	XiaoNa Lin	Andrew T. Shan	614678	05/16/18	1,999	0.046	$450,000	$225.11	Outer Mission	RH-1	Residential, House Character
96	1401 Illinois Street	1401 Illinois LLC	Sheedy, Inc.	609303	05/01/18	79,997	1.836	$23,400,000	$292.51	Central Waterfront	PDR-1-G	Production, Distribution & Repair
97	599 Crestmont Dr	Arsha LLC	San Francisco Overlook Development, LLC	609175	04/30/18	50,094	1.150	$7,600,000	$151.71	Forest Knolls	RM-1	Residential, Mixed
98	1065 Innes Avenue	Jianfeng Chen	The AVTBKH Trust	598515	04/06/18	7,500	0.172	$1,200,000	$160.00	Hunters Point	RH-1	Residential, House Character
99	2175 Hayes Street	Thomas Mc Grath	Charles B. Darke, I	584880	03/05/18	3,868	0.089	$1,650,000	$426.58	North Panhandle	RH-3	Residential, House Character
100	325 29th Avenue	Kenneth Chow	HaeSook Yuo & Kenneth Fukuda	583090	02/27/18	2,996	0.069	$1,300,000	$433.91	Central Richmond	RH-2	Residential, House Character
101	562 28th Ave	Jakon Investment Group LP	T&T Real Estate Dev., LLC	576301	02/08/18	4,796	0.110	$1,925,000	$401.38	Central Richmond	RM-1	Residential, Mixed
102	922 Jamestown Avenue	Yin Kwan Tam, et al	Tatyana Zaytseva	543892	11/30/17	2,609	0.060	$325,000	$124.57	Bayview	RH-1	Residential, House Character
103	127 Edgehill Way	Vladimir Chernyvskiy	Edgehill Properties LLC	561461	10/26/17	3,937	0.090	$880,000	$223.52	Forest Hills Extension	RH-1(D)	Residential, House Character
104	363 21st Avenue	Paramount Estate LLC	Woods Family Investments LP	497189	08/22/17	2,996	0.069	$1,750,000	$584.11	Central Richmond	RM-1	Residential, Mixed
105	423 24th Avenue	Jias Investment LLC	Guo Fu Huang & Qi Nong Ma, H/W	471961	06/30/17	3,000	0.069	$1,960,000	$653.33	Central Richmond	RM-1	Residential, Mixed
106	477 Eucalyptus Drive	Jing Si Chen & Jian Feng Kuang, H/W	Wen Xiong	452049	05/18/17	4,000	0.092	$1,360,000	$340.00	Lakeshore	RH-1(D)	Residential, House Character
Total						1,646,724	37.804	$836,414,950				
Weighted Average									$507.93			

EXHIBIT "W - 3"
LAND SALES & ADJUSTMENTS
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

Comp #	Location	Buyer (Grantee)	Seller (Grantor)	Document No.	COE	Size (sf)	Size (ac)	Sale Price	Price per SF	District	Zoning	Zoning Use District
SUMMARY												
Low					02/04/15	750	0.017	$275,000	$89.74			
High					03/17/23	343,688	7.890	$78,000,000	$6,359.04			
Average					02/11/19	15,834	0.364	$8,042,451	$701.15			
Median					01/04/19	4,501	0.103	$1,937,500	$450.69			
Count					104	104	104	104	104			

(Item Nos. 58 through 62 are excluded)

EXHIBIT "W - 3"
LAND SALES & ADJUSTMENTS
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

					Market Conditions Adjustment							Entitlement Adjustment			Data - Adjusted		
Comp #	Location	Height/Bulk	Entitled at Sale	Quadrant	Sale Price	Sale Date	07/27/21 Date of Value (DOV)	Months from DOV	Monthly Adjustment	Total Adjustment	Time Adjusted Sale Price	Entitled at Sale	20.00% for Entitlement	Time & Entitlement Adjusted	Adjusted Sale Price	Land Area	Price per SF
1	524 Howard Street	450-S (450)	Yes	8	$78,000,000	05/07/19	07/27/21	26.68	0.250%	7.00%	$83,460,000	Yes	0.00%	$83,460,000	$83,460,000	12,266	$6,804.17
2	325 Fremont Street	85/250-R (250)	Yes	8	$28,500,000	02/26/15	07/27/21	76.98	0.417%	32.00%	$37,620,000	Yes	0.00%	$37,620,000	$37,620,000	6,434	$5,847.06
3	525 Harrison Street	65/250-R (250)	Yes	8	$36,000,000	06/26/17	07/27/21	49.02	0.417%	20.00%	$43,200,000	Yes	0.00%	$43,200,000	$43,200,000	12,981	$3,327.94
4	547 Howard Street	350-S (350)	No	8	$6,300,000	04/22/15	07/27/21	75.17	0.250%	19.00%	$7,497,000	No	20.00%	$8,996,400	$8,996,400	2,126	$4,231.61
5	555 Howard Street	350-S (350)	No	8	$27,000,100	04/28/15	07/27/21	74.97	0.250%	19.00%	$32,130,119	No	20.00%	$38,556,143	$38,556,143	8,250	$4,673.47
6	557 Howard Street	350-S (350)	No	8	$12,250,000	05/01/15	07/27/21	74.87	0.250%	19.00%	$14,577,500	No	20.00%	$17,493,000	$17,493,000	4,121	$4,244.84
7	901 Illinois Street	65-J (65)	Partial/Y	8	$24,000,000	02/13/19	07/27/21	29.40	0.833%	24.00%	$29,760,000	Partial/Y	10.00%	$32,736,000	$32,736,000	67,988	$481.50
8	790 Pennsylvania Avenue	40-X (40)	Partial/Y	12	$35,000,000	03/03/16	07/27/21	64.79	0.417%	27.00%	$44,450,000	Partial/Y	10.00%	$48,895,000	$48,895,000	119,885	$407.85
9	1755 Egbert Avenue	65-J (65)	No	16	$16,950,000	01/29/21	07/27/21	5.88	0.833%	5.00%	$17,797,500	No	20.00%	$21,357,000	$21,357,000	70,446	$303.17
10	2270 Jerrod Avenue	65-J (65)	No	12	$70,070,000	05/09/22	07/27/21	(9.40)	0.833%	-8.00%	$64,464,400	No	20.00%	$77,357,280	$77,357,280	154,883	$499.46
11	2150 Oakdale Avenue	65-J (65)	No	12	$13,750,000	05/07/19	07/27/21	26.68	0.833%	22.00%	$16,775,000	No	20.00%	$20,130,000	$20,130,000	52,085	$386.49
12	2000 Marin Street	65-J (65)	No	12	$63,600,000	04/30/20	07/27/21	14.88	0.833%	12.00%	$71,232,000	No	20.00%	$85,478,400	$85,478,400	343,688	$248.71
13	430 Eddy Street	80-T (80)	Yes	7	$3,250,000	11/12/20	07/27/21	8.44	0.417%	4.00%	$3,380,000	Yes	0.00%	$3,380,000	$3,380,000	3,578	$944.66
14	199 Turk and 180 Jones Streets	80-T-120-T (120)	Yes	7	$4,000,000	11/30/16	07/27/21	55.85	0.417%	23.00%	$4,920,000	Yes	0.00%	$4,920,000	$4,920,000	4,744	$1,037.10
15	530-540 Turk Street	80-T (80)	No	7	$3,850,000	06/26/22	07/27/21	(10.97)	-0.333%	4.00%	$4,004,000	No	20.00%	$4,804,800	$4,804,800	9,583	$501.39
16	500 Turk Street	80-T (80)	No	7	$12,250,000	12/20/16	07/27/21	55.20	0.417%	23.00%	$15,067,500	No	20.00%	$18,081,000	$18,081,000	18,906	$956.36
17	719-725 Larkin Street	80-T (80)	No	7	$3,000,000	12/31/15	07/27/21	66.86	0.417%	28.00%	$3,840,000	No	20.00%	$4,608,000	$4,608,000	5,998	$768.26
18	1550 Market Street	120-R-2 (120)	Yes	7	$23,000,000	11/24/15	07/27/21	68.07	0.417%	28.00%	$29,440,000	Yes	0.00%	$29,440,000	$29,440,000	12,567	$2,342.64
19	72-80 Ellis Street	80-130-F (130)	Yes	7	$9,900,000	05/13/15	07/27/21	74.48	0.250%	19.00%	$11,781,000	Yes	0.00%	$11,781,000	$11,781,000	8,240	$1,429.73
20	1121-1125 Mission Street	120-X (120)	Partial/Y	7	$19,800,000	05/22/15	07/27/21	74.18	0.250%	19.00%	$23,562,000	Partial/Y	10.00%	$25,918,200	$25,918,200	12,402	$2,089.84
21	30 Van Ness St	120/400-R-2; 140/520-R-2	No	7	$70,000,000	05/05/17	07/27/21	50.73	0.250%	13.00%	$79,100,000	No	20.00%	$94,920,000	$94,920,000	38,124	$2,489.77
22	1338-1370 Mission Street	120-X (120)/150-S (150)	No	7	$25,000,000	11/20/15	07/27/21	68.21	0.250%	17.00%	$29,250,000	No	20.00%	$35,100,000	$35,100,000	18,901	$1,857.04
23	2100 Mission Street	65-B (65)	Yes	7	$4,800,000	08/22/19	07/27/21	23.16	0.417%	10.00%	$5,280,000	Yes	0.00%	$5,280,000	$5,280,000	6,370	$828.89
24	1490 Ocean Avenue	45-X (45)	No	14	$5,300,000	08/25/15	07/27/21	71.06	0.417%	30.00%	$6,890,000	No	20.00%	$8,268,000	$8,268,000	10,237	$807.66
25	1455 Irving Street	40-X (40)	No	6	$1,570,000	11/07/16	07/27/21	56.61	0.250%	14.00%	$1,789,800	No	20.00%	$2,147,760	$2,147,760	4,792	$448.20
26	3820 24th Street	1-Story	No	11	$2,100,000	05/20/16	07/27/21	62.23	0.250%	16.00%	$2,436,000	No	20.00%	$2,923,200	$2,923,200	2,849	$1,026.04
27	2550 Irving Street	40-X (40)	No	5	$9,000,000	11/19/21	07/27/21	(3.78)	0.250%	-1.00%	$8,910,000	No	20.00%	$10,692,000	$10,692,000	19,162	$557.98
28A	42 & 44 Cook Street	40-X (40)	Yes	6	$3,350,000	03/17/23	07/27/21	(19.65)	-0.333%	7.00%	$3,584,500	Yes	0.00%	$3,584,500	$3,584,500	3,000	$1,194.83
28B	42 & 44 Cook Street	40-X (40)	No	6	$1,670,000	02/03/21	07/27/21	5.72	0.417%	2.00%	$1,703,400	No	20.00%	$2,044,080	$2,044,080	3,000	$681.36
29	524 Hickory Street	40-X (40)	Yes	7	$1,300,000	07/27/17	07/27/21	48.00	0.417%	20.00%	$1,560,000	Yes	0.00%	$1,560,000	$1,560,000	1,250	$1,248.00
30	166 Parker Avenue	40-X (40)	No	6	$1,650,000	03/20/18	07/27/21	40.25	0.417%	17.00%	$1,930,500	No	20.00%	$2,316,600	$2,316,600	2,775	$834.81
31	2677 Harrison Street	40-X (40)	No	11	$1,295,000	09/27/17	07/27/21	45.96	0.417%	19.00%	$1,541,050	No	20.00%	$1,849,260	$1,849,260	2,304	$802.63
32	1120 Valencia St	55-X (55)	No	11	$3,460,000	10/16/18	07/27/21	33.35	0.417%	14.00%	$3,944,400	No	20.00%	$4,733,280	$4,733,280	4,134	$1,144.96
33	1090-1098 Valencia Street	55-X (55)	No	11	$11,898,000	11/22/17	07/27/21	44.12	0.417%	18.00%	$14,039,640	No	20.00%	$16,847,568	$16,847,568	10,114	$1,665.77
34	606 Capp Street	40-X (40)	No	11	$3,300,000	07/31/15	07/27/21	71.89	0.417%	30.00%	$4,290,000	No	20.00%	$5,148,000	$5,148,000	7,350	$700.41
35	1526 Powell Street	40-X (40)	No	3	$2,900,000	04/14/22	07/27/21	(8.57)	0.250%	-2.00%	$2,842,000	No	20.00%	$3,410,400	$3,410,400	5,259	$648.49
36	555 Jackson Street	40-X (40)	No	4	$6,500,000	09/27/19	07/27/21	21.98	0.417%	9.00%	$7,085,000	No	20.00%	$8,502,000	$8,502,000	8,089	$1,051.06
37	1198 Columbus Ave/2568 Jones St	40-X (40)	No	3	$4,500,000	11/26/18	07/27/21	32.00	0.250%	8.00%	$4,860,000	No	20.00%	$5,832,000	$5,832,000	6,420	$908.41
38	425 Broadway Street	65-A-1 (65)	No	4	$11,000,000	05/30/17	07/27/21	49.91	0.250%	12.00%	$12,320,000	No	20.00%	$14,784,000	$14,784,000	13,641	$1,083.79
39	1598 Bay Street	40-X (40)	No	3	$7,875,000	12/07/15	07/27/21	67.65	0.250%	17.00%	$9,213,750	No	20.00%	$11,056,500	$11,056,500	12,541	$881.63
40	1633 Cabrillo Street	40-X (40)	No	6	$1,650,000	03/20/18	07/27/21	40.25	0.417%	17.00%	$1,930,500	No	20.00%	$2,316,600	$2,316,600	2,775	$834.81
41	36 Tehama Street	350-S (350)	No	8	$2,500,000	06/28/18	07/27/21	36.96	0.250%	9.00%	$2,725,000	No	20.00%	$3,270,000	$3,270,000	2,000	$1,635.00
42	135 Wetmore Street	65-A (65)	No	3	$2,700,000	01/04/17	07/27/21	54.70	0.417%	23.00%	$3,321,000	No	20.00%	$3,985,200	$3,985,200	2,225	$1,791.10
43	361-365 21st Street	40-X (40)	Yes	11	$1,850,000	03/04/16	07/27/21	64.76	0.417%	27.00%	$2,349,500	Yes	0.00%	$2,349,500	$2,349,500	2,997	$783.95
44	53 States Street	40-X (40)	Yes	7	$1,920,000	02/27/17	07/27/21	52.93	0.417%	22.00%	$2,342,400	Yes	0.00%	$2,342,400	$2,342,400	2,642	$886.60
45	2055 Taraval Street	50-X (50)	No	9	$1,260,000	02/04/20	07/27/21	17.71	0.250%	4.00%	$1,310,400	No	20.00%	$1,572,480	$1,572,480	3,250	$483.84
46	134 Athens Street	40-X (40)	Yes	15	$713,000	06/24/22	07/27/21	(10.91)	-0.333%	4.00%	$741,520	Yes	0.00%	$741,520	$741,520	2,495	$297.20
47	332 Bradford Street	40-X (40)	Yes	11	$563,000	02/01/21	07/27/21	5.78	0.417%	2.00%	$574,260	Yes	0.00%	$574,260	$574,260	1,751	$327.96
48	300 University Street	40-X (40)	Yes	15	$660,000	11/15/19	07/27/21	20.37	0.417%	8.00%	$712,800	Yes	0.00%	$712,800	$712,800	2,060	$346.02
49	302 University Street	40-X (40)	Yes	15	$560,000	11/15/19	07/27/21	20.37	0.417%	8.00%	$604,800	Yes	0.00%	$604,800	$604,800	2,060	$293.59
50	326 Gambier Street	40-X (40)	No	15	$500,000	06/24/21	07/27/21	1.08	0.417%	0.00%	$500,000	No	20.00%	$600,000	$600,000	2,950	$203.39
51	1654 Kirkwood Avenue	40-X (40)	Yes	12	$1,200,000	04/08/21	07/27/21	3.61	0.417%	2.00%	$1,224,000	Yes	0.00%	$1,224,000	$1,224,000	5,000	$244.80
52A	1782 Quesada Avenue	40-X (40)	Yes	12	$675,000	07/30/20	07/27/21	11.89	0.417%	5.00%	$708,750	Yes	0.00%	$708,750	$708,750	2,500	$283.50
52B	1782 Quesada Avenue	40-X (40)	No	12	$380,000	01/13/17	07/27/21	54.41	0.417%	23.00%	$467,400	No	20.00%	$560,880	$560,880	2,500	$224.35
52C	1782 Quesada Avenue	40-X (40)	Yes	12	$400,000	09/09/22	07/27/21	(13.44)	-0.333%	4.00%	$416,000	Yes	0.00%	$416,000	$416,000	2,500	$166.40
53	1750 Oakdale Avenue	40-X (40)	No	12	$320,000	01/25/22	07/27/21	(5.98)	-0.333%	2.00%	$326,400	No	20.00%	$391,680	$391,680	2,500	$156.67
54	1528 Hudson Avenue	40-X (40)	No	12	$398,000	02/28/22	07/27/21	(7.10)	-0.333%	2.00%	$405,960	No	20.00%	$487,152	$487,152	2,500	$194.86
55	1390 Oakdale Avenue	40-X (40)	No	12	$425,000	03/08/19	07/27/21	28.65	0.417%	12.00%	$476,000	No	20.00%	$571,200	$571,200	2,663	$214.49

EXHIBIT "W - 3"
LAND SALES & ADJUSTMENTS
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

							Market Conditions Adjustment					Entitlement Adjustment			Data - Adjusted		
Comp #	Location	Height/Bulk	Entitled at Sale	Quadrant	Sale Price	Sale Date	07/27/21 Date of Value (DOV)	Months from DOV	Monthly Adjustment	Total Adjustment	Time Adjusted Sale Price	Entitled at Sale	20.00% for Entitlement	Time & Entitlement Adjusted	Adjusted Sale Price	Land Area	Price per SF
56	150 Eureka Street	40-X (40)	No	11	$2,325,000	02/04/15	07/27/21	77.70	0.417%	32.00%	$3,069,000	No	20.00%	$3,682,800	$3,682,800	6,069	$606.82
57	56 Laussat Street	40-X (40)	No	7	$428,000	04/23/21	07/27/21	3.12	0.417%	1.00%	$432,280	No	20.00%	$518,736	$518,736	750	$691.65
58	1 Gull Drive	N/Appl.	N/Appl.	---	---	---	---	---	---	---	---	---	---	---	---	---	---
59	165 S. Linden Avenue	N/Appl.	N/Appl.	---	---	---	---	---	---	---	---	---	---	---	---	---	---
60	1030 Brittan Avenue	N/Appl.	N/Appl.	---	---	---	---	---	---	---	---	---	---	---	---	---	---
61	595 Industrial Road & 810-850 E. San Carlos Avenue	N/Appl.	N/Appl.	---	---	---	---	---	---	---	---	---	---	---	---	---	---
62	1401 Shoreway Road	N/Appl.	N/Appl.	---	---	---	---	---	---	---	---	---	---	---	---	---	---
63	514-580 Minna Street	45-X (45)	No	7	$1,700,000	08/14/20	07/27/21	11.40	0.417%	5.00%	$1,785,000	No	20.00%	$2,142,000	$2,142,000	3,375	$634.67
64	1288 Howard Street		No	7	$23,000,000	08/28/19	07/27/21	22.97	0.417%	10.00%	$25,300,000	No	20.00%	$30,360,000	$30,360,000	37,116	$817.98
65	230-237 7th Street	65-X (65)	No	7	$6,100,000	07/31/18	07/27/21	35.88	0.417%	15.00%	$7,015,000	No	20.00%	$8,418,000	$8,418,000	12,197	$690.17
66	220 9th Street	55-X (55)	No	7	$10,350,000	01/12/18	07/27/21	42.45	0.417%	18.00%	$12,213,000	No	20.00%	$14,655,600	$14,655,600	16,121	$909.10
67	915 Minna Street	45-X (45)	No	7	$6,250,000	06/13/17	07/27/21	49.45	0.417%	21.00%	$7,562,500	No	20.00%	$9,075,000	$9,075,000	11,617	$781.18
68	292 Arleta Avenue	40-X (40)	No	15	$400,000	11/30/22	07/27/21	(16.13)	-0.333%	5.00%	$420,000	No	20.00%	$504,000	$504,000	2,495	$202.00
69	3338 San Bruno Avenue	40-X (40)	No	16	$275,000	04/01/22	07/27/21	(8.15)	-0.333%	3.00%	$283,250	No	20.00%	$339,900	$339,900	1,750	$194.23
70	666 Hamilton Street	40-X (40)	No	15	$1,650,000	09/13/19	07/27/21	22.44	0.417%	9.00%	$1,798,500	No	20.00%	$2,158,200	$2,158,200	9,962	$216.64
71	154 Delta Street	40-X (40)	No	15	$590,000	07/26/17	07/27/21	48.03	0.417%	20.00%	$708,000	No	20.00%	$849,600	$849,600	5,000	$169.92
72	2168 Bayshore Boulevard	40-X (40)	No	16	$300,000	01/03/17	07/27/21	54.74	0.417%	23.00%	$369,000	No	20.00%	$442,800	$442,800	2,195	$201.73
73	342 22nd Avenue	40-X (40)	Yes	5	$1,800,000	03/17/23	07/27/21	(19.65)	-0.333%	7.00%	$1,926,000	Yes	0.00%	$1,926,000	$1,926,000	3,000	$642.00
74	347 5th Avenue	40-X (40)	Yes	6	$1,825,000	06/03/22	07/27/21	(10.22)	-0.333%	3.00%	$1,879,750	Yes	0.00%	$1,879,750	$1,879,750	3,000	$626.58
75	112 Kensington Way	40-X (40)	Yes	10	$1,046,850	05/20/22	07/27/21	(9.76)	-0.333%	3.00%	$1,078,256	Yes	0.00%	$1,078,256	$1,078,256	4,100	$262.99
76	1713 Yosemite Avenue	65-J (65)	Yes	16	$1,550,000	03/30/22	07/27/21	(8.08)	0.833%	-7.00%	$1,441,500	Yes	0.00%	$1,441,500	$1,441,500	5,000	$288.30
77	448 Valley Street	40-X (40)	Yes	11	$1,925,000	10/12/21	07/27/21	(2.53)	-0.333%	1.00%	$1,944,250	Yes	0.00%	$1,944,250	$1,944,250	2,642	$735.90
78	47 Montclair Terrace	40-X (40)	No	3	$1,200,000	09/24/21	07/27/21	(1.94)	-0.333%	1.00%	$1,212,000	No	20.00%	$1,454,400	$1,454,400	2,644	$550.08
79	1133 S. Van Ness Avenue	50-X (50)	Yes	11	$4,600,000	08/23/21	07/27/21	(0.89)	-0.333%	0.00%	$4,600,000	Yes	0.00%	$4,600,000	$4,600,000	11,500	$400.00
80	1450 Marin Street	65-J (65)	No	12	$2,495,000	07/02/21	07/27/21	0.82	0.833%	1.00%	$2,519,950	No	20.00%	$3,023,940	$3,023,940	14,125	$214.08
81	552 Ortega Street	40-X (40)	No	10	$940,000	06/04/21	07/27/21	1.74	0.417%	1.00%	$949,400	No	20.00%	$1,139,280	$1,139,280	3,458	$329.46
82	1 Castenada Avenue	40-X (40)	No	10	$750,000	04/07/21	07/27/21	3.65	0.417%	2.00%	$765,000	No	20.00%	$918,000	$918,000	8,140	$112.78
83	39 Santa Rosa Avenue	40-X (40)	No	15	$600,000	03/05/21	07/27/21	4.73	0.417%	2.00%	$612,000	No	20.00%	$734,400	$734,400	2,495	$294.35
84	1251 Thomas Avenue	40-X (40)	No	16	$1,950,000	02/23/21	07/27/21	5.06	0.833%	4.00%	$2,028,000	No	20.00%	$2,433,600	$2,433,600	9,600	$253.50
85	1245 Van Dyke Avenue	40-X (40)	No	16	$7,050,000	02/02/21	07/27/21	5.75	0.833%	5.00%	$7,402,500	No	20.00%	$8,883,000	$8,883,000	78,556	$113.08
86	7 Edgar Place	40-X (40)	Partial/Y	14	$699,000	07/16/20	07/27/21	12.35	0.417%	5.00%	$733,950	Partial/Y	10.00%	$807,345	$807,345	4,258	$189.61
87	2011 Filbert Street	40-X (40)	No	3	$935,000	07/10/20	07/27/21	12.55	0.417%	5.00%	$981,750	No	20.00%	$1,178,100	$1,178,100	1,650	$714.00
88	5222-5250 3rd Street	40-X (40)	No	16	$3,000,000	07/10/20	07/27/21	12.55	0.250%	3.00%	$3,090,000	No	20.00%	$3,708,000	$3,708,000	18,883	$196.37
89	1230 - 1240 Twin Peaks Boulevard	40-X (40)	No	10	$1,506,000	06/01/20	07/27/21	13.83	0.417%	6.00%	$1,596,360	No	20.00%	$1,915,632	$1,915,632	10,723	$178.65
90	4512 23rd Street	40-X (40)	Partial/Y	10	$800,000	08/19/19	07/27/21	23.26	0.417%	10.00%	$880,000	Partial/Y	10.00%	$968,000	$968,000	3,027	$319.79
91	2921 Vallejo Street	40-X (40)	Yes	2	$8,000,000	07/23/19	07/27/21	24.15	0.417%	10.00%	$8,800,000	Yes	0.00%	$8,800,000	$8,800,000	4,008	$2,195.61
92	923 Kansas Street	40-X (40)	Yes	12	$7,150,000	06/25/19	07/27/21	25.07	0.417%	10.00%	$7,865,000	Yes	0.00%	$7,865,000	$7,865,000	12,500	$629.20
93	1713 Yosemite Avenue	65-J (65)	Unknown	16	$1,388,000	08/23/18	07/27/21	35.12	0.833%	29.00%	$1,790,520	Unknown	0.00%	$1,790,520	$1,790,520	5,000	$358.10
94	287 Minerva Street	40-X (40)	No	14	$425,000	05/29/18	07/27/21	37.95	0.417%	16.00%	$493,000	No	20.00%	$591,600	$591,600	3,125	$189.31
95	95 Santa Cruz Avenue	40-X (40)	No	14	$450,000	05/16/18	07/27/21	38.37	0.417%	16.00%	$522,000	No	20.00%	$626,400	$626,400	1,999	$313.36
96	1401 Illinois Street	40-X (40)	No	12	$23,400,000	05/01/18	07/27/21	38.87	0.833%	32.00%	$30,888,000	No	20.00%	$37,065,600	$37,065,600	79,997	$463.34
97	599 Crestmont Dr	40-X (40)	Yes	10	$7,600,000	04/30/18	07/27/21	38.90	0.417%	16.00%	$8,816,000	Yes	20.00%	$10,579,200	$10,579,200	50,094	$211.19
98	1065 Innes Avenue	40-X (40)	Yes	12	$1,200,000	04/06/18	07/27/21	39.69	0.417%	17.00%	$1,404,000	Yes	0.00%	$1,404,000	$1,404,000	7,500	$187.20
99	2175 Hayes Street	40-X (40)	No	6	$1,650,000	03/05/18	07/27/21	40.74	0.417%	17.00%	$1,930,500	No	20.00%	$2,316,600	$2,316,600	3,868	$598.91
100	325 29th Avenue	40-X (40)	Yes	5	$1,300,000	02/27/18	07/27/21	40.94	0.417%	17.00%	$1,521,000	Yes	0.00%	$1,521,000	$1,521,000	2,996	$507.68
101	562 28th Ave	40-X (40)	Yes	5	$1,925,000	02/08/18	07/27/21	41.56	0.417%	17.00%	$2,252,250	Yes	0.00%	$2,252,250	$2,252,250	4,796	$469.61
102	922 Jamestown Avenue	40-X (40)	No	16	$325,000	11/30/17	07/27/21	43.86	0.417%	18.00%	$383,500	No	20.00%	$460,200	$460,200	2,609	$176.39
103	127 Edgehill Way	40-X (40)	Yes	10	$880,000	10/26/17	07/27/21	45.01	0.417%	19.00%	$1,047,200	Yes	0.00%	$1,047,200	$1,047,200	3,937	$265.99
104	363 21st Avenue	40-X (40)	Yes	5	$1,750,000	08/22/17	07/27/21	47.15	0.417%	20.00%	$2,100,000	Yes	0.00%	$2,100,000	$2,100,000	2,996	$700.93
105	423 24th Avenue	40-X (40)	Yes	5	$1,960,000	06/30/17	07/27/21	48.89	0.417%	20.00%	$2,352,000	Yes	0.00%	$2,352,000	$2,352,000	3,000	$784.00
106	477 Eucalyptus Drive	40-X (40)	Yes	13/14	$1,360,000	05/18/17	07/27/21	50.30	0.417%	21.00%	$1,645,600	Yes	0.00%	$1,645,600	$1,645,600	4,000	$411.40
Total											$953,071,515			$1,078,237,852	$1,078,237,852	1,646,724 37.80 acres	
Weighted Average											$578.77			$654.78			$654.78

EXHIBIT "W - 3"
LAND SALES & ADJUSTMENTS
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

					Market Conditions Adjustment						Entitlement Adjustment			Data - Adjusted		
Comp #	Location	Height/Bulk	Entitled at Sale	Quadrant	Sale Price	Sale Date	07/27/21 Date of Value (DOV)	Months from DOV	Monthly Adjustment	Total Adjustment	Time Adjusted Sale Price	Entitled at Sale	20.00% for Entitlement	Time & Entitlement Adjusted	Adjusted Sale Price	Land Area	Price per SF

SUMMARY

	Adjusted Sale Price	Land Area	Price per SF
Low	$339,900	750	$112.78
High	$94,920,000	343,688	$6,804.17
Average	$10,367,672	15,834	$891.89
Median	$2,350,750	4,501	$578.45
Count	104	104	104

MARKET CONDITIONS ADJUSTMENTS

Description	Adjustment Annual	Adjustment Monthly		Zoning Use District
Residential Zoning Use Districts:	5.000%	0.417%	Sale Prior to Date of Value	(Residential, House Character; Residential, Mixed; Residential-Commercial Combined; Downtown Residential)
Residential Zoning Use Districts:	-4.000%	-0.333%	Sale After Date of Value	(Residential, House Character; Residential, Mixed; Residential-Commercial Combined; Downtown Residential)
Mixed Use Zoning Use Districts:	5.000%	0.417%	Sale Date to Date of Value	(Eastern Neighborhoods Mixed Use; Chinatown Mixed Use; Neighborhood Commercial Transit)
Industrial Zoning Use Districts:	10.000%	0.833%	Sale Date to Date of Value	(Industrial; Production, Distribution & Repair)
Commercial Zoning Use Districts:	3.000%	0.250%	Sale Date to Date of Value	(Commercial; Neighborhood Commercial)

Exhibit W-4: Land Sales Summary & Adjustments – By Quadrant

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

			Market Conditions Adjustment							Entitlement Adjustment			Data - Adjusted			Quadrant 1		
Comp #	Location	Quadrant	Sale Price	Sale Date	07/27/21 Date of Value (DOV)	Months from DOV	Monthly Adjustment	Total Adjustment	Time Adjusted Sale Price	Entitled at Sale	20.00% for Entitlement	Time & Entitlement Adjusted	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF
1	524 Howard Street	8	$78,000,000	05/07/19	07/27/21	26.68	0.250%	7.00%	$83,460,000	Yes	0.00%	$83,460,000	$83,460,000	12,266	$6,804.17			
2	325 Fremont Street	8	$28,500,000	02/26/15	07/27/21	76.98	0.417%	32.00%	$37,620,000	Yes	0.00%	$37,620,000	$37,620,000	6,434	$5,847.06			
3	525 Harrison Street	8	$36,000,000	06/26/17	07/27/21	49.02	0.417%	20.00%	$43,200,000	Yes	0.00%	$43,200,000	$43,200,000	12,981	$3,327.94			
4	547 Howard Street	8	$6,300,000	04/22/15	07/27/21	75.17	0.250%	19.00%	$7,497,000	No	20.00%	$8,996,400	$8,996,400	2,126	$4,231.61			
5	555 Howard Street	8	$27,000,100	04/28/15	07/27/21	74.97	0.250%	19.00%	$32,130,119	No	20.00%	$38,556,143	$38,556,143	8,250	$4,673.47			
6	557 Howard Street	8	$12,250,000	05/01/15	07/27/21	74.87	0.250%	19.00%	$14,577,500	No	20.00%	$17,493,000	$17,493,000	4,121	$4,244.84			
7	901 Illinois Street	8	$24,000,000	02/13/19	07/27/21	29.40	0.833%	24.00%	$29,760,000	Partial/Y	10.00%	$32,736,000	$32,736,000	67,988	$481.50			
8	790 Pennsylvania Avenue	12	$35,000,000	03/03/16	07/27/21	64.79	0.417%	27.00%	$44,450,000	Partial/Y	10.00%	$48,895,000	$48,895,000	119,885	$407.85			
9	1755 Egbert Avenue	16	$16,950,000	01/29/21	07/27/21	5.88	0.833%	5.00%	$17,797,500	No	20.00%	$21,357,000	$21,357,000	70,446	$303.17			
10	2270 Jerrod Avenue	12	$70,070,000	05/09/22	07/27/21	(9.40)	0.833%	-8.00%	$64,464,400	No	20.00%	$77,357,280	$77,357,280	154,883	$499.46			
11	2150 Oakdale Avenue	12	$13,750,000	05/07/19	07/27/21	26.68	0.833%	22.00%	$16,775,000	No	20.00%	$20,130,000	$20,130,000	52,085	$386.49			
12	2000 Marin Street	12	$63,600,000	04/30/20	07/27/21	14.88	0.833%	12.00%	$71,232,000	No	20.00%	$85,478,400	$85,478,400	343,688	$248.71			
13	430 Eddy Street	7	$3,250,000	11/12/20	07/27/21	8.44	0.417%	4.00%	$3,380,000	Yes	0.00%	$3,380,000	$3,380,000	3,578	$944.66			
14	199 Turk and 180 Jones Streets	7	$4,000,000	11/30/16	07/27/21	55.85	0.417%	23.00%	$4,920,000	Yes	0.00%	$4,920,000	$4,920,000	4,744	$1,037.10			
15	530-540 Turk Street	7	$3,850,000	06/26/22	07/27/21	(10.97)	-0.333%	4.00%	$4,004,000	No	20.00%	$4,804,800	$4,804,800	9,583	$501.39			
16	500 Turk Street	7	$12,250,000	12/20/16	07/27/21	55.20	0.417%	23.00%	$15,067,500	No	20.00%	$18,081,000	$18,081,000	18,906	$956.36			
17	719-725 Larkin Street	7	$3,000,000	12/31/15	07/27/21	66.86	0.417%	28.00%	$3,840,000	No	20.00%	$4,608,000	$4,608,000	5,998	$768.26			
18	1550 Market Street	7	$23,000,000	11/24/15	07/27/21	68.07	0.417%	28.00%	$29,440,000	Yes	0.00%	$29,440,000	$29,440,000	12,567	$2,342.64			
19	72-80 Ellis Street	7	$9,900,000	05/13/15	07/27/21	74.48	0.250%	19.00%	$11,781,000	Yes	0.00%	$11,781,000	$11,781,000	8,240	$1,429.73			
20	1121-1125 Mission Street	7	$19,800,000	05/22/15	07/27/21	74.18	0.250%	19.00%	$23,562,000	Partial/Y	10.00%	$25,918,200	$25,918,200	12,402	$2,089.84			
21	30 Van Ness St	7	$70,000,000	05/05/17	07/27/21	50.73	0.250%	13.00%	$79,100,000	No	20.00%	$94,920,000	$94,920,000	38,124	$2,489.77			
22	1338-1370 Mission Street	7	$25,000,000	11/20/15	07/27/21	68.21	0.250%	17.00%	$29,250,000	No	20.00%	$35,100,000	$35,100,000	18,901	$1,857.04			
23	2100 Mission Street	7	$4,800,000	08/22/19	07/27/21	23.16	0.417%	10.00%	$5,280,000	Yes	0.00%	$5,280,000	$5,280,000	6,370	$828.89			
24	1490 Ocean Avenue	14	$5,300,000	08/25/15	07/27/21	71.06	0.417%	30.00%	$6,890,000	No	20.00%	$8,268,000	$8,268,000	10,237	$807.66			
25	1455 Irving Street	6	$1,570,000	11/07/16	07/27/21	56.61	0.250%	14.00%	$1,789,800	No	20.00%	$2,147,760	$2,147,760	4,792	$448.20			
26	3820 24th Street	11	$2,100,000	05/20/16	07/27/21	62.23	0.250%	16.00%	$2,436,000	No	20.00%	$2,923,200	$2,923,200	2,849	$1,026.04			
27	2550 Irving Street	5	$9,000,000	11/19/21	07/27/21	(3.78)	0.250%	-1.00%	$8,910,000	No	20.00%	$10,692,000	$10,692,000	19,162	$557.98			
28A	42 & 44 Cook Street	6	$3,350,000	03/17/23	07/27/21	(19.65)	-0.333%	7.00%	$3,584,500	Yes	0.00%	$3,584,500	$3,584,500	3,000	$1,194.83			
28B	42 & 44 Cook Street	6	$1,670,000	02/03/21	07/27/21	5.72	0.417%	2.00%	$1,703,400	No	20.00%	$2,044,080	$2,044,080	3,000	$681.36			
29	524 Hickory Street	7	$1,300,000	07/27/17	07/27/21	48.00	0.417%	20.00%	$1,560,000	Yes	0.00%	$1,560,000	$1,560,000	1,250	$1,248.00			
30	166 Parker Avenue	6	$1,650,000	03/20/18	07/27/21	40.25	0.417%	17.00%	$1,930,500	No	20.00%	$2,316,600	$2,316,600	2,775	$834.81			
31	2677 Harrison Street	11	$1,295,000	09/27/17	07/27/21	45.96	0.417%	19.00%	$1,541,050	No	20.00%	$1,849,260	$1,849,260	2,304	$802.63			
32	1120 Valencia St	11	$3,460,000	10/16/18	07/27/21	33.35	0.417%	14.00%	$3,944,400	No	20.00%	$4,733,280	$4,733,280	4,134	$1,144.96			
33	1090-1098 Valencia Street	11	$11,898,000	11/22/17	07/27/21	44.12	0.417%	18.00%	$14,039,640	No	20.00%	$16,847,568	$16,847,568	10,114	$1,665.77			
34	606 Capp Street	11	$3,300,000	07/31/15	07/27/21	71.89	0.417%	30.00%	$4,290,000	No	20.00%	$5,148,000	$5,148,000	7,350	$700.41			
35	1526 Powell Street	3	$2,900,000	04/14/22	07/27/21	(8.57)	0.250%	-2.00%	$2,842,000	No	20.00%	$3,410,400	$3,410,400	5,259	$648.49			
36	555 Jackson Street	4	$6,500,000	09/27/19	07/27/21	21.98	0.417%	9.00%	$7,085,000	No	20.00%	$8,502,000	$8,502,000	8,089	$1,051.06			
37	1198 Columbus Ave/2568 Jones St	3	$4,500,000	11/26/18	07/27/21	32.00	0.250%	8.00%	$4,860,000	No	20.00%	$5,832,000	$5,832,000	6,420	$908.41			
38	425 Broadway Street	4	$11,000,000	05/30/17	07/27/21	49.91	0.250%	12.00%	$12,320,000	No	20.00%	$14,784,000	$14,784,000	13,641	$1,083.79			
39	1598 Bay Street	3	$7,875,000	12/07/15	07/27/21	67.65	0.250%	17.00%	$9,213,750	No	20.00%	$11,056,500	$11,056,500	12,541	$881.63			
40	1633 Cabrillo Street	6	$1,650,000	03/20/18	07/27/21	40.25	0.417%	17.00%	$1,930,500	No	20.00%	$2,316,600	$2,316,600	2,775	$834.81			
41	36 Tehama Street	8	$2,500,000	06/28/18	07/27/21	36.96	0.250%	9.00%	$2,725,000	No	20.00%	$3,270,000	$3,270,000	2,000	$1,635.00			
42	135 Wetmore Street	3	$2,700,000	01/04/17	07/27/21	54.70	0.417%	23.00%	$3,321,000	No	20.00%	$3,985,200	$3,985,200	2,225	$1,791.10			
43	361-365 21st Street	11	$1,850,000	03/04/16	07/27/21	64.76	0.417%	27.00%	$2,349,500	Yes	0.00%	$2,349,500	$2,349,500	2,997	$783.95			
44	53 States Street	7	$1,920,000	02/27/17	07/27/21	52.93	0.417%	22.00%	$2,342,400	Yes	0.00%	$2,342,400	$2,342,400	2,642	$886.60			
45	2055 Taraval Street	9	$1,260,000	02/04/20	07/27/21	17.71	0.250%	4.00%	$1,310,400	No	20.00%	$1,572,480	$1,572,480	3,250	$483.84			
46	134 Athens Street	15	$713,000	06/24/22	07/27/21	(10.91)	-0.333%	4.00%	$741,520	Yes	0.00%	$741,520	$741,520	2,495	$297.20			
47	332 Bradford Street	11	$563,000	02/01/21	07/27/21	5.78	0.417%	2.00%	$574,260	Yes	0.00%	$574,260	$574,260	1,751	$327.96			
48	300 University Street	15	$660,000	11/15/19	07/27/21	20.37	0.417%	8.00%	$712,800	Yes	0.00%	$712,800	$712,800	2,060	$346.02			
49	302 University Street	15	$560,000	11/15/19	07/27/21	20.37	0.417%	8.00%	$604,800	Yes	0.00%	$604,800	$604,800	2,060	$293.59			
50	326 Gambier Street	15	$500,000	06/24/21	07/27/21	1.08	0.417%	0.00%	$500,000	No	20.00%	$600,000	$600,000	2,950	$203.39			
51	1654 Kirkwood Avenue	12	$1,200,000	04/08/21	07/27/21	3.61	0.417%	2.00%	$1,224,000	Yes	0.00%	$1,224,000	$1,224,000	5,000	$244.80			
52A	1782 Quesada Avenue	12	$675,000	07/30/20	07/27/21	11.89	0.417%	5.00%	$708,750	Yes	0.00%	$708,750	$708,750	2,500	$283.50			
52B	1782 Quesada Avenue	12	$380,000	01/13/17	07/27/21	54.41	0.417%	23.00%	$467,400	No	20.00%	$560,880	$560,880	2,500	$224.35			

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

			Market Conditions Adjustment							Entitlement Adjustment			Data - Adjusted			Quadrant 1		
Comp #	Location	Quadrant	Sale Price	Sale Date	07/27/21 Date of Value (DOV)	Months from DOV	Monthly Adjustment	Total Adjustment	Time Adjusted Sale Price	Entitled at Sale	20.00% for Entitlement	Time & Entitlement Adjusted	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF
52C	1782 Quesada Avenue	12	$400,000	09/09/22	07/27/21	(13.44)	-0.333%	4.00%	$416,000	Yes	0.00%	$416,000	$416,000	2,500	$166.40			
53	1750 Oakdale Avenue	12	$320,000	01/25/22	07/27/21	(5.98)	-0.333%	2.00%	$326,400	No	20.00%	$391,680	$391,680	2,500	$156.67			
54	1528 Hudson Avenue	12	$398,000	02/28/22	07/27/21	(7.10)	-0.333%	2.00%	$405,960	No	20.00%	$487,152	$487,152	2,500	$194.86			
55	1390 Oakdale Avenue	12	$425,000	03/08/19	07/27/21	28.65	0.417%	12.00%	$476,000	No	20.00%	$571,200	$571,200	2,663	$214.49			
56	150 Eureka Street	11	$2,325,000	02/04/15	07/27/21	77.70	0.417%	32.00%	$3,069,000	No	20.00%	$3,682,800	$3,682,800	6,069	$606.82			
57	56 Laussat Street	7	$428,000	04/23/21	07/27/21	3.12	0.417%	1.00%	$432,280	No	20.00%	$518,736	$518,736	750	$691.65			
58	1 Gull Drive	---	---	---	---	---	---	---	---	---	---	---	---	---	---			
59	165 S. Linden Avenue	---	---	---	---	---	---	---	---	---	---	---	---	---	---			
60	1030 Brittan Avenue	---	---	---	---	---	---	---	---	---	---	---	---	---	---			
61	595 Industrial Road & 810-850 E. San Carlos Avenue	---	---	---	---	---	---	---	---	---	---	---	---	---	---			
62	1401 Shoreway Road	---	---	---	---	---	---	---	---	---	---	---	---	---	---			
63	514-580 Minna Street	7	$1,700,000	08/14/20	07/27/21	11.40	0.417%	5.00%	$1,785,000	No	20.00%	$2,142,000	$2,142,000	3,375	$634.67			
64	1288 Howard Street	7	$23,000,000	08/28/19	07/27/21	22.97	0.417%	10.00%	$25,300,000	No	20.00%	$30,360,000	$30,360,000	37,116	$817.98			
65	230-237 7th Street	7	$6,100,000	07/31/18	07/27/21	35.88	0.417%	15.00%	$7,015,000	No	20.00%	$8,418,000	$8,418,000	12,197	$690.17			
66	220 9th Street	7	$10,350,000	01/12/18	07/27/21	42.45	0.417%	18.00%	$12,213,000	No	20.00%	$14,655,600	$14,655,600	16,121	$909.10			
67	915 Minna Street	7	$6,250,000	06/13/17	07/27/21	49.45	0.417%	21.00%	$7,562,500	No	20.00%	$9,075,000	$9,075,000	11,617	$781.18			
68	292 Arleta Avenue	15	$400,000	11/30/22	07/27/21	(16.13)	-0.333%	5.00%	$420,000	No	20.00%	$504,000	$504,000	2,495	$202.00			
69	3338 San Bruno Avenue	16	$275,000	04/01/22	07/27/21	(8.15)	-0.333%	3.00%	$283,250	No	20.00%	$339,900	$339,900	1,750	$194.23			
70	666 Hamilton Street	15	$1,650,000	09/13/19	07/27/21	22.44	0.417%	9.00%	$1,798,500	No	20.00%	$2,158,200	$2,158,200	9,962	$216.64			
71	154 Delta Street	15	$590,000	07/26/17	07/27/21	48.03	0.417%	20.00%	$708,000	No	20.00%	$849,600	$849,600	5,000	$169.92			
72	2168 Bayshore Boulevard	16	$300,000	01/03/17	07/27/21	54.74	0.417%	23.00%	$369,000	No	20.00%	$442,800	$442,800	2,195	$201.73			
73	342 22nd Avenue	5	$1,800,000	03/17/23	07/27/21	(19.65)	-0.333%	7.00%	$1,926,000	Yes	0.00%	$1,926,000	$1,926,000	3,000	$642.00			
74	347 5th Avenue	6	$1,825,000	06/03/22	07/27/21	(10.22)	-0.333%	3.00%	$1,879,750	Yes	0.00%	$1,879,750	$1,879,750	3,000	$626.58			
75	112 Kensington Way	10	$1,046,850	05/20/22	07/27/21	(9.76)	-0.333%	3.00%	$1,078,256	Yes	0.00%	$1,078,256	$1,078,256	4,100	$262.99			
76	1713 Yosemite Avenue	16	$1,550,000	03/30/22	07/27/21	(8.08)	0.833%	-7.00%	$1,441,500	Yes	0.00%	$1,441,500	$1,441,500	5,000	$288.30			
77	448 Valley Street	11	$1,925,000	10/12/21	07/27/21	(2.53)	-0.333%	1.00%	$1,944,250	Yes	0.00%	$1,944,250	$1,944,250	2,642	$735.90			
78	47 Montclair Terrace	3	$1,200,000	09/24/21	07/27/21	(1.94)	-0.333%	1.00%	$1,212,000	No	20.00%	$1,454,400	$1,454,400	2,644	$550.08			
79	1133 S. Van Ness Avenue	11	$4,600,000	08/23/21	07/27/21	(0.89)	-0.333%	0.00%	$4,600,000	Yes	0.00%	$4,600,000	$4,600,000	11,500	$400.00			
80	1450 Marin Street	12	$2,495,000	07/02/21	07/27/21	0.82	0.833%	1.00%	$2,519,950	No	20.00%	$3,023,940	$3,023,940	14,125	$214.08			
81	552 Ortega Street	10	$940,000	06/04/21	07/27/21	1.74	0.417%	1.00%	$949,400	No	20.00%	$1,139,280	$1,139,280	3,458	$329.46			
82	1 Castenada Avenue	10	$750,000	04/07/21	07/27/21	3.65	0.417%	2.00%	$765,000	No	20.00%	$918,000	$918,000	8,140	$112.78			
83	39 Santa Rosa Avenue	15	$600,000	03/05/21	07/27/21	4.73	0.417%	2.00%	$612,000	No	20.00%	$734,400	$734,400	2,495	$294.35			
84	1251 Thomas Avenue	16	$1,950,000	02/23/21	07/27/21	5.06	0.833%	4.00%	$2,028,000	No	20.00%	$2,433,600	$2,433,600	9,600	$253.50			
85	1245 Van Dyke Avenue	16	$7,050,000	02/02/21	07/27/21	5.75	0.833%	5.00%	$7,402,500	No	20.00%	$8,883,000	$8,883,000	78,556	$113.08			
86	7 Edgar Place	14	$699,000	07/16/20	07/27/21	12.35	0.417%	5.00%	$733,950	Partial/Y	10.00%	$807,345	$807,345	4,258	$189.61			
87	2011 Filbert Street	3	$935,000	07/10/20	07/27/21	12.55	0.417%	5.00%	$981,750	No	20.00%	$1,178,100	$1,178,100	1,650	$714.00			
88	5222-5250 3rd Street	16	$3,000,000	07/10/20	07/27/21	12.55	0.250%	3.00%	$3,090,000	No	20.00%	$3,708,000	$3,708,000	18,883	$196.37			
89	1230 - 1240 Twin Peaks Boulevard	10	$1,506,000	06/01/20	07/27/21	13.83	0.417%	6.00%	$1,596,360	No	20.00%	$1,915,632	$1,915,632	10,723	$178.65			
90	4512 23rd Street	10	$800,000	08/19/19	07/27/21	23.26	0.417%	10.00%	$880,000	Partial/Y	10.00%	$968,000	$968,000	3,027	$319.79			
91	2921 Vallejo Street	2	$8,000,000	07/23/19	07/27/21	24.15	0.417%	10.00%	$8,800,000	Yes	0.00%	$8,800,000	$8,800,000	4,008	$2,195.61			
92	923 Kansas Street	12	$7,150,000	06/25/19	07/27/21	25.07	0.417%	10.00%	$7,865,000	Yes	0.00%	$7,865,000	$7,865,000	12,500	$629.20			
93	1713 Yosemite Avenue	16	$1,388,000	08/23/18	07/27/21	35.12	0.833%	29.00%	$1,790,520	Unknown	0.00%	$1,790,520	$1,790,520	5,000	$358.10			
94	287 Minerva Street	14	$425,000	05/29/18	07/27/21	37.95	0.417%	16.00%	$493,000	No	20.00%	$591,600	$591,600	3,125	$189.31			
95	95 Santa Cruz Avenue	14	$450,000	05/16/18	07/27/21	38.37	0.417%	16.00%	$522,000	No	20.00%	$626,400	$626,400	1,999	$313.36			
96	1401 Illinois Street	12	$23,400,000	05/01/18	07/27/21	38.87	0.833%	32.00%	$30,888,000	No	20.00%	$37,065,600	$37,065,600	79,997	$463.34			
97	599 Crestmont Dr	10	$7,600,000	04/30/18	07/27/21	38.90	0.417%	16.00%	$8,816,000	Yes	20.00%	$10,579,200	$10,579,200	50,094	$211.19			
98	1065 Innes Avenue	12	$1,200,000	04/06/18	07/27/21	39.69	0.417%	17.00%	$1,404,000	Yes	0.00%	$1,404,000	$1,404,000	7,500	$187.20			
99	2175 Hayes Street	6	$1,650,000	03/05/18	07/27/21	40.74	0.417%	17.00%	$1,930,500	No	20.00%	$2,316,600	$2,316,600	3,868	$598.91			
100	325 29th Avenue	5	$1,300,000	02/27/18	07/27/21	40.94	0.417%	17.00%	$1,521,000	Yes	0.00%	$1,521,000	$1,521,000	2,996	$507.68			
101	562 28th Ave	5	$1,925,000	02/08/18	07/27/21	41.56	0.417%	17.00%	$2,252,250	Yes	0.00%	$2,252,250	$2,252,250	4,796	$469.61			
102	922 Jamestown Avenue	16	$325,000	11/30/17	07/27/21	43.86	0.417%	18.00%	$383,500	No	20.00%	$460,200	$460,200	2,609	$176.39			
103	127 Edgehill Way	10	$880,000	10/26/17	07/27/21	45.01	0.417%	19.00%	$1,047,200	Yes	0.00%	$1,047,200	$1,047,200	3,937	$265.99			
104	363 21st Avenue	5	$1,750,000	08/22/17	07/27/21	47.15	0.417%	20.00%	$2,100,000	Yes	0.00%	$2,100,000	$2,100,000	2,996	$700.93			

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

					Market Conditions Adjustment					Entitlement Adjustment			Data - Adjusted			Quadrant 1		
Comp #	Location	Quadrant	Sale Price	Sale Date	07/27/21 Date of Value (DOV)	Months from DOV	Monthly Adjustment	Total Adjustment	Time Adjusted Sale Price	Entitled at Sale	20.00% for Entitlement	Time & Entitlement Adjusted	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF
105	423 24th Avenue	5	$1,960,000	06/30/17	07/27/21	48.89	0.417%	20.00%	$2,352,000	Yes	0.00%	$2,352,000	$2,352,000	3,000	$784.00			
106	477 Eucalyptus Drive	13/14	$1,360,000	05/18/17	07/27/21	50.30	0.417%	21.00%	$1,645,600	Yes	0.00%	$1,645,600	$1,645,600	4,000	$411.40			
Total									$953,071,515			$1,078,237,852	$1,078,237,852	1,646,724		$0	0	---
														37.80 acres			0.00 acres	
Weighted Average									$578.77			$654.78			$654.78			---

SUMMARY

	Data - Adjusted			Quadrant 1		
Low	$339,900	750	$112.78	$0	0	$0.00
High	$94,920,000	343,688	$6,804.17	$0	0	$0.00
Average	$10,367,672	15,834	$891.89	---	---	---
Median	$2,350,750	4,501	$578.45	---	---	---
Count	104	104	104	0	0	0

MARKET CONDITIONS ADJUSTMENTS

Description	Adjustment Annual	Adjustment Monthly		Zoning Use District
Residential Zoning Use Districts:	5.000%	0.417%	Sale Prior to Date of Value	(Residential, House Character; Residential, Mixed; Residential-Commercial Combined; Downtown Residential)
Residential Zoning Use Districts:	-4.000%	-0.333%	Sale After Date of Value	(Residential, House Character; Residential, Mixed; Residential-Commercial Combined; Downtown Residential)
Mixed Use Zoning Use Districts:	5.000%	0.417%	Sale Date to Date of Value	(Eastern Neighborhoods Mixed Use; Chinatown Mixed Use; Neighborhood Commercial Transit)
Industrial Zoning Use Districts:	10.000%	0.833%	Sale Date to Date of Value	(Industrial; Production, Distribution & Repair)
Commercial Zoning Use Districts:	3.000%	0.250%	Sale Date to Date of Value	(Commercial; Neighborhood Commercial)

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Quadrant 2			Quadrant 3			Quadrant 4			Quadrant 5			Quadrant 6			Quadrant 7		
Comp #	Location	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF
1	524 Howard Street																		
2	325 Fremont Street																		
3	525 Harrison Street																		
4	547 Howard Street																		
5	555 Howard Street																		
6	557 Howard Street																		
7	901 Illinois Street																		
8	790 Pennsylvania Avenue																		
9	1755 Egbert Avenue																		
10	2270 Jerrod Avenue																		
11	2150 Oakdale Avenue																		
12	2000 Marin Street																		
13	430 Eddy Street																$3,380,000	3,578	$944.66
14	199 Turk and 180 Jones Streets																$4,920,000	4,744	$1,037.10
15	530-540 Turk Street																$4,804,800	9,583	$501.39
16	500 Turk Street																$18,081,000	18,906	$956.36
17	719-725 Larkin Street																$4,608,000	5,998	$768.26
18	1550 Market Street																$29,440,000	12,567	$2,342.64
19	72-80 Ellis Street																$11,781,000	8,240	$1,429.73
20	1121-1125 Mission Street																$25,918,200	12,402	$2,089.84
21	30 Van Ness St																$94,920,000	38,124	$2,489.77
22	1338-1370 Mission Street																$35,100,000	18,901	$1,857.04
23	2100 Mission Street																$5,280,000	6,370	$828.89
24	1490 Ocean Avenue																		
25	1455 Irving Street													$2,147,760	4,792	$448.20			
26	3820 24th Street																		
27	2550 Irving Street										$10,692,000	19,162	$557.98						
28A	42 & 44 Cook Street													$3,584,500	3,000	$1,194.83			
28B	42 & 44 Cook Street													$2,044,080	3,000	$681.36			
29	524 Hickory Street																$1,560,000	1,250	$1,248.00
30	166 Parker Avenue													$2,316,600	2,775	$834.81			
31	2677 Harrison Street																		
32	1120 Valencia St																		
33	1090-1098 Valencia Street																		
34	606 Capp Street																		
35	1526 Powell Street	$3,410,400	5,259	$648.49															
36	555 Jackson Street				$8,502,000	8,089	$1,051.06												
37	1198 Columbus Ave/2568 Jones St	$5,832,000	6,420	$908.41															
38	425 Broadway Street				$14,784,000	13,641	$1,083.79												
39	1598 Bay Street	$11,056,500	12,541	$881.63															
40	1633 Cabrillo Street													$2,316,600	2,775	$834.81			
41	36 Tehama Street																		
42	135 Wetmore Street	$3,985,200	2,225	$1,791.10															
43	361-365 21st Street																		
44	53 States Street																$2,342,400	2,642	$886.60
45	2055 Taraval Street																		
46	134 Athens Street																		
47	332 Bradford Street																		
48	300 University Street																		
49	302 University Street																		
50	326 Gambier Street																		
51	1654 Kirkwood Avenue																		
52A	1782 Quesada Avenue																		
52B	1782 Quesada Avenue																		

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Quadrant 2			Quadrant 3			Quadrant 4			Quadrant 5			Quadrant 6			Quadrant 7		
Comp #	Location	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF
52C	1782 Quesada Avenue																		
53	1750 Oakdale Avenue																		
54	1528 Hudson Avenue																		
55	1390 Oakdale Avenue																		
56	150 Eureka Street																		
57	56 Laussat Street																$518,736	750	$691.65
58	1 Gull Drive																		
59	165 S. Linden Avenue																		
60	1030 Brittan Avenue																		
61	595 Industrial Road & 810-850 E. San Carlos Avenue																		
62	1401 Shoreway Road																		
63	514-580 Minna Street																$2,142,000	3,375	$634.67
64	1288 Howard Street																$30,360,000	37,116	$817.98
65	230-237 7th Street																$8,418,000	12,197	$690.17
66	220 9th Street																$14,655,600	16,121	$909.10
67	915 Minna Street																$9,075,000	11,617	$781.18
68	292 Arleta Avenue																		
69	3338 San Bruno Avenue																		
70	666 Hamilton Street																		
71	154 Delta Street																		
72	2168 Bayshore Boulevard																		
73	342 22nd Avenue										$1,926,000	3,000	$642.00						
74	347 5th Avenue													$1,879,750	3,000	$626.58			
75	112 Kensington Way																		
76	1713 Yosemite Avenue																		
77	448 Valley Street																		
78	47 Montclair Terrace				$1,454,400	2,644	$550.08												
79	1133 S. Van Ness Avenue																		
80	1450 Marin Street																		
81	552 Ortega Street																		
82	1 Castenada Avenue																		
83	39 Santa Rosa Avenue																		
84	1251 Thomas Avenue																		
85	1245 Van Dyke Avenue																		
86	7 Edgar Place																		
87	2011 Filbert Street				$1,178,100	1,650	$714.00												
88	5222-5250 3rd Street																		
89	1230 - 1240 Twin Peaks Boulevard																		
90	4512 23rd Street																		
91	2921 Vallejo Street	$8,800,000	4,008	$2,195.61															
92	923 Kansas Street																		
93	1713 Yosemite Avenue																		
94	287 Minerva Street																		
95	95 Santa Cruz Avenue																		
96	1401 Illinois Street																		
97	599 Crestmont Dr																		
98	1065 Innes Avenue																		
99	2175 Hayes Street													$2,316,600	3,868	$598.91			
100	325 29th Avenue										$1,521,000	2,996	$507.68						
101	562 28th Ave										$2,252,250	4,796	$469.61						
102	922 Jamestown Avenue																		
103	127 Edgehill Way																		
104	363 21st Avenue										$2,100,000	2,996	$700.93						

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
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CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Quadrant 2			Quadrant 3			Quadrant 4			Quadrant 5			Quadrant 6			Quadrant 7		
Comp #	**Location**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**
105	423 24th Avenue										$2,352,000	3,000	$784.00						
106	477 Eucalyptus Drive																		
Total		$8,800,000	4,008		$26,916,600	30,739		$23,286,000	21,730		$20,843,250	35,950		$16,605,890	23,210		$307,304,736	224,481	
			0.09 acres			0.71 acres			0.50 acres			0.83 acres			0.53 acres			5.15 acres	
Weighted Average				$2,195.61			$875.65			$1,071.61			$579.78			$715.46			$1,368.96
SUMMARY																			
Low		$8,800,000	4,008	$2,195.61	$1,178,100	1,650	$550.08	$8,502,000	8,089	$1,051.06	$1,521,000	2,996	$469.61	$1,879,750	2,775	$448.20	$518,736	750	$501.39
High		$8,800,000	4,008	$2,195.61	$11,056,500	12,541	$1,791.10	$14,784,000	13,641	$1,083.79	$10,692,000	19,162	$784.00	$3,584,500	4,792	$1,194.83	$94,920,000	38,124	$2,489.77
Average		$8,800,000	4,008	$2,195.61	$4,486,100	5,123	$915.62	$11,643,000	10,865	$1,067.42	$3,473,875	5,992	$610.37	$2,372,270	3,316	$745.64	$16,173,933	11,815	$1,152.90
Median		$8,800,000	4,008	$2,195.61	$3,697,800	3,952	$797.81	$11,643,000	10,865	$1,067.42	$2,176,125	3,000	$599.99	$2,316,600	3,000	$681.36	$8,418,000	9,583	$909.10
Count		1	1	1	6	6	6	2	2	2	6	6	6	7	7	7	19	19	19

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Quadrant 8			Quadrant 9			Quadrant 10			Quadrant 11			Quadrant 12			Quadrant 13		
Comp #	Location	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF
1	524 Howard Street	$83,460,000	12,266	$6,804.17															
2	325 Fremont Street	$37,620,000	6,434	$5,847.06															
3	525 Harrison Street	$43,200,000	12,981	$3,327.94															
4	547 Howard Street	$8,996,400	2,126	$4,231.61															
5	555 Howard Street	$38,556,143	8,250	$4,673.47															
6	557 Howard Street	$17,493,000	4,121	$4,244.84															
7	901 Illinois Street	$32,736,000	67,988	$481.50															
8	790 Pennsylvania Avenue													$48,895,000	119,885	$407.85			
9	1755 Egbert Avenue																		
10	2270 Jerrod Avenue													$77,357,280	154,883	$499.46			
11	2150 Oakdale Avenue													$20,130,000	52,085	$386.49			
12	2000 Marin Street													$85,478,400	343,688	$248.71			
13	430 Eddy Street																		
14	199 Turk and 180 Jones Streets																		
15	530-540 Turk Street																		
16	500 Turk Street																		
17	719-725 Larkin Street																		
18	1550 Market Street																		
19	72-80 Ellis Street																		
20	1121-1125 Mission Street																		
21	30 Van Ness St																		
22	1338-1370 Mission Street																		
23	2100 Mission Street																		
24	1490 Ocean Avenue																		
25	1455 Irving Street																		
26	3820 24th Street										$2,923,200	2,849	$1,026.04						
27	2550 Irving Street																		
28A	42 & 44 Cook Street																		
28B	42 & 44 Cook Street																		
29	524 Hickory Street																		
30	166 Parker Avenue																		
31	2677 Harrison Street										$1,849,260	2,304	$802.63						
32	1120 Valencia St										$4,733,280	4,134	$1,144.96						
33	1090-1098 Valencia Street										$16,847,568	10,114	$1,665.77						
34	606 Capp Street										$5,148,000	7,350	$700.41						
35	1526 Powell Street																		
36	555 Jackson Street																		
37	1198 Columbus Ave/2568 Jones St																		
38	425 Broadway Street																		
39	1598 Bay Street																		
40	1633 Cabrillo Street																		
41	36 Tehama Street	$3,270,000	2,000	$1,635.00															
42	135 Wetmore Street																		
43	361-365 21st Street										$2,349,500	2,997	$783.95						
44	53 States Street																		
45	2055 Taraval Street				$1,572,480	3,250	$483.84												
46	134 Athens Street																		
47	332 Bradford Street										$574,260	1,751	$327.96						
48	300 University Street																		
49	302 University Street																		
50	326 Gambier Street																		
51	1654 Kirkwood Avenue													$1,224,000	5,000	$244.80			
52A	1782 Quesada Avenue													$708,750	2,500	$283.50			
52B	1782 Quesada Avenue													$560,880	2,500	$224.35			

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Quadrant 8			Quadrant 9			Quadrant 10			Quadrant 11			Quadrant 12			Quadrant 13		
Comp #	Location	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF
52C	1782 Quesada Avenue													$416,000	2,500	$166.40			
53	1750 Oakdale Avenue													$391,680	2,500	$156.67			
54	1528 Hudson Avenue													$487,152	2,500	$194.86			
55	1390 Oakdale Avenue													$571,200	2,663	$214.49			
56	150 Eureka Street										$3,682,800	6,069	$606.82						
57	56 Laussat Street																		
58	1 Gull Drive																		
59	165 S. Linden Avenue																		
60	1030 Brittan Avenue																		
61	595 Industrial Road & 810-850 E. San Carlos Avenue																		
62	1401 Shoreway Road																		
63	514-580 Minna Street																		
64	1288 Howard Street																		
65	230-237 7th Street																		
66	220 9th Street																		
67	915 Minna Street																		
68	292 Arleta Avenue																		
69	3338 San Bruno Avenue																		
70	666 Hamilton Street																		
71	154 Delta Street																		
72	2168 Bayshore Boulevard																		
73	342 22nd Avenue																		
74	347 5th Avenue																		
75	112 Kensington Way							$1,078,256	4,100	$262.99									
76	1713 Yosemite Avenue																		
77	448 Valley Street										$1,944,250	2,642	$735.90						
78	47 Montclair Terrace																		
79	1133 S. Van Ness Avenue										$4,600,000	11,500	$400.00						
80	1450 Marin Street													$3,023,940	14,125	$214.08			
81	552 Ortega Street							$1,139,280	3,458	$329.46									
82	1 Castenada Avenue							$918,000	8,140	$112.78									
83	39 Santa Rosa Avenue																		
84	1251 Thomas Avenue																		
85	1245 Van Dyke Avenue																		
86	7 Edgar Place																		
87	2011 Filbert Street																		
88	5222-5250 3rd Street																		
89	1230 - 1240 Twin Peaks Boulevard							$1,915,632	10,723	$178.65									
90	4512 23rd Street							$968,000	3,027	$319.79									
91	2921 Vallejo Street																		
92	923 Kansas Street													$7,865,000	12,500	$629.20			
93	1713 Yosemite Avenue																		
94	287 Minerva Street																		
95	95 Santa Cruz Avenue																		
96	1401 Illinois Street													$37,065,600	79,997	$463.34			
97	599 Crestmont Dr							$10,579,200	50,094	$211.19									
98	1065 Innes Avenue													$1,404,000	7,500	$187.20			
99	2175 Hayes Street																		
100	325 29th Avenue																		
101	562 28th Ave																		
102	922 Jamestown Avenue																		
103	127 Edgehill Way							$1,047,200	3,937	$265.99									
104	363 21st Avenue																		

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Quadrant 8			Quadrant 9			Quadrant 10			Quadrant 11			Quadrant 12			Quadrant 13		
Comp #	**Location**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**
105	423 24th Avenue																		
106	477 Eucalyptus Drive																$1,645,600	4,000	$411.40
Total		$265,331,543	116,166		$1,572,480	3,250		$17,645,568	83,479		$44,652,118	51,710		$285,578,882	804,826		$1,645,600	4,000	
			2.67 acres			0.07 acres			1.92 acres			1.19 acres			18.48 acres			0.09 acres	
Weighted Average				$2,284.07			$483.84			$211.38			$863.51			$354.83			$411.40
SUMMARY																			
Low		$3,270,000	2,000	$481.50	$1,572,480	3,250	$483.84	$918,000	3,027	$112.78	$574,260	1,751	$327.96	$391,680	2,500	$156.67	$1,645,600	4,000	$411.40
High		$83,460,000	67,988	$6,804.17	$1,572,480	3,250	$483.84	$10,579,200	50,094	$329.46	$16,847,568	11,500	$1,665.77	$85,478,400	343,688	$629.20	$1,645,600	4,000	$411.40
Average		$33,166,443	14,521	$3,905.70	$1,572,480	3,250	$483.84	$2,520,795	11,926	$240.12	$4,465,212	5,171	$819.44	$19,038,592	53,655	$301.43	$1,645,600	4,000	$411.40
Median		$35,178,000	7,342	$4,238.23	$1,572,480	3,250	$483.84	$1,078,256	4,100	$262.99	$3,303,000	3,566	$759.93	$1,404,000	7,500	$244.80	$1,645,600	4,000	$411.40
Count		8	8	8	1	1	1	7	7	7	10	10	10	15	15	15	1	1	1

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Quadrant 14			Quadrant 15			Quadrant 16		
Comp #	Location	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF
1	524 Howard Street									
2	325 Fremont Street									
3	525 Harrison Street									
4	547 Howard Street									
5	555 Howard Street									
6	557 Howard Street									
7	901 Illinois Street									
8	790 Pennsylvania Avenue									
9	1755 Egbert Avenue							$21,357,000	70,446	$303.17
10	2270 Jerrod Avenue									
11	2150 Oakdale Avenue									
12	2000 Marin Street									
13	430 Eddy Street									
14	199 Turk and 180 Jones Streets									
15	530-540 Turk Street									
16	500 Turk Street									
17	719-725 Larkin Street									
18	1550 Market Street									
19	72-80 Ellis Street									
20	1121-1125 Mission Street									
21	30 Van Ness St									
22	1338-1370 Mission Street									
23	2100 Mission Street									
24	1490 Ocean Avenue	$8,268,000	10,237	$807.66						
25	1455 Irving Street									
26	3820 24th Street									
27	2550 Irving Street									
28A	42 & 44 Cook Street									
28B	42 & 44 Cook Street									
29	524 Hickory Street									
30	166 Parker Avenue									
31	2677 Harrison Street									
32	1120 Valencia St									
33	1090-1098 Valencia Street									
34	606 Capp Street									
35	1526 Powell Street									
36	555 Jackson Street									
37	1198 Columbus Ave/2568 Jones St									
38	425 Broadway Street									
39	1598 Bay Street									
40	1633 Cabrillo Street									
41	36 Tehama Street									
42	135 Wetmore Street									
43	361-365 21st Street									
44	53 States Street									
45	2055 Taraval Street									
46	134 Athens Street				$741,520	2,495	$297.20			
47	332 Bradford Street									
48	300 University Street				$712,800	2,060	$346.02			
49	302 University Street				$604,800	2,060	$293.59			
50	326 Gambier Street				$600,000	2,950	$203.39			
51	1654 Kirkwood Avenue									
52A	1782 Quesada Avenue									
52B	1782 Quesada Avenue									

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Quadrant 14			Quadrant 15			Quadrant 16		
Comp #	Location	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF
52C	1782 Quesada Avenue									
53	1750 Oakdale Avenue									
54	1528 Hudson Avenue									
55	1390 Oakdale Avenue									
56	150 Eureka Street									
57	56 Laussat Street									
58	1 Gull Drive									
59	165 S. Linden Avenue									
60	1030 Brittan Avenue									
61	595 Industrial Road & 810-850 E. San Carlos Avenue									
62	1401 Shoreway Road									
63	514-580 Minna Street									
64	1288 Howard Street									
65	230-237 7th Street									
66	220 9th Street									
67	915 Minna Street									
68	292 Arleta Avenue				$504,000	2,495	$202.00			
69	3338 San Bruno Avenue							$339,900	1,750	$194.23
70	666 Hamilton Street				$2,158,200	9,962	$216.64			
71	154 Delta Street				$849,600	5,000	$169.92			
72	2168 Bayshore Boulevard							$442,800	2,195	$201.73
73	342 22nd Avenue									
74	347 5th Avenue									
75	112 Kensington Way									
76	1713 Yosemite Avenue							$1,441,500	5,000	$288.30
77	448 Valley Street									
78	47 Montclair Terrace									
79	1133 S. Van Ness Avenue									
80	1450 Marin Street									
81	552 Ortega Street									
82	1 Castenada Avenue									
83	39 Santa Rosa Avenue				$734,400	2,495	$294.35			
84	1251 Thomas Avenue							$2,433,600	9,600	$253.50
85	1245 Van Dyke Avenue							$8,883,000	78,556	$113.08
86	7 Edgar Place	$807,345	4,258	$189.61						
87	2011 Filbert Street									
88	5222-5250 3rd Street							$3,708,000	18,883	$196.37
89	1230 - 1240 Twin Peaks Boulevard									
90	4512 23rd Street									
91	2921 Vallejo Street									
92	923 Kansas Street									
93	1713 Yosemite Avenue							$1,790,520	5,000	$358.10
94	287 Minerva Street	$591,600	3,125	$189.31						
95	95 Santa Cruz Avenue	$626,400	1,999	$313.36						
96	1401 Illinois Street									
97	599 Crestmont Dr									
98	1065 Innes Avenue									
99	2175 Hayes Street									
100	325 29th Avenue									
101	562 28th Ave									
102	922 Jamestown Avenue							$460,200	2,609	$176.39
103	127 Edgehill Way									
104	363 21st Avenue									

EXHIBIT "W - 4"
LAND SALES & ADJUSTMENTS
BY QUADRANT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Quadrant 14			Quadrant 15			Quadrant 16		
Comp #	**Location**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**
105	423 24th Avenue									
106	477 Eucalyptus Drive	$1,645,600	4,000	$411.40						
Total		$11,938,945	23,619		$6,905,320	29,517		$40,856,520	194,039	
			0.54 acres			0.68 acres			4.45 acres	
Weighted Average				$505.48			$233.94			$210.56
SUMMARY										
Low		$591,600	1,999	$189.31	$504,000	2,060	$169.92	$339,900	1,750	$113.08
High		$8,268,000	10,237	$807.66	$2,158,200	9,962	$346.02	$21,357,000	78,556	$358.10
Average		$2,387,789	4,724	$382.27	$863,165	3,690	$252.89	$4,539,613	21,560	$231.65
Median		$807,345	4,000	$313.36	$723,600	2,495	$255.12	$1,790,520	5,000	$201.73
Count		5	5	5	8	8	8	9	9	9

Exhibit W-5: Land Sales Summary & Adjustments – By Zoning Use District

EXHIBIT "W - 5"
LAND SALES & ADJUSTMENTS
BY ZONING USE DISTRICT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

					Market Conditions Adjustment							Entitlement Adjustment			Data - Adjusted		
Comp #	Location	Zoning	Zoning Use District	Entitled at Sale	Sale Price	Sale Date	07/27/21 Date of Value (DOV)	Months from DOV	Monthly Adjustment	Total Adjustment	Time Adjusted Sale Price	Entitled at Sale	20.00% for Entitlement	Time & Entitlement Adjusted	Adjusted Sale Price	Land Area	Price per SF
1	524 Howard Street	C-3-O (SD)	Commercial	Yes	$78,000,000	05/07/19	07/27/21	26.68	0.250%	7.00%	$83,460,000	Yes	0.00%	$83,460,000	$83,460,000	12,266	$6,804.17
2	325 Fremont Street	RH DTR	Downtown Residential	Yes	$28,500,000	02/26/15	07/27/21	76.98	0.417%	32.00%	$37,620,000	Yes	0.00%	$37,620,000	$37,620,000	6,434	$5,847.06
3	525 Harrison Street	RH DTR	Downtown Residential	Yes	$36,000,000	06/26/17	07/27/21	49.02	0.417%	20.00%	$43,200,000	Yes	0.00%	$43,200,000	$43,200,000	12,981	$3,327.94
4	547 Howard Street	C-3-O (SD)	Commercial	No	$6,300,000	04/22/15	07/27/21	75.17	0.250%	19.00%	$7,497,000	No	20.00%	$8,996,400	$8,996,400	2,126	$4,231.61
5	555 Howard Street	C-3-O (SD)	Commercial	No	$27,000,100	04/28/15	07/27/21	74.97	0.250%	19.00%	$32,130,119	No	20.00%	$38,556,143	$38,556,143	8,250	$4,673.47
6	557 Howard Street	C-3-O (SD)	Commercial	No	$12,250,000	05/01/15	07/27/21	74.87	0.250%	19.00%	$14,577,500	No	20.00%	$17,493,000	$17,493,000	4,121	$4,244.84
7	901 Illinois Street	PDR-2	Production, Distribution & Repair	Partial/Y	$24,000,000	02/13/19	07/27/21	29.40	0.833%	24.00%	$29,760,000	Partial/Y	10.00%	$32,736,000	$32,736,000	67,988	$481.50
8	790 Pennsylvania Avenue	UMU (Lot 13)/ PDR-1-G (Lot 11)	Eastern Neighborhoods Mixed Use / Production, Distribution & Repair	Partial/Y	$35,000,000	03/03/16	07/27/21	64.79	0.417%	27.00%	$44,450,000	Partial/Y	10.00%	$48,895,000	$48,895,000	119,885	$407.85
9	1755 Egbert Avenue	PDR-2	Production, Distribution & Repair	No	$16,950,000	01/29/21	07/27/21	5.88	0.833%	5.00%	$17,797,500	No	20.00%	$21,357,000	$21,357,000	70,446	$303.17
10	2270 Jerrod Avenue	PDR-2	Production, Distribution & Repair	No	$70,070,000	05/09/22	07/27/21	(9.40)	0.833%	-8.00%	$64,464,400	No	20.00%	$77,357,280	$77,357,280	154,883	$499.46
11	2150 Oakdale Avenue	PDR-2	Production, Distribution & Repair	No	$13,750,000	05/07/19	07/27/21	26.68	0.833%	22.00%	$16,775,000	No	20.00%	$20,130,000	$20,130,000	52,085	$386.49
12	2000 Marin Street	PDR-2	Production, Distribution & Repair	No	$63,600,000	04/30/20	07/27/21	14.88	0.833%	12.00%	$71,232,000	No	20.00%	$85,478,400	$85,478,400	343,688	$248.71
13	430 Eddy Street	RC-4	Residential-Commercial Combined	Yes	$3,250,000	11/12/20	07/27/21	8.44	0.417%	4.00%	$3,380,000	Yes	0.00%	$3,380,000	$3,380,000	3,578	$944.66
14	199 Turk and 180 Jones Streets	RC-4	Residential-Commercial Combined	Yes	$4,000,000	11/30/16	07/27/21	55.85	0.417%	23.00%	$4,920,000	Yes	0.00%	$4,920,000	$4,920,000	4,744	$1,037.10
15	530-540 Turk Street	RC-4	Residential-Commercial Combined	No	$3,850,000	06/26/22	07/27/21	(10.97)	-0.333%	4.00%	$4,004,000	No	20.00%	$4,804,800	$4,804,800	9,583	$501.39
16	500 Turk Street	RC-4	Residential-Commercial Combined	No	$12,250,000	12/20/16	07/27/21	55.20	0.417%	23.00%	$15,067,500	No	20.00%	$18,081,000	$18,081,000	18,906	$956.36
17	719-725 Larkin Street	RC-4	Residential-Commercial Combined	No	$3,000,000	12/31/15	07/27/21	66.86	0.417%	28.00%	$3,840,000	No	20.00%	$4,608,000	$4,608,000	5,998	$768.26
18	1550 Market Street	C-3-G	Commercial	Yes	$23,000,000	11/24/15	07/27/21	68.07	0.417%	28.00%	$29,440,000	Yes	0.00%	$29,440,000	$29,440,000	12,567	$2,342.64
19	72-80 Ellis Street	C-3-R	Commercial	Yes	$9,900,000	05/13/15	07/27/21	74.48	0.250%	19.00%	$11,781,000	Yes	0.00%	$11,781,000	$11,781,000	8,240	$1,429.73
20	1121-1125 Mission Street	C-3-G	Commercial	Partial/Y	$19,800,000	05/22/15	07/27/21	74.18	0.250%	19.00%	$23,562,000	Partial/Y	10.00%	$25,918,200	$25,918,200	12,402	$2,089.84
21	30 Van Ness St	C-3-G	Commercial	No	$70,000,000	05/05/17	07/27/21	50.73	0.250%	13.00%	$79,100,000	No	20.00%	$94,920,000	$94,920,000	38,124	$2,489.77
22	1338-1370 Mission Street	C-3-G	Commercial	No	$25,000,000	11/20/15	07/27/21	68.21	0.250%	17.00%	$29,250,000	No	20.00%	$35,100,000	$35,100,000	18,901	$1,857.04
23	2100 Mission Street	NCT	Neighborhood Commercial Transit	Yes	$4,800,000	08/22/19	07/27/21	23.16	0.417%	10.00%	$5,280,000	Yes	0.00%	$5,280,000	$5,280,000	6,370	$828.89
24	1490 Ocean Avenue	NCT	Neighborhood Commercial Transit	No	$5,300,000	08/25/15	07/27/21	71.06	0.417%	30.00%	$6,890,000	No	20.00%	$8,268,000	$8,268,000	10,237	$807.66
25	1455 Irving Street	NCD	Neighborhood Commercial	No	$1,570,000	11/07/16	07/27/21	56.61	0.250%	14.00%	$1,789,800	No	20.00%	$2,147,760	$2,147,760	4,792	$448.20
26	3820 24th Street	NCD	Neighborhood Commercial	No	$2,100,000	05/20/16	07/27/21	62.23	0.250%	16.00%	$2,436,000	No	20.00%	$2,923,200	$2,923,200	2,849	$1,026.04
27	2550 Irving Street	NCD	Neighborhood Commercial	No	$9,000,000	11/19/21	07/27/21	(3.78)	0.250%	-1.00%	$8,910,000	No	20.00%	$10,692,000	$10,692,000	19,162	$557.98
28A	42 & 44 Cook Street	RH-2	Residential, House Character	Yes	$3,350,000	03/17/23	07/27/21	(19.65)	-0.333%	7.00%	$3,584,500	Yes	0.00%	$3,584,500	$3,584,500	3,000	$1,194.83
28B	42 & 44 Cook Street	RH-2	Residential, House Character	No	$1,670,000	02/03/21	07/27/21	5.72	0.417%	2.00%	$1,703,400	No	20.00%	$2,044,080	$2,044,080	3,000	$681.36
29	524 Hickory Street	RH-3 Hayes Valley	Residential, House Character	Yes	$1,300,000	07/27/17	07/27/21	48.00	0.417%	20.00%	$1,560,000	Yes	0.00%	$1,560,000	$1,560,000	1,250	$1,248.00
30	166 Parker Avenue	RH-2	Residential, House Character	No	$1,650,000	03/20/18	07/27/21	40.25	0.417%	17.00%	$1,930,500	No	20.00%	$2,316,600	$2,316,600	2,775	$834.81
31	2677 Harrison Street	RH-3	Residential, House Character	No	$1,295,000	09/27/17	07/27/21	45.96	0.417%	19.00%	$1,541,050	No	20.00%	$1,849,260	$1,849,260	2,304	$802.63
32	1120 Valencia St	NCT	Neighborhood Commercial Transit	No	$3,460,000	10/16/18	07/27/21	33.35	0.417%	14.00%	$3,944,400	No	20.00%	$4,733,280	$4,733,280	4,134	$1,144.96
33	1090-1098 Valencia Street	NCT	Neighborhood Commercial Transit	No	$11,898,000	11/22/17	07/27/21	44.12	0.417%	18.00%	$14,039,640	No	20.00%	$16,847,568	$16,847,568	10,114	$1,665.77
34	606 Capp Street	RTO-M	Residential, Transit Oriented	No	$3,300,000	07/31/15	07/27/21	71.89	0.417%	30.00%	$4,290,000	No	20.00%	$5,148,000	$5,148,000	7,350	$700.41
35	1526 Powell Street	NCD - North Beach	Neighborhood Commercial	No	$2,900,000	04/14/22	07/27/21	(8.57)	0.250%	-2.00%	$2,842,000	No	20.00%	$3,410,400	$3,410,400	5,259	$648.49
36	555 Jackson Street	CRNC	Chinatown Mixed Use	No	$6,500,000	09/27/19	07/27/21	21.98	0.417%	9.00%	$7,085,000	No	20.00%	$8,502,000	$8,502,000	8,089	$1,051.06
37	1198 Columbus Ave/2568 Jones St	C-2	Commercial	No	$4,500,000	11/26/18	07/27/21	32.00	0.250%	8.00%	$4,860,000	No	20.00%	$5,832,000	$5,832,000	6,420	$908.41
38	425 Broadway Street	NCD	Neighborhood Commercial	No	$11,000,000	05/30/17	07/27/21	49.91	0.250%	12.00%	$12,320,000	No	20.00%	$14,784,000	$14,784,000	13,641	$1,083.79
39	1598 Bay Street	NC-2	Neighborhood Commercial	No	$7,875,000	12/07/15	07/27/21	67.65	0.250%	17.00%	$9,213,750	No	20.00%	$11,056,500	$11,056,500	12,541	$881.63
40	1633 Cabrillo Street	RH-2	Residential, House Character	No	$1,650,000	03/20/18	07/27/21	40.25	0.417%	17.00%	$1,930,500	No	20.00%	$2,316,600	$2,316,600	2,775	$834.81
41	36 Tehama Street	C-3-O (SD)	Commercial	No	$2,500,000	06/28/18	07/27/21	36.96	0.250%	9.00%	$2,725,000	No	20.00%	$3,270,000	$3,270,000	2,000	$1,635.00
42	135 Wetmore Street	RM-3	Residential, Mixed	No	$2,700,000	01/04/17	07/27/21	54.70	0.417%	23.00%	$3,321,000	No	20.00%	$3,985,200	$3,985,200	2,225	$1,791.10
43	361-365 21st Street	RH-2	Residential, House Character	Yes	$1,850,000	03/04/16	07/27/21	64.76	0.417%	27.00%	$2,349,500	Yes	0.00%	$2,349,500	$2,349,500	2,997	$783.95
44	53 States Street	RH-2	Residential, House Character	Yes	$1,920,000	02/27/17	07/27/21	52.93	0.417%	22.00%	$2,342,400	Yes	0.00%	$2,342,400	$2,342,400	2,642	$886.60
45	2055 Taraval Street	NCD	Neighborhood Commercial	No	$1,260,000	02/04/20	07/27/21	17.71	0.250%	4.00%	$1,310,400	No	20.00%	$1,572,480	$1,572,480	3,250	$483.84
46	134 Athens Street	RH-1	Residential, House Character	Yes	$713,000	06/24/22	07/27/21	(10.91)	-0.333%	4.00%	$741,520	Yes	0.00%	$741,520	$741,520	2,495	$297.20
47	332 Bradford Street	RH-1	Residential, House Character	Yes	$563,000	02/01/21	07/27/21	5.78	0.417%	2.00%	$574,260	Yes	0.00%	$574,260	$574,260	1,751	$327.96
48	300 University Street	RH-1	Residential, House Character	Yes	$660,000	11/15/19	07/27/21	20.37	0.417%	8.00%	$712,800	Yes	0.00%	$712,800	$712,800	2,060	$346.02
49	302 University Street	RH-1	Residential, House Character	Yes	$560,000	11/15/19	07/27/21	20.37	0.417%	8.00%	$604,800	Yes	0.00%	$604,800	$604,800	2,060	$293.59
50	326 Gambier Street	RH-1	Residential, House Character	No	$500,000	06/24/21	07/27/21	1.08	0.417%	0.00%	$500,000	No	20.00%	$600,000	$600,000	2,950	$203.39
51	1654 Kirkwood Avenue	RH-2	Residential, House Character	Yes	$1,200,000	04/08/21	07/27/21	3.61	0.417%	2.00%	$1,224,000	Yes	0.00%	$1,224,000	$1,224,000	5,000	$244.80
52A	1782 Quesada Avenue	RH-2	Residential, House Character	Yes	$675,000	07/30/20	07/27/21	11.89	0.417%	5.00%	$708,750	Yes	0.00%	$708,750	$708,750	2,500	$283.50
52B	1782 Quesada Avenue	RH-2	Residential, House Character	No	$380,000	01/13/17	07/27/21	54.41	0.417%	23.00%	$467,400	No	20.00%	$560,880	$560,880	2,500	$224.35
52C	1782 Quesada Avenue	RH-1	Residential, House Character	Yes	$400,000	09/09/22	07/27/21	(13.44)	-0.333%	4.00%	$416,000	Yes	0.00%	$416,000	$416,000	2,500	$166.40
53	1750 Oakdale Avenue	RH-2	Residential, House Character	No	$320,000	01/25/22	07/27/21	(5.98)	-0.333%	2.00%	$326,400	No	20.00%	$391,680	$391,680	2,500	$156.67
54	1528 Hudson Avenue	RH-2	Residential, House Character	No	$398,000	02/28/22	07/27/21	(7.10)	-0.333%	2.00%	$405,960	No	20.00%	$487,152	$487,152	2,500	$194.86

EXHIBIT "W - 5"
LAND SALES & ADJUSTMENTS
BY ZONING USE DISTRICT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

					Market Conditions Adjustment							Entitlement Adjustment			Data - Adjusted		
Comp #	Location	Zoning	Zoning Use District	Entitled at Sale	Sale Price	Sale Date	07/27/21 Date of Value (DOV)	Months from DOV	Monthly Adjustment	Total Adjustment	Time Adjusted Sale Price	Entitled at Sale	20.00% for Entitlement	Time & Entitlement Adjusted	Adjusted Sale Price	Land Area	Price per SF
55	1390 Oakdale Avenue	RH-2	Residential, House Character	No	$425,000	03/08/19	07/27/21	28.65	0.417%	12.00%	$476,000	No	20.00%	$571,200	$571,200	2,663	$214.49
56	150 Eureka Street	RH-2	Residential, House Character	No	$2,325,000	02/04/15	07/27/21	77.70	0.417%	32.00%	$3,069,000	No	20.00%	$3,682,800	$3,682,800	6,069	$606.82
57	56 Laussat Street	RTO	Residential, House Character	No	$428,000	04/23/21	07/27/21	3.12	0.417%	1.00%	$432,280	No	20.00%	$518,736	$518,736	750	$691.65
58	1 Gull Drive	N/Appl.	N/Appl.	N/Appl.	---	---	---	---	---	---	---	---	---	---	---	---	---
59	165 S. Linden Avenue	N/Appl.	N/Appl.	N/Appl.	---	---	---	---	---	---	---	---	---	---	---	---	---
60	1030 Brittan Avenue	N/Appl.	N/Appl.	N/Appl.	---	---	---	---	---	---	---	---	---	---	---	---	---
61	595 Industrial Road & 810-850 E. San Carlos Avenue	N/Appl.	N/Appl.	N/Appl.	---	---	---	---	---	---	---	---	---	---	---	---	---
62	1401 Shoreway Road	N/Appl.	N/Appl.	N/Appl.	---	---	---	---	---	---	---	---	---	---	---	---	---
63	514-580 Minna Street	MUG	Eastern Neighborhoods Mixed Use	No	$1,700,000	08/14/20	07/27/21	11.40	0.417%	5.00%	$1,785,000	No	20.00%	$2,142,000	$2,142,000	3,375	$634.67
64	1288 Howard Street	Eastern Neighborhoods Mixed Use / Neighborhood Commercial		No	$23,000,000	08/28/19	07/27/21	22.97	0.417%	10.00%	$25,300,000	No	20.00%	$30,360,000	$30,360,000	37,116	$817.98
65	230-237 7th Street	WMUG	Eastern Neighborhoods Mixed Use	No	$6,100,000	07/31/18	07/27/21	35.88	0.417%	15.00%	$7,015,000	No	20.00%	$8,418,000	$8,418,000	12,197	$690.17
66	220 9th Street	RCD	Neighborhood Commercial Transit	No	$10,350,000	01/12/18	07/27/21	42.45	0.417%	18.00%	$12,213,000	No	20.00%	$14,655,600	$14,655,600	16,121	$909.10
67	915 Minna Street	RED-MX	Eastern Neighborhoods Mixed Use	No	$6,250,000	06/13/17	07/27/21	49.45	0.417%	21.00%	$7,562,500	No	20.00%	$9,075,000	$9,075,000	11,617	$781.18
68	292 Arleta Avenue	RH-1	Residential, House Character	No	$400,000	11/30/22	07/27/21	(16.13)	-0.333%	5.00%	$420,000	No	20.00%	$504,000	$504,000	2,495	$202.00
69	3338 San Bruno Avenue	RH-1	Residential, House Character	No	$275,000	04/01/22	07/27/21	(8.15)	-0.333%	3.00%	$283,250	No	20.00%	$339,900	$339,900	1,750	$194.23
70	666 Hamilton Street	RH-1	Residential, House Character	No	$1,650,000	09/13/19	07/27/21	22.44	0.417%	9.00%	$1,798,500	No	20.00%	$2,158,200	$2,158,200	9,962	$216.64
71	154 Delta Street	RH-1	Residential, House Character	No	$590,000	07/26/17	07/27/21	48.03	0.417%	20.00%	$708,000	No	20.00%	$849,600	$849,600	5,000	$169.92
72	2168 Bayshore Boulevard	RH-1	Residential, House Character	No	$300,000	01/03/17	07/27/21	54.74	0.417%	23.00%	$369,000	No	20.00%	$442,800	$442,800	2,195	$201.73
73	342 22nd Avenue	RM-1	Residential, Mixed	Yes	$1,800,000	03/17/23	07/27/21	(19.65)	-0.333%	7.00%	$1,926,000	Yes	0.00%	$1,926,000	$1,926,000	3,000	$642.00
74	347 5th Avenue	RM-1	Residential, Mixed	Yes	$1,825,000	06/03/22	07/27/21	(10.22)	-0.333%	3.00%	$1,879,750	Yes	0.00%	$1,879,750	$1,879,750	3,000	$626.58
75	112 Kensington Way	RH-1(D)	Residential, House Character	Yes	$1,046,850	05/20/22	07/27/21	(9.76)	-0.333%	3.00%	$1,078,256	Yes	0.00%	$1,078,256	$1,078,256	4,100	$262.99
76	1713 Yosemite Avenue	M-1	Industrial	Yes	$1,550,000	03/30/22	07/27/21	(8.08)	0.833%	-7.00%	$1,441,500	Yes	0.00%	$1,441,500	$1,441,500	5,000	$288.30
77	448 Valley Street	RH-2	Residential, House Character	Yes	$1,925,000	10/12/21	07/27/21	(2.53)	-0.333%	1.00%	$1,944,250	Yes	0.00%	$1,944,250	$1,944,250	2,642	$735.90
78	47 Montclair Terrace	RH-1	Residential, House Character	No	$1,200,000	09/24/21	07/27/21	(1.94)	-0.333%	1.00%	$1,212,000	No	20.00%	$1,454,400	$1,454,400	2,644	$550.08
79	1133 S. Van Ness Avenue	RH-3	Residential, House Character	Yes	$4,600,000	08/23/21	07/27/21	(0.89)	-0.333%	0.00%	$4,600,000	Yes	0.00%	$4,600,000	$4,600,000	11,500	$400.00
80	1450 Marin Street	PRD-2	Production, Distribution & Repair	No	$2,495,000	07/02/21	07/27/21	0.82	0.833%	1.00%	$2,519,950	No	20.00%	$3,023,940	$3,023,940	14,125	$214.08
81	552 Ortega Street	RH-1	Residential, House Character	No	$940,000	06/04/21	07/27/21	1.74	0.417%	1.00%	$949,400	No	20.00%	$1,139,280	$1,139,280	3,458	$329.46
82	1 Castenada Avenue	RH-1 (D)	Residential, House Character	No	$750,000	04/07/21	07/27/21	3.65	0.417%	2.00%	$765,000	No	20.00%	$918,000	$918,000	8,140	$112.78
83	39 Santa Rosa Avenue	RH-1	Residential, House Character	No	$600,000	03/05/21	07/27/21	4.73	0.417%	2.00%	$612,000	No	20.00%	$734,400	$734,400	2,495	$294.35
84	1251 Thomas Avenue	PDR-2	Production, Distribution & Repair	No	$1,950,000	02/23/21	07/27/21	5.06	0.833%	4.00%	$2,028,000	No	20.00%	$2,433,600	$2,433,600	9,600	$253.50
85	1245 Van Dyke Avenue	PDR-2	Production, Distribution & Repair	No	$7,050,000	02/02/21	07/27/21	5.75	0.833%	5.00%	$7,402,500	No	20.00%	$8,883,000	$8,883,000	78,556	$113.08
86	7 Edgar Place	RH-1	Residential, House Character	Partial/Y	$699,000	07/16/20	07/27/21	12.35	0.417%	5.00%	$733,950	Partial/Y	10.00%	$807,345	$807,345	4,258	$189.61
87	2011 Filbert Street	RH-2	Residential, House Character	No	$935,000	07/10/20	07/27/21	12.55	0.417%	5.00%	$981,750	No	20.00%	$1,178,100	$1,178,100	1,650	$714.00
88	5222-5250 3rd Street	NCD	Neighborhood Commercial	No	$3,000,000	07/10/20	07/27/21	12.55	0.250%	3.00%	$3,090,000	No	20.00%	$3,708,000	$3,708,000	18,883	$196.37
89	1230 - 1240 Twin Peaks Boulevard	RH-1	Residential, House Character	No	$1,506,000	06/01/20	07/27/21	13.83	0.417%	6.00%	$1,596,360	No	20.00%	$1,915,632	$1,915,632	10,723	$178.65
90	4512 23rd Street	RM-1	Residential, Mixed	Partial/Y	$800,000	08/19/19	07/27/21	23.26	0.417%	10.00%	$880,000	Partial/Y	10.00%	$968,000	$968,000	3,027	$319.79
91	2921 Vallejo Street	RH-1(D)	Residential, House Character	Yes	$8,000,000	07/23/19	07/27/21	24.15	0.417%	10.00%	$8,800,000	Yes	0.00%	$8,800,000	$8,800,000	4,008	$2,195.61
92	923 Kansas Street	RH-2	Residential, House Character	Yes	$7,150,000	06/25/19	07/27/21	25.07	0.417%	10.00%	$7,865,000	Yes	0.00%	$7,865,000	$7,865,000	12,500	$629.20
93	1713 Yosemite Avenue	M-1	Industrial	Unknown	$1,388,000	08/23/18	07/27/21	35.12	0.833%	29.00%	$1,790,520	Unknown	0.00%	$1,790,520	$1,790,520	5,000	$358.10
94	287 Minerva Street	RH-1	Residential, House Character	No	$425,000	05/29/18	07/27/21	37.95	0.417%	16.00%	$493,000	No	20.00%	$591,600	$591,600	3,125	$189.31
95	95 Santa Cruz Avenue	RH-1	Residential, House Character	No	$450,000	05/16/18	07/27/21	38.37	0.417%	16.00%	$522,000	No	20.00%	$626,400	$626,400	1,999	$313.36
96	1401 Illinois Street	PDR-1-G	Production, Distribution & Repair	No	$23,400,000	05/01/18	07/27/21	38.87	0.833%	32.00%	$30,888,000	No	20.00%	$37,065,600	$37,065,600	79,997	$463.34
97	599 Crestmont Dr	RM-1	Residential, Mixed	Yes	$7,600,000	04/30/18	07/27/21	38.90	0.417%	16.00%	$8,816,000	Yes	20.00%	$10,579,200	$10,579,200	50,094	$211.19
98	1065 Innes Avenue	RH-1	Residential, House Character	Yes	$1,200,000	04/06/18	07/27/21	39.69	0.417%	17.00%	$1,404,000	Yes	0.00%	$1,404,000	$1,404,000	7,500	$187.20
99	2175 Hayes Street	RH-3	Residential, House Character	No	$1,650,000	03/05/18	07/27/21	40.74	0.417%	17.00%	$1,930,500	No	20.00%	$2,316,600	$2,316,600	3,868	$598.91
100	325 29th Avenue	RH-2	Residential, House Character	Yes	$1,300,000	02/27/18	07/27/21	40.94	0.417%	17.00%	$1,521,000	Yes	0.00%	$1,521,000	$1,521,000	2,996	$507.68
101	562 28th Ave	RM-1	Residential, Mixed	Yes	$1,925,000	02/08/18	07/27/21	41.56	0.417%	17.00%	$2,252,250	Yes	0.00%	$2,252,250	$2,252,250	4,796	$469.61
102	922 Jamestown Avenue	RH-1	Residential, House Character	No	$325,000	11/30/17	07/27/21	43.86	0.417%	18.00%	$383,500	No	20.00%	$460,200	$460,200	2,609	$176.39
103	127 Edgehill Way	RH-1(D)	Residential, House Character	Yes	$880,000	10/26/17	07/27/21	45.01	0.417%	19.00%	$1,047,200	Yes	0.00%	$1,047,200	$1,047,200	3,937	$265.99
104	363 21st Avenue	RM-1	Residential, Mixed	Yes	$1,750,000	08/22/17	07/27/21	47.15	0.417%	20.00%	$2,100,000	Yes	0.00%	$2,100,000	$2,100,000	2,996	$700.93
105	423 24th Avenue	RM-1	Residential, Mixed	Yes	$1,960,000	06/30/17	07/27/21	48.89	0.417%	20.00%	$2,352,000	Yes	0.00%	$2,352,000	$2,352,000	3,000	$784.00
106	477 Eucalyptus Drive	RH-1(D)	Residential, House Character	Yes	$1,360,000	05/18/17	07/27/21	50.30	0.417%	21.00%	$1,645,600	Yes	0.00%	$1,645,600	$1,645,600	4,000	$411.40
Total											$953,071,515			$1,078,237,852	$1,078,237,852	1,646,724 37.80 acres	
Weighted Average											$578.77			$654.78			$654.78

EXHIBIT "W - 5"
LAND SALES & ADJUSTMENTS
BY ZONING USE DISTRICT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

						Market Conditions Adjustment					Entitlement Adjustment			Data - Adjusted		
Comp #	Location	Zoning	Zoning Use District	Entitled at Sale	Sale Price	Sale Date	07/27/21 Date of Value (DOV)	Months from DOV	Monthly Adjustment	Total Adjustment	Time Adjusted Sale Price	Entitled at Sale	20.00% for Entitlement	Time & Entitlement Adjusted	Adjusted Sale Price	Land Area	Price per SF
SUMMARY																	
Low															$339,900	750	$112.78
High															$94,920,000	343,688	$6,804.17
Average															$10,367,672	15,834	$891.89
Median															$2,350,750	4,501	$578.45
Count															104	104	104

MARKET CONDITIONS ADJUSTMENTS

Description	Adjustment Annual	Adjustment Monthly		Zoning Use District
Residential Zoning Use Districts:	5.000%	0.417%	Sale Prior to Date of Value	(Residential, House Character; Residential, Mixed; Residential-Commercial Combined; Downtown Residential)
Residential Zoning Use Districts:	-4.000%	-0.333%	Sale After Date of Value	(Residential, House Character; Residential, Mixed; Residential-Commercial Combined; Downtown Residential)
Mixed Use Zoning Use Districts:	5.000%	0.417%	Sale Date to Date of Value	(Eastern Neighborhoods Mixed Use; Chinatown Mixed Use; Neighborhood Commercial Transit)
Industrial Zoning Use Districts:	10.000%	0.833%	Sale Date to Date of Value	(Industrial; Production, Distribution & Repair)
Commercial Zoning Use Districts:	3.000%	0.250%	Sale Date to Date of Value	(Commercial; Neighborhood Commercial)

EXHIBIT "W - 5"
LAND SALES & ADJUSTMENTS
BY ZONING USE DISTRICT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Residential, House Character			Residential, Mixed			Residential-Commercial Combined / Residential, Transit Oriented			Downtown Residential			Commercial			Neighborhood Commercial / Neighborhood Commercial Transit		
Comp #	Location	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Sale Price	Adjusted Sale Price	Land Area	Sale Price
1	524 Howard Street													$83,460,000	12,266	$6,804.17			
2	325 Fremont Street										$37,620,000	6,434	$5,847.06						
3	525 Harrison Street										$43,200,000	12,981	$3,327.94						
4	547 Howard Street													$8,996,400	2,126	$4,231.61			
5	555 Howard Street													$38,556,143	8,250	$4,673.47			
6	557 Howard Street													$17,493,000	4,121	$4,244.84			
7	901 Illinois Street																		
8	790 Pennsylvania Avenue																		
9	1755 Egbert Avenue																		
10	2270 Jerrod Avenue																		
11	2150 Oakdale Avenue																		
12	2000 Marin Street																		
13	430 Eddy Street							$3,380,000	3,578	$944.66									
14	199 Turk and 180 Jones Streets							$4,920,000	4,744	$1,037.10									
15	530-540 Turk Street							$4,804,800	9,583	$501.39									
16	500 Turk Street							$18,081,000	18,906	$956.36									
17	719-725 Larkin Street							$4,608,000	5,998	$768.26									
18	1550 Market Street													$29,440,000	12,567	$2,342.64			
19	72-80 Ellis Street													$11,781,000	8,240	$1,429.73			
20	1121-1125 Mission Street													$25,918,200	12,402	$2,089.84			
21	30 Van Ness St													$94,920,000	38,124	$2,489.77			
22	1338-1370 Mission Street													$35,100,000	18,901	$1,857.04			
23	2100 Mission Street																$5,280,000	6,370	$828.89
24	1490 Ocean Avenue																$8,268,000	10,237	$807.66
25	1455 Irving Street																$2,147,760	4,792	$448.20
26	3820 24th Street																$2,923,200	2,849	$1,026.04
27	2550 Irving Street																$10,692,000	19,162	$557.98
28A	42 & 44 Cook Street	$3,584,500	3,000	$1,194.83															
28B	42 & 44 Cook Street	$2,044,080	3,000	$681.36															
29	524 Hickory Street	$1,560,000	1,250	$1,248.00															
30	166 Parker Avenue	$2,316,600	2,775	$834.81															
31	2677 Harrison Street	$1,849,260	2,304	$802.63															
32	1120 Valencia St																$4,733,280	4,134	$1,144.96
33	1090-1098 Valencia Street																$16,847,568	10,114	$1,665.77
34	606 Capp Street							$5,148,000	7,350	$700.41									
35	1526 Powell Street																$3,410,400	5,259	$648.49
36	555 Jackson Street																		
37	1198 Columbus Ave/2568 Jones St													$5,832,000	6,420	$908.41			
38	425 Broadway Street																$14,784,000	13,641	$1,083.79
39	1598 Bay Street																$11,056,500	12,541	$881.63
40	1633 Cabrillo Street	$2,316,600	2,775	$834.81															
41	36 Tehama Street													$3,270,000	2,000	$1,635.00			
42	135 Wetmore Street				$3,985,200	2,225	$1,791.10												
43	361-365 21st Street	$2,349,500	2,997	$783.95															
44	53 States Street	$2,342,400	2,642	$886.60															
45	2055 Taraval Street																$1,572,480	3,250	$483.84
46	134 Athens Street	$741,520	2,495	$297.20															
47	332 Bradford Street	$574,260	1,751	$327.96															
48	300 University Street	$712,800	2,060	$346.02															
49	302 University Street	$604,800	2,060	$293.59															
50	326 Gambier Street	$600,000	2,950	$203.39															
51	1654 Kirkwood Avenue	$1,224,000	5,000	$244.80															
52A	1782 Quesada Avenue	$708,750	2,500	$283.50															
52B	1782 Quesada Avenue	$560,880	2,500	$224.35															
52C	1782 Quesada Avenue	$416,000	2,500	$166.40															
53	1750 Oakdale Avenue	$391,680	2,500	$156.67															
54	1528 Hudson Avenue	$487,152	2,500	$194.86															

EXHIBIT "W - 5"
LAND SALES & ADJUSTMENTS
BY ZONING USE DISTRICT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Residential, House Character			Residential, Mixed			Residential-Commercial Combined / Residential, Transit Oriented			Downtown Residential			Commercial			Neighborhood Commercial / Neighborhood Commercial Transit		
Comp #	Location	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Price per SF	Adjusted Sale Price	Land Area	Sale Price	Adjusted Sale Price	Land Area	Sale Price
55	1390 Oakdale Avenue	$571,200	2,663	$214.49															
56	150 Eureka Street	$3,682,800	6,069	$606.82															
57	56 Laussat Street	$518,736	750	$691.65															
58	1 Gull Drive																		
59	165 S. Linden Avenue																		
60	1030 Brittan Avenue																		
61	595 Industrial Road & 810-850 E. San Carlos Avenue																		
62	1401 Shoreway Road																		
63	514-580 Minna Street																		
64	1288 Howard Street																$30,360,000	37,116	$817.98
65	230-237 7th Street																		
66	220 9th Street																		
67	915 Minna Street																		
68	292 Arleta Avenue	$504,000	2,495	$202.00															
69	3338 San Bruno Avenue	$339,900	1,750	$194.23															
70	666 Hamilton Street	$2,158,200	9,962	$216.64															
71	154 Delta Street	$849,600	5,000	$169.92															
72	2168 Bayshore Boulevard	$442,800	2,195	$201.73															
73	342 22nd Avenue				$1,926,000	3,000	$642.00												
74	347 5th Avenue				$1,879,750	3,000	$626.58												
75	112 Kensington Way	$1,078,256	4,100	$262.99															
76	1713 Yosemite Avenue																		
77	448 Valley Street	$1,944,250	2,642	$735.90															
78	47 Montclair Terrace	$1,454,400	2,644	$550.08															
79	1133 S. Van Ness Avenue	$4,600,000	11,500	$400.00															
80	1450 Marin Street																		
81	552 Ortega Street	$1,139,280	3,458	$329.46															
82	1 Castenada Avenue	$918,000	8,140	$112.78															
83	39 Santa Rosa Avenue	$734,400	2,495	$294.35															
84	1251 Thomas Avenue																		
85	1245 Van Dyke Avenue																		
86	7 Edgar Place	$807,345	4,258	$189.61															
87	2011 Filbert Street	$1,178,100	1,650	$714.00															
88	5222-5250 3rd Street																$3,708,000	18,883	$196.37
89	1230 - 1240 Twin Peaks Boulevard	$1,915,632	10,723	$178.65															
90	4512 23rd Street				$968,000	3,027	$319.79												
91	2921 Vallejo Street	$8,800,000	4,008	$2,195.61															
92	923 Kansas Street	$7,865,000	12,500	$629.20															
93	1713 Yosemite Avenue																		
94	287 Minerva Street	$591,600	3,125	$189.31															
95	95 Santa Cruz Avenue	$626,400	1,999	$313.36															
96	1401 Illinois Street																		
97	599 Crestmont Dr				$10,579,200	50,094	$211.19												
98	1065 Innes Avenue	$1,404,000	7,500	$187.20															
99	2175 Hayes Street	$2,316,600	3,868	$598.91															
100	325 29th Avenue	$1,521,000	2,996	$507.68															
101	562 28th Ave				$2,252,250	4,796	$469.61												
102	922 Jamestown Avenue	$460,200	2,609	$176.39															
103	127 Edgehill Way	$1,047,200	3,937	$265.99															
104	363 21st Avenue				$2,100,000	2,996	$700.93												
105	423 24th Avenue				$2,352,000	3,000	$784.00												
106	477 Eucalyptus Drive	$1,645,600	4,000	$411.40															
Total		$76,499,281	178,595		$26,042,400	72,138		$40,941,800	50,159		$80,820,000	19,415		$354,766,743	125,417		$115,783,188	148,348	
			4.10 acres			1.66 acres			1.15 acres			0.45 acres			2.88 acres			3.41 acres	
Weighted Average				$428.34			$361.01			$816.24			$4,162.76			$2,828.70			$780.48

EXHIBIT "W - 5"
LAND SALES & ADJUSTMENTS
BY ZONING USE DISTRICT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

	Residential, House Character			Residential, Mixed			Residential-Commercial Combined / Residential, Transit Oriented			Downtown Residential			Commercial			Neighborhood Commercial / Neighborhood Commercial Transit		
Comp # Location	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Price per SF**	**Adjusted Sale Price**	**Land Area**	**Sale Price**	**Adjusted Sale Price**	**Land Area**	**Sale Price**
SUMMARY																		
Low	$339,900	750	$112.78	$968,000	2,225	$211.19	$3,380,000	3,578	$501.39	$37,620,000	6,434	$3,327.94	$3,270,000	2,000	$908.41	$1,572,480	2,849	$196.37
High	$8,800,000	12,500	$2,195.61	$10,579,200	50,094	$1,791.10	$18,081,000	18,906	$1,037.10	$43,200,000	12,981	$5,847.06	$94,920,000	38,124	$6,804.17	$30,360,000	37,116	$1,665.77
Average	$1,627,644	3,800	$462.68	$3,255,300	9,017	$693.15	$6,823,633	8,360	$818.03	$40,410,000	9,708	$4,587.50	$32,251,522	11,402	$2,973.32	$8,906,399	11,411	$814.74
Median	$1,078,256	2,775	$297.20	$2,176,125	3,000	$634.29	$4,862,400	6,674	$856.46	$40,410,000	9,708	$4,587.50	$25,918,200	8,250	$2,342.64	$5,280,000	10,114	$817.98
Count	47	47	47	8	8	8	6	6	6	2	2	2	11	11	11	13	13	13

EXHIBIT "W - 5"
LAND SALES & ADJUSTMENTS
BY ZONING USE DISTRICT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Chinatown Mixed Use / Eastern Neighborhoods Mixed Use			Production, Distribution & Repair			Industrial		
Comp #	Location	Adjusted Sale Price	Land Area	Sale Price	Adjusted Sale Price	Land Area	Sale Price	Adjusted Sale Price	Land Area	Sale Price
1	524 Howard Street									
2	325 Fremont Street									
3	525 Harrison Street									
4	547 Howard Street									
5	555 Howard Street									
6	557 Howard Street									
7	901 Illinois Street				$32,736,000	67,988	$481.50			
8	790 Pennsylvania Avenue	$48,895,000	119,885	$407.85	$48,895,000	119,885	$407.85			
9	1755 Egbert Avenue				$21,357,000	70,446	$303.17			
10	2270 Jerrod Avenue				$77,357,280	154,883	$499.46			
11	2150 Oakdale Avenue				$20,130,000	52,085	$386.49			
12	2000 Marin Street				$85,478,400	343,688	$248.71			
13	430 Eddy Street									
14	199 Turk and 180 Jones Streets									
15	530-540 Turk Street									
16	500 Turk Street									
17	719-725 Larkin Street									
18	1550 Market Street									
19	72-80 Ellis Street									
20	1121-1125 Mission Street									
21	30 Van Ness St									
22	1338-1370 Mission Street									
23	2100 Mission Street									
24	1490 Ocean Avenue									
25	1455 Irving Street									
26	3820 24th Street									
27	2550 Irving Street									
28A	42 & 44 Cook Street									
28B	42 & 44 Cook Street									
29	524 Hickory Street									
30	166 Parker Avenue									
31	2677 Harrison Street									
32	1120 Valencia St									
33	1090-1098 Valencia Street									
34	606 Capp Street									
35	1526 Powell Street									
36	555 Jackson Street	$8,502,000	8,089	$1,051.06						
37	1198 Columbus Ave/2568 Jones St									
38	425 Broadway Street									
39	1598 Bay Street									
40	1633 Cabrillo Street									
41	36 Tehama Street									
42	135 Wetmore Street									
43	361-365 21st Street									
44	53 States Street									
45	2055 Taraval Street									
46	134 Athens Street									
47	332 Bradford Street									
48	300 University Street									
49	302 University Street									
50	326 Gambier Street									
51	1654 Kirkwood Avenue									
52A	1782 Quesada Avenue									
52B	1782 Quesada Avenue									
52C	1782 Quesada Avenue									
53	1750 Oakdale Avenue									
54	1528 Hudson Avenue									

EXHIBIT "W - 5"
LAND SALES & ADJUSTMENTS
BY ZONING USE DISTRICT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

		Chinatown Mixed Use / Eastern Neighborhoods Mixed Use			Production, Distribution & Repair			Industrial		
Comp #	Location	Adjusted Sale Price	Land Area	Sale Price	Adjusted Sale Price	Land Area	Sale Price	Adjusted Sale Price	Land Area	Sale Price
55	1390 Oakdale Avenue									
56	150 Eureka Street									
57	56 Laussat Street									
58	1 Gull Drive									
59	165 S. Linden Avenue									
60	1030 Brittan Avenue									
61	595 Industrial Road & 810-850 E. San Carlos Avenue									
62	1401 Shoreway Road									
63	514-580 Minna Street									
64	1288 Howard Street	$30,360,000	37,116	$817.98						
65	230-237 7th Street									
66	220 9th Street									
67	915 Minna Street									
68	292 Arleta Avenue									
69	3338 San Bruno Avenue									
70	666 Hamilton Street									
71	154 Delta Street									
72	2168 Bayshore Boulevard									
73	342 22nd Avenue									
74	347 5th Avenue									
75	112 Kensington Way									
76	1713 Yosemite Avenue							$1,441,500	5,000	$288.30
77	448 Valley Street									
78	47 Montclair Terrace									
79	1133 S. Van Ness Avenue									
80	1450 Marin Street				$3,023,940	14,125	$214.08			
81	552 Ortega Street									
82	1 Castenada Avenue									
83	39 Santa Rosa Avenue									
84	1251 Thomas Avenue				$2,433,600	9,600	$253.50			
85	1245 Van Dyke Avenue				$8,883,000	78,556	$113.08			
86	7 Edgar Place									
87	2011 Filbert Street									
88	5222-5250 3rd Street									
89	1230 - 1240 Twin Peaks Boulevard									
90	4512 23rd Street									
91	2921 Vallejo Street									
92	923 Kansas Street									
93	1713 Yosemite Avenue							$1,790,520	5,000	$358.10
94	287 Minerva Street									
95	95 Santa Cruz Avenue									
96	1401 Illinois Street				$37,065,600	79,997	$463.34			
97	599 Crestmont Dr									
98	1065 Innes Avenue									
99	2175 Hayes Street									
100	325 29th Avenue									
101	562 28th Ave									
102	922 Jamestown Avenue									
103	127 Edgehill Way									
104	363 21st Avenue									
105	423 24th Avenue									
106	477 Eucalyptus Drive									
Total		$87,757,000	165,090		$337,359,820	991,253		$3,232,020	10,000	
			3.79 acres			22.76 acres			0.23 acres	
Weighted Average				$531.57			$340.34			$323.20

EXHIBIT "W - 5"
LAND SALES & ADJUSTMENTS
BY ZONING USE DISTRICT
CITY AND COUNTY OF SAN FRANCISCO
DATE OF VALUE: JULY 27, 2021

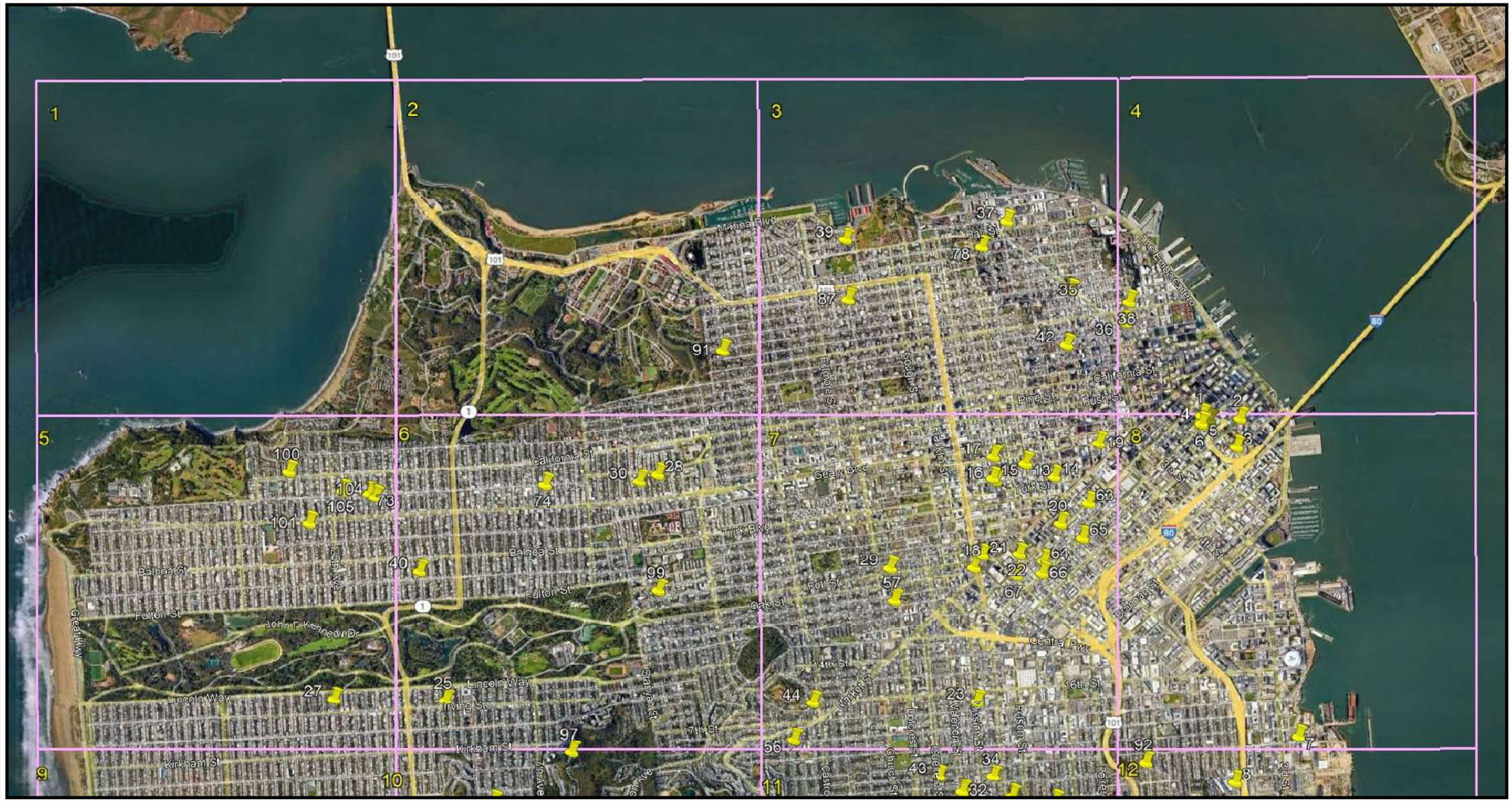
	Chinatown Mixed Use / Eastern Neighborhoods Mixed Use			Production, Distribution & Repair			Industrial		
Comp # Location	**Adjusted Sale Price**	**Land Area**	**Sale Price**	**Adjusted Sale Price**	**Land Area**	**Sale Price**	**Adjusted Sale Price**	**Land Area**	**Sale Price**
SUMMARY									
Low	$8,502,000	8,089	$407.85	$2,433,600	9,600	$113.08	$1,441,500	5,000	$288.30
High	$48,895,000	119,885	$1,051.06	$85,478,400	343,688	$499.46	$1,790,520	5,000	$358.10
Average	$29,252,333	55,030	$758.96	$33,735,982	99,125	$337.12	$1,616,010	5,000	$323.20
Median	$30,360,000	37,116	$817.98	$27,046,500	74,501	$344.83	$1,616,010	5,000	$323.20
Count	3	3	3	10	10	10	2	2	2

Market Data Maps

Fort Mason
Fisherman's Wharf
Marina
North Beach
Embarcadero
Presidio of San Francisco
South Bay
Presidio Golf Course
Lincoln Park
Sea Cliff
Outer Richmond
Inner Richmond
Anza Vista
North of the Panhandle
San Francisco
Hayes Valley
Golden Gate Park 9th Avenue Playground
Golden Gate Park Golf Course
Buena Vista Park
Eureka Valley
The Castro
Mission District
Mt Sutro Open Space Reserve
Golden Gate Heights
Twin Peaks
Laguna Honda Hospital and Rehabilitation Center
Outer Sunset
West Sunset Playground
Sunset District
Sunset Parkway
Lower Great Highway Park
Zoo
Lakeshore
Harding Park
San Francisco State University
Lake Merced Park
Ingleside
Olympic Golf Club
Mt Davidson Park
Bernal Heights Park
Portola
Portola Plaza
Bayview
Hunters Point
India Basin
Heron's Head Park
China Basin
Mission Bay
Dogpatch
Central Waterfront
Candlestick Point State Recreation Area
Candlestick Park
Little Hollywood
Sunnydale
Crocker-Amazon
Gleneagles Golf Course
John McLaren Park
Cayuga Terrace
Moscone Center
Chinatown
Pacific Heights
UCSF Med Center
Doyle Dr
Mason St
Marina Blvd
Lombard St
Bay Bridge
Lincoln Highway
Geary Blvd
Balboa St
Fulton St
Lincoln Way
Kirkham St
Noriega St
Sloat Blvd
Taraval St
Portola Dr
Monterey Blvd
Ocean Ave
Holloway Ave
Alemany Blvd
Persia Ave
Mansell St
Bosworth St
Southern Fwy
Cesar Chavez St
Bayshore Fwy
Oakdale Ave
Geneva Ave
Great Hwy
Skyline Blvd
John Muir Dr
Lake Merced Blvd
Junipero Serra Blvd
Park Presidio Blvd
Sunset Blvd
19th Ave
Van Ness Ave
Gough St
Webster St
Fillmore St
Divisadero St
Baker St
Lyon St
Presidio Blvd
Geary Blvd
California St
Pine St
Bush St
Turk St
Fell St
Page St
Haight St
Market St
17th St
22nd St
24th St
16th St
Cesar Chavez St
Bayshore Fwy
Van Ness Ave
Mission St
Folsom St
Potrero Ave
Dolores St
Guerrero St
Castro St
Cole St
Stanyan St
Kezar
7th Ave
Diamond St
San Jose Avenue
Brannan St
7th St
3rd St
Embarcadero
Bay Bridge
Lincoln Highway
Cesar Chavez St
Oakdale Ave
Geneva Ave
Harrison Ave
Jennings St
James Lick Fwy

Market Data Aerial - San Francisco

N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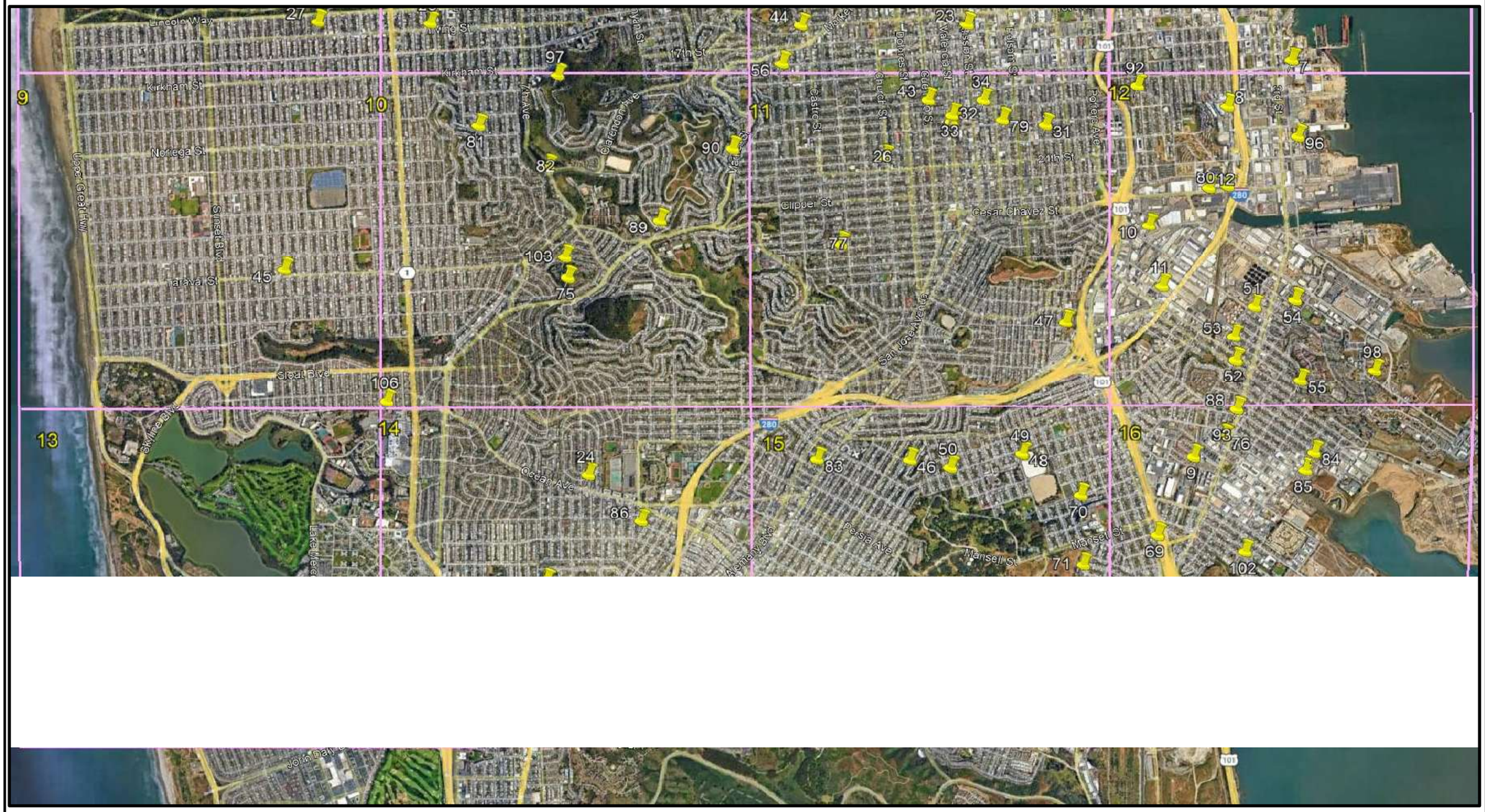
Marina Blvd
Bay St
The Embarcadero
California St
Pine St
Bush St
Geary Blvd
Turk Blvd
Fell St
Oak St
Baker St
Fulton St
Lincoln Way
Kirkham St
Irving St
Sloat Blvd
Great Hwy
John F Kennedy Dr
Stanyan St
Masonic Ave
Divisadero St
Fillmore St
Webster St
Steiner St
Pierce St
Scott St
Gough St
Octavia St
Laguna St
Franklin St
Van Ness Ave
Polk St
Larkin St
Hyde St
Leavenworth St
Jones St
Taylor St
Mason St
Powell St
Stockton St
Grant Ave
Kearny St
Montgomery St
Sansome St
Battery St
Front St
Drumm St
Davis St
Market St
Beale St
Main St
Spear St
Steuart St
Fremont St
Beale St
Davis St
Drumm St
Front St
Battery St
Sansome St
Montgomery St
Kearny St
Grant Ave
Stockton St
Powell St
Mason St
Taylor St
Jones St
Hyde St
Leavenworth St
Larkin St
Polk St
Van Ness Ave
Franklin St
Gough St
Octavia St
Laguna St
Buchanan St
Webster St
Fillmore St
Steiner St
Pierce St
Scott St
Divisadero St
Masonic Ave
Stanyan St
Arguello Blvd
Funston Ave
Great Hwy
Sloat Blvd
Lincoln Way
Irving St
Kirkham St
Noriega St
Rivera St
Judah St
Kirkham St
Lincoln Way
Fulton St
Balboa St
Geary Blvd
Turk Blvd
Fell St
Oak St
Page St
Haight St
Waller St
Frederick St
Carl St
Beulah St
Clayton St
Cole St
Shrader St
Stanyan St
Masonic Ave
Central Fwy
16th St
17th St
Duboce Ave
Market St
Mission St
Valencia St
Guerrero St
Dolores St
Castro St
Noe St
Sanchez St
Church St
Diamond St
Chenery St
Castro St
Dolores St
Guerrero St
Valencia St
Mission St
Bryant St
Harrison St
Folsom St
Howard St
Langton St
Hooper St
Brannan St
Townsend St
King St
Berry St
Bryant St
Harrison St
Folsom St
Howard St
Langton St
Hooper St
Brannan St
Townsend St
King St
Berry St
Embarcadero
Pier 39
Fisherman's Wharf
Ferry Bldg
Ferry Bldg
Pier 39
Fisherman's Wharf

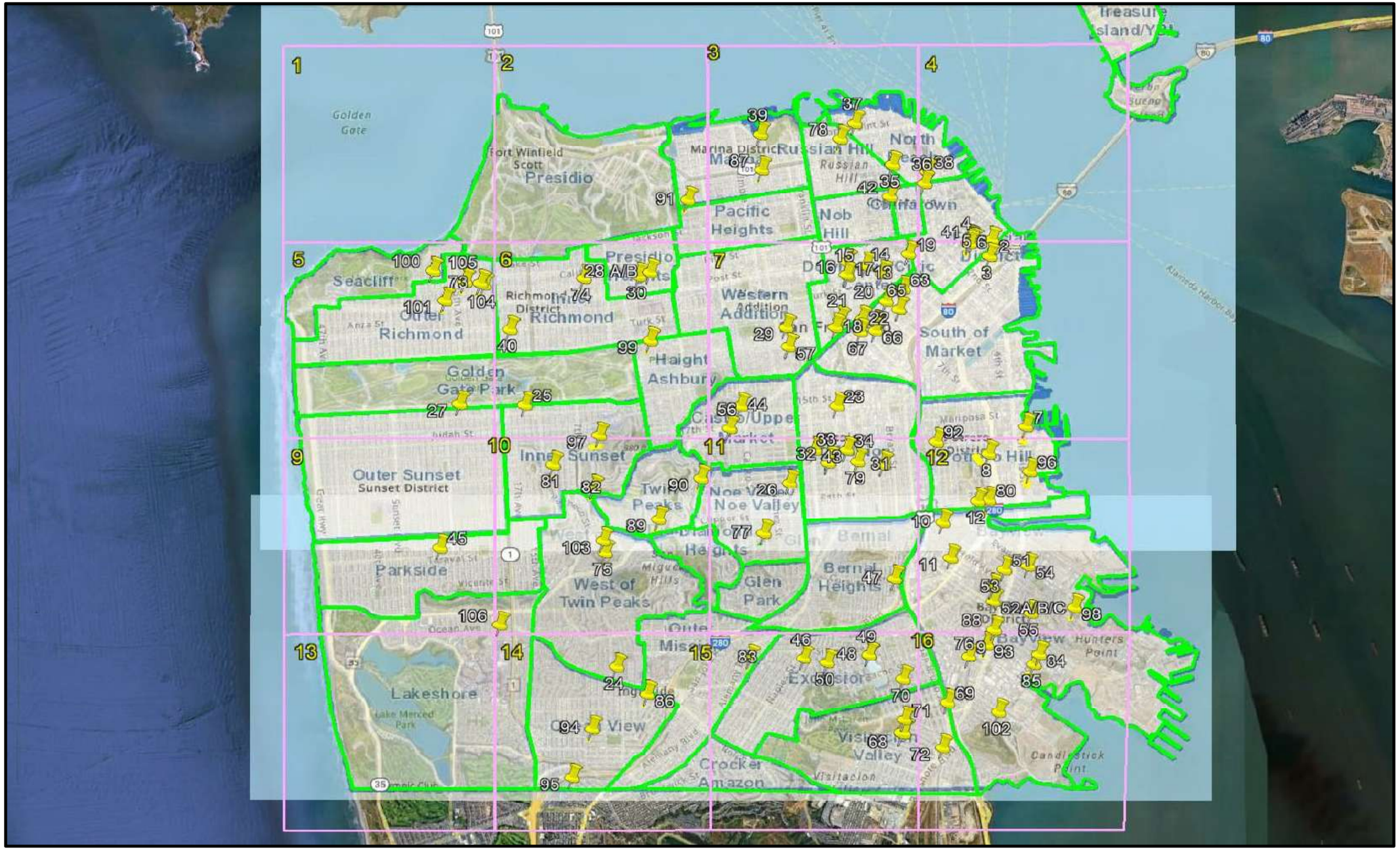


Market Data Aerial - South

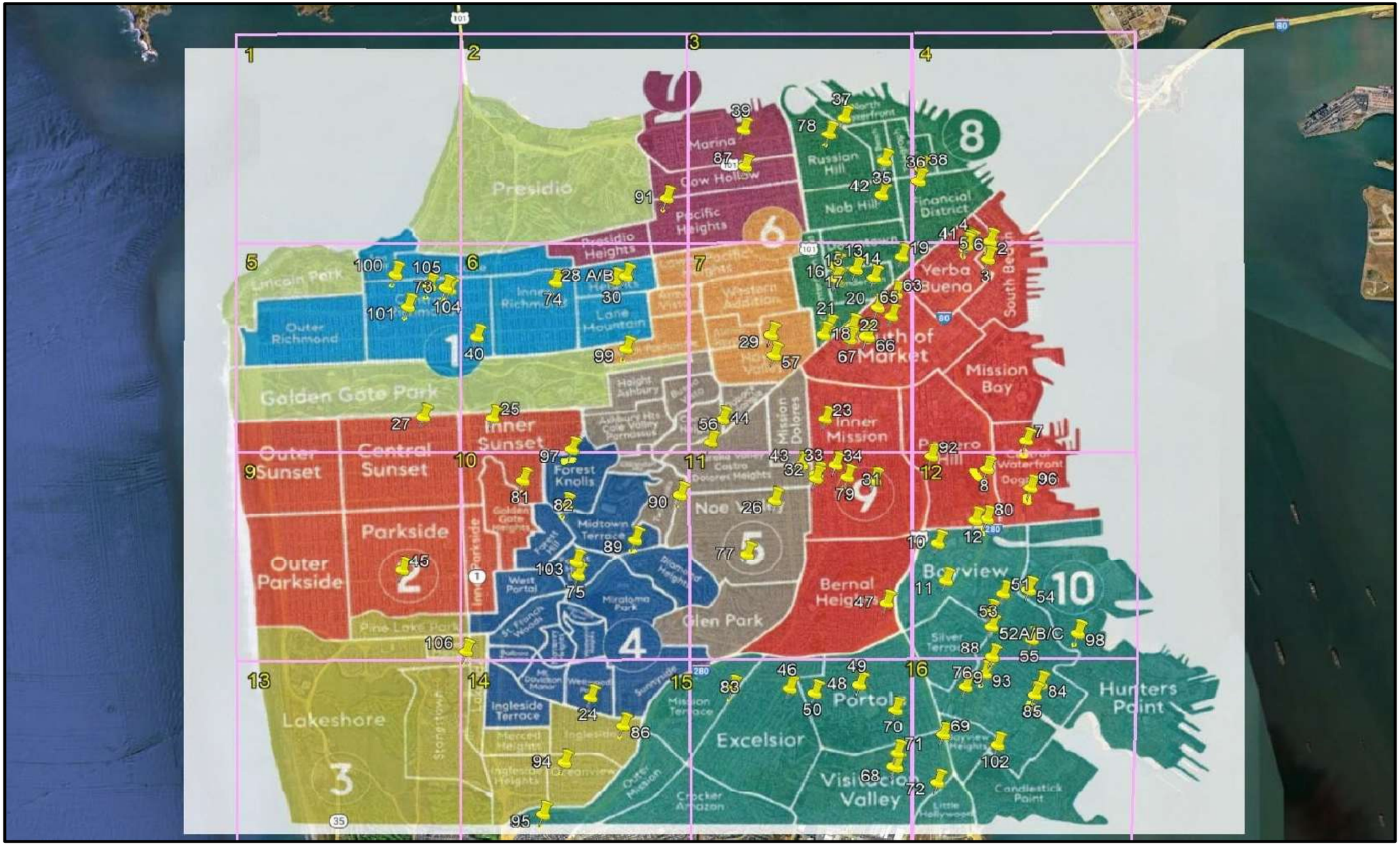
N

Market Data Aerial - Planning Areas

N



Market Data Aerial - Neighborhood



Market Data Aerial - Multiple Listing Service

Qualifications of Appraisers

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PROPERTY ADVISORS

INDEPENDENT VALUATIONS FOR A VARIABLE WORLD

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STATE CERTIFICATION
California

EDUCATION
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A.B., International Relations
University of Southern California

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Walter D. Carney, MAI
Senior Managing Director
Valbridge Property Advisors | Northern California

EXPERIENCE, continued

Appraisal/valuation and consulting assignments include Special Purpose: Professional/Major Leagues Sports venues – stadiums, land: MLB, MLS, NBA, NFL, NHL; airport fixed base operators, chemical/metal plating, worship facilities. Railroad and public utility corridors; trails; various right-of-way uses. Remnant ("plottage") parcels. Wetlands and Waters of the U.S.; private and public reservoirs; open space; endangered and protected habitats; abandoned public streets. **Commercial:** office buildings, medical/dental buildings, retail buildings, shopping centers, C-stores, restaurants, hotels/lodgings, service stations, mixed-use projects, banks, auto dealerships, telecommunications, cell towers, communications facilities, truck stops, public and private schools, land. **Industrial:** light industrial; warehouse; R&D buildings; refuse and recycling facilities; asphalt and concrete mixing plants; food processing and cold storage facilities; maritime leases, maritime ship building, boat building and repair; land. **Residential**: Single-family and Multi-family: condominiums, apartments, subdivisions, mobile home parks, trailer parks, RV parks, land. **Agricultural:** livestock, ranching, farming, permanent plantings, field and row crops, farmland, open space. **Easements and Various Rights:** surface, subsurface, air, conservation, historic-façade-preservation, TDR's (Transfer Density Rights). **Other:** fractional interest valuations, contaminated properties, feasibility studies, market studies, review appraisals. **Litigation and Support:** judge and jury trials; mediations; arbitrations.

CERTIFICATION

Business, Consumer Services & Housing Agency
BUREAU OF REAL ESTATE APPRAISERS
REAL ESTATE APPRAISER LICENSE

Walter D. Carney

has successfully met the requirements for a license as a residential and commercial real estate appraiser in the State of California and is, therefore, entitled to use the title:

"Certified General Real Estate Appraiser"

This license has been issued in accordance with the provisions of the Real Estate Appraisers' Licensing and Certification Law.

BREA APPRAISER IDENTIFICATION NUMBER: AG 003413

Effective Date: May 15, 2024
Date Expires: May 14, 2026

I certify, under penalty of perjury, that this is a true and correct copy of my original license or certificate.
Signature:
Date: 5/15/2024

Angela Jemmott, Bureau Chief, BREA

3076437

THIS DOCUMENT CONTAINS A TRUE WATERMARK - HOLD UP TO LIGHT TO SEE "DRAIN LINE"

WALDRON & ASSOCIATES, INC.
REAL ESTATE APPRAISERS AND CONSULTANTS

Experience (Continued)

Since obtaining his degree, he has practiced as a field appraiser and real property consultant throughout the Western United States, primarily within California. Appraisals and consulting assignments cover properties located in the states of Arizona, California, Hawaii, Minnesota, Nevada, Oregon, and Washington.

Appraisals have also been conducted in Canada. Appraisal and consulting assignments cover all types of real property interests for varying purposes for both private and public clientele. Assignments personally completed include appraisals and consultations for all types of real property, including, but not limited to, improved commercial, industrial, residential, mixed-use, and special use properties, as well as vacant land in each of these use categories. Appraisals and consulting cover all property interests including fee simple, leased fee, leasehold, fractional interests, and easement interests. Appraisals have been completed for public projects, including acquisitions for redevelopment, schools, utilities, transportation, and other right-of-way assignments with consideration due partial and full takings. In addition to real property appraisal, he provides real estate consulting for pre-litigation preparation on behalf of public and private clientele.

Most of Mr. Waldron's assignments involve complex litigation issues. He has provided expert testimony in the United States District Court, the Superior Courts of Contra Costa, Kern, Los Angeles, Monterey, Orange, Riverside, San Bernardino, San Diego, San Francisco, San Luis Obispo, Santa Barbara, Stanislaus, and Ventura counties, as well as Federal Bankruptcy Court and various arbitration and mediation panels as expert and arbitrator. He has been mutually retained by opposing parties as the neutral appraiser to determine compensation for all parties. His application of valuation methodologies and valuation opinions have been tried, held, and affirmed in Superior Courts, Appellate Courts, and the California Supreme Court.

With a focus on eminent domain assignments, Mr. Waldron has participated in providing expert testimony in hundreds of depositions and approximately one hundred jury trials. In addition to authoring various real property articles, Mr. Waldron has been an invited speaker and instructor at various real property seminars, including the Real Property Law Section of The State Bar of California, the International Right-of-Way Association, Appraisal Institute, and other private and public organizations.

WALDRON & ASSOCIATES, INC.
REAL ESTATE APPRAISERS AND CONSULTANTS

Experience (Continued)

Notable assignments include consulting on behalf of the Presidio Trust in regard to the south access to the Golden Gate Bridge through The Presidio in San Francisco; consulting for the California Coastal Conservancy with regards to the purchase of a conservation easement covering Hearst Ranch in San Luis Obispo, California; appraisals covering portions of Disneyland, NBC Universal's Universal Studios, Great America Theme Park in Santa Clara, and Los Angeles International Airport; California's largest single acquisition (dollar-wise) of open space in Playa Vista; the Hsi Lai Temple, the largest Buddhist temple in the Western Hemisphere; acquisitions by the USA in the Tijuana River Valley for the construction of the Border Fence in San Diego county; and numerous acquisition appraisals for the development of the Staples Arena in Los Angeles and PETCO Park in San Diego.

Qualified As Expert Witness

United States District Court

Contra Costa County Superior Court
Federal Bankruptcy Court
Kern County Superior Court
Los Angeles County Superior Court
Monterey County Superior Court
Orange County Superior Court
Riverside County Superior Court
San Bernardino Superior Court
San Diego County Superior Court
San Francisco County Superior Court
San Luis Obispo County Superior Court
Santa Barbara County Superior Court
Stanislaus County Superior Court
Ventura County Superior Court
American Arbitration Association

WALDRON & ASSOCIATES, INC.
REAL ESTATE APPRAISERS AND CONSULTANTS

Instructor - Lecturer - Author

CLE International, Eminent Domain Conference, 2024
Instructor - "What Attorneys Don't Know About Appraisal and What They Really Need to Know"

CLE International, Eminent Domain Conference, 2023
Instructor - "Does a Shrinking Litigation Appraiser Pool Impair Just Compensation for Owner and Agency?"

Appraisal Institute's 55th Annual Litigation Seminar, 2022
Guest Speaker - "Valuation Concepts Around the Public Project"

CLE International, Eminent Domain Conference, 2019
Instructor - "Mock Cross-Examination of an Expert Real Estate Appraiser"

International Right of Way Association, 27th Annual Valuation Seminar, 2019
Guest Speaker - "What Buyer Intentionally Pays the Highest Price?"

CLE International, Eminent Domain Conference, 2019
Instructor - "Mock Cross-Examination of an Expert Real Estate Appraiser"

International Right of Way Association, 26th Annual Valuation Seminar, 2018
Guest Speaker - "Highest and Best Use"

CLE International, 20th Anniversary Conference, Eminent Domain, 2018
Instructor - "Highest and Best Use – How Speculative Can You Be?"

International Right of Way Association & Appraisal Institute Joint Seminar, 2017
Guest Speaker - "The Anatomy of an Appraiser's Deposition"

CLE International, Eminent Domain Conference, 2017
Instructor - "Why the Project Design & Plans Matter"

Law Seminars International, Landslides in California, 2016
Speaker – "Practical Tips for Assembling the Case and Presenting the Science at Trial"

WALDRON & ASSOCIATES, INC.
REAL ESTATE APPRAISERS AND CONSULTANTS

Instructor - Lecturer - Author (Continued)

Real Property Law Section of The State Bar of California, 24th Annual Real Property Retreat, 2005
Guest Speaker – "Use of an Expert Witness"

International Right of Way Association, Bundle of Rights, 2005
Author - "The Project – To Be or Not to Be?"

Appraisal Institute's 36th Annual Litigation Seminar, 2003
Guest Speaker - "Witness Skills"

International Right of Way Association, Bundle of Rights, 2002
Author - "All Damage is Permanent on the Date of Valuation"

International Right of Way Association, 2001
Co-Author and Participant – Mock Trial Presentation

Appraisal Institute's Candidate Workshop, 1995
Guest Speaker - Comprehensive Exam

Trust Services of America, Los Angeles, and Newport Beach, 1991
Instructor - "Financial Applications in Real Estate"

Appraisal Institute's 24th Annual Litigation Seminar, 1991
Guest Speaker - "Appraiser/Attorney Trial Preparation"

Project Area Committee, Hawthorne, 1990
Guest Speaker - "Fair Market Value and Condemnation Appraisals"

City of Pasadena, Real Estate Subcommittee, 1989
Guest Speaker - "The Appraisal Process"

Glendale Redevelopment Agency, 1985
Guest Speaker - "The Appraisal Process"

Client References

Public, private, corporate, financial, and legal all available upon request.

WALDRON & ASSOCIATES, INC.
REAL ESTATE APPRAISERS AND CONSULTANTS

CHRISTER FIEGE-KOLLMANN, MAI

Senior Appraiser
Waldron & Associates, Inc.

SPECIALIZING IN COMPLEX VALUATION AND LITIGATION SERVICES

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christer@waldronandassoc.com

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STATE CERFICATION
California Certified General (AG)

EDUCATION
University of California, Irvine;
Bachelor of Arts in Economics,
1983

Memberships & Affiliations

Appraisal Institute, Member
MAI DESIGNATION

California Certified General Real Estate Appraiser, Certificate No. AG015749

Appraisal Institute & Related Courses

Continuing education courses taken through the Appraisal Institute, and other real estate organizations.

Employment

Waldron & Associates, Inc.
SENIOR APPRAISER
1997 - PRESENT

Experience

Kollmann & Associates, Inc., Santa Ana, California
President

Deloitte & Touche LLP, Los Angeles, California, 1993 - 1997
Manager - Valuation & Realty Consulting Group

Mitchell Company, Calabasas, California, 1989 - 1993
Director of Market Research

Great Western Real Estate, Yorba Linda, California, 1985 - 1989
Director of Market Research

WALDRON & ASSOCIATES, INC.
REAL ESTATE APPRAISERS AND CONSULTANTS

Experience (Continued)

Mr. Fiege-Kollmann is experienced in all facets of real estate consulting and valuation. Assignment personally completed include: full and partial acquisition appraisals; market value appraisals; consulting on highest and best use; appraisal review; market and financial feasibility analysis; portfolio analysis; and market research for project development. Appraisal and consulting assignments have been completed for properties located in California, Arizona, Oregon, Hawaii, and Nevada. International experience includes assignments completed in Canada and Argentina.

Past affiliations include directing all real estate market research and consulting efforts for prominent real estate organizations. Experience includes feasibility and marketability studies, market research, and consumer surveys for various types of real estate, including mixed-use, residential, and multi-family developments. Assignments performed for construction financing, land acquisition, product determination, and highest and best use.

Property Types Evaluated

Residential/Multi-Family: Vacant land, single-family subdivisions and multi-family projects including apartments and condominiums. Special studies include supply/demand analysis, absorption studies, product determination, floorplan critiques, feature and amenity mix, pro-forma analysis, and consumer research.

Industrial: Warehouses, R & D buildings, self-storage facilities, and vacant land.

Commercial: Regional shopping malls, community shopping centers, big box retail centers, office buildings, business parks, quick-service restaurants, service stations, carwashes, and vacant land.

Special Purpose: Master-planned communities, mixed-use developments, hotels, mobile home parks, dairies, amusement parks, and sports facilities.

WALDRON & ASSOCIATES, INC.
REAL ESTATE APPRAISERS AND CONSULTANTS

Client References

Public, private, corporate, financial, and legal all available upon request.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

APPRAISAL OF THE SUBJECT ASSETS

WITNESSES: DR. JOHN A. WILLIAMS, PHD, PE, MBA, ASA,

AICHE FELLOW; RICHARD GERGER

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
APPRAISAL OF THE SUBJECT ASSETS
WITNESSES: DR. JOHN A. WILLIAMS, PHD, PE, MBA, ASA, AICHE FELLOW;
RICHARD GERGER

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
APPRAISAL OF THE SUBJECT ASSETS

A. Introduction

I submit this testimony on behalf of Pacific Gas and Electric Company ("PG&E") to appraise the fair market value as of July 27, 2021 ("Petition Date") of the electric transmission and distribution assets in and around San Francisco for which the City and County of San Francisco ("CCSF") seeks valuation in this proceeding ("Subject Assets"). This testimony conforms to the California Public Utilities Commission's ("Commission" or "CPUC") Interim Decision, which requires the parties "to submit valuations using the sales comparison approach, income approach, and cost approach" and to include "an appraisal of the fair market value of the property to be condemned as of July 27, 2021."[1] My testimony is accompanied by the attached Appraisal (Attachment A).[2]

I conducted an appraisal of the Subject Assets pursuant to the Uniform Standards of Professional Appraisal Practice ("USPAP").[3] The appraisal applies and reconciles valuations of the Subject Assets under the cost approach, the income approach, and the market approach (also called the sales-comparison approach). It is my professional opinion that the fair market value of the Subject Assets as of the Petition Date is $13.88 billion.

I also address errors in the appraisal submitted by Grant Rabon of NewGen Strategies & Solutions ("NewGen") on behalf of CCSF. NewGen appraised the Subject Assets at a fair market value of $3.43 billion.[4]

---

1 Decision Establishing Methods and Standards for Just Compensation and Valuation, D.25-10-039 at 2, 35 ("Interim Decision").

2 Richard Gerger, MBA, of Cornell/Gerger Consulting co-sponsors this chapter of testimony with respect to the income-approach model only. All other aspects of the chapter and the attached Appraisal are sponsored by Dr. John A. Williams of EPS. *See* Appraisal at Section 7.3.0.4.

3 USPAP establishes professional standards for impartiality, competent analysis, and clear reporting of appraisal opinions. Its purpose is to promote public trust in appraisal practice.

4 Ex. CCSF-004C – Prepared Direct Testimony of Grant Rabon, ASA on Behalf of the City and County of San Francisco at 3 (Apr. 20, 2026) (Errata May 21, 2026) ("Rabon Testimony").

Table 5-1 summarizes my appraisal of the Subject Assets and compares my conclusions to NewGen's appraisal.

TABLE 5-1
FAIR MARKET VALUE OF THE SUBJECT ASSETS (AS OF JULY 27, 2021)[5]

($ million)	CCSF's Appraisal	PG&E's Appraisal	Net (CCSF–PG&E)
Cost Approach	**0% Weight**	**65% Weight**	
RCNLD (July 27, 2021)			
Underground Assets[6]	2,919.4	7,960.9	-5,042
Non-Underground Assets	1,761.4	2,278.4	-517
less Economic Obsolescence	1,859.6	0	1,860
Intangible Assets	0	9.7	-9.7
Real Estate	606.3	4,299.4	-3,693
Cost Approach Value	3,427.5	14,548.4	-11,121
Income Approach	**100% Weight (regulated IOU)**	**25% Weight (unregulated POU)**	
Net Book Value (July 27, 2021)	2,403.3	2,676.4	-273
Growth (Net Plant CAGR)[7]	-0.26%	4.93%	
WACC (Hypothetical Buyer)	6.2% (IOU)	4.6% (POU)	
Income Approach Value	3,427.5	11,996.5	-8,569
Market Approach	**0% Weight**	**10% Weight**	
Operating Assets & Spares	3,086.6	9,957.9	
Real Estate	*Included above*	4,299.4	
Market Approach Value	3,086.6	14,257.3	-11,171
Appraised Fair Market Value	**3,428.0**	**13,881.3**	**-10,453.3**

Fundamentally, the appraisal required here is an appraisal of operating machinery and equipment. The Subject Assets are not a standalone operating business to be acquired through a merger. There is no workforce transferred. The Subject Assets are not separately financed with debt or equity capital, and no liabilities from the larger corporation are assumed.

---

5 Appraisal at Sections 1.0.0.2 & 6.0.0.4 (reconciliation), 11 (cost approach), 12 (income approach), 13 (market approach); Rabon Testimony at 4 & Table 1, Workpapers.

6 Underground assets include FERC accounts 366.00, 367.00, 368.02, and 369.02 (distribution), and 357.00 and 358.00 (transmission), including the in-service spares.

7 The growth estimate is the compound annual growth rate ("CAGR") from 2021 through 2031 (the length of forecast in NewGen's income-approach model) in net plant, which includes distribution, transmission, land, and in-service spares. CCSF also submitted testimony by Jefferies, which calculated an earnings CAGR of -0.1% for 2021–2026, using the projected changes to net plant from NewGen's analysis.

The Subject Assets are also unique. They consist of a comprehensive, highly reliable electric distribution and transmission network, largely underground, and located in a dense, urban area. These characteristics drive the value of the Subject Assets much higher than merely their net book value or rate base accounting value as of the Petition Date, which is essentially the entire basis of CCSF's appraised value.

As set out in the "Net" column in Table 5-1 (far right), the key differences between my appraisal and CCSF's analysis are as follows:

- *Cost Approach*. CCSF makes four principal errors. CCSF significantly understates the costs of replacing underground assets in San Francisco's urban setting. CCSF overstates physical depreciation by using straight-line rather than present-worth methods. CCSF vastly undervalues the real-estate associated with the Subject Assets, including by failing to value easements and to consider a corridor-enhancement factor for the land and improvements. And CCSF reduces the cost-approach by $1.86 billion (35%) to equal its income-approach with an "economic obsolescence" adjustment without any analysis, thereby replacing the cost approach with the income approach in disguise.
- *Income Approach*. CCSF undervalues the Subject Assets significantly by failing to consider that the highest-value class of hypothetical buyers for the Subject Assets are tax-exempt, non-regulated buyers ("Publicly Owned Utilities" or "POUs"), which results in CCSF applying the wrong cost of capital in its discounted cash flow analysis and undervaluing the cashflows. CCSF also ignores PG&E's records on net book value, capital expenditure ("CapEx") forecast, and authorized return; it instead constructs its own projections that reduce value through depressed net plant, lower authorized return, and inadequate CapEx that result in negative growth in plant over its ten-year projections (*i.e.*, a CapEx forecast that would result in the shrinking of the Subject Assets' net plant from 2021 to 2031).
- *Market Approach*. CCSF erred in its market approach by (i) including transactions involving entities that are not comparable to the Subject Assets and (ii) developing market multiples based on the net plant (historical original cost less accounting or regulatory depreciation) of the assets sold. The price a buyer is willing to pay for assets does not depend on their historical cost or

their accounting depreciation. As the American Society of Appraisers ("ASA") explains, "appraisal depreciation measures value inferiority, whereas accounting depreciation is a mathematical convention for recovering an asset's cost."[8] The principle of substitution dictates the current price of assets that could serve as substitutes and the current physical condition of the assets for sale.[9] ASA describes the percentage-of-cost technique as comparing market transaction purchase price with current cost new at the time of sale. In my opinion, this is the correct market comparison technique for the Subject Assets. I trend original cost to the transaction date. I then adjust for physical condition so that the price and cost comparisons refer to the same assets in their existing condition. This ratio will correlate the price paid in market transactions to the quality of the assets and the available substitutes. It is similar to buying a used car. The price a buyer pays depends on the cost of a new car at the time of the intended purchase, the availability and cost of other similar used cars, and the condition of the subject used car. If the cost of a new car is very high, the subject car is rare or unique, and/or the subject car is in good condition, it will command a higher price. What the seller originally paid for the car or whether it has been fully depreciated as a matter of accounting does not matter. I have correctly applied these principles in the market approach and weighed the approach in my appraisal, whereas CCSF disregarded its market-approach valuation by using it only as "support" for the income-approach value, without factoring it into the ultimate weighting used for its final value reconciliation.

- *Reconciliation*. CCSF also errs in its reconciliation of the three approaches because it did not evaluate the three valuation approaches independently. By relying on economic obsolescence to drive its cost approach to equal its income valuation, and by using the market approach as mere support for the income approach, CCSF effectively relies on the income approach alone.

CCSF also submitted the testimony of Scott Beicke of Jefferies's Americas Power, Utilities & Infrastructure Group ("Jefferies"), as an "additional

---

8 Valuing Machinery and Equipment at 6 (Am. Soc'y Appraisers 4th ed. 2020).

9 California State Board of Equalization, Assessors' Handbook Section 501, Basic Appraisal at 57 (Jan. 2002); Valuing Machinery and Equipment at 32 (Am. Soc'y Appraisers 4th ed. 2020).

perspective."[10] CCSF calls Jefferies's analysis an "investment banking" perspective, but the label adds nothing. CCSF admits that Jefferies's testimony is "not an appraisal,"[11] and NewGen's actual appraisal ignores it entirely; for this reason alone, the Commission should give Jefferies's analysis no weight.[12] In my professional opinion, the Jefferies analysis includes multiple fundamental flaws: (i) it is not an appraisal; (ii) it applies business-valuation indications without connection or adjustments to the Subject Assets and omits the asset-based approach without adequate explanation; (iii) it excludes the potential for a public-utility buyer; and (iv) it relies on NewGen's erroneous inputs for cash-flow modeling and growth without independent verification.[13]

The remainder of my testimony proceeds as follows: I summarize my qualifications and experience (Section B) and my overall appraisal approach (Section C). I then describe the Subject Assets' appraised value under the cost approach (Section D), the income approach (Section E), and the market approach (Section F). Finally, I conclude by explaining my reconciliation analysis to determine a weighted fair market value of the Subject Assets (Section G). I provide my critiques of CCSF's testimony within each section.

B. Qualification and Experience

My name is Dr. John A. Williams. I am the owner, General Manager, and founder of EPS, Inc., an engineering and valuation firm. I am an Accredited Senior Appraiser with the American Society of Appraisers in Machinery and Technical Specialties and am a Licensed Professional Engineer in the State of California. I have over 40 years of experience in the energy and industrial sectors and have appraised numerous pieces of equipment and facilities, including electric transmission and distribution systems. I also hold a Ph.D. and an M.S. in Chemical and Fuels Engineering from the University of Utah, an M.B.A. in Finance from the University of Chicago, and a B.S. in Chemistry from the University of Delaware. Further background on my qualification and USPAP

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10 Ex. CCSF-005 – Prepared Direct Testimony of Scott Beicke on Behalf of the City and County of San Francisco at 1, 3 (Apr. 20, 2026) (Errata May 15, 2026) ("Beicke Testimony").

11 Rabon Testimony at 31–32 (internal quotation marks omitted).

12 Beicke Testimony at 3; Interim Decision at 43 (Ordering ¶ 4).

13 Beicke Testimony at 2, 4–5, 7–9.

competency is contained in Appendix A (curriculum vitae) of the Appraisal.

C. Appraisal Approach

1. Governing Legal Standard: Fair Market Value

Under California law, the measure of damages for the valuation of the part taken is fair market value.[14] Fair market value is the "highest price" that a willing buyer and a willing seller would agree to in a voluntary transaction on the open market, neither party under compulsion and both fully informed of the uses to which the property is suited.[15] The highest price is the value based on the highest and best use, defined as the most probable and legal use of the property that is physically possible, appropriately supported, and financially feasible, and that results in the highest value.[16] The highest and best use of the Subject Assets, as all parties agree, is as an operating, integrated electric transmission and distribution system serving San Francisco.

Because fair market value equates to the *highest price* between a willing buyer and seller, the appraisal *must* include a valuation from the perspective of the class of purchasers that would pay the most for the property.[17] Here, that class is POUs, which are exempt from taxes and free from the Commission's rate regulation, resulting in a lower cost of capital to operate the Subject Assets. Given the State of California's previously-stated interest in potentially purchasing Investor-Owned Utilities ("IOUs") such as PG&E, this is not hypothetical.[18]

The determination of fair market value of the part taken therefore must include an analysis of a hypothetical transaction featuring a POU purchaser. My appraisal includes a POU buyer under the different valuation approaches outlined in this testimony, in particular as part of the Income Approach (where the impacts are most significant). By contrast, CCSF excludes a

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14 Interim Decision at 25.

15 *Id.*; *see also* Appraisal at Sections 3.0.0.2, 10.

16 Appraisal at Section 10.

17 *Id.* at Section 12.

18 For further discussion of the POU as a hypothetical purchaser, see PG&E Testimony, Ch. 7 (Rubin).

POU purchaser from their valuation of the Subject Assets. But this mistaken assumption artificially depresses CCSF's valuation and fails to estimate fair market value because its appraisal is not "the highest price estimated in terms of money which the land would bring if exposed for sale in the open market."[19]

2. The Subject Assets

In this case, as described in more detail in Chapter 2 of PG&E's Testimony and my Appraisal, the Subject Assets comprise electric transmission and distribution ("T&D") assets serving San Francisco. These assets are part of PG&E's larger, integrated electric system. They include, for example, assets inside and outside of San Francisco (*e.g.*, the Martin Substation); assets both aboveground (*e.g.*, poles) and underground (*e.g.*, conduits); and assets that constitute real property, tangible personal property, or intangible property interests.[20] The vast majority of these assets are capital assets used to operate the electric transmission and distribution system (*e.g.*, substations, poles, conductors, and transformers, among others), but they also include a small portion of intangible assets such as records and drawings.

Two characteristics of the Subject Assets substantially impact their appraised value: extensive undergrounding and redundancy.

Undergrounding. Due to its location within a densely-populated urban area, a significant portion of the Subject Assets are underground, including underground conduit systems and subsurface structures.[21] Compared to overhead assets, underground assets are generally more reliable and better protected from environmental and other exposures, as shown in Figure 5-1 below.

---

[19] Interim Decision at 25.

[20] Appraisal at Section 2; Proposed Stipulation of Assets.

[21] Appraisal at 13.4.2; *see also* PG&E Ch. 3.1 (Thibodeau) at Section C(3).

CONFIDENTIAL FIGURE 5-1

[redacted]

[redacted]

However, underground assets are also far more costly to build or replace. In San Francisco, the costs to construct underground assets have increased significantly and have well outpaced cost indices for electrical equipment and construction.[22] As can be seen in Figure 5-2 below, there is extensive existing equipment underground in San Francisco (in addition to PG&E's), which makes replacing the current system more expensive.

CONFIDENTIAL FIGURE 5-2

[redacted]

[redacted]

[22] Appraisal at Section 13.4.2.1 & Figure 13.2.

Redundancy. The network configuration used for portions of PG&E's San Francisco grid provides greater redundancy than a typical, radial electric system. San Francisco's downtown core is served by a secondary-network (spot and grid) system, with parallel feeders and multiple network transformers operating to minimize the interruption to power.[23] An electric system with redundancy is more reliable, but also more costly to build or replace.

Due to the extensive undergrounding and redundancy, the Subject Assets have historically had a high reliability rating as compared to PG&E's electric system as a whole. These features drive some of the valuation differences between my appraisal and CCSF's, notably in the estimate of replacement cost within the cost approach.

3. Real Property

The Subject Assets include real property, such as land, easements over private property, and substation buildings and site improvements. I did not conduct a separate real-estate appraisal and instead rely on the appraisal ($4.3 billion) by Walter D. Carney of Valbridge and by Michael F. Waldron of Waldron & Associates, Inc. ("Valbridge/Waldron").[24] Both my cost and market approaches derive a value for the operating assets associated with the Subject Assets independent of the underlying real property. As such, to reach an overall fair market value for the Subject Assets under the cost and market approaches, the separate real property valuation developed by Valbridge/Waldron must be added to my calculated values. This is shown in Table 5-1 above and in the reconciliation section below.

The income approach is different. The income approach values the assembled enterprise as a whole and already reflects the value of real property in rate base. Thus, to avoid double-counting, I do not add the $4.3 billion real estate valuation to my final income approach valuation.

4. Summary of Appraisal Approaches

To assess the fair market value of the Subject Assets, and consistent with the Commission's Interim Decision, I performed an analysis using the

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23 *Id.* at Section 9.1.0.2.

24 PG&E Testimony, Ch. 4 (Carney & Waldron).

three recognized valuation methodologies—the cost approach, the income approach, and the market approach—using information known or knowable to market participants as of the Petition Date.[25] I then performed a reconciliation of the three valuation approaches.

D. The Cost Approach

1. Methodology

The cost approach assesses the value of the Subject Assets based on the cost of acquiring an equivalent functioning substitute of each component. The cost approach operates under the presumption that a hypothetical purchaser of assets would pay no more than the cost of acquiring an equivalent substitute.[26] The cost approach first computes the Replacement Cost New ("RCN"), then deducts physical depreciation, and finally examines and adjusts, if appropriate, for functional or economic obsolescence for Replacement Cost New Less Depreciation ("RCNLD").[27]

I computed the cost-approach valuation by relying on the RCN input calculated by Matthew R. Thibodeau of Sargent & Lundy ("S&L") and the depreciation input calculated by Ned W. Allis of GFT Infrastructure, Inc. ("GFT").[28] I then reviewed whether the resulting RCN less physical depreciation and functional obsolescence output should be adjusted, such as by applying economic obsolescence, and whether the value of any intangible assets should be added. Finally, I added the real-estate appraisal performed by Valbridge/Waldron.[29]

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25 Appraisal at Sections 11 (cost approach), 12 (income approach), and 13 (market approach).

26 Valuing Machinery and Equipment at 5, 34 (Am. Soc'y Appraisers 4th ed. 2020).

27 In my testimony, I use the term RCNLD to mean RCN less *all* depreciation, including physical and (if any) adjustments based on functional or economic obsolescence. I use the term Replacement Cost New Less Physical Depreciation ("RCNLPD") to mean the RCN less *physical* depreciation only (*i.e.*, the $10.24 billion calculated by Mr. Allis of GFT in Chapter 3.2). *See* Appraisal at Section 11.2.0.4 & n.44.

28 PG&E Testimony, Ch. 3.1 (Thibodeau) and Ch. 3.2 (Allis).

29 PG&E Testimony, Ch. 4 (Carney & Waldron).

2. The RCN and Physical-Depreciation Calculations Are Reasonable

The RCN Input Is Reasonable. I first examined S&L's RCN input.[30] S&L performed a physical asset-by-asset estimate of installation cost, which includes the material cost, labor cost, and construction equipment cost. S&L then adjusted the installation costs by applying various allowances. S&L's calculations are reasonable, and I therefore rely on S&L's computation of the RCN.

The Depreciation Input Is Reasonable. I next reviewed the physical depreciation calculation by GFT and determined that the analysis is reasonable.[31] Unlike CCSF, which used a straight-line depreciation method, GFT adopted the present worth depreciation method, consistent with the Interim Decision's guidance to deduct "accrued depreciation (not book depreciation)" from the RCN.[32] The present worth method uses asset age and survivor curves to estimate how much longer an asset still in service is expected to last, and then determines what percentage of a new asset's value remains by comparing the present value of that asset's remaining service with the present value of service provided by a new asset. Based on my review, GFT's physical-depreciation analysis is reasonable. I therefore rely on GFT's depreciation analysis and the calculated RCN less physical depreciation ($10.24 billion).

3. Appraiser Adjustments

I considered three types of adjustments: (i) functional obsolescence, (ii) economic obsolescence, and (iii) any additional values from intangible assets.[33] Like CCSF, I concluded that functional obsolescence does not apply in this appraisal.[34] Unlike CCSF, I concluded that there is no economic obsolescence and that some of PG&E's intangible assets should be added to the RCNLD.

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30 Appraisal at Section 11.1.

31 *Id.* at Section 11.2.

32 Interim Decision at 35.

33 Appraisal at Sections 11.3 (functional obsolescence), 11.4 (economic obsolescence), and 11.5 (intangible assets).

34 Rabon Testimony, App'x II at 4-3 ("[N]o adjustment for *functional obsolescence* was made.").

Economic Obsolescence. Economic obsolescence is a loss in value caused by factors external to the property. Economic obsolescence must be assessed on a cause-by-cause basis to determine whether a particular external condition either existed or was knowable as of the Petition Date and affected the fair market value indicated by the Cost Approach of the Subject Assets.

In this appraisal, I assessed the applicability of economic obsolescence by first conducting a systematic, cause-by-cause screen across the full list of external causes and external causes specific to utilities identified by the American Society of Appraisers. For each cause, I considered whether it (a) was in fact external to the Subject Assets (*i.e.*, not a loss in value already captured by the analyses of RCN, physical depreciation, or functional obsolescence); (b) had existed or been knowable as of the Petition Date; (c) affected fair market value under the applicable premises; (d) was quantifiable and allocable to the Subject Assets; and (e) created a reduction in value that the utility could not recover through other means, such as by increasing rates, passing the cost through to a third party, or recovering through favorable tax treatment.[35] Based on this analysis, I conclude that none of the 14 candidate causes of economic obsolescence was present in July 2021, and I made no adjustment, as summarized in Table 5-2.

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35 Appraisal at Sections 11.4.0.3–11.4.0.4 & Table 11.1, App'x D.1. *See also* Valuing Machinery and Equipment at 49 (Am. Soc'y Appraisers 4th ed. 2020).

TABLE 5-2
SUMMARY OF ECONOMIC OBSOLESCENCE[36]

No.	Candidate Causes	Description	Finding
1	Industry economics	Whether the electric utility industry was economically unhealthy.	**Negative**. Utilities made new capital investment industry-wide.
2	Availability or cost of financing	Whether it was difficult or expensive to borrow capital.	**Negative**. Interest rates were at a historical low in July 2021.
3	Loss of material or labor sources	Whether electric utilities lost access to essential workers or materials such that assets were more expensive or difficult to operate, repair, or replace.	**Negative**. Increased construction and labor costs are factored into the calculation of RCN, and there is no evidence of additional loss to trigger a separate adjustment based on economic obsolescence.
4	Legislation, ordinances, or regulations	Whether a new law or regulation burdened utilities' abilities to recover capital investments.	**Negative**. Although new wildfire-related regulations increased cost, utilities have been generally permitted to recover these costs through rates.
5	External cost increases without offset	Whether an external force drove up cost without PG&E having the ability to increase revenue requirement.	**Negative**. Ordinary T&D cost increases were recovered through rates. A spike in cost in 2018–2019 was related to wildfire claims, which is not a condition impairing the T&D assets.
6	Reduced demand or load decline	Whether ratepayers were using less electricity.	**Negative**. Although energy deliveries had declined due primarily to COVID, peak demand increased; decoupling also protects PG&E's authorized revenue if sales volumes fall.
7	Increased competition or substitution	Whether PG&E saw increased competition or substitution from another electricity provider.	**Negative**. Changes to the electricity providers generally affect generation; departing bundled customers generally remain distribution and transmission ratepayers.
8	Inflation or high interest rates	Whether macroeconomic conditions, expressed through change in high inflation or interest rates, depressed the value of the electric assets.	**Negative**. Interest rates were at a historical low. Although inflation was rising, higher construction prices were reflected in cost indices.
9	Environmental or operating restrictions	Whether environmental causes prohibited PG&E from fully operating the assets.	**Negative**. Although the Public Safety Power Shutoff causes plants to idle, the restriction does not apply to San Francisco's underground assets, and associated mitigation cost is recoverable in rates.
10	External inutility or underutilization	Whether PG&E built more T&D capacity than customers needed, leaving excess stranded infrastructure.	**Negative**. Capacity and use moved together through valuation date, and redundancy in the system was by design to promote reliability.
11	Sea-level rise, flooding, or climate resilience	Whether climate change exposed San Francisco to greater vulnerability so as to reduce the value of the assets.	**Negative**. Known climate-change exposure had no measurable value loss on the Subject Assets.
12	Cybersecurity, vendor support, and technology-platform risk	Whether cyber risk reduced the value of the assets.	**Negative**. PG&E can recover the costs spent on cybersecurity and on replacing obsolete technology.
13	Permitting, access, and local work restrictions	Whether San Francisco's regulatory control lowered the value of the assets.	**Negative**. Associated cost is recoverable in rates.
14	Transmission-topology, CAISO, and FERC cost-recovery conditions	Whether transmission-related governance caused assets to be stranded.	**Negative**. No indication that transmission assets are stranding or that PG&E is prohibited from recovering their cost.

I also tested the cost indication against the other evidence of value. A difference between the cost and income indications calls for investigation. I examined it in the cause screen and again in the reconciliation. My income approach values cash flow earned on an original-cost rate base, while the cost approach measures replacement cost, so comparing the two directly is a mismatch, and the gap between them does not by itself show a loss in value from an external cause.

Identified Intangible Assets. The Subject Assets, although primarily machinery and equipment, also include a small portion of intangible assets (*e.g.*, records, data, configurations, and technical operating information), which CCSF must either take or recreate if not taken. I estimated the value of these intangible assets item by item based on the cost of recreating an equivalent that has been adjusted for any diminished utility. Based on my analysis, I conclude that two categories of intangible assets should be added: (i) customer-service information ($3.4 million), and (ii) technical operating information ($6.3 million), for a total of $9.7 million.[37]

Given the foregoing summary of RCNLD and appraiser adjustments, combined with the real-estate valuation, I conclude that the appraised value of the Subject Assets under the cost approach is $14.55 billion. Figure 5-3 provides a comparison of my cost-approach value and NewGen's.

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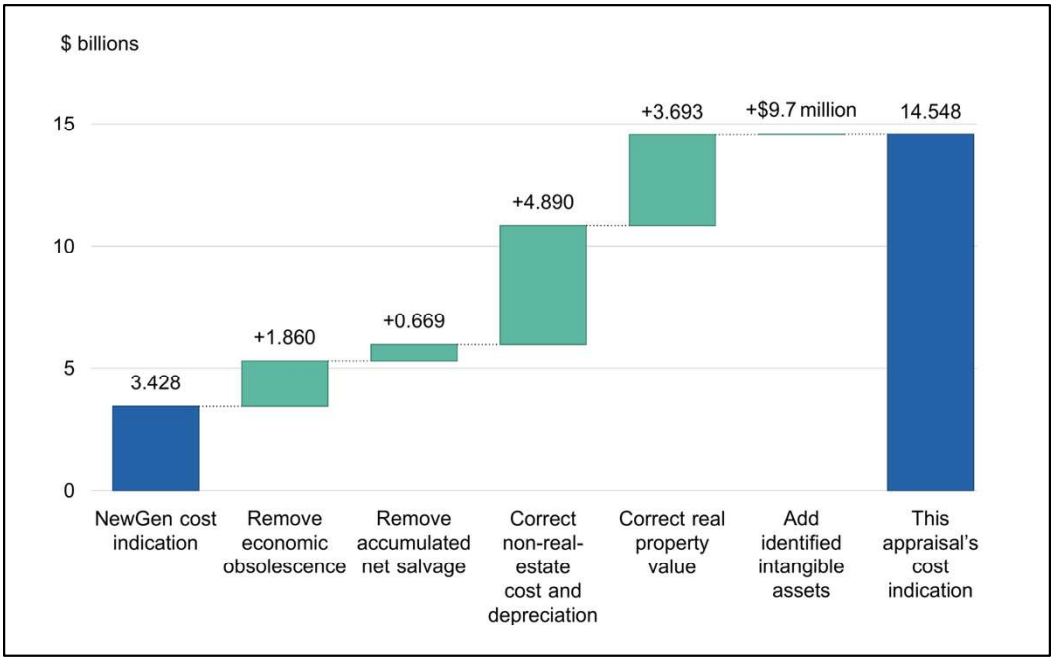
36 Appraisal at Section 11.4.0.4 & Table 11.1, App'x D (Economic obsolescence supporting evidence).

37 PG&E did not learn of the full scope of CCSF's proposed condemnation, including its intent to take additional assets such as the Martin Substation and the Martin Triangle, until CCSF served its amended and restated testimony in April 2026. As PG&E previously explained in prior filings before the Commission, PG&E will need at least *eight months* to prepare its responsive testimony given the number of issues raised in this proceeding and their complexity. *E.g.*, PG&E Comments on ALJ's Ruling Soliciting Comments Regarding Schedule, at 9–11 & n.24 (Feb. 2, 2026); PG&E's Comments on Proposed Interim Decision at 10 (Oct. 16, 2025). Because the Scheduling Order provided substantially less time, PG&E's testimony on certain issues (*e.g.* on the values of intangible assets) necessarily reflects its best estimates based on the information and analysis that it could reasonably develop within the time provided. PG&E respectfully reserves the right to augment or otherwise supplement this testimony as appropriate and permitted by the Commission.

FIGURE 5-3
COMPARISON OF COST APPROACH



4. Rebuttal of CCSF Cost Approach

In CCSF's expert testimony, NewGen calculates an RCNLD value of the Subject Assets at $5.29 billion and then applies a $1.86 billion deduction under economic obsolescence to bring the RCNLD approach to the same value estimated under the income approach: $3.43 billion.[38] NewGen makes several critical errors.[39]

First, NewGen incorrectly calculates RCNLD (a net difference of $5.56 billion as compared to PG&E's figure) by significantly undervaluing the underground assets ($3.76 billion less in RCN, $1.28 billion more in depreciation, resulting in approximately $5.04 billion less in RCNLD).[40] It also overestimates depreciation of all assets ($2.02 billion more in accumulated depreciation of both underground and non-underground

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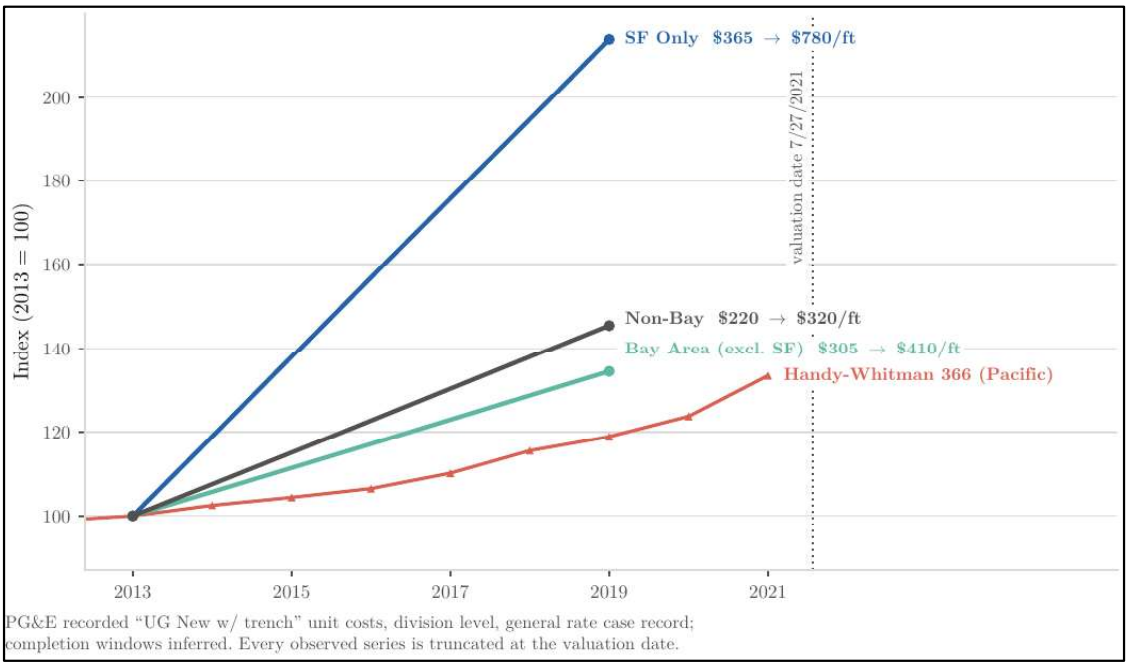
38 Rabon Testimony at 4 & Tables 1, 24 & Table 4.

39 My testimony here focuses on NewGen's application of the appraiser adjustments. For rebuttal on CCSF calculations of RCN and depreciation, *see* PG&E Testimony, Ch. 3.1 (Thibodeau), Section F (RCN rebuttal); Chapter 3.2 (Allis), Section G (physical-depreciation rebuttal).

40 *See* PG&E Testimony, Chapter 3.1 (Thibodeau) and Chapter 3.2 (Allis) Workpapers.

assets).[41] As Mr. Thibodeau explains in his testimony in Chapter 3.1, CCSF undervalues the underground assets by failing to adequately account for the complexity of constructing underground conduit and subsurface structures in a dense urban environment like San Francisco.[42] As a result, CCSF's estimated per-foot cost for the installation of underground conduit is substantially below any comparable project or industry benchmark, whereas PG&E's calculated per-foot cost is in line with both CPUC benchmarks and actual costs from analogous completed projects.[43] Fundamentally, CCSF's analysis overlooks that the cost of building and replacing underground assets has grown substantially in recent years (between 2013 and 2019), outpacing the pricing in conventional cost indices such as Handy-Whitman, as illustrated in Figure 5-4.

FIGURE 5-4
COMPARISON OF UNDERGROUND CONSTRUCTION COSTS



Second, NewGen relies on an erroneous appraisal of the real-estate properties (approximately $606 million) by Timothy P. Runde of Runde &

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41 *See* PG&E Testimony, Chapter 3.2 (Allis) Workpapers.

42 PG&E Testimony, Ch. 3.1 (Thibodeau), Sections F(2)(a)–F(2)(c).

43 *Id.* at Section F(2)(d) & Table 3.1-27.

Partners, Inc. ("Runde"). As further explained by Valbridge/Waldron, Runde's real-estate appraisal undervalues PG&E's real property interest by nearly $3.7 billion.[44] Among other flaws, Runde erroneously assigned a value of $0 to PG&E's easements, licenses, permits, and other similar rights and property interests (accounting for $1.7 billion of the differences); failed to assign value to the properties based on their synergistic assemblage and integration that allows for an operative and integrated electric system (accounting for $870 million of the differences); and improperly relied on an unreasonably low per-square-foot value that is not supported by market data.[45]

Third, NewGen errs in applying an economic-obsolescence adjustment that forced CCSF's cost-approach value to equal CCSF's income-approach value. NewGen's sole reason for applying economic obsolescence is that the existence of rate regulation "restricts PG&E's earnings" and functions as "an 'external factor.'"[46] NewGen is wrong for several reasons. Most obviously, NewGen's analysis does not apply to a POU buyer. Even using an IOU buyer for the income approach, a delta in the values of the cost and income approaches prompts an investigation of economic obsolescence; it alone does not establish economic obsolescence. As illustrated by my cause-by-cause screening, none of the external candidate causes was present in July 2021.

The literature guidance on which NewGen relied supports my conclusion. NewGen cited two sources that generally recommend investigating economic obsolescence where there is a difference between

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44 PG&E Testimony, Ch. 4 (Carney & Waldron), Section K & Table 4-11.

45 *Id.*

46 Rabon Testimony at 24.

the cost approach and the other approaches.[47] Neither treats the difference alone as the measure of it. ASA advises that the appraiser "should verify that all the depreciation was properly quantified, especially economic obsolescence" when "the cost approach is significantly higher than the income approach."[48] But NewGen stops there. It did not go one step further to investigate whether the observed difference in valuation approaches actually warrants such adjustment for the Subject Assets. My cause-by-cause analysis does investigate economic obsolescence and concludes that an adjustment is not warranted.

NewGen also cites *Valuation of Railroad and Utility Property* by Arlo Woolery for the proposition that "economic obsolescence due to rate regulation is of primary concern [for utility property]."[49] NewGen mischaracterizes Woolery's analysis. Woolery explains that regulatory restrictions could render utilities economically obsolete if the regulation prohibits the recovery of "an adequate rate base," "an adequate rate of return," or "an adequate recovery of costs."[50] With regards to the Subject Assets in this case, I found no indication that the Commission's policies as of July 2021 prohibited a utility from recovering its rate base or from earning an adequate rate of return.

By focusing on the difference between the income-approach and cost-approach values, NewGen also misapplied the economic-obsolescence analysis. For the income approach, both parties estimated earnings by using the Subject Assets' rate base, which is derived from their *original* cost less depreciation ("OCLD"). The cost approach, when properly applied,

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47 *Id.* at 24–25 nn.37–38 (citing Shannon P. Pratt & Alina V. Niculita, Valuing a Business: The Analysis and Appraisal of Closely Held Companies at 888 (McGraw-Hill 5th ed. 2008) (economic obsolescence "typically" exists where "business enterprise value" is below the "depreciated replacement cost of the company's assets") and Valuing Machinery and Equipment at 176 (Am. Soc'y Appraisers 4th ed. 2020) (appraiser "should verify" economic obsolescence where the cost approach is "significantly higher" than the income approach)). The Pratt passage concerns enterprise value for ad valorem taxation, which includes financial assets, real estate, and intangible property as well as the tangible assets. Here, I cite Pratt (5th ed.) because that is the edition relied on by NewGen. Elsewhere in my testimony, I generally cite the 6th edition (2022).

48 Valuing Machinery and Equipment at 176 (Am. Soc'y Appraisers 4th ed. 2020).

49 Rabon Testimony at 25 n.40.

50 Arlo Woolery, Valuation of Railroad and Utility Property at 44 (Lincoln Institute 1996).

instead measures the value of these assets based on *replacement* cost, a different method than OCLD. A proper economic-obsolescence analysis must consider whether any of the external causes affect the utility's ability to recover that estimated replacement cost, not whether the replacement cost exceeds the OCLD.

Under the cost-approach, the cost to build the Subject Assets is equal to the RCNLD, and the Commission's rate regulation provides for full recovery of those costs plus an authorized return. The Commission does not limit a utility's ability to recover the costs to build plant to the OCLD of a comparable asset. Stated differently, the mere fact that a utility is rate regulated is not an "external" cause that renders its RCNLD value obsolete, the kind of external factors that the economic-obsolescence analysis is intended to capture. Conceptually, NewGen misapplies the principle of substitution. A buyer pays more if there are no alternatives and if the buyer would otherwise be forced to replace it rather than buy it. Although NewGen alludes to this concept,[51] it fails to apply it properly.

Fourth, NewGen errs by failing to recognize the value of intangible assets that it must either acquire or recreate. Although NewGen acknowledges that some "maps, drawings, and records" are included in the Subject Assets, it dismisses these because NewGen thought it "highly probable" that these assets were already included in the comparable transactions that it analyzed, and therefore need not be separately valued.[52] Putting aside whether NewGen's assumption is correct, even if the intangible assets were factored into its market-approach analysis, NewGen must still count them in the cost approach.

Based on these errors, NewGen understated its cost-approach valuation by $11.12 billion.

E. The Income Approach

The income approach assesses the value of the Subject Assets by calculating the present value of expected future cash flows from the appraised

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51 Rabon Testimony at 15 (cost approach is "most relevant" when the subject property is "unique" and with few comparables), 25–26, 30–31.

52 *Id.* at 29-30.

properties. In this appraisal, I conduct an income-approach valuation using a multistage discounted cash flow ("DCF") methodology. My DCF analysis forecasts growth in regulated cash flows from the subject properties across a 30-year period before those cash flows reach a steady-state, constant growth rate, which coincides with terminal value in the DCF formula. I then discount those cash flows and the terminal value back to net present value using the weighted average cost of capital of the hypothetical purchaser that would value the assets most highly, which in this case is a POU. The result of this analysis values the Subject Assets at $12.00 billion.[53]

The income approach analysis involves (i) estimating future free cash flows from PG&E's operations, which requires projecting current free cash flows into the future based on (among other things) expected CapEx that will impact those cash flows going forward, and (ii) selecting and applying the appropriate rate at which to discount future free cash flows to present value, based on the cost of capital of the class of purchasers that would place the highest value on the Subject Assets (here, POUs). I describe this approach below.

1. Estimating Future Free Cash Flows

The income approach analysis measures the present value of the cash flow being acquired, *i.e.*, the income-generating capacity of the Subject Assets. The right to receive that cash flow, as generated under current ownership of the assets, is the transferable economic opportunity being valued; thus, my analysis is based on the cash flow the system would generate under continued PG&E ownership at its regulated rates. This is consistent with the Interim Decision's determination that just compensation is "measured by what the landowner has lost rather than by what the condemnor has gained."[54] Any adjustment to the cash flow that may occur in the future as a result of decisions made by the purchasing entity (such as, for example, the decision to raise or lower rates) is therefore irrelevant to the valuation.[55]

Because the income approach is based on the cash flow the system

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53 *See* Appraisal at Section 12 (Income Approach).

54 Interim Decision at 40 (Findings of Fact ¶ 7).

55 Appraisal at Section 12.1.0.1.

would generate under continued PG&E ownership at regulated rates, my analysis also assumes the "perfect regulation" convention (as does NewGen).[56] Pursuant to this convention, the utility is assumed to earn exactly its authorized rate of return. Operating expenses and their recovery in the regulated revenue stream therefore offset and drop out of free cash flow, meaning they need not be included in the analysis.[57]

The chief inputs for valuing cash flow for a regulated utility like PG&E are net book value and rate base of the assets, CapEx, and the authorized rate of return on rate base. I used PG&E accounting records to determine starting rate base as of the Petition Date (July 27, 2021).[58] In this respect, my input differs from that of NewGen, which calculated its own OCLD figure as a net plant estimate rather than use PG&E's accounting records—a decision that lowers CCSF's net plant (OCLD) by $273 million.[59] For CapEx, I used the portion of PG&E's forecast attributable to the Subject Assets, excluding wildfire-related spending. The forecast increases annual CapEx from approximately $[redacted] in 2021 to $[redacted] in 2026.[60] After accounting for additions, retirements, cost of removal, and depreciation, my model projects net plant to grow by approximately [redacted]% compound annual growth rate (CAGR) from July 27, 2021 through year-end 2026.[61] After 2026, I gradually reduce the growth rate of net plant linearly until it converges with the steady-state growth rate, which occurs in year 30 of service. For authorized rate of return, I used the 7.34% weighted-average cost of capital approved for PG&E by the Commission in D.21-06-030 just a month prior to the Petition Date for CPUC-jurisdictional distribution assets, and a 7.35% weighted-average cost of capital for transmission assets, which reflects a weighting by net-book-value asset class of the rates of return authorized by the CPUC and FERC.[62]

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56 Rabon Testimony at 11.

57 Appraisal at Section 12.1.0.3.

58 *Id.* at Section 12.2; PG&E Testimony, Ch. 6 (Hegarty *et al.*), Section C.

59 PG&E Testimony, Ch. 6 (Hegarty *et al.*), Table 6-1.

60 *Id.* at Table 6-6.

61 Appraisal at Section 12 and App'x E; PG&E Workpapers, Income Approach Model.

62 Appraisal at Section 12.2.0.9.

I use a multistage DCF valuation to project future cash flows for the Subject Assets under continued PG&E ownership, which involves (a) forecasting the future growth in free cash flows over an explicitly defined period (here 30 years), and then (b) determining a constant, steady-state growth rate for purposes of calculating terminal cash flow value, which accounts for all of the years of value beyond the period of explicitly forecasted growth. I use a steady-state growth rate of 3.121%, which is a product of 2.1 percent long-run inflation and 1.0 percent real growth.[63] I use an explicit forecast period of thirty years to allow for the growth in plant from CapEx to reach the 3.121% steady-state growth rate (which does not occur until year 30 in my model). Given the useful and depreciation lives of assets like the Subject Assets, and the regulated return, a thirty-year forecast is reasonable and sufficiently predictable.

I nevertheless prepared a version with only ten years of forecasted cash flows before the terminal period, as an alternative to my 30-year forecast. Since growth has not reached a steady state as of year ten, however, the terminal value must be adjusted for greater real growth. I analyzed and presented the results using different terminal growth rates to show the sensitivity of the valuation to that assumption and to show that if properly done, a ten-year forecast produces a comparable value to my thirty-year forecast model. For my base-case analysis, I used a forecast period long enough to capture convergence between the growth rates during the explicit forecast period and the long-term growth rate.[64]

2. Selecting and Applying the Appropriate Discount Rate

Under the DCF income approach methodology, cash flows are discounted at the cost of capital of the hypothetical purchaser, meaning valuation is dependent on the business profile of the purchaser. Because fair market value is the *highest price* that a willing buyer and a willing seller would agree to in a voluntary transaction on the open market, an income-approach appraisal should be conducted from the perspective of the

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63 *Id.* at Section 12.2.0.7.

64 *See* Appraisal App'x E; Appraisal Workpapers, Income Approach Model, Worksheets "DCF – 30 yr Base Case" and "DCF 10-Yr A."

hypothetical purchaser that would place the highest value on the assets. Here, that purchaser is a POU. This is because POUs are exempt from taxes and cost-based regulation, which lowers their overall cost of capital to operate the Subject Assets and increases the net present value of the future cash flows. Put differently, all else equal, future cash flows are worth substantially more in fair market value terms to a POU than to an IOU. As a result, my income approach analysis estimates the fair market value of the system assets to a hypothetical tax-exempt, non-regulated buyer—*i.e.*, a POU—the highest-value class of buyer for the assets.[65]

Valuing the Subject Assets using the DCF methodology requires calculating the hypothetical POU purchaser's weighted average cost of capital ("WACC"), which is a measure of the entity's cost of equity and cost of debt weighted for its capital structure. While POUs do not issue publicly traded stock (meaning their cost of equity cannot be measured directly), they do issue municipal debt, which is priced by the bond market as materially less risky than IOU and corporate debt. The observable cost of debt of the hypothetical POU buyer can then be used to estimate the cost of equity. The result of my analysis yields a WACC for the hypothetical POU purchaser of 4.6%, which is used as the rate at which to discount future cash flows associated with the Subject Assets in my DCF analysis.[66]

To derive a final overall valuation, I applied the WACC of 4.6% to discount the cash flows for the 30-year explicit forecast period back to present value, and also to discount the terminal value cash flow back to present value, then added these two present-value figures. The result is $12.00 billion.[67]

3. Rebuttal of CCSF Income Approach

a. NewGen

Incorrect Hypothetical Buyer. NewGen's income approach valuation has a fundamental flaw: an incorrect assumption that the hypothetical

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[65] *Id.* at Section 12.1. For discussion of the hypothetical POU buyers, see PG&E Testimony, Ch. 7 (Rubin).

[66] Appraisal at Section 12.3.

[67] *Id.* at Sections 12.0.0.1, 12.5.

buyer of the Subject Assets must be a regulated taxable IOU. NewGen dismisses out of hand the possibility of the hypothetical buyer being a non-regulated, tax-exempt entity that would place greater value on the Subject Assets because of its significantly lower WACC.[68] Flowing from this assumption, NewGen discounts the forecast cash flows at a regulated IOU's cost of capital, which builds the IOU premise into the value and leaves out the class of buyer that would pay the highest price. Adjusting NewGen's income model to reflect a non-regulated, tax-exempt buyer would increase the resulting valuation by billions of dollars.

Some corrections could be made to NewGen's flawed approach to arrive at a more accurate representation of value. *First*, using the discount rate applicable to a POU (4.6%) instead of the IOU-based discount rate (6.2%) increases NewGen's value estimate from $3.43 billion to $5.86 billion (a $2.43 billion increase). *Second*, removing NewGen's calculation of ADIT and income tax payments to reflect the fact that the value-maximizing hypothetical buyer would be a tax-exempt government entity increases the value estimate to $7.23 billion (an additional $1.37 billion). *Third*, increasing NewGen's constant growth rate (as used to calculate terminal value in the DCF formula) from the artificially low 2.1% used in its formula (which reflects only long-run inflation with no real growth) to include real growth of 1% further increases the value to $11.15 billion (an additional $3.93 billion). *Finally*, replacing NewGen's calculated regulatory rates of return with PG&E's actual approved regulatory rates of return as of the Petition Date further increases the value under NewGen's income model to $12.21 billion.[69] I illustrate these necessary adjustments to the NewGen income analysis in Table 5-3 and Figure 5-5 below. These four

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68 NewGen's erroneous assumptions that the hypothetical buyer would be an IOU earning exactly the regulated rate of return also lead to an income-approach valuation that is inconsistent with its cost approach (RCNLD), prior to a flawed adjustment for economic obsolescence.

69 Appraisal Workpapers, Income Approach Workbook, Change 1 through Change 4 worksheets, Bottom-up DCF D46; PG&E Testimony, Ch. 6 (Hegarty *et al.*), Table 6-1; Appraisal Section 12.

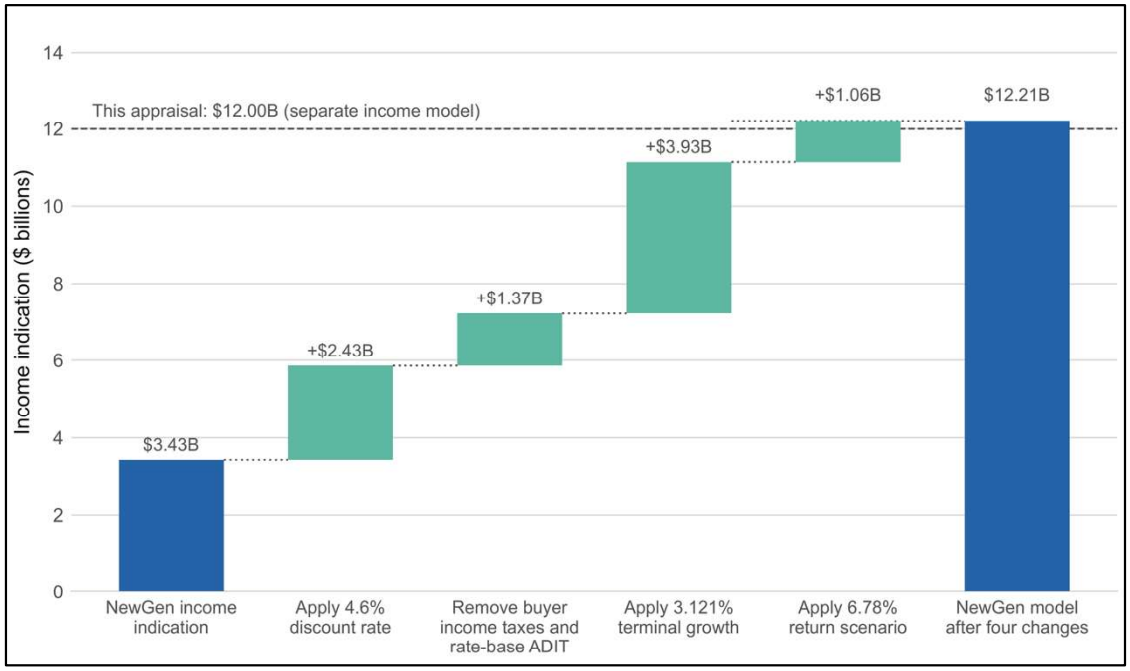
1 corrections lead to an overall valuation that is even greater than my
2 income valuation of $12.00 billion.[70]

TABLE 5-3
RABON'S INCOME MODEL WITH PREMISE-INCONSISTENT INPUTS CORRECTED STEP BY STEP
(BILLIONS OF DOLLARS)

Correction Applicable to Rabon's Model	Effect	Running Indication (Rounded)
Rabon's indication as filed:		$3.43
Substitute the tax-exempt buyer's 4.6% discount rate for the 6.2% IOU rate:	+$2.43	$5.86
Remove the income-tax and deferred-tax calculations, which do not apply to a tax-exempt owner:	+$1.37	$7.23
Replace the 2.1% terminal growth (inflation with no real growth) with the 3.121% steady-state rate:	+$3.93	$11.15
Replace the calculated regulatory rates of return with PG&E's actual authorized rates at the valuation date:	+$1.06	$12.21

70 Appraisal at Section 12.

FIGURE 5-5
COMPARISON OF INCOME APPROACH



Incorrect Net Plant and Rate Base. These adjustments above do not include the required correction to net plant and rate base. NewGen's model starts from a *calculated* beginning net plant in service of $2.403 billion,[71] which is $273 million lower than the actual net book value of $2.676 billion as of the Petition Date.[72] In NewGen's model, each dollar of beginning net plant in service carries approximately $1.43 in value, so this understatement depresses its overall valuation by approximately $391 million.[73] Combined with the corrections described above, replacing NewGen's calculated net plant in service with the actual book balance would increase its valuation further, above my income valuation of $12.00 billion.[74]

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71 Rabon Testimony at 24 & Table 4.

72 PG&E Testimony, Ch. 6 (Hegarty *et al.*), at Section C(2)(c), Table 6-1.

73 The $391 million is calculated by multiplying the difference in net book value between CCSF's and PG&E's calculations ($273 million) by NewGen's income-value multiple (1.43), as provided in Rabon Testimony at Attachment B, Table B-4.

74 Appraisal Workpapers (Income Approach Workbooks), "Change #1" through "Change #4," Worksheets "Bottom-up DCF" (D46).

Incorrect Forecast of Growth. NewGen's income approach is also fundamentally flawed because it models negative growth associated with the Subject Assets. For the forecast years of 2021 through 2026, my income-approach model used actual PG&E systemwide forecasts of CapEx, adjusted those forecasts to exclude wildfire-related expenditures that are unlikely attributable to San Francisco, and then allocated a portion of the resulting total forecast to the Subject Assets. Based on this methodology, the annual capital-expenditures forecast is $[redacted] in 2021 to $[redacted] in 2026,[75] increasing net plant by 4.93% (CAGR to EOY 2031).[76] Instead of using PG&E's contemporaneous forecasts, NewGen calculated its own CapEx forecast ($113 million per year for the starting year of its income-approach model), which is [redacted] of PG&E's estimates.[77] As explained in Chapter 6 of PG&E's testimony, NewGen's CapEx calculation is almost entirely a flawed estimate of replacement CapEx, with no cost of removal and minimal growth CapEx.[78] NewGen also uses an incorrect growth factor and applies it incorrectly in its income-approach model. As a result, these errors lead NewGen to model net utility plant *declining* by an approximate -0.26% CAGR over ten years.[79] This decline in net utility plant from the Petition Date to the end of the 10-year forecast period (and a corresponding decline in rate base, from $2.4 billion as of the Petition Date to $2.2 billion at the end of the 10-year forecast period[80]) in turn leads NewGen to forecast a significant

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75 PG&E Testimony, Ch. 6 (Hegarty *et al.*), Section D & Table 6-6.

76 *Id.* at Introduction; Appraisal at Section 12, App'x E, and Workpapers (Income Approach Model).

77 Rabon Testimony, App'x II, Attachment B, Table B-1 (lines 3, 19, 35, 2021 column). Distribution, Transmission, and Structures & Improvements additions sum to approximately $113 million.

78 PG&E Testimony, Ch. 6 (Hegarty *et al.*), at Section D(2).

79 Rabon Testimony, App'x II, Attachment B, Assumptions & Table B-2 (CAGR of net utility plant from $2,403,258,432 in July 2021 to $2,342,447,167 in July 2031, inclusive of spares).

80 *Id.* at Assumptions (Petition Date OCLD / rate base) & Table B-2.

decline in cash flow from years 2 to 10 of the forecast, from $194 million down to $151 million.[81]

NewGen's negative growth assumption contradicts the historically observed patterns of growth in the net utility plant and rate base associated with the Subject Assets, as shown in PG&E's accounting records. For example, CCSF's estimated $113 million per year in CapEx in 2021 is well below the nominal (*i.e.*, not inflation-adjusted) CapEx for every year from 2011 through 2021.[82] Between 2007 and 2020, PG&E's systemwide distribution and transmission rate bases grew at compound annual rates of 5.32% and 10.29%, respectively.[83] Projecting a decline in the net plant, rate base, and cash flow associated with the Subject Assets across its 10-year forecast reflects incorrect underlying assumptions about growth and further undermines NewGen's ultimate income valuation.

b. Jefferies

Jefferies presents an analysis using unlevered and levered DCFs that contain significant errors.

First, like NewGen, Jefferies's DCF models exclude a non-regulated, tax-exempt public-utility buyer, making its analysis fundamentally flawed for the reasons described above.

Second, Jefferies relies upon NewGen's calculation of net plant and CapEx forecast to support its analysis without independent verification, producing understated free cash flow values.[84] Those calculations are wrong for the reasons stated above.

Jefferies then compounds this error by carrying NewGen's CapEx into its cash flows without reconciling the capital-investment evidence from PG&E's regulatory filings. Jefferies estimates that the rate base associated with the Subject Assets will grow by $42 million (1.72% total

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81 *Id.* at Table B-4.

82 PG&E Testimony, Ch. 6 (Hegarty *et al.*), Figure 6-3; Appraisal Section 12.2.0.4 and Table 12.2.

83 Appraisal at Section 12.2.0.8 & Table 12.3.

84 Beicke Testimony at 2, 4, 8–9, 26–28, 31–33.

growth) from year end 2021 to year-end 2031, an unrealistically low CAGR over that period of 0.17% that fails to account for realistic forecasts for demand growth and asset replacements.[85]

Third, Jefferies's terminal-value estimates depend on the multiples it selected and on its modeled 2032 net income and EBITDA. Its price/earnings and aggregate-value/EBITDA multiples are drawn solely from publicly traded IOUs.[86] An exit multiple brings the market approach into the income approach, so Jefferies's terminal value carries the same taxable, rate-regulated buyer premise as its market methods and does not independently test them.[87] Here again, that premise excludes the non-regulated, tax-exempt POU, the buyer that would place the highest value on the Subject Assets.

Additionally, Jefferies's forecast of the net income and EBITDA of the Subject Assets in 2032, used to calculate terminal value, is derived directly from its unreasonably low rate base forecast. This in turn results in an unreasonably low terminal value estimate. Notably, the *maximum* of the valuation range produced by Jefferies's income approach using an earnings multiple is *below* the *minimum* of the valuation range under its guideline public company and precedent transaction market approaches,[88] implying that the value produced by Jefferies's income approach is unreasonably and unrealistically depressed below the value that would be observed in an actual market transaction.

In sum, NewGen's income approach contains fundamental flaws that do not provide a reasonable estimate of the fair market value of the Subject Assets. Jefferies's analysis is not an appraisal and, in any event, makes those same mistakes.

F. The Market Approach

The market approach values property by identifying and analyzing

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85 *Id.* at 13, Table 3.

86 *Id.* at 14–15 (derived trading multiples from publicly traded companies in Jefferies's "Peer Group").

87 Shannon P. Pratt & ASA Educational Foundation, Valuing a Business: The Analysis and Appraisal of Closely Held Companies at 170 & n.14 (McGraw Hill 6th ed. 2022).

88 Beicke Testimony at Figure 7.

comparable sales or transactions involving similar properties. For personal property, USPAP requires analysis of the appropriate market and available comparable-sales data, together with an explanation of the methods and reasoning supporting the value conclusion. My market approach applies these requirements by examining transaction comparability and using a consistent basis to compare the property sold with the Subject Assets.

I computed the market-approach valuation by applying the percentage of cost comparison technique. As further described below, this method calculates how much buyers paid in comparable transactions as a percentage of the cost to reproduce those used assets at the time of the transaction (the principle of substitution). My market approach shows that buyers paid between 81 and 90 percent of that cost. Based on my analysis, the value of the Subject Assets under the market approach is $14.26 billion, of which $9.96 billion is non-real property and $4.3 billion is the separately appraised real property valuation.[89]

The percentage-of-cost approach is appropriate because CCSF seeks to condemn certain of PG&E's assets, not PG&E's operating business or a whole business with assets and liabilities. CCSF itself uses a similar market approach by calculating a ratio of purchase price to net plant, which compares what buyers paid relative to the cost of the assets.[90] CCSF, however, uses historical original cost less accounting depreciation (OCLD) as its "cost" input, while I trend the original cost forward to the date of the comparable transaction to measure changes in construction costs and determine the percent of remaining useful life for the assets at that time—a more accurate way to determine what buyers are paying for the assets at the time of the transaction. Historical cost alone is not a relevant number for a seller that did not recently purchase or manufacture the subject asset. For example, an asset with a long useful life may simultaneously have a low OCLD (because it was purchased long ago), a high trended cost (because it has become expensive to replace—*e.g.*, if it requires underground construction), and substantial remaining useful life, making it quite valuable even if sold in its used condition.

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89 *See* Appraisal at Section 13 (Market Approach).

90 Rabon Testimony at 28 & Table 5.

Consider the case of buying a used car. The price a buyer pays depends on the cost of a new car at the time of the intended purchase, the availability and cost of other similar used cars, and the condition of the subject used car. If the cost of a new car is very high, the subject car is rare or unique, and/or the subject car is in good condition, it will command a commensurately high price. What the seller originally paid for the car and whether it has been fully depreciated as a matter of accounting is irrelevant.

CCSF's approach of comparing the purchase price to rate base does not evaluate the current cost of the assets purchased, how old they were, or—critically—their condition. Thus, CCSF cannot explain why some transactions in its market analyses occurred anywhere from 1 times net plant to 3.2 times rate base.[91] Nor can CCSF explain why NewGen uses lower value multiples (leading to a valuation of $3.1 billion) than Jefferies for the same transactions (leading to an estimate of up to $4.6 billion).[92] This wide gap in CCSF's own expert witnesses demonstrates the unreliability of NewGen's approach and why the percentage of cost as applied here is reasonable and more reliable.

1. Methodology

The market approach requires (i) identifying a list of comparable transactions, (ii) calculating a ratio that compares the value of the assets in those transactions against an appropriate unit of comparison, and (iii) applying that ratio to the relevant data in the appraisal.

Comparable Transactions. To identify sufficiently comparable transactions, I reviewed sale, merger, and acquisition sources for electric utility transactions, including those considered by NewGen.[93] I considered only transactions that qualified under the fair market value standard (arm's length between unrelated parties with no compulsion to sell) and that

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91 NewGen's purchase price/net plant calculation for its precedent transactions ranges from 1.00x to 1.59x, with a mean of 1.3x (Rabon Testimony, Table 5), while Jefferies's aggregate value/rate base calculation for its precedent transactions ranges from 1.3x to 3.2x, with a median of 1.9x (Beicke Testimony, Figure 4).

92 *See* Beicke Testimony at 33 & Table 10. Both NewGen and Jefferies analyze the following four transactions, with different calculations of multiples based on costs: NextEra Energy / Gulf Power Co., ENMAX / Emera Maine, JP Morgan Chase / El Paso Elec. Co., and PPL Corp. / Narragansett Elec. Co.

93 Appraisal App'x at Table F.2; Rabon Testimony at Table 4-3.

actually closed. I then screened those transactions for comparability across four criteria: (1) asset mix (distribution assets comprising *a significant percentage* of the subject property), (2) scale (a system large enough to file a FERC Form 1, *i.e.*, annual power delivery of at least approximately 1 million MWh), (3) transaction structure (cash purchase of a full ownership interest), and (4) market conditions (whether differences in economic and utility-industry conditions between transaction and valuation date affect comparability).[94] I also reviewed transactions with public entities. Public ownership alone neither establishes nor defeats comparability. For example, although ENMAX, the purchaser of Emera Maine, is municipally owned, the acquired utility remained rate regulated. Using these selection criteria, I considered 18 transactions in total.[95]

I selected Gulf Power, Emera Maine, and Narragansett because each transaction involved acquiring an operating electric utility with distribution assets, a cash purchase of the full ownership interest, and financial and plant records that support comparison with the Subject Assets. Each acquired system was large enough to provide a useful comparison, and regulated utility operations continued after each sale. The available records allowed me to compare the purchase price attributable to the relevant utility assets with the cost of those assets.

These systems differ from the Subject Assets in their underground share, density, and operating configuration. My Appraisal accounts for and explains those differences, the limitations of the allocations, and the reasons other transactions were not selected. For example, for Gulf Power, I removed its generation property from both the purchase price and the corresponding cost calculation; for Narragansett, I allocated the transaction to the electric operations before making the transmission-and-distribution comparison.[96]

Unit of Comparison. The Subject Assets, distinctive among electrical transmission and distribution systems, are largely underground and serve a

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94 Appraisal at Section 13.2.0.1.

95 Appraisal App'x, Section F, Table F.1.

96 Appraisal at Section 13.2; Appraisal App'x at G.2.

geographically small but very densely populated urban and suburban area. This makes a market analysis challenging, as comparable sales transactions primarily involve utilities that served thousands of square miles through predominantly aboveground transmission and distribution systems.[97] There is not a direct match, nor a comparable match transaction of an electric system that serves as many people as the Subject Assets in so condensed an urban and suburban area, that has equivalent redundancy, or that includes such a high percentage of undergrounded conductor line miles. A measure of utility derived from predominantly aboveground conductor assets would inherently undervalue the primarily undergrounded line-mileage associated with the Subject Assets, which is significantly more expensive to install and correspondingly carries a significantly lesser risk profile and higher reliability.[98]

Because of these major differences, the market analysis technique utilized must be one that creates a common unit of measurement applicable across distinct utility systems. I determined that the percentage of cost technique accomplishes this goal and is the only workable methodology for deriving an accurate market analysis appraisal of the Subject Assets.

The percentage of cost technique asks what percentage of current cost new of the assets a buyer paid for comparable used property.[99] It is expressed as a ratio, by dividing the portion of the observed transaction price attributable to the assets at issue by the current cost new of those assets, which serves to supply a common unit of comparison for disparate utility asset transactions.

The numerator in the percentage-of-cost ratio is the market price paid for the utility plant included in the comparison—*i.e.*, the portion of the transaction sale price fairly allocated to the electric-system assets (distribution and transmission plant). Thus, the percentage of cost approach requires deriving the asset-level price for the utility property at issue from the overall price of the comparable sales transaction, in order to ensure a

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97 *See* Appraisal App'x at G.1 (Physical comparability).

98 *See* Appraisal at Section 2.

99 *Id.* at Section 13.1.

matching comparison of asset sale price versus asset cost new. This is done by reducing observed transaction prices to a cash-equivalent price and allocating that price to different bases: consideration for the seller's equity, for the seller's invested capital, and for the identified assets.[100]

The denominator in the ratio is the reproduction cost new of the assets, which is a measure of what the transmission or distribution plant assets would currently cost on the open market if new, developed by trending the recorded original cost of the asset forward to the date of the transaction.[101] Reproduction cost is estimated through a vintage reconstruction of the comparable transaction's physical assets using original cost and any additions and retirements as reported in FERC filings.[102] This adjusted original cost by vintage is then trended forward to the transaction date using the Handy-Whitman index, which measures regional utility construction cost change over time, to calculate reproduction cost new.

Properties of similar age and condition can be compared directly via this price-to-cost-new ratio, which is the basic percentage-of-cost observation. However, where age and condition of the assets differ (as they do here), a modeled physical-deterioration adjustment (derived from each utility's FERC depreciation schedules and Iowa Curve present-worth calculations) can be added to reproduction cost new as an additional age-and-condition normalization.[103] The resulting value is reproduction cost new less physical deterioration. Dividing this value by reproduction cost new results in a "percent good" ratio, *i.e.*, the fraction of new condition the assets retain after physical deterioration. Dividing the price-to-cost-new ratio by this percent good ratio, in turn, results in a price-to-depreciated-cost ratio. This price-to-depreciated-cost ratio compares prices relative to the estimated physical condition retained by systems of different ages.[104]

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100 Appraisal App'x at G.2.

101 Appraisal at Section 13.1. This *reproduction* cost new value used in my market approach is distinct from the *replacement* cost new RCN value used in my cost approach.

102 *Id.* at Section 13.1.0.8, Appraisal App'x at G.2.

103 *Id.* at Section 13.1, Appraisal App'x at G.2.

104 Appraisal at Section 13.1.0.5.

Percentage of cost, and in particular the price-to-depreciated cost ratio, is the most workable market approach valuation technique here, given the distinctions between the Subject Assets and the assets included in the identified comparable sales. This is because reproduction cost provides a common scale for systems that contain different quantities and mixes of plant, while reproduction cost new less physical deterioration provides an explicit age-and-condition measure, both of which serve to compensate for significant differences in assets.

Application to the Subject Assets. Because there is no FERC data specifically on the Subject Assets as an isolated system, to estimate reproduction cost, I analyzed original cost from the record of net plant in service as of the Petition Date. For all non-underground assets, I trended this value to the Petition Date using the Handy-Whitman index, as I did for the comparable transactions. Doing so for underground assets, however, would significantly undervalue the Subject Assets, because the index does not appropriately capture the escalation in value of undergrounded conductor in San Francisco, which makes up 50% of the Subject Assets' original cost (as compared to between 1 and 16% of the assets included in the comparable transactions).[105] For example, PG&E's recorded costs for new underground construction in San Francisco rose 2.14x from 2013 to 2019, from $365 to $780 per foot—based on increased costs from permitting, base-mapping and design requirements, paving and restoration standards, and city-specific work restrictions, among other factors—while the Handy-Whitman index rose only 1.19x during that period.[106]

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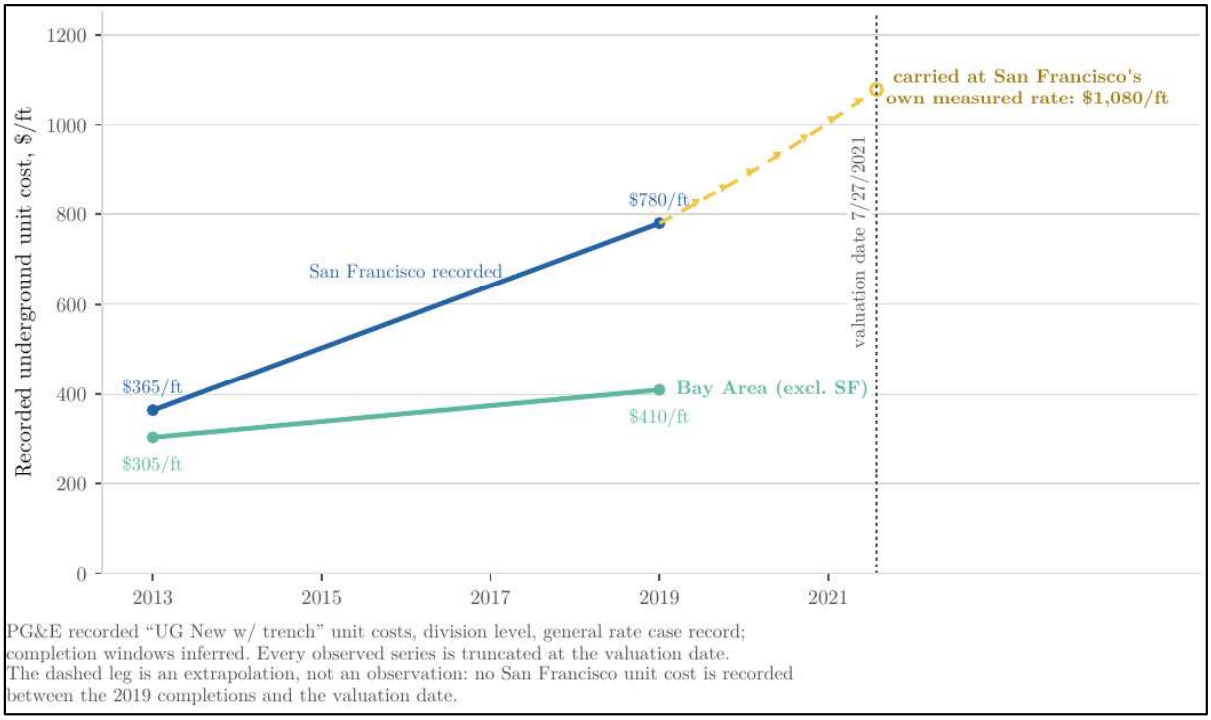
[105] Original cost percentages are derived from underground FERC Accounts 366.00, 367.00, 368.02, and 369.02 (distribution), and 357.00 and 358.00 (transmission) as reported in FERC Form 1 and PG&E Testimony, Ch. 6 (Hegarty *et al.*) Workpapers, Worksheet "Net Book Value."

[106] Appraisal at Section 13.4.2.1.

FIGURE 5-6
COMPARISON OF UNDERGROUND COST



For underground assets, I adjusted the Handy-Whitman index to account for this escalation, resulting in reproduction cost new of the transmission and distribution assets (excluding real property) of $14.24 billion.[107] I then applied a physical depreciation adjustment, using the same present-worth method, service lives, and Iowa survivor curves GFT developed for the Subject Assets but applied to the original cost trended new, resulting in an original cost trended new less physical depreciation for the transmission and distribution assets (excluding real property) of $11.61 billion.[108] This subject calculation uses the same kind of original cost record and escalation, rather than S&L's replacement cost, to maintain consistency within the percent of cost technique and the treatment of the comparables.

The final step in my market analysis is to calculate the percentage of cost ratios for the comparable transactions and the Subject Assets. For the three comparable transactions, the price-to-cost-new ratio ranged from

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107 *Id.* at Section 13.4.3.1.

108 *Id.*

69.8% to 76.3%, while the ratio of price-to-depreciated-cost ranged from 81.2% to 89.4%, with an average of 85.7%.[109] As discussed above, price-to-depreciated cost is the more applicable ratio here, given the significant differences between the Subject Assets and the assets involved in the comparable transactions. Applying the average price-to-depreciated-cost ratio from the comparable transactions of 85.7% to the $11.61 billion original cost trended new less physical depreciation results in a market value of the non-real property assets of approximately $9.96 billion. With the real-estate appraisal added, the total market-approach valuation is $14.26 billion.

2. Rebuttal of CCSF Market Approach

CCSF submitted two market-approach analyses, from NewGen and Jefferies. NewGen calculated an average ratio of Purchase Price to Net Plant by looking at twelve transactions, resulting in a ratio of 1.28 times OCLD and a valuation of $3.09 billion.[110] Jefferies conducted two market approach analyses—one of comparable trading multiples and one of precedent transactions, resulting in a weighted valuation range of $3.24 to $3.76 billion (inclusive of its DCF analyses discussed above).[111] Both NewGen and Jefferies make several critical errors that render their resulting valuations unreliable.

a. NewGen

NewGen bases its market analysis on a multiple of net plant (defined as original accounting cost less depreciation), which is not a relevant multiple for a market approach indicator of value.[112] Net plant reflects historical installation prices, reserve allocations and the plant included in each accounting balance—not the price that a buyer would pay for the assets on the open market today. Besides improperly importing the historical book reserve into the unit of comparison, the

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[109] Appraisal Table 13.1

[110] Rabon Testimony at 28–29 & Tables 5 & 6.

[111] Beicke Testimony at 34 & Table 11.

[112] Additionally, NewGen's analysis starts from an understated OCLD figure of approximately $2.4 billion, significantly below PG&E's actual net book value as of the Petition Date, which artificially depresses its market valuation.

transaction price numerator NewGen uses in its price-to-net-plant ratio fails to allocate the price paid for the assets at issue, leading to a mismatched comparison between transaction price and asset cost. Business-acquisition evidence can inform a property appraisal only when the price is allocated to the relevant property, and matched to a common unit of comparison. NewGen acknowledges wide differences among the comparable transactions it selected for its market approach analysis, without adjusting them to the Subject Assets, contrary to a proper market approach indication of value. NewGen concedes that the comparables it selected vary significantly in size, location, and plant type from the Subject Assets, but states that "no attempt was made to adjust the sales to correlate with the characteristics of the Subject Property."[113] Its price-to-net-plant ratio requires both a property and a price-basis reconciliation before it can be relied on for valuation purposes. As used in my percentage of cost methodology, reproduction cost new provides a more suitable unit of comparison for this property's heterogeneous transmission and distribution assets because it measures their composition and scale at a common price date. It divides an allocated property price by the current cost of that same property, while also normalizing for physical condition, allowing for a relevant comparison between assets with significant differences—adjustments NewGen fails to make.

NewGen's sample of comparable transactions is also flawed in itself. NewGen uses a date range of 2011 to 2022 for selecting comparable transactions,[114] resulting in the inclusion of transactions that occurred too many years prior to the Petition Date (July 27, 2021) for their market conditions to be shown comparable. Sales transactions inherently reflect general economic circumstances as well as specific market conditions at the time of the transaction, and thus should be selected from a more recent period for this industry. The closer in time a transaction is to the Petition Date, the greater the similarity in those

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[113] Rabon Testimony at 27.

[114] *Id.* at Table 5.

conditions and the greater the relevance of that transaction in a market comparable analysis. Valuation literature treats the relevant period as a matter of judgment rather than a fixed rule: three to five years is the period most commonly used for analysis of operating data, and the more market conditions have changed since a transaction, the less reliable its indication of value.[115] NewGen performs no such analysis. It neither adjusts its older transactions for changes in market conditions nor shows that conditions from 2011 through 2015 resemble those at the Petition Date. Without that analysis, NewGen's older transactions do not establish comparable market conditions and are unreliable.

In addition to using a lookback period approximately twice the five-year window I used for my primary comparisons, NewGen fails to explain its screening criteria, other than to state that the transactions it selected as comparable all "involv[e] electric utility distribution property."[116] Not surprisingly based on this lack of clear guidelines, three of NewGen's sales transactions are plainly incomparable and should be excluded, either because they were too small or were forced sales.[117] Providing a transparent screening process to identify sales transactions ensures that the selection of comparable sales is not subjective, can be replicated, and can be tested to ensure outliers are excluded. NewGen's lack of transparency makes it difficult to determine whether it arbitrarily excluded potentially relevant transactions or to assess the quality of its sample.

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115 Shannon Pratt, *Valuing a Business: The Analysis and Appraisal of Closely Held Companies*, 6th ed. (McGraw Hill 2022), at 297 ("In the absence of a compelling reason to do otherwise, the time period most commonly used for analysis of operating data is three to five years.") and at 327 ("Generally, the more market conditions and/or value drivers have changed as between the transaction date and the date of value, the derived value indication has the potential to be less reliable.").

116 Rabon Testimony at 27, App'x II at 4-6 to 4-7 & n.12.

117 These 3 transactions are: Oncor / AEP Texas (approximately 3,100 customers at stake), Murfreesboro / Middle Tennessee Electric (under $1 billion transaction and involved a cooperative purchasing the assets of a municipality), and Anchorage Municipal Light & Power / Chugach Electric Assn. (not a willing seller). *See* Rabon Testimony at Table 4-3.

b. Jefferies

Jefferies's "investment banking" perspective is inapplicable to this proceeding and makes several errors. The Jefferies analysis presents two market methods. In business valuation, Jefferies's "Comparable Trading Multiples Analysis" is referred to as the Guideline Public Company Method and its "Precedent Transactions Analysis" is referred to as the Guideline Transaction Method. They are tested against the same standards as any valuation: how the comparables are selected, whether the differences are adjusted for, and whether the business valued corresponds to the property being taken. Jefferies's market analysis falls short on each.

First, CCSF seeks to condemn PG&E's property; the taking does not include corporate securities or a workforce. Jefferies does not adequately establish how its business-valuation indications correspond to the property being appraised, including the applicable benefit streams and the determination of what percentage of the overall enterprise value is properly allocated to the Subject Assets. Its regulated-buyer premise also excludes a public-utility buyer. These shortcomings limit the reliability of its market value indications for the Subject Assets.[118] Jefferies does not adequately establish the connection needed to support its use of business-valuation indications nor perform the necessary adjustments for the Subject Assets.[119]

Second, Jefferies (like NewGen) fails to sufficiently explain its selection criteria for its precedent transactions, stating only that it selected transactions "involving companies in the electric utility industry" that it "viewed as generally relevant in analyzing the [Subject Assets]."[120] For this reason, Jefferies also selected the wrong transactions for valuing the Subject Assets—of its 14 selected transactions, *only one is comparable*.

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[118] Beicke Testimony at 2, 5, 8–9, 25–28.

[119] *Id.*

[120] *Id.* at 28.

Five of the transactions lack the forward-looking earnings data to calculate the 12-month earnings and EBITDA multiples, appearing in Jefferies's analysis as "na" [not applicable].[121] Three more occurred before the relevant five-year lookback period, which for reasons already discussed, does not represent the relevant economic and market conditions.[122] And of the remaining six transactions, five should be excluded based on a business profile of the subject entity that is incompatible with the Subject Assets, inconsistency with the legal premise of just compensation (distressed sales), or dissimilar transaction structure.[123] That leaves Jefferies with an insufficient sample on which to base a market approach valuation.

Third, Jefferies utilizes the negative growth input from NewGen, significantly diverging from historical trends[124] in order to limit the market valuation to the data's median or less without comparative analysis.

The differences between Jefferies's and NewGen's market indications are significant. Despite the errors in both reports, Jefferies's market indications are significantly higher than NewGen's, yet NewGen fails to analyze the differences or adjust its market indication or overall weighting.

G. Reconciliation

1. Methodology

The final step of my appraisal is to determine the fair market value of the Subject Assets based on the cost, income, and market approaches. The final appraisal value should reconcile these three approaches by weighing

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121 *See id.* at 30 (Figure 5).

122 These are: WEC Energy Group / Integrys (June 2014), Emera / TECO (September 2015), and Fortis / ITC (February 2016).

123 These are: WGL / AltaGas (acquired company is primarily a regulated gas utility), Energy Future Holdings / Sempra (distressed sale), SCANA Corporation / Dominion Energy (sale occurred when the acquired company was near bankruptcy), Vectren Corp. / CenterPoint (acquired company has a larger portion of gas than electric customers), and InfraREIT / Oncor (complex transactions involving two concurrent purchases of assets and of equity interests).

124 PG&E Testimony, Ch. 6 (Hegarty *et al.*), at Section D.

each in a manner that reflects the relevance and quality of the evidence for this specific property and market, considering asset-specific detail, data reliability, comparability, and the effect of necessary assumptions and adjustments. The determination of these weights requires appraisal judgment.

2. Weighing of the Three Approaches

Based on these criteria and my appraisal judgment, I weigh the three approaches as follows:

TABLE 5-4
SUMMARY OF RECONCILIATION

Value indication	Weight	Value ($ billion)
Cost Approach	65%	$14.55
Income Approach	25%	$12.00
Market Approach	10%	$14.26
Reconciled Value of the Subject Assets	100%	$13.88

Cost Approach: **65%**. The cost approach provides the most direct and detailed evidence about the particular assets being appraised. It is highly asset-specific, utilizing specific data on the Subject Assets themselves to establish value, including asset-level depreciation studies. The detailed inventory lists developed in this proceeding permit direct examination of this specialized, asset-intensive property by major component, allowing greater confidence in appraised value. The cost approach is also highly applicable here given its ability to capture the capital-intensive, special-purpose character of the electric transmission and distribution system at issue, which drives value. Finally, it is reasonable to afford additional weight to the cost approach given that the subject system has not been exposed to a sale in the marketplace—there are no truly comparable transactions, and only three transactions are comparable enough to consider in the market approach.

Income Approach: **25%**. The income approach maps directly onto the legal premise of just compensation, because it values the Subject Assets from the perspective of a POU, the class of purchaser that will value the system most highly, and therefore ensures the highest price for the property

in a voluntary open-market transaction. The income approach is also grounded in verifiable asset data regarding PG&E's rate base and capital expenditure growth rate. It is appropriate to weight the income approach 25% based on this earning-capacity evidence and the assumptions needed to forecast and discount cash flows.

Market Approach: **10%**. The strength of this approach is its market derivation, given its analysis of arm's-length sales of comparable utility systems. There are a limited number of comparable market sales transactions, given the Subject Assets' underground share, urban configuration, and plant vintages. While the percentage of cost methodology I use compensates for these differences, it is nevertheless appropriate to give the market approach limited weight in the final reconciliation compared to the cost and income approaches.

Based on the foregoing weighting, I appraise the fair market value of the Subject Assets at $13.88 billion.

3. Rebuttal of CCSF Weighing

NewGen estimated the values of the Subject Assets at $5.29 billion (cost approach), $3.43 billion (income approach), and $3.09 billion (market approach), yet does not reconcile these values using accepted appraisal techniques. Rather, NewGen discounted the cost approach by attributing any difference over the income approach as economic obsolescence, forcing it to equal its income value. And NewGen assigned no weight to the market approach except as a "reasonableness" reference.[125] Ultimately, NewGen effectively drew its conclusion of value based *solely* on the income approach. This is not a proper reconciliation of the indications of value.

NewGen's underlying methodology is also flawed because it incorrectly applied the cost, income, and market approaches. Correcting NewGen's cost and market approaches would render its income value ($3.43 billion)—currently bearing 100% of the weight of NewGen's appraisal—an outlier.

H. Conclusion

I have performed an appraisal of the Subject Assets consistent with the Interim Decision requirements including cost, income, and market approaches to

[125] Rabon Testimony at 27, 31.

value and reconciled them. Based on the foregoing, it is my opinion that the fair market value of the Subject Assets is $13.88 billion.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

ATTACHMENT A

APPRAISAL OF THE SUBJECT ASSETS

CONFIDENTIAL IN ITS ENTIRETY

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

SUBJECT ASSETS NET BOOK VALUE, RATE BASE, AND FORECAST OF CAPITAL EXPENDITURES

WITNESSES: KERRY HEGARTY, BRYON WINGET, TIM WEDLAKE, NED W. ALLIS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
SUBJECT ASSETS NET BOOK VALUE, RATE BASE, AND FORECAST OF CAPITAL EXPENDITURES
WITNESSES: KERRY HEGARTY, BRYON WINGET, TIM WEDLAKE, NED W. ALLIS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
SUBJECT ASSETS NET BOOK VALUE, RATE BASE, AND FORECAST OF CAPITAL EXPENDITURES

A. Introduction

This chapter of testimony covers two topics: (i) the net book value ("NBV") and related rate base figures of Pacific Gas and Electric Company's ("PG&E") electric transmission and distribution system serving San Francisco that the City and County of San Francisco ("CCSF") proposes to take (the "Subject Assets"); and (ii) the forecast of capital expenditures ("CapEx Forecast") associated with the Subject Assets. The NBV and rate base figures, and the CapEx Forecast, come primarily from PG&E's financial information and are provided as inputs that support PG&E's other chapters of testimony, including the income-approach analysis performed by Dr. John A. Williams of EPS, Inc. and PG&E's calculation of business severance damages.[1] This chapter also addresses the errors in the calculations of net plant and CapEx Forecast by Grant Rabon of NewGen Strategies & Solutions ("NewGen") on behalf of CCSF.

PG&E Net Book Value and Rate Base. The NBV of the Subject Assets as of July 27, 2021 ("Petition Date"), calculated based on PG&E's accounting records for assets within San Francisco, and using an inventory approach for assets outside of San Francisco, was $2.68 billion. The rate base of the Subject Assets was $2.44 billion.

CCSF's Errors Related to Net Book Value. The significant difference between PG&E's value and the figure relied upon by CCSF is the NBV of plant in service, with CCSF assuming a far larger accumulated depreciation than recorded in PG&E's accounting records. CCSF calculated its own accumulated depreciation rather than using the accounting records produced by PG&E and used by PG&E to calculate the revenue requirement customers pay to recover the costs of assets in service. Moreover, CCSF calculated its accumulated depreciation incorrectly, overstating the calculated accrued depreciation by

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[1] PG&E Testimony, Ch. 5 (Williams & Gerger), Ch. 8 (Rubin).

hundreds of millions of dollars. CCSF's departure from the records used for actual ratemaking results in NewGen applying excess depreciation and calculating its own net plant in service (referred to by NewGen as "OCLD / Rate Base")[2] that is $[redacted] too low. In effect, NewGen's approach, if implemented, would deny recovery of $[redacted] of invested capital in plant in service. This error alone, as discussed in other chapters,[3] lowers CCSF's appraised value of the Subject Assets by approximately $391 million (an error of more than 10% based on NewGen's own assumptions and conclusion of the Subject Assets' value).[4]

PG&E CapEx Forecast. To project the growth in capital expenditures to serve customers in CCSF for 2021 through 2026 in connection with the income approach (the "CapEx Forecast"), PG&E allocated its 2021 systemwide five-year CapEx forecast to the portion applicable to the Subject Assets. PG&E started with its systemwide forecast published in PG&E's General Rate Case ("GRC") and its Stakeholder Transmission Asset Review ("STAR"), removed wildfire related capital expenditures, and then allocated the remaining forecast capital expenditures based on the ratio of the original cost of the Subject Assets to the original cost of the systemwide assets. The CapEx Forecast provides growth of net plant from Petition Date through year end 2026 of [redacted]%, with annual expenditures of $[redacted] per year. That growth is used in the income approach for those years and then declines over the following years before reaching a long-term perpetual growth rate.[5]

CCSF's Errors Related to CapEx Forecast. CCSF made its own calculations of CapEx Forecast at $113 million per year (subject to annual escalation), a figure less than [redacted] PG&E's estimates ($[redacted] per year). Three errors explain CCSF's unreasonably low forecast: CCSF's CapEx

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2 Ex. CCSF-04C – Prepared Direct Testimony of Grant Rabon at Attachment A, Table A-1 n.2 (Apr. 20, 2026) (Errata May 21, 2026) ("Rabon Testimony") (defining "OCLD / Rate Base" as "an estimate of only the plant portion of rate base" without "miscellaneous additions or reductions" such as accumulated deferred income taxes).

3 PG&E Testimony, Ch. 5 (Williams & Gerger) at Section E(3).

4 The $391 million is calculated by multiplying the difference in NBV between CCSF's and PG&E's calculations ($273 million) by NewGen's income-value multiple (1.43), as provided in Rabon Testimony at Attachment B, Table B-4.

5 *See* PG&E Testimony, Ch. 5 (Williams & Gerger), at Section E(1).

calculations almost entirely comprise replacement CapEx, with no cost of removal and minimal growth CapEx. CCSF also incorrectly calculated replacement CapEx, incorrectly applying a methodology that produces results that imply an unreasonably long average life of *85 years* for the Subject Assets' transmission and distribution plant (*i.e.*, it would take an average of 85 years to replace these assets). And CCSF uses a growth factor that is incorrect and incorrectly applied. These errors lead CCSF to reach the unreasonable conclusion that the Subject Assets' net plant shrinks over its ten-year income forecast. As discussed in other chapters, CCSF's erroneously low CapEx forecasts cause CCSF to undervalue the Subject Assets significantly.[6]

B. Sponsoring Witnesses

1. Kerry Hegarty (Rate Base)

Mr. Hegarty is the Senior Manager of the Capital Recovery & Analysis team in the Capital Accounting department at PG&E. He is the witness for plant and rate base in PG&E's GRC, and he also supports various other PG&E rate cases held before the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). Mr. Hegarty holds a Bachelor of Arts degree in Psychology from the University of California, Berkeley. In this chapter, Mr. Hegarty sponsors the testimony regarding the net book value of the Subject Assets and the calculation of rate base as of the Petition Date.

2. Bryon Winget (CapEx Forecast)

Mr. Winget is the Vice President of Integrated Planning at PG&E. He leads enterprise planning and investment strategies that align operational, financial, regulatory, and infrastructure priorities to support the safe and reliable delivery of energy services. Mr. Winget holds a Bachelor of Science and Master of Science degrees in Material Science and Engineering from the University of California, Berkeley. In this chapter, Mr. Winget sponsors the testimony regarding PG&E's calculations of CapEx and addresses errors by CCSF related to CapEx growth.

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6 *Id.* at Section E(3).

3. Tim Wedlake (Tax)

Mr. Wedlake is a Principal Tax Analyst on the Research, Audits and Planning Team in the Tax Department of PG&E. He primarily manages PG&E's fixed asset tax depreciation and deferred tax system and its related work products. Mr. Wedlake holds a Bachelor of Arts degree and a Master's degree in Finance from California State University, Hayward, and a Juris Doctor from the University of California, College of the Law, San Francisco. In this chapter, Mr. Wedlake sponsors the testimony regarding tax-related topics.

4. Ned W. Allis (Rate Base & CapEx Forecast)

Mr. Allis is the Senior Vice President of GFT Infrastructure, Inc. ("GFT"). A fuller description of his experience and qualifications appears in PG&E Testimony, Chapter 3.2. In this chapter, Mr. Allis sponsors the testimony regarding the net book value of certain of the Subject Assets, including accumulated depreciation, and addresses errors by CCSF related to accumulated depreciation and CapEx Forecast.

C. The Subject Assets' Net Book Value and Calculation of Rate Base

1. Summary

Rate base is the invested capital on which a regulated utility is permitted to earn a return. Rate base of the Subject Assets is equal to the NBV (also known as "net plant" or "net plant in service") of the Subject Assets, which is the "original cost" (also known as "gross plant") less accumulated depreciation, plus or minus certain regulatory adjustments such as accumulated deferred income taxes ("ADIT"), working capital, and customer advances. The NBV and rate base of the Subject Assets are used as inputs in other chapters of PG&E's testimony, notably the income-approach model. CCSF refers to NBV as original cost less depreciation ("OCLD") and derives that figure using a different methodology than PG&E. The comparative amounts used by PG&E and CCSF are summarized in Table 6-1.

TABLE 6-1
COMPARISON OF NET BOOK VALUE USED BY CCSF AND PG&E[7]

Line No.	($ millions)	CCSF			PG&E		
		Original Cost	Accumulated Depreciation	OCLD / Rate Base	Original Cost	Accumulated Depreciation	Net Book Value
Assets Inside San Francisco							
1	Transmission	794.2	200.3	593.9	875.2	161.4	713.9
2	Distribution	2,770.5	1,272.2	1,498.3	2,821.2	1,026.6	1,794.7
Additional Assets Outside San Francisco							
3	Martin Substation	191.8	65.5	126.3	175.1	41.5	133.6
4	Martin Triangle	13.5	7.5	6.0	12.8	7.5	5.3
5	Spares	43.2	0	43.2	29.0[8]	0	29.0
Assets CCSF Separately Valued							
6	Land & Land Rights	108.3	0	108.3	*Included in the PG&E figures above.*		
7	Structures & Improvements	60.9	33.5	27.4			
8	**Total (Subject Assets)**	**3,982.3**	**1,579.0**	**2,403.3**	**3,913.4**	**1,236.9**	**2,676.4**
9	*Net (CCSF – PG&E)*	-	-	-	*68.9*	*342.1*	*-273.2*
10	**Rate Base (July 27, 2021)[9]**			**2,403.3 (Unadjusted)**			**2,435.9 (Adjusted)**

As shown in Table 6-1, the largest difference between PG&E and CCSF is accumulated depreciation, with NewGen overestimating accumulated

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7 GFT Workpapers (NBV), Worksheet "Table 6-1." FERC Account 397 (Communications Equipment) is included within Distribution plant.

8 PG&E's $29.0 million figure excludes spare assets that are included in a separate FERC account as part of the Subject Assets within San Francisco. PG&E's NBV of all Spares within the Subject Assets is $34.1 million. *See* PG&E Workpapers (Rate Base & CapEx), Worksheet "Spares." All spare assets are referred to as "in-service spares" and are included in either Distribution or Transmission plant in service in the income model.

9 CCSF's OCLD is the same as rate base as of the Petition Date because it models income cash flows based on an assumed new investor owned utility that starts without any working capital, ADIT, or other adjustments to OCLD (thus, it is labeled in Table 6-1 as "unadjusted" rate base). By contrast, PG&E calculated its rate base by adjusting the NBV (thus, it is labeled as "adjusted" in the table), so as to value the cash flows that the assets would generate as of the Petition Date and that would be sold to any hypothetical buyer.

depreciation by $342 million, which causes CCSF to understate the Subject Assets' NBV by $273 million. The reason for this difference is that CCSF made its own calculation of accumulated depreciation for transmission and distribution assets in San Francisco, and it disregarded the accumulated depreciation appearing in PG&E's accounting records, which are the records used to calculate PG&E's revenue requirement paid by customers to recover the cost of plant in service.[10]

For the remainder of this section, PG&E describes its process for assembling the NBV of the Subject Assets, which includes assets inside San Francisco (Section 2.a) and additional assets outside of San Francisco (Section 2.b). PG&E then explains the reasons why CCSF's NBV figure is less than PG&E's by approximately $273 million (Section 3). Lastly, PG&E describes how it adjusted the NBV to calculate rate base as of Petition Date (Section 4), and it provides the figure for construction work in progress ("CWIP") as of the Petition Date.

2. Net Book Value (Kerry Hegarty & Ned Allis)

NBV represents the portion of PG&E's investment in utility plant that has not yet been recovered from customers. With respect to the Subject Assets, PG&E used two methods to derive the NBV. For Subject Assets located inside San Francisco (referred to by NewGen as "Facilities in Service within CCSF"[11]), PG&E used its accounting records for assets coded to the county code for San Francisco. For Subject Assets located outside of San Francisco, consisting of the Martin Substation, the "Martin Triangle,"[12] and spares, PG&E (like CCSF) used an "inventory method" that calculates the replacement cost, trends it back to original cost, and then deducts a

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10 CCSF and PG&E both used information provided by PG&E for original cost (original cost as of year end 2020 and year end 2021), but CCSF averaged the numbers to calculate original cost as of the Petition Date, whereas PG&E interpolated the numbers by day to the Petition Date. CCSF's use of averages caused it to underestimate original cost by approximately $11 million.

11 Rabon Testimony, Attachment A, Table A-3.

12 *Id.* at 22 (indicating that CCSF will condemn the Martin Substation, which is outside of San Francisco, and "some distribution assets outside of the City . . . labeled as 'Martin Triangle' assets").

depreciation amount as applicable.[13]

a. Subject Assets Inside San Francisco

For Subject Assets located inside San Francisco, which constitute the vast majority of the Subject Assets, PG&E used the NBV from its accounting records that are maintained in the ordinary course of serving customers and produced in this proceeding.

Group Accounting & PowerPlan. PG&E utilizes group accounting and tracks the original cost and accumulated depreciation of assets at the asset-class level, rather than at the unit level. The asset classes are set forth by the FERC Uniform System of Accounts, including, among other categories, Transmission Plant and Distribution Plant.

Like most other utilities, PG&E uses PowerPlan, a fixed-asset accounting software, to track the original cost of assets in service and their associated accumulated depreciation. When a capital asset is placed in service, PG&E records its original cost in PowerPlan under the applicable asset class (*i.e.*, FERC Account). PG&E calculates book depreciation using the straight-line, remaining-life method, using depreciation accrual rates approved by FERC for transmission assets[14] and by the CPUC for distribution assets.[15] These depreciation rates are based on group-level averages, including expected service life, distribution of retirements, and expected net salvage, and are applied uniformly to all assets in the applicable asset class. Each month, PowerPlan records depreciation expense for each asset class by multiplying the end-of-month plant balances by one-twelfth of the

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13 CCSF likewise used an inventory approach to calculate the NBV of these additional assets separately from the assets within San Francisco, as illustrated by Rabon Testimony, Attachment A, Table A-3.

14 Approximately 95% of PG&E's transmission plant is under operational control of the California Independent System Operator ("CAISO") and FERC jurisdiction. The other ~5% is under CPUC jurisdiction. Depreciation in PowerPlan for transmission assets is calculated using a blended FERC/CPUC rate for each asset class.

15 Adopted CPUC electric distribution depreciation rates are from PG&E's 2020 GRC, D.20-12-005, which adopted parties' Joint Settlement Motion, Appendix D, Average Service Lives/Mortality Curves, Net Salvage Percentages and Accrual Rates. Adopted FERC electric transmission rates are from PG&E's TO20 Rate Case Docket ER19-13-000. The FERC adopted Section 4.3 of parties' Settlement as provided in Schedule 12-DepRates.

adopted annual depreciation rate for that asset class. At year end, accumulated depreciation is calculated by (1) beginning with the accumulated depreciation balances as of January 1, (2) adding depreciation expense recorded from January through December, (3) subtracting the original cost of any assets retired during the year, (4) subtracting any removal costs incurred, and (5) adding any gross salvage amounts received from those retirements.

Group accounting, including group depreciation, is the standard approach among utilities, is endorsed by the CPUC,[16] and forms the basis by which PG&E and the CPUC determine the authorized revenue requirement for customers.

PowerPlan's Net Book Value Reports. For the NBV of the Subject Assets inside San Francisco, PG&E produced in this proceeding the following PowerPlan reports (the "NBV Reports"): (i) a report showing, as of December 31, 2020, the group-level original cost ("Book Cost"), accumulated depreciation ("Allocated Reserve"), and net book value for 34 asset classes that are tagged with county code 038 (San Francisco) (PGE000103590); and (ii) the same report as of December 31, 2021 (PGE000103591).[17] For the Allocated Reserve, PowerPlan allocates the accumulated depreciation for each asset class for the entire system to the Subject Assets in proportion to the calculated accrued depreciation for each set of assets. The calculated accrued depreciation incorporates the respective age, service life, and other attributes of the relevant assets. PG&E uses the same accounting data as in the NBV Reports for its systemwide NBV, which is used to determine the revenue requirement charged to customers.

Calculating Net Book Value as of the Petition Date. The NBV

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[16] CPUC, Standard Practice for Determination of Straight-Line Remaining Life Depreciation Accruals U-4-W, at 8 (Jan. 3, 1961) ("Where groups of property, such as an entire account, comprise the base, the method is spoken of as *group accounting*. . . . Because of greater simplicity in maintaining records, the group basis is more feasible for most classes of utility property where large numbers of units are involved[, including] electric[.]" (emphasis added)).

[17] Additional reports of PowerPlan records have also been produced in this proceeding, including reports related to book costs, additions, and retirements from 2011 to 2021 (PGE000082649).

Reports provide data for year end 2020 and 2021. To determine the NBV as of July 27, 2021, PG&E does not simply average the December 31, 2020 and December 31, 2021 balances in the NBV Reports. Doing so would estimate the value at the midpoint between those dates—approximately June 30, 2021—not the Petition Date. Instead, PG&E interpolates between the two year-end balances by assuming that the change in the recorded accounting numbers occurred evenly over the year and then calculates the portion of that change attributable to the 208 days between December 31, 2020 and July 27, 2021. This produces an estimate specifically aligned with the Petition Date. As of that date, the NBV of the Subject Assets inside San Francisco was $2,508,535,637.

b. Additional Assets Outside of San Francisco

In its amended and restated testimony, CCSF disclosed an intent to take certain additional assets, including the Martin Substation, the Martin Triangle, and certain spare assets. The Martin Substation is a transmission-to-distribution substation located in Daly City just south of San Francisco. The Martin Triangle refers to a location that includes [redacted] assets [redacted] that are required for electricity flow from the Martin Substation into San Francisco. Spares refer to an inventory of spare materials outside of San Francisco used for repair or replacement of assets in San Francisco and include equipment for [redacted]).[18] There is no dispute regarding the specific items constituting these three groups.

Martin Substation and Martin Triangle. To calculate the NBV of the assets constituting the Martin Substation and the Martin Triangle, PG&E could not use PowerPlan in the same manner as it did for the Subject Assets inside San Francisco, because it is not possible to isolate the subset of assets that CCSF proposed to take. Instead, PG&E used an

[18] PG&E Testimony, Ch. 2 (Bahramirad *et al.*), at Section D(12) (describing the spare assets supporting San Francisco); Ch. 3.1 (Thibodeau), at Section E(6) (providing a more detailed description of the spare and [redacted] assets and their locations).

"inventory approach" to determine the value of these assets—*i.e.*, identifying the full inventory of assets associated with the Martin Substation and the Martin Triangle and then comparing the original cost and accumulated depreciation for every single asset.[19] To calculate original cost, PG&E utilized the output of the Replacement Cost New ("RCN") analysis in the cost approach for those same assets and converted the RCN into original cost by using the Handy-Whitman index, which tracks changes in costs for various types of equipment and assets. For accumulated depreciation, Mr. Allis of GFT performed an allocation analysis consistent with the approach used by PowerPlan in generating the NBV Reports—*i.e.*, calculating the theoretical reserves and reserve ratios for those assets and applying the reserve ratios to the total accumulated depreciation for the appropriate asset classes. GFT then interpolated the NBV to conclude that, as of the Petition Date, the NBV of the Martin Substation was $133,563,422 and of the Martin Triangle was $5,337,652.[20]

Spares. PG&E calculated the NBV of the spare assets in the same way as the Martin-related assets, by conducting an asset-by-asset inventory analysis and estimating original cost by using their corresponding RCN inputs and the Handy-Whitman index. No depreciation is deducted as these assets are assumed to have been purchased and treated as plant in service on the Petition Date. However, because some of these spare assets are located within San Francisco, PG&E conservatively omitted a portion of these assets to avoid double counting. Using this method, PG&E calculated a net book value of $28,980,658 for the spare assets outside of San Francisco.[21]

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[19] CCSF used a similar inventory method. *See* Rabon Testimony, Attachment A, Table A-7.

[20] As set forth in GFT's workpapers, any assets related to the Martin Substation that had been coded to San Francisco in PowerPlan and included in the NBV Reports were deducted from the calculation of NBV for the Subject Assets inside San Francisco to avoid double counting. This includes FERC account 390, which primarily consists of [redacted].

[21] *See* GFT Workpapers (Martin & Spares), Worksheet "Spares."

c. Net Book Value of the Subject Assets as of the Petition Date

The net book value of the Subject Assets—the sum of the net book values of the assets inside San Francisco, the Martin Substation, the Martin Triangle, and Spares—is $2,676,417,368.[22]

3. Differences Between PG&E's and CCSF's Methods (Kerry Hegarty & Ned Allis)

The most significant difference is that NewGen erroneously disregarded the actual book depreciation recorded in PowerPlan in favor of its own, incorrectly calculated accumulated depreciation. As a result of its erroneous calculation of accumulated depreciation, NewGen overestimated accumulated depreciation by $342 million, which thereby caused it to undercount the NBV and rate base of the Subject Assets by approximately $273 million.[23]

a. CCSF Disregarded Book Depreciation and Incorrectly Relied on Its Own Calculated Depreciation

First, although CCSF accepted the original costs figures in the NBV Reports, it ignored the actual recorded accumulated depreciation in those same documents—*i.e.*, the accounting records in PowerPlan. Instead, NewGen calculated its own alternative accumulated depreciation based on its own estimate of asset ages, survivor curves, remaining lives, and net salvage ratios, which it deducted from original cost to arrive at its "OCLD / rate base."[24]

NewGen's approach is not reasonable. Net book value—and rate base—reflects the utility's recorded investment in specific, identifiable assets at a defined point in time. For those assets, the accumulated depreciation reserve is not hypothetical; it is a fixed, auditable balance already reflected in the books that directly reduces net book value. CCSF's calculated accumulated depreciation does not correspond to the actual capital already paid by customers. By substituting its own

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22 *See* GFT Workpapers (NBV), Worksheet "Net Book Value."

23 CCSF makes additional errors, but PG&E emphasizes only certain of them in this chapter of testimony.

24 Rabon Testimony at 22–25.

calculated accumulated depreciation, NewGen essentially posits that the net book value of the Subject Assets will decline by $342 million the moment after CCSF's taking rather than continue at the same value.

Second, CCSF did not calculate accumulated depreciation correctly. Calculated accrued depreciation ("CAD") is a function of the age, survivor curve and net salvage for a group of property. For each vintage of plant, the calculated accrued depreciation is determined by first calculating CAD on a percentage basis, known as the Calculated Accrued Depreciation Ratio ("CADR"), using the following formula:

$$CADR = (\frac{1 - Remaining\ Life}{ASL})$$

The CADR is then applied to the original cost (or original cost less net salvage if net salvage is included) to determine the CAD. The *Remaining Life* and *ASL* are both derived from the survivor curve estimate for the account, with the remaining life a function of the age of the vintage of plant at the time of the calculation.

CCSF calculates the CADR (which it refers to as the "Reserve Ratio") for each vintage of plant based on the vintages determined in its inventory approach.[25] It then calculates a weighted average reserve ratio, based on its inventory approach balances, which it then applies to the total balances from PG&E's accounting records for each account and then separately applies to the estimated net salvage. CCSF's calculation is incorrect—the vintages in CCSF's inventory approach are not the same as in PG&E's accounting records and, as a result, CCSF has not used the correct reserve ratios. The result is that CCSF overstates the CAD by approximately $342 million.[26]

CCSF's erroneous estimate of accumulated depreciation is further

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25 These calculations are provided in CCSF Workpapers, titled "Cost Approach.xlsx," Worksheets "Trans Inventory" and "Dist Inventory." CCSF does not provide the actual calculations of the reserve ratios, but indicates in Footnote 5 of these same worksheets that they are "Based on applicable survivor curve with a cap of 90% (and no net salvage)."

26 CCSF calculates accumulated depreciation of approximately $1.579 billion, whereas the CAD calculated with the actual ages from PG&E's accounting records would be approximately $1.237 billion. *See* Table 6-1.

evidenced by its need to apply a depreciation floor. NewGen imposed a rule that accumulated depreciation is "capped at 90%," so that no asset can depreciate to a net book value less than 10% of its original cost.[27] NewGen applied this 10% floor in two instances related to poles, towers, and fixtures (FERC Asset Class 364), as summarized in Table 6-2.

TABLE 6-2
NEWGEN'S APPLICATION OF 10% DEPRECIATION FLOOR[28]
($ THOUSANDS)

Line No.	Asset Class	Description	Original Cost	Accumulated Depreciation	Accumulated Net Salvage	Unadjusted OCLD	Adjustment	Adjusted OCLD
Distribution Plant								
1	364	Poles, towers and fixtures	176,433.9	148,433.9	73,548.0	-45,548.0	63,191.4	17,643.4
Martin Substation								
2	364	Poles, towers and fixtures	42.8	36.0	17.8	-11.1	15.3	4.3

Although presented as a conservative assumption, NewGen's use of the 10% floor demonstrates the fundamental flaw in its approach. Had NewGen calculated depreciation accurately, it would not need to apply a 10% floor to an entire asset class. NewGen's rule confirms that NewGen's entire approach to calculating OCLD is not reliable.[29]

NewGen's rationales for ignoring the historical accumulated depreciation in PG&E's accounting records are not valid. NewGen first argues that the accumulated depreciation from PowerPlan is inaccurate because its own calculated depreciation is larger. As discussed above, this is the result of CCSF calculating depreciation incorrectly by applying the wrong ages of PG&E's assets. Notwithstanding that issue, it is also not unusual for the book accumulated depreciation to be less than a calculated depreciation amount. Book accumulated depreciation reflects the depreciation rates approved by the CPUC in past rate cases,

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27 Rabon Testimony, Attachment A, Table A-3 & n.5 ("[T]he analysis assumes the estimated sum of deductions to estimate OCLD is capped at 90%.").

28 *Id.* at Table A-3, Columns H, J, L–O.

29 *See also* PG&E Testimony, Ch. 3.2 (Allis), at Section G(2)(d) (further critique of the 10% depreciation floor).

which are lower than those authorized in the 2020 GRC. Among other reasons, in prior rate cases, the CPUC has adopted lower negative net salvage due to its policy of gradualism, which applies "where there is recognized need to revise estimated parameters, but where the change is allowed to occur incrementally over time rather than all at once," so that such change does not cause an "approved increase [in rates] that would otherwise be warranted."[30] Historical depreciation accruals were lower than would have resulted from the current net salvage estimates used by NewGen, and historical recorded cost of removal was higher than reflected in NewGen's calculations. For example, for the entire PG&E electric transmission and distribution system, the calculated accrued depreciation for PG&E's systemwide assets is nearly $1.5 billion higher than PG&E's book accumulated depreciation.[31] Using NewGen's approach would therefore understate PG&E's net plant by almost $1.5 billion. Moreover, because NewGen's approach is not tied to the actual depreciation that has been recovered through rates over time, using NewGen's depreciation figures would deny recovery of costs that were not recovered in prior years when depreciation rates were lower.

CCSF's second rationale, that PG&E did not provide supporting documentation and that it did not find the results of allocating the actual book depreciation "reasonable,"[32] is also incorrect. PowerPlan's allocation can be duplicated and verified. To do so, Mr. Allis of GFT calculated both estimated depreciation and allocated book depreciation based on the same methodology and the same vintage balances as PowerPlan, but using GFT's depreciation software. That result is summarized in Table 6-3.

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30 PG&E 2014 GRC, D.14-08-032, at 598.

31 GFT Workpapers (NBV), Worksheet "Reserve."

32 CCSF Response to PG&E Data Request Set 3, No. 33. *See also*, CCSF Response to PG&E Data Request Set 3, No. 10 ("If accurate historical data regarding the reserve for accumulated depreciation is available in the books and records of the utility, this data would typically be used to calculate the OCLD component of rate base.").

TABLE 6-3
COMPARISON OF ALLOCATED DEPRECIATION (AS OF JULY 27, 2021)[33]

			A	B
Line No.	**Asset Class**	**Description**	**GFT Calculations ($)**	**PowerPlan Calculations ($)**
Transmission				
1	350	Land Rights	1,483,629	1,830,613
2	352	Structures and Improvements	5,492,448	5,976,788
3	353	Station Equipment	70,156,644	73,106,832
4	354	Towers and Fixtures	61,035	70,665
5	355	Poles and Fixtures	157,268	170,288
6	356	Overhead Conductors and Devices	53,503	65,538
7	357	Underground Conduit	43,537,489	43,401,540
8	358	Underground Conductors and Devices	37,076,971	36,751,721
Total (Transmission)			**158,018,988**	**161,373,985**
Distribution				
9	360	Land Rights	290,328	333,063
10	361	Structures and Improvements	23,710,120	23,542,012
11	362	Station Equipment	102,761,931	101,289,111
12	364	Poles, Towers and Fixtures	68,286,826	69,467,008
13	365	Overhead Conductors and Devices	75,615,873	76,771,571
14	366	Underground Conduit	182,643,959	181,854,983
15	367	Underground Conductors and Devices	309,008,422	318,479,369
16	368.01	Line Transformers – Overhead	22,073,376	22,579,418
17	368.02	Line Transformers – Underground	29,826,523	31,432,815
18	369.01	Services – Overhead	16,327,318	17,290,236
19	369.02	Services – Underground	63,900,880	63,715,631
20	370	Meters	55,059,406	54,866,531
21	371	Installations on Customers' Premises	31,962,779	31,960,939
22	372	Leased Property on Customers' Premises	65,570	87,244
23	373	Street Lighting and Signal Systems	29,737,471	30,902,296
Total (Distribution)			**1,011,270,781**	**1,024,572,226**
Total (Transmission & Distribution)			**1,169,289,769**	**1,185,946,211**

As shown in Table 6-3, the resultant allocated book reserves that Mr. Allis has calculated for the Subject Assets in San Francisco

33 GFT Workpapers (NBV), Worksheet "Table 6-3."

(Column A) are substantially similar to the calculations performed by PowerPlan and reflected in the NBV Reports (Column B). These calculations confirm that PowerPlan's allocation methodology is reasonable. CCSF's substantially higher accumulated depreciation does not result from a materially different allocation of the book reserve; it results from NewGen's decision to disregard book depreciation and substitute its separately calculated accumulated depreciation.

CCSF's final rationale is to note that the allocated book depreciation for the Subject Assets in San Francisco is lower than the allocated book depreciation for PG&E's assets systemwide.[34] But CCSF's argument ignores the unremarkable observation that the reserve ratios for a subset of assets (*e.g.*, the relevant assets in San Francisco) and for the entire PG&E electric system may be different. This occurs because the age distribution of the subset of assets is different from the age distribution of the entire system. In this instance, on a dollar-weighted basis, PG&E's assets in San Francisco are, on average, younger than those for the system as a whole for several asset classes because the cost of newer assets in San Francisco has increased faster than for the system as a whole.[35]

As shown in Table 6-3 below, there are several asset classes for which the average age for assets in San Francisco is lower than the average age for the system as a whole. These asset classes also have lower reserve ratios, because the assets have been in service for, on average, a shorter period and have, therefore, accumulated less depreciation. For example, for Account 365, approximately 63% of the total 2021 plant balance is for vintages installed within the last 10

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34 CCSF Response to PG&E Data Request Set 4, No. 3 (stating that the PG&E systemwide reserve ratio is 46%, whereas the allocated reserve ratio for the assets in San Francisco is 32%).

35 Note that the average age based on dollars will be different from those based on quantities because unit costs can vary. For this reason, the average age for an RCN will be different from the average age based on original cost.

years.[36] These assets would have less than 10 years of depreciation, which results in a lower reserve ratio than for the system as a whole.

TABLE 6-4
COMPARISON OF ACCUMULATED DEPRECIATION AND RESERVE RATIOS –
PG&E SYSTEMWIDE V. SUBJECT ASSETS IN SAN FRANCISCO (AS OF JULY 27, 2021) [37]

	PG&E TOTAL				SUBJECT ASSETS			
($ millions)	A	B			C	D		
ACCOUNT	PLANT BAL.	BOOK RSRV.	B / A	AVG. AGE	PLANT BAL.	BOOK RSRV.	D / C	AVG. AGE
ELECTRIC PLANT								
TRANSMISSION PLANT	[redacted]							
350 Land Rights								
352 Structures & Improvements								
353 Station Equipment								
354 Towers & Fixtures								
355 Poles & Fixtures								
356 Overhead Conductors & Equip.								
357 Underground Conduit								
358 Underground Conductors & Equip.								
TOTAL TRANSMISSION PLANT								
DISTRIBUTION PLANT								
360 Land Rights								
361 Structures & Improvements								
362 Station Equipment								
364 Poles, Towers & Fixtures								
365 Overhead Conductors & Equip.								
366 Underground Conduit								
367 Underground Conductors & Equip.								
368.01 Line Transformers – OH								
368.02 Line Transformers – UG								
369.01 Services – Overhead								
369.02 Services – Underground								
370 Meters								
371 Customer-Premises Installations								
Leased Customer-Premises								
372 Property								
373 Street Lighting & Signals								
TOTAL DISTRIBUTION PLANT								
TOTAL ELECTRIC PLANT								

The difference in ages for San Francisco assets compared to the system as a whole is due, at least in part, to the higher cost of recent additions. Capital additions are a function of both the volume of capital work

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36 Total original cost for Account 365 as of December 31, 2021 in the NBV Report ("PGE000103591") is $208.6 million, compared to $130.8 million in original cost for vintages age 10 or newer (*e.g.*, installed in vintage 2012 or later).

37 GFT Workpapers (NBV), Worksheet "Table 6-4." The accounts represented in Table 6-4 do not include all Subject Assets (*e.g.*, Martin).

performed and the cost per project. Cost drivers—such as labor costs, the complexity of work, and various state and municipal work requirements—have been more pronounced in densely populated, urban areas like San Francisco. Thus, it is not surprising that capital additions for the Subject Assets have been proportionally higher than the PG&E system as a whole and that the average age of those same assets is less than that of PG&E's assets systemwide for several accounts, resulting in less allocated book depreciation.

4. Converting Net Book Value to Rate Base (Kerry Hegarty & Tim Wedlake)

To convert the NBV to rate base, PG&E considered four adjustments, though ultimately only applied one for ADIT. PG&E did not apply rate base adjustments for working capital, customer advances or CWIP for reasons explained below. The adjustment for ADIT resulted in a reduction of $240.5 million to the NBV of the Subject Assets, producing a total rate base as of the Petition Date of $2.44 billion.

a. Accumulated Deferred Income Tax

ADIT arises from timing differences between book and tax depreciation and reduces rate base for purposes of calculating the revenue requirement for the authorized return on rate base. Under cost of service ratemaking principles, tax expenses are included in the revenue requirement paid by PG&E's customers. However, tax law permits regulated utilities like PG&E to accelerate certain tax deductions, which causes PG&E to pay less in current income taxes than the tax expense included in the revenue requirement during the early years of an asset's life. Under the Normalized Tax Accounting method, these tax savings are not immediately flowed through to customers. Instead, the timing difference creates a deferred tax liability, or ADIT, representing taxes that will be paid in future years as the difference between book and tax depreciation reverses. PG&E maintains ADIT balances for both federal and state taxes.

Federal ADIT Balance. The Tax Cuts and Jobs Act of 2017 ("TCJA") impacted the treatment of PG&E's ADIT balance related to federal tax as of December 31, 2017. The TCJA, among other

provisions, reduced the applicable federal corporate income tax rate from 35% to 21%, effective January 1, 2018.[38] The reduction in the tax rate means that PG&E will owe less deferred tax in the future for assets that generated an ADIT balance through December 31, 2017. The change in tax rates resulted in a division of PG&E's federal ADIT balance as of December 31, 2017 into "IRS ADIT," based on the new 21% tax rate effective January 1, 2018, and "Excess ADIT," based on the 14% differential between the old and the new tax rate.

PG&E has been crediting customers a portion of the Excess ADIT balance over the regulatory book life of the assets that generated the Excess ADIT balance. Only IRS ADIT is used to reduce NBV to rate base for the Subject Assets. Unlike IRS ADIT, the Excess ADIT will continue to be credited to remaining customers following a taking of the Subject Assets by CCSF. The Excess ADIT has therefore been excluded in calculating rate base.[39]

State ADIT Balance. PG&E maintains a state ADIT balance for the transmission assets, because those assets are primarily subject to FERC ratemaking, under which applicable federal and state income-tax timing differences are subject to the Normalized Tax Accounting method.

Mr. Wedlake of PG&E estimated the state component to be approximately 10% of the corresponding federal ADIT balance. That estimate accounts for the higher federal tax rate and longer state depreciation lives, which result in a state ADIT balance that is substantially smaller than the corresponding federal ADIT balance.

Calculating IRS, State, and Excess ADIT. Based on the TCJA, as of December 31, 2017, IRS ADIT represented approximately 60% of the PG&E's federal ADIT balance (21%/35% = 60%), with Excess ADIT

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38 Tax Cuts and Jobs Act, Pub. L. No. 115-97 (Dec. 22, 2017), 131 Stat. 2054 (codified as amended in various sections of 26 U.S.C.).

39 Because Excess ADIT is already being credited to customers systemwide and reduces the rates they would otherwise pay, it is already accounted for in the overall calculation of lost revenue from San Francisco (the starting point of Business Severance Damages). To avoid double counting or double credit to CCSF, Excess ADIT is not separately included in the income approach.

representing the remaining 40% (14%/35% = 40%). The IRS ADIT percentage of the federal ADIT balance increases as Excess ADIT is credited to ratepayers. When Excess ADIT is reduced to zero, IRS ADIT will represent 100% of the federal ADIT balance. A reasonable estimate of the amortization, especially for early years, is 1% per year. Using this estimate, IRS ADIT would represent 63% of the federal ADIT balance as of December 31, 2020 and 64% as of December 31, 2021. PG&E has applied these allocation factors to the federal ADIT balance relating to PG&E's Transmission and Distribution plant and calculated IRS ADIT as of Petition Date based on a linear interpolation.

For PG&E's distribution plant systemwide, the total federal ADIT balances were $2,479 million as of year end 2020 and $2,217 million as of year end 2021. No state ADIT is added, because there was no corresponding state ADIT balance for distribution assets. Applying the allocation factors described above, PG&E determined that approximately $1,562 million (63%) and $1,419 million (64%) was IRS ADIT as of year end 2020 and 2021, respectively, with Excess ADIT constituting the remaining balances ($917 million in 2020, and $798 million in 2021). The interpolated balance of IRS ADIT as of Petition Date was $1,480 million.[40] To determine the portion of IRS ADIT attributable to the Subject Assets, PG&E allocated an amount to the Subject Assets based on the ratio of the NBV of the Subject Assets to the NBV of the entire PG&E system, which for distribution plant is approximately [redacted]%. Using this method, the final IRS ADIT attributable to the Subject Assets' distribution plant as of Petition Date is approximately $134 million ($1,480 million x 9.1%).[41]

PG&E used the same method to calculate the ADIT balance for its transmission assets. The total transmission ADIT balances, inclusive of both federal and state ADIT, were $2,094 million and $2,216 million for year end 2020 and 2021, respectively. Applying the 10% estimate described above, the state ADIT balances were $190 and $201 million

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40 PG&E Workpapers (Rate Base & CapEx), Worksheet "ADIT Allocation."

41 *Id.* at Worksheet "Rate Base."

for year end 2020 and 2021, respectively, with the remaining constituting federal ADIT ($1,903 million for 2020 and $2,014 million for 2021). From the federal ADIT amounts, PG&E then determined that $1,199 million (63%) and $1,289 million (64%) were IRS ADIT for 2020 and 2021, respectively. Adding the state and IRS ADIT balances—and interpolating those values—produce a balance of $1,447 million of transmission ADIT as of July 27, 2021. Using the same allocation methodology described above, PG&E allocated an amount to the Subject Assets based on the ratio of the NBV of the Subject Assets to the NBV of the entire PG&E system (▇% for transmission plant), producing a transmission ADIT balance of approximately $106 million.[42]

Together, PG&E made an ADIT adjustment of approximately $241 million.[43]

b. Customer Advances

When PG&E extends utility services to new customers, it may require a refundable or partially refundable advance made by the customers before PG&E constructs new infrastructure, line extensions, or specialized energy facilities.

Mr. Hegarty of PG&E has reviewed the appropriate PG&E accounting records and confirmed that, as of the Petition Date, there was no customer advances balance attributable to the Subject Assets. Therefore, PG&E did not apply this adjustment in the calculation of rate base.

c. Working Capital

Working capital consists of (i) Materials and Supplies ("M&S") inventory and (ii) working cash. M&S inventory are items such as meters, poles, wire, cables and other items that are stored on hand for future use in utility operations but are not yet placed into service as utility plant. Under standard utility ratemaking, M&S inventory is included in rate base. Because CCSF does not intend to take any additional inventory outside of the Subject Assets, and will not take any

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42 *Id.*

43 *Id.* (rounded figure).

working cash, PG&E has not made any adjustment to rate base for working capital.

d. Construction Work in Progress

CWIP is the accumulated cost of capital assets that are still under construction and have not yet been placed in service. Because they are not in service, they are not included in rate base. CCSF conceded that it did not identify or assign a value to CWIP in its testimony and instead deferred the question of whether they would take any CWIP to "at the time of acquisition and may be subject to a future determination . . . at the request of either the CITY or PG&E."[44]

PG&E has not included CWIP in rate base or the income model, but has included it as part of business severance damages.[45] The monthly CWIP balances recorded by work order include a county code designating the applicable county, including for San Francisco County. As of July 2021, the outstanding CWIP balance for San Francisco County was $169,610,896. Additionally, PG&E's CWIP records provide sufficient information to identify those that indicate a Martin Substation functional location. As of July 2021, the outstanding CWIP balance related to the Martin Substation was $5,775,589. Combined, the total outstanding CWIP balance as of July 2021 attributable to the Subject Assets was $175,386,485.

e. Summary of the Subject Assets' Rate Base

PG&E made the following adjustments in converting the Subject Assets' NBV ($2.68 billion) to rate base ($2.44 billion), as summarized in Table 6-5.

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44 CCSF Response to PG&E Data Request Set 26, No. 1.

45 PG&E Testimony, Ch. 8.1 (Rubin *et al.*), at Section C(3)(c).

TABLE 6-5
SUMMARY OF RATE BASE OF SUBJECT ASSETS (AS OF JULY 27, 2021)[46]

Line No.	($ millions)	Subject Assets	% PG&E Systemwide
Transmission			
1	Net Book Value	813	[redacted]
2	*less* IRS & State ADIT	106	
3	Customer Advances	-	
4	Working Capital	-	
5	CWIP	-	
6	**Total (Transmission)**	**707**	
Distribution			
7	Net Book Value	1,863	
8	*less* IRS ADIT	134	
9	Customer Advances	-	
10	Working Capital	-	
11	CWIP	-	
12	**Total (Distribution)**	**1,729**	
13	**Total (Subject Assets)**	**2,436**	

D. Forecast of Capital Expenditures

1. PG&E's CapEx Forecast in San Francisco (Bryon Winget)

CapEx is an input in PG&E's income-approach model.[47] CapEx maintains and grows PG&E's electric service and encompasses multiple areas of investment, including, among others, expenditures to repair or replace existing assets, to build new plant to meet load or customer needs, to modernize and upgrade existing electric system, to enhance physical and cybersecurity, to improve emergency preparedness and responses, and to remove idle assets at retirement. CapEx generally includes three broad categories of spending: (i) those associated with replacement of the existing capital assets, (ii) those associated with growth of the capital assets (categories i and ii combined are referred to as "additions"); and (iii) those associated with removal of capital assets upon their retirement from service ("cost of removal").[48] Conceptually, total annual CapEx could generally be

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46 PG&E Workpapers (Rate Base & CapEx), Worksheet "Rate Base."

47 PG&E Testimony, Ch. 5 (Williams & Gerger), at Section E(1).

48 PG&E's additions estimate include business records (*e.g.*, original drawings) but does not include maintenance records or other intangible assets that are not otherwise part of rate base.

expressed as:

Total CapEx = Replacement CapEx + Growth CapEx + Cost of Removal

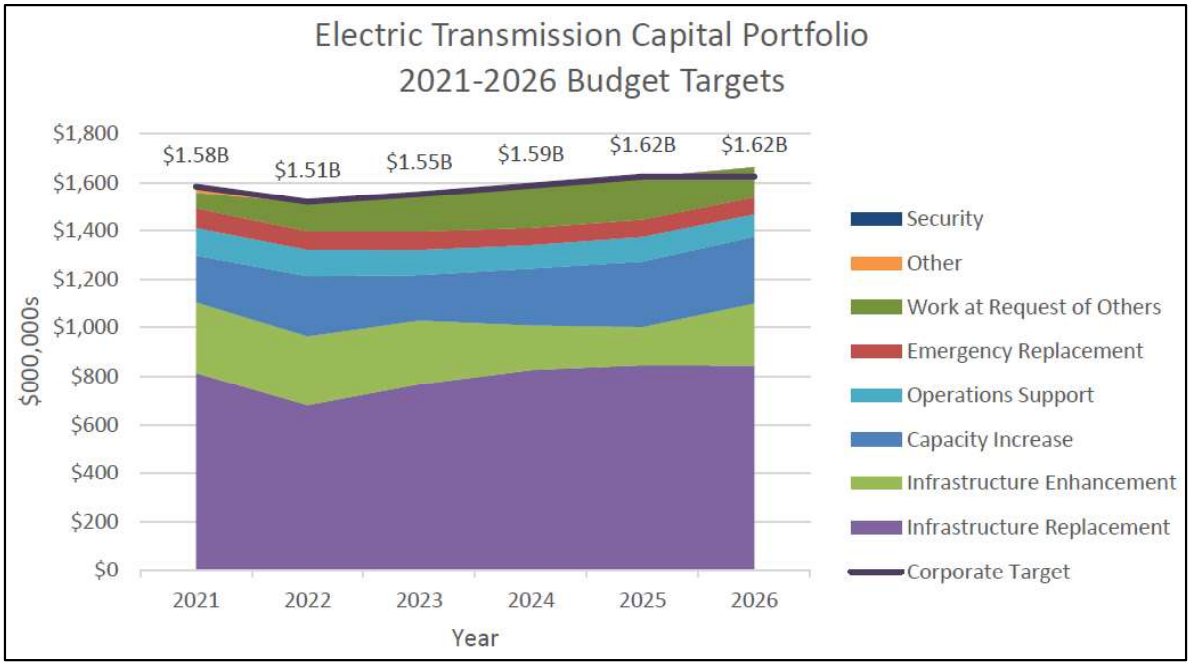
PG&E regularly prepares and provides forecasts of total CapEx across its entire electric transmission and distribution system. Although these systemwide forecasts include CapEx within San Francisco, PG&E does not maintain a forecast specific to that geographic region. To estimate the CapEx attributable to the Subject Assets, PG&E allocated its existing forecast as described below.

a. CapEx Forecast from 2021 through 2026

Transmission System. PG&E utilizes the five-year forecast of transmission CapEx submitted on June 1, 2021 in its Stakeholder Transmission Asset Review (STAR) Process, which provides the forecast capex by major category.[49] *See* Figure 6-1.

[49] PG&E did not rely on its Transmission Owner ("TO") Rate Case filing with FERC, because that filing only includes a one-year forecast of transmission CapEx.

FIGURE 6-1
PG&E CAPEX FORECAST – TRANSMISSION (2021-2026) [50]



Distribution System. PG&E utilizes the six-year forecast of distribution CapEx published in its 2023 GRC, filed on June 30, 2021.[51] *See* Figure 6-2.

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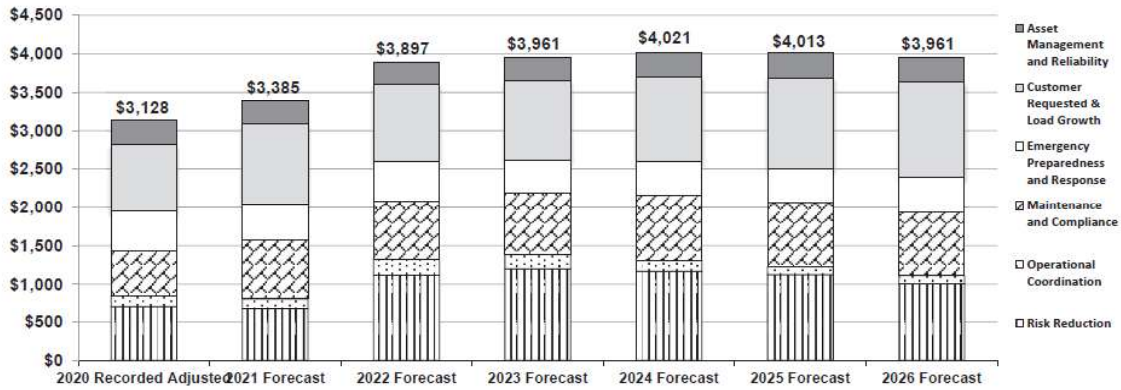
50 PG&E, June 1, 2021 Submission of Section 3.1 Material for the Stakeholder Transmission Asset Review, Figure 2.

51 PG&E 2023 GRC, Exh. PG&E-4, at WP 2-4, 2-5, and 2-10 (June 30, 2021).

FIGURE 6-2
PG&E CAPEX FORECAST – DISTRIBUTION (2021-2026)[52]

	2020 Recorded Adjusted	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Workpaper Reference
Asset Management and Reliability	$314	$301	$286	$304	$314	$321	$329	WP 2-10, Line 14
Customer Requested & Load Growth	$864	$1,048	$1,004	$1,035	$1,115	$1,187	$1,234	WP 2-10, Line 24
Emergency Preparedness and Response	$519	$459	$522	$433	$441	$448	$457	WP 2-10, Line 36
Maintenance and Compliance	$579	$769	$755	$799	$839	$832	$828	WP 2-10, Line 61
Operational Coordination	$141	$133	$213	$191	$147	$101	$106	WP 2-10, Line 90
Risk Reduction	$712	$675	$1,116	$1,199	$1,166	$1,125	$1,006	WP 2-10, Line 124
Total	**$3,128**	**$3,385**	**$3,897**	**$3,961**	**$4,021**	**$4,013**	**$3,961**	



Systemwide Forecast without Wildfire. Because San Francisco is not an area with significant wildfire risks, PG&E conservatively omits forecasted spending specifically designed to mitigate wildfires as well as those that include a mix of wildfire and non-wildfire expenditures.[53]

Allocation to Subject Assets. PG&E allocated the systemwide CapEx forecast by applying a ratio of the original cost of the Subject Assets compared to the original cost of its entire electric transmission and distribution system, broken out between transmission ([redacted] of systemwide transmission original cost) and distribution ([redacted] of systemwide distribution original cost). PG&E used the accumulated original cost because additions vary by year, and so using any particular look-back period (*e.g.*, 1, 5, or 10 years) to compare systemwide versus San Francisco additions could provide varying allocation ratios. Rather than picking any particular look-back period, which would be arbitrary, PG&E uses accumulated original cost between San Francisco and the entire system to allocate the systemwide CapEx forecast. In addition,

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52 *Id.* at WP 2-5.

53 PG&E Workpapers (Rate Base & CapEx), Worksheet "CapEx Forecast."

PG&E uses original cost here—rather than NBV—because CapEx is conceptually tied to the gross plant of the system, which is reflected in original cost. In any event, PG&E's methodology here is conservative as the percentages would be higher if PG&E were to use net book value instead of gross plant.

CapEx Forecast for the Subject Assets. PG&E then applied the percentages calculated to the systemwide CapEx forecast, as summarized in Table 6-6.

TABLE 6-6
SUMMARY OF PG&E CAPEX FORECAST (SUBJECT ASSETS)[54]
($ MILLIONS)

Line No.	CapEx Forecast	2021	2022	2023	2024	2025	2026
Transmission Percentage of Systemwide: [redacted]							
1	PG&E Systemwide Less Wildfire	[redacted]					
2	Subject Assets (Allocated)						
Distribution Percentage of Systemwide: [redacted]							
3	PG&E Systemwide Less Wildfire	[redacted]					
4	Subject Assets (Allocated)						
5	**Total (Transmission and Distribution)**						

The resulting CapEx figures are used as inputs in the income-approach model for the period of 2021 through 2026. For the subsequent periods, the net plant growth rate converges linearly until it reaches the constant growth rate in Year 30.[55] The CapEx figures include the anticipated costs of removal. Only the non-cost of removal portion of CapEx is recorded as an addition to plant in PG&E's accounting records.[56]

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54 *Id.* (table display rounded figures).

55 PG&E Testimony, Ch. 5 (Williams & Gerger) Workpapers, Income Approach Model.

56 For discussion regarding the percent of costs of removal used in the income model, see PG&E Testimony, Ch. 5 (Williams & Gerger).

2. Difference Between PG&E and CCSF Calculations of Capex (Bryon Winget & Ned Allis)

CCSF did not use PG&E's CapEx forecast in STAR, GRC or the historical capital expenditures recorded in PG&E's accounting system. Instead, NewGen made its own forecast that is less than half of either of those forecasts due to errors both in NewGen's starting CapEx calculation and in NewGen's assumption of growth as well as the exclusion of the cost of removal. The result is a significant understatement of CapEx that causes modeled net plant to decrease. For example, NewGen's model results in a compound annual growth rate ("CAGR") of -0.26% in net plant—a decline of net plant over its ten-year forecast.[57] By comparison, PG&E's CapEx Forecast shows growth of 4.93% over that same period.[58]

As explained below, CCSF's implausible result—negative growth in net plant—is due to three errors that unreasonably reduce its CapEx forecast. *First*, CCSF anchored its forecast to the CapEx necessary to replace existing plant as of the Petition Date, without including cost of removal. *Second*, CCSF failed to properly calculate even the CapEx necessary to replace existing plant. *Third*, CCSF relies on an incorrect factor for growth and then applies it incorrectly.

a. Summary of NewGen's CapEx Forecast

In its income-approach model, NewGen calculated starting CapEx of $113,010,394 for the first year of its income-approach model and then escalated that number each year by (i) a growth adjustment of 0.7%, based on net coincident peak demand for the Greater San Francisco Bay Area, which NewGen derived from the 2022 Integrated Energy Policy Report ("2022 IEPR"), and (ii) an inflation adjustment (2.4% for

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[57] Rabon Testimony, App'x II, Attachment B, Table B-2 (Net utility plant falls from $2,403,258,432 in July 2021 to $2,342,447,167 in July 2031, which has a CAGR of -0.26%).

[58] The growth rate calculated by PG&E is the CAGR for the period of July 27, 2021 to December 31, 2031, as PG&E's model uses calendar year end dates. *See* PG&E Income Model, Worksheet "DCF – 30 yr Base Case." NewGen's model, by contrast, ends on July 27, 2031, and so the growth rate based on NewGen's model is the CAGR for the period of Petition Date to that end date.

Transmission Plant, 3.6% for Distribution Plant, and 2.1% for Structures & Improvements).[59] CCSF's methodology is illustrated in Table 6-7.

TABLE 6-7
SUMMARY OF NEWGEN'S CAPEX FORECAST[60]
($ THOUSANDS)

Line No.	Categories	2021 (Starting CapEx)	Growth Rate	Growth CapEx	Inflation Rate	2022 Total CapEx (A+C)*(1+D)	2030 Total CapEx
		A	B	C	D	E	
1	Transmission	20,821	0.7%	146	2.4%	21,469	27,444
2	Distribution	89,733	0.7%	628	3.6%	93,614	131,358
3	Structures & Improvements	2,457	0.7%	17	2.1%	2,526	3,154
4	**Total (CapEx)**	**113,011**		**791**		**117,610**	**161,956**

As stated above, total annual Capex is generally equal to replacement CapEx plus growth CapEx plus cost of removal. In its income-approach model, NewGen's starting CapEx of $113,010,394 is almost entirely replacement CapEx.[61] NewGen's starting CapEx further ignores the cost of removal. This error alone results in an unreasonably low estimate of CapEx for each year of NewGen's 10-year forecast.

The following two sections explain how CCSF also miscalculates the replacement CapEx and the growth CapEx components, both of which also improperly reduce the estimate of CapEx for each year of NewGen's 10-year forecast.

b. CCSF's Calculation of Replacement CapEx Is Unreasonably Low

NewGen's starting CapEx of $113 million is composed of $2.5 million for Structures & Improvements, and $110.6 million for Transmission and Distribution.

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59 Rabon Testimony, Workpaper "Income Approach.xlsx," Worksheets "Assumptions" and "Plant."

60 Rabon Testimony, App'x II, Attachment B, Tables Assumption & B-1.

61 Although NewGen relied on historical additions to estimate the starting CapEx for Structures and Improvements (approximately $2.5 million), NewGen did not adjust the historical data for inflation. That omission alone suggests that NewGen's starting CapEx for Structures and Improvements also does not include a proper estimate of growth CapEx.

For Structures & Improvements, NewGen relied on PG&E's accounting records (PGE000082649). PGE000082649 contains eleven-year historical data (2011–2021) on PG&E spending for additions, *i.e.*, replacement CapEx and growth CapEx, in San Francisco. These records only capture a small percentage of PG&E's additions for the Martin Substation assets and as noted do not include PG&E's spending for the cost of removal in San Francisco. Relying on this historical data, NewGen calculated a starting CapEx estimate for Structures & Improvements ($2,456,953) by averaging the historical additions for ten of those years; CCSF excluded the additions from 2011 as an "outlier."[62]

For starting CapEx attributable to the bulk of the Subject Assets, assets categorized as Transmission ($20,820,450) and Distribution ($89,732,991), NewGen did not use that same historical data and instead made its own simplistic calculation of projected physical deterioration of transmission and distribution plant by looking at the change in survivorship percentages over a period of fifteen years.

Specifically, for each asset class within Transmission and Distribution, NewGen relied on a single RCN for the class as a whole, a single average service life and survivor curve based on PG&E's authorized depreciation parameters, and a single weighted average age of the assets based on inventory data. The RCN NewGen used is the same calculation from CCSF's cost approach, which insufficiently estimates the value of the Subject Assets due in large part to CCSF's undercalculation of the costs of underground assets.[63] NewGen then assumed that CapEx for a given year equals the change in survivor

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62 Rabon Testimony, Workpaper "Income Approach.xlsx," Worksheets "Assumptions" & "2011-2021 CCSF Ad Ret Compiled."

63 *See* PG&E Testimony, Ch. 3.1 (Thibodeau), at Section F(2)(d).

percentages multiplied by the starting RCN figure for that asset class.[64] NewGen performed this calculation for 15 years and used the 15 year average as the starting CapEx for each asset class.

NewGen's method is erroneous for several reasons. *First*, in NewGen's methodology, of the $113 million starting CapEx in NewGen's income model, $110.6 million (98%) was calculated as just NewGen's replacement of estimated physical depreciation, without reference to either PG&E's historical spending on additions or any other PG&E forecasts or records, and without considering cost of removal, growth, or any other inputs that drive CapEx.

Second, NewGen also underestimated the CapEx for the assets categorized as Transmission and Distribution by incorrectly applying its methodology, resulting in significantly understating annual additions. NewGen's analysis assumes that the change in survivor curve percentages represents the percentage of assets requiring replacement. That is incorrect. The difference in percent surviving from one year to the next provides the frequency of retirements, which is the percentage of the population of assets installed at *age zero* that retire in a given year. NewGen did not apply these frequency-of-retirement percentages to year zero balances, but to the current, older population.[65] But the Subject Assets are not all aged zero. Indeed, some assets have survived to ages older than the useful life, rendering the use of the change in percents surviving an inappropriate metric to estimate replacement.[66] To use Distribution Plant – Poles as an example, NewGen calculates annual additions for the first year of approximately

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64 For example, for "Distribution Station Equipment," NewGen used a single RCN figure ($[redacted]), a survivor curve all assets within this asset class (46-R1.5), a single average age for these same assets ([redacted] years), then used the percent surviving for the average age for this survivor curve as of 2021 ([redacted]%) and the change in that percentage to the following year based on its survivor-curve assumptions (*e.g.*, [redacted]% (rounded figure) from 2021 to 2022), and multiplied that figure by the RCN number [redacted].

65 For example, "Distribution Station Equipment," NewGen applied these to a balance that has an average age of [redacted] years.

66 The analysis that NewGen intended to perform would require the calculation of a *retirement ratio, i.e.*, the change in percentage surviving into a conditional retirement rate for assets that have already survived to the current age.

$[redacted] for 2021 ([redacted]). The corrected calculation would instead be approximately $[redacted] [redacted]). Thus, for this account alone, NewGen's method underestimates replacement costs in the first year by nearly $[redacted] and produced an estimate less than a quarter of the correctly calculated amount.

The overall inadequacy of NewGen's method becomes even clearer when applied to the overall plant being replaced. Based on NewGen's calculation, $110.6 million of transmission and distribution assets will be replaced each year. At that level of CapEx, given CCSF's assumption of the RCN for those assets of $9.4 billion,[67] it will take 85 years ($9.4 billion / $110.6 million) to replace the transmission and distribution plant. *Eighty-five* years is an unreasonably long average service life. CCSF's approach is not reasonable to forecast capital expenditures and does not keep pace with depreciation and retirements of the assets.

The unreasonably low starting CapEx projected by NewGen is also apparent when compared to PG&E's actual historical additions for the portion of the Subject Assets in San Francisco.[68] Had NewGen relied on PG&E's accounting records showing historical additions for transmission and distribution (as it did for Structures & Improvements), its CapEx estimates (adjusted for inflation using NewGen's own assumptions) would double and move closer to PG&E's estimates.

As shown in Figure 6-3 below, CCSF's estimates are well below even the nominal (*i.e.*, not inflation-adjusted) CapEx for every year from 2011 through 2021.[69]

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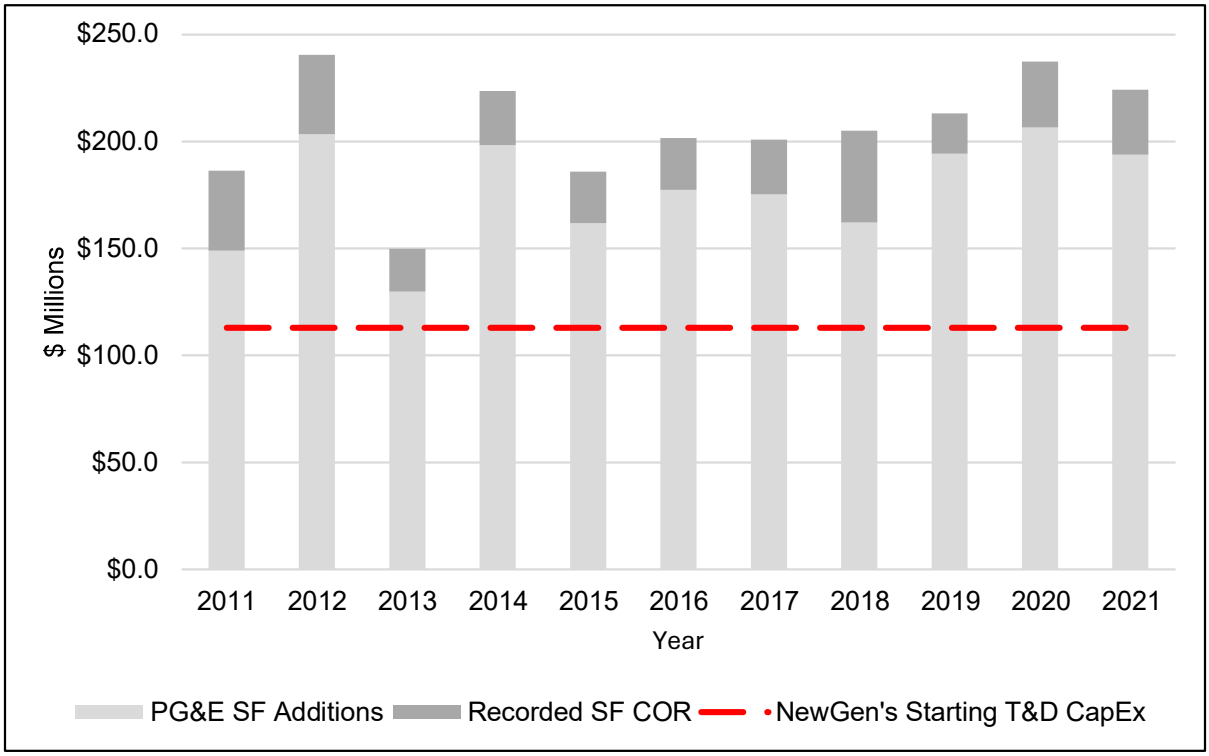
67 Rabon Testimony, Workpaper "Income Approach.xlsx," Worksheet "Cap Ex" (sum of cells B9 through P9).

68 The amounts shown in Figure 6-3 for "PG&E SF Additions" and "Recorded SF COR" do not include the Martin Assets not associated with the county of San Francisco in PG&E's historical accounting data.

69 Figure 6-3 normalizes PG&E's 2016 additions to account for an unusually large transmission plant addition recorded that year. For assets categorized as Distribution, Transmission, and Structures & Improvements by NewGen, 2016 additions were approximately $469.1 million; for purposes of the figure, the 2016 amount was replaced with the average annual additions for the other years shown.

FIGURE 6-3
COMPARISON OF NEWGEN'S CALCULATED ADDITIONS (DISTRIBUTION, TRANSMISSION, AND STRUCTURES & IMPROVEMENTS) AND PG&E HISTORICAL DATA (ADDITIONS & COST OF REMOVAL)[70]



Between 2011 and 2021, PG&E's historical additions (adjusted for inflation) of assets categorized by NewGen as Distribution, Transmission and Structures & Improvements is an annual average of $240 million ($243 million if 2011 is excluded).[71] These annual figures are lower than the total CapEx because the recorded additions, as discussed above, do not include cost of removal for any assets and do not capture all Martin-related additions. Nevertheless, they are much more in line with the additions for 2021 in PG&E's CapEx Forecast of

[70] GFT Workpapers (NBV), Worksheet "Figure 6-3."

[71] *Id.* at Worksheet "NewGen Additions."

$[redacted].[72] Thus, unlike CCSF's calculations, PG&E's forecast is reasonable when compared to its actual historical activity.

In short, NewGen uses an unreliable method to calculate a starting CapEx that significantly understates CapEx needed just to replace existing plant.

c. CCSF's Growth Assumption Is Incorrect and Misapplied

In addition to having a depressed starting CapEx, NewGen applies an inappropriate annual growth rate of 0.7% (0.007). NewGen used the CAGR of coincident peak demand for the period of 2022 through 2035 in the San Francisco Greater Bay Area set forth in the 2022 IEPR. As CCSF explained, coincident peak demand represents a forecast of "plant additions increase with estimated increases in capital costs . . . for load growth."[73] CCSF is wrong for multiple reasons.

First, fundamentally, NewGen incorrectly assumes that growth in demand alone drives CapEx. Many other factors drive CapEx, including investments in modernization upgrades (such as automation), emergency preparedness and responses, physical and cybersecurity, and other reliability improvements, among others.

Second, NewGen also applies the wrong metric by looking at *coincident* peak demand for the entire San Francisco Bay Area. The Subject Assets in San Francisco constitute only a small portion of the larger Bay Area, which includes hot inland areas with different electricity use patterns than coastal customers. Coincident peak demand measures load across that entire area at the time of the systemwide peak, which does not necessarily reflect the growth in the local demand that San Francisco's distribution facilities must accommodate, because San Francisco's local demands that drive the need to increase capacity may occur at different times and grow at different rates. If using

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72 The number $[redacted] million is calculated by taking the 2021 CapEx Forecast allocated to the Subject Assets for Distribution ($[redacted]) and Transmission ($[redacted]) and multiplying each by their respective percentage allocated to additions ([redacted]% and [redacted]%, respectively), which are provided in PG&E Testimony, Ch. 5 (Williams & Gerger) Workpapers, Income Approach Model.

73 CCSF Responses to Data Request Set 17, No. 15.

demand growth as a proxy for the incremental CapEx for local distribution assets, as presumed in NewGen's analysis, then growth in local *noncoincident* demand is generally more directly related to the capacity those assets must provide than growth in a broad region-wide coincident peak, which in the case of the Bay Area is much more impacted by hot summer temperatures—very uncharacteristic of the demand drivers in San Francisco.

NewGen itself recognizes this distinction. In its feasibility study prepared for the City of San Diego, NewGen acknowledges that "the *non-coincident* peak [demand] is the *maximum* expected load that would be experienced at the feeder and transformer level and is the load used to determine the reinforcements that would be needed."[74] Thus, NewGen concluded that non-coincident peak demand, not coincident peak demand, is the appropriate factor that "drives the investments at the substation and the feeders."[75] PG&E has previously published a forecast of non-coincident peak demand in its 2023 Grid Needs Assessment proceeding. For the period of 2023 through 2027, PG&E forecasted that the annual demand growth in San Francisco is 2.7%—a number nearly four times NewGen's 0.7% assumption.[76]

Third, NewGen applies the growth factor only to the prior year's additions. As discussed above, NewGen's additions for the first year of its forecast omits growth CapEx for assets categorized as Transmission or Distribution. Because NewGen largely limited its CapEx forecast to replacement CapEx, the annual growth rate implied by NewGen's method is actually significantly below the assumed growth rate.

Table 6-8 demonstrates the problem. In year 2 of its forecast, NewGen calculated approximately $800,000 of growth CapEx (before adjusting for inflation). When compared to NewGen's estimate of RCN of the Subject Assets, $800,000 is inconsequential, representing less

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74 NewGen Strategies & Solutions, Public Power Feasibility Study Phase II for the City of San Diego, at 8-1 (Apr. 3, 2026) (emphasis added).

75 *Id.* at 8-3.

76 PG&E Workpapers (Rate Base & CapEx), Worksheet "GNA - Feeder Growth."

than 0.0085% (0.000085).[77] Mathematically, NewGen's methodology does not result in NewGen's RCN as of the Petition Date growing in real terms at 0.7% per year, which is what a CAGR of 0.7% would produce.[78]

In short, NewGen understates the CapEx needed to maintain and grow the Subject Assets by starting with an inadequate CapEx estimate and by applying its growth factor only to the prior year's Additions. These errors understate growth CapEx and Additions, causing net plant to decline over NewGen's 10-year forecast period.

E. Conclusion

This chapter of testimony supports several inputs in PG&E's income-approach model, including (i) the Subject Assets' NBV is $2.68 billion and has a calculated rate base of $2.44 billion, and (ii) an estimate of CapEx for the period of 2021 through 2026.

This chapter further critiques CCSF's calculations of rate base and CapEx Forecast. On rate base, CCSF ignored actual PG&E accounting records from PowerPlan and instead overestimated the accumulated depreciations applicable to the Subject Assets inside San Francisco. This error resulted in an undervaluation of the Subject Assets by approximately $391 million. On CapEx Forecast, CCSF calculated an unreasonably low starting CapEx and applied an unreasonable growth rate to that figure, leading CCSF to the erroneous conclusion that the Subject Assets' net plant will shrink.

Accordingly, the CPUC should reject CCSF's flawed numbers and adopt PG&E's numbers in evaluating the value of the Subject Assets.

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77 This number is less than 0.0085% if using the RCN NewGen uses in its CapEx estimate for assets categorized as Transmission and Distribution ($0.8 million / $9,414.7 million). *See* Rabon Testimony, Workpaper "Income Approach.xlsx," Worksheet "Cap Ex." This number declines further if using NewGen's RCN estimate for all Subject Assets ($10,216.6 million). *See* Rabon Testimony, Workpaper "Cost Approach.xlsx," Worksheet "RCNLD."

78 Due to the compounding effect imbedded in NewGen's calculation of growth CapEx and the potential inclusion of a small amount of growth CapEx in assets categorized as Structures and Improvements, the real growth rate over NewGen's implied replacement life—approximately 85 years in average service life—is above the NewGen's assumed growth rate of 0.7%.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

HYPOTHETICAL BUYERS

WITNESS: DAVID RUBIN

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
HYPOTHETICAL BUYERS
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
HYPOTHETICAL BUYERS

A. Introduction

My name is David Rubin. I am an outside consultant for Pacific Gas and Electric Company ("PG&E") and a retired employee of PG&E, where I was, among other positions, the Director of PG&E's Service Analysis Department (1995 to 2018) and Director of Strategy Formulation (2018 to 2020). In this chapter of testimony, I discuss hypothetical buyers for PG&E's electric assets within and serving San Francisco ("Subject Assets").

The California Public Utilities Commission's (CPUC or Commission) Interim Decision in this proceeding confirmed the "foundational principle" that, in determining the just compensation owed to PG&E, the value of the assets taken must be "the highest price estimated in terms of money which the land would bring if exposed for sale in the open market, with reasonable time allowed in which to find *a purchaser, buying with knowledge of all of the uses and purposes to which it was adapted and for which it was capable.*"[1] Such purchasers are often called *"hypothetical buyers."*

Because an assessment of fair market value requires consideration of every legally possible buyer, hypothetical buyers for electric utility property can include not just private entities, such as investor-owned utilities, but also public entities, such as local governments. Within the last decade alone, multiple local public entities in Northern California have offered to purchase portions of PG&E's electric utility property. In a December 13, 2019 letter to the CPUC Commissioners, for example, four such entities—the City and County of San Francisco ("CCSF"), the Nevada Irrigation District ("NID"), the South San Joaquin Irrigation District ("SSJID"), and Valley Clean Energy—conveyed their interest in acquiring and operating portions of PG&E's grid.[2] Their letter noted

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[1] Decision Establishing Methods and Standards for Just Compensation and Valuation, D.25-10-039 at 25 (Oct. 30, 2025) ("Interim Decision") (emphasis altered) (quoting *Sacramento S.R. Co. v. Heilbron*, 156 Cal. 408, 409 (1909)).

[2] *See* Dec. 13, 2019 Letter from CCSF et al. to CPUC ("Dec. 13, 2019 Letter"), available at page 7 of https://www.peninsulacleanenergy.com/wp-content/uploads/2019/12/2019-12-19-PCE-BOD-Supplemental-Agenda-Packet-corrected-1.pdf#page=7.

that "[p]ublicly owned utility service has a long history in California," expressed an interest in "working collaboratively with the Commission, PG&E, and other parties" on the proposed acquisitions, and attached each entity's purchase offers for portions of PG&E's electric grid.[3] In fact, the same letter went on to describe the existence of "specific proposals" to replace PG&E with "a larger publicly owned utility serving all of PG&E's service area ... Converting PG&E into a large public entity would have all the benefits discussed above."[4]

Recognizing the reality that public entities are significant players in the market for electric utility properties, the Interim Decision instructed the parties to consider "sales to both public and private entities" in the market approach as part of the "minimum information that should be included" in their testimony.[5] The Commission also implicitly recognized the parties' ability to consider hypothetical purchasers in other parts of their testimony.[6]

In this testimony chapter, I provide an overview of the many different categories of public electric utilities in California and explain that several categories of public entities should be considered hypothetical buyers of the Subject Assets. In addition to a municipality like CCSF, other public entities—such as municipal utility districts (MUD), irrigation districts, electric cooperatives, and the State of California—have the right to acquire and operate the Subject Assets. In other words, the hypothetical market for the Subject Assets includes multiple public entity purchasers. Any appraisal of the fair market value of the Subject Assets must recognize this core element of the relevant market.

I also explain that, within the Northern and Central California market, public entities are both more numerous than and more active buyers of electric utility properties than private entities. Over the last four decades, I am aware of more than ten instances in which a public entity acquired electric assets and/or initiated/expanded operation as an electric utility. I am also aware of more than a half-dozen additional instances in which public entities have attempted to

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3 *Id.* at 3–4.

4 *Id.* at 4. The letter also described the existence of "specific proposals" for a customer-owned utility.

5 Interim Decision at 33, 35.

6 *See* Interim Decision at 33 ("Nothing in the foregoing or ensuing limits what parties may provide in addition as they see fit to argue their valuation claims.").

begin providing or to expand their electric services. By contrast, I am aware of very few situations in which private entities have acquired electric utility property in Northern and Central California. Accordingly, I conclude that public entities are more active market participants than private entities, which further supports my conclusion that multiple public entities would exist in the hypothetical market for the Subject Assets.

Finally, at the end of this testimony chapter, I discuss CCSF's testimony concerning private and public hypothetical buyers in the hypothetical marketplace for the Subject Assets and explain why its conclusions are either inapposite, incorrect, or both.

B. Background: Electric Utilities in California

Broadly speaking, two different categories of entities provide electric delivery (transmission and distribution) service to end-use consumers in California. The first category, investor-owned utilities ("IOU"), is comprised of private entities such as PG&E. Currently, there are six IOUs operating in California: PG&E, Southern California Edison Company (SCE), San Diego Gas & Electric Company, Bear Valley Electric Service, Liberty Utilities, and PacifiCorp. Each serves a distinct and non-overlapping geographic service territory.

While IOUs are privately owned, their business and financial decisions are generally subject to oversight and approval by the Federal Energy Regulatory Commission ("FERC"), the CPUC, and other regulatory bodies. Within this broad regulatory construct, IOUs are legally obligated to provide universal service at regulated rates within defined service territories. In order to begin providing service to a new area, IOUs need to seek and receive CPUC approval through a Certificate of Public Convenience and Necessity ("CPCN") and obtain a franchise agreement with the local jurisdiction to place electric facilities within the public rights of way, amongst other things.

The second category, publicly-owned utilities ("POU"), is comprised of public entities—such as CCSF, local and regional governments, and other publicly-owned entities—that provide electric service. There are over 40 POUs currently providing electric delivery services in California (see list in Table 1, below), representing approximately 30% of total energy consumption in the State. The majority of these operate in Northern and Central California.

TABLE 7-1
PUBLICLY-OWNED UTILITIES IN CALIFORNIA

Line No.	Northern and Central California	Southern California
1	Alameda Municipal Power	Anaheim, City of
2	Biggs Municipal Utilities	Anza Electric Cooperative, Inc.
3	Calaveras Public Power Agency	Azusa Light and Water
4	Gridley Electric Utility	Banning, City of
5	Healdsburg, City of	Burbank Water and Power
6	Kirkwood Meadows Public Utility District	Cerritos, City of
7	Lassen Municipal Utility District	Colton Public Utilities
8	Lathrop Irrigation District	Corona, City of
9	Lodi Electric Utility	Eastside Power Authority
10	Lompoc, City of	Glendale Water and Power
11	Merced Irrigation District	Imperial Irrigation District
12	Modesto Irrigation District	Industry, City of
13	Palo Alto, City of	Los Angeles Department of Water and Power
14	Pittsburg, City of (dba Island Energy on Mare Island)	Metropolitan Water District of Southern California
15	Plumas-Sierra Rural Electric Cooperative	Moreno Valley Electric Utility
16	Power and Water Resource Pooling Authority	Needles, City of
17	Port of Oakland	Pasadena Water and Power
18	Port of Stockton	Rancho Cucamonga Municipal Utility
19	Power Enterprise of the San Francisco PUC	Riverside, City of
20	Redding Electric Utility	Vernon, City of
21	Roseville Electric	Victorville Municipal Utility Services
22	Sacramento Municipal Utility District	California Department of Water Resources
23	Shasta Lake, City of	
24	Silicon Valley Power	
25	Surprise Valley Electric Cooperative	
26	Truckee Donner Public Utility District	
27	Turlock Irrigation District	
28	Tuolumne County Public Power Agency	
29	Ukiah, City of	
30	USBR WAPA Central Valley Project	
31	California Department of Water Resources	

Most POUs in California fit within one of the following categories:

Municipal Utilities are utilities that exist as part of a city government (*i.e.*, a municipality). Examples include the utilities serving the cities of Palo Alto, Santa Clara, and Alameda, which all provide retail electric delivery service within their borders. Another example is Pittsburg Power Company, which provides retail electric delivery service on Mare Island in Vallejo.

Irrigation Districts ("ID") were originally formed to obtain and distribute irrigation water within their boundaries. However, IDs also have a latent right to deliver electricity. There are currently close to 100 IDs in California, five of which are currently providing retail electric delivery services to end-use electric customers—Modesto, Turlock, Merced, and Lathrop in Northern and Central

California and Imperial in Southern California. However, any one of the other IDs may choose to pursue their latent rights to provide electric delivery service.

Municipal Utility Districts ("MUD") are special districts that can form to cover either one municipality and unincorporated territory, or two or more municipalities (with or without unincorporated territory). MUDs have the legal authority to deliver electricity to end-use customers. There are currently two MUDs (Sacramento and Lassen MUDs) providing electric delivery service in Northern and Central California. Other MUDs geographically proximate to San Francisco (*e.g.,* the East Bay MUD) currently provide other utility services but have the right to seek to provide electric service as well.

Public Utility Districts ("PUD") are special districts that are very similar to MUDs, except that they serve wholly unincorporated territory. There are three PUDs (the Kirkwood, Trinity, and Truckee/Donner PUDs) providing electric distribution service in Northern and Central California.

Ports that are part of charter cities in California can also have authority to provide electric delivery services. For example, in Northern California the Port of Oakland provides electric delivery service.

Joint Powers Authorities ("JPAs") are entities created by two or more other public entities to exercise common powers, potentially including (depending on the JPA) the power to furnish electric service.

Electric Cooperatives ("Co-ops") are non-profit electric utilities owned by the customers served. Electric distribution cooperatives deliver electricity to member customers, while generation and transmission cooperatives provide power to distribution cooperatives through their own generation plants and/or power purchases and transmission facilities. Although co-ops differ from other POUs in that they are not government entities, they share many relevant features with such entities—including exemption from CPUC rate regulation—and I therefore consider them to be a category of POU. A November 4, 2019, letter to the CPUC from 22 mayors throughout California promoted this type of ownership across PG&E's service territory.[7] There are currently three electric

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[7] Nov. 4, 2019 Letter from Mayor Sam Liccardo et al. to CPUC, available at https://www.documentcloud.org/documents/6540522-Mayor-Letter-to-PG-E/.

delivery cooperatives in California: Anza, Plumas-Sierra, and Surprise Valley, the latter two of which are in Northern California.

State Entities can also operate electric utilities. The State of California does not currently provide electric service but has authority to acquire and operate PG&E's electric delivery assets. Specifically, in 2020, the Golden State Energy Act (Senate Bill 350 (2020)), established Golden State Energy as an entity and granted the State the power to exercise such authority. Although the aforementioned December 2019 letter from CCSF, SSJID, NID and Valley Clean Energy did not specify which entity would assume the role, it did recognize the prospect and existence of specific proposals for "a larger publicly owned utility serving all of PG&E's service area."

Federal Entities, including Tribal Communities and the Federal Government (through various departments such as the National Park Service and Western Area Power Authority) currently provide electric delivery service in California. They typically provide service to their own facilities and/or, in the case of WAPA, to specialized electric accounts such as water supply agencies. One example of a federal electric provider is the Presidio Trust, which is part of the National Park Service, and which owns and operates the electric distribution system that serves the Presidio in San Francisco. The Presidio Trust inherited the electric system from the Army, which owned and operated this system while the Presidio operated as an active army base.

C. Multiple Publicly Owned Utilities Could Be Hypothetical Buyers of the Subject Assets

Considering the rights and legal authority of the above categories of POUs to provide electric service, I conclude that at least five categories of public entities could be hypothetical buyers of the Subject Assets: municipalities, municipal utility districts, irrigation districts, electric co-ops, and the State of California.[8]

I am instructed by counsel that, as a legal matter, PG&E is not required to identify *specific, existing government entities* that could be hypothetical buyers,

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[8] This is not, nor is it intended to be, a comprehensive list of all categories of entities that could be permissible public entity buyers. These are simply the major categories of such buyers that I would expect, based on my experience, to be present in such a market.

nor is PG&E required to demonstrate that any particular buyer or category of buyer is *likely*. The question, for purposes of this proceeding, is whether a hypothetical market for the Subject Assets would include POU buyers that could permissibly acquire and operate the Subject Assets. I answer that question in the affirmative with respect to each category of POU described below.

Municipalities. Municipalities generally have the right to own and operate electric utilities within their borders and provide electric service to their residents. This is precisely why CCSF initiated this proceeding: It seeks to value and, ultimately, acquire the Subject Assets so that it can become the electric utility within its borders.[9]

The Subject Assets, for the most part, serve electric customers in San Francisco, rendering CCSF perhaps the most plausible municipality in the hypothetical market for those Assets as a whole.[10] However, municipalities are not limited to serving the geographic area that aligns with their political boundaries. For example, the City of Pittsburg, dba Island Energy, provides electric delivery service on Mare Island, which is located in Vallejo, approximately 30 miles from Pittsburg.

Municipal Utility Districts. A MUD could also be a hypothetical purchaser of the Subject Assets. In fact, in the early 2000s, there was an effort to create an entity called the San Francisco-Brisbane MUD, that proposed to acquire and operate PG&E's electric assets in, and provide electric service to, San Francisco and the adjacent area.

In 2000, proponents of municipal electric distribution service in San Francisco began gathering signatures to place a measure on the ballot to create a MUD that would take over the distribution of electric power in San Francisco. Upon discovering that a MUD needs to cover more than a single jurisdiction, the initiative was amended to include the adjacent City of Brisbane. The measure received the requisite number of signatures and was placed on the ballots in San Francisco and Brisbane for November 2001.

The measure did not pass in that election, so the San Francisco-Brisbane MUD was not created at that time—but the attempt itself indicates that it is

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9 Prepared Direct Testimony of Dennis Herrera at 1–2 (Apr. 20, 2026).

10 As noted above, however, I am instructed that plausibility is not the applicable legal standard and I do not, by my use of the term, suggest otherwise.

possible, and indeed plausible, for a MUD to form to acquire and operate the Subject Assets. The 2001 election loss does not preclude a renewed effort to create a San Francisco-Brisbane MUD or a different MUD encompassing San Francisco. If voters so desired, they could begin the process to initiate the creation of a new MUD to provide electric service in the greater San Francisco area at any time.

Irrigation Districts. As noted above, irrigation districts have the inherent power to provide electric delivery service. What's more, irrigation districts also have the explicit power to operate electric assets outside of their own geographic boundaries. In other words, a hypothetical irrigation district buyer could acquire the Subject Assets and use them to serve San Francisco customers even if the irrigation district did not itself contain San Francisco within its irrigation boundaries.

As such, any number of irrigation districts in Northern or Central California could permissibly expand their electric service territory to encompass San Francisco (potentially alongside other territory). One example of an irrigation district providing electric delivery service outside of its irrigation boundaries is Modesto Irrigation District (MID). As described below, MID expanded beyond its traditional service territory starting in 1995 – extending service to selected customers within Ripon, Escalon, Riverbank and Oakdale. In the late 1990's, MID was selected by the San Joaquin County Board of Supervisors to provide electric delivery service in the community of Mountain House. Mountain House is located approximately 38 miles from Modesto.

Electric Co-ops. An electric co-op could form in or around San Francisco and permissibly provide electric service to its residents. In fact, as CCSF and three other public entities explicitly acknowledged in their December 2019 letter, a proposal to "replac[e] PG&E" with an "electric cooperative" was "raised publicly" at around the time of PG&E's bankruptcy proceeding, including a coalition of 22 then-mayors of cities within PG&E's service territory.[11]

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[11] Dec. 13, 2019 Letter at 4; *see also* KQED, "22 Mayors Want PG&E to Become a Customer-Owned Co-Op" (Nov. 5, 2019), available at https://www.kqed.org/news/11784972/22-mayors-want-pge-to-become-a-customer-owned-co-op).

<u>The State of California</u>. Finally, the State of California could permissibly acquire and operate the Subject Assets. As with electric co-ops, there were proposals during PG&E's bankruptcy proceeding for the State to take over PG&E's electric grid and operate a public electric utility covering not only the Subject Assets, but the entirety of PG&E's grid. The December 2019 letter from CCSF and three other public entities explicitly acknowledges the possibility of "a larger publicly owned utility serving all of PG&E's service area."[12] In 2020, the state legislature passed a law that provides for the State of California to take over PG&E's grid under specified circumstances. And as noted above, the state government of California has the authority to pass additional laws allowing it to acquire some or all of PG&E's assets under other circumstances as well.

D. Publicly-Owned Utilities Are More Active Buyers/Developers of Electric Assets in Northern California than Private Buyers.

My conclusion that the universe of hypothetical buyers includes multiple public entities finds additional support in the actual market for electric utility property in California generally and in Northern and Central California specifically. Although both IOUs and POUs exist and provide electric delivery service in California, there are a significantly greater number of POUs than IOUs operating in the state (40+ compared to six). Additionally, POUs have experienced greater expansions in their numbers and service footprints than IOUs over the last several decades. In other words, POUs are more active participants in the applicable electric utility market, as further described below.

1. Several POUs Have Acquired/Developed Electric Utility Property in Northern and Central California.

POUs are not only *hypothetical* buyers of electric utilities—they are the most common actual purchasers/developers of such property in Northern and Central California. POUs are responsible for virtually all of the creation and/or expansion of third-party electric distribution infrastructure within Northern and

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[12] Dec. 13, 2019 Letter at 4.

Central California over the past four decades.[13] Below are several examples of POU creation and/or expansion.

Modesto Irrigation District (MID): MID is an irrigation district located within the San Joaquin Valley, headquartered in Stanislaus County, California. MID has provided electric distribution within its irrigation territory since the 1920s.

Beginning in 1995, MID began extending its electric distribution facilities north of its geographic irrigation service area. It displaced PG&E as the electric service provider for a number of large customers that PG&E had previously served (for example, a large industrial company) and extended its service to mixed-use developments in Ripon, Escalon, Riverbank and Oakdale in southern San Joaquin County. Additionally, MID attempted to provide service to a large industrial customer located in Pittsburg, CA – approximately 65 miles from Modesto. At the time, MID's service extension and conversion of existing and/or future PG&E customers to MID electric service generated a dispute that carried into the development of the 1996 electric market restructuring law (AB 1890) and eventually to the enactment of AB 2638 (2000) to address many of the outstanding disagreements between PG&E and several Central Valley irrigation districts.

As part of AB 2638, MID became the exclusive electric delivery service provider to existing and new customers in the newly developing community of Mountain House, located approximately 38 miles from Modesto. PG&E was no longer allowed to serve electric customers in that area, but at the same time MID did not have the immediate ability to fulfill its service obligation, as it did not own any electric assets in the vicinity. In 2001, PG&E and MID negotiated an agreement whereby PG&E sold and leased a number of electric distribution assets to enable MID to abide by the legislative directive and become the exclusive service provider in Mountain House (D.04-03-036).

Today, MID serves approximately 135,000 electric customers, representing approximately 750 MWs of electric load. This includes approximately 7,000 customers that were former or prospective PG&E customers.

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[13] Communities within the SCE service territory have also experienced the creation of POUs during this same time-frame. My testimony focuses on those within or immediately adjacent to PG&E's footprint.

Turlock Irrigation District (TID): TID is an irrigation district in Stanislaus and Merced Counties. It was founded in 1887 as the first irrigation district in California.

TID was actively marketing its electric service to the cities of Patterson, Newman, Gustine, and Los Banos in the 1997-1999 timeframe. In conjunction with AB 2638, PG&E and TID agreed to a sale of PG&E's electric distribution facilities serving the City of Patterson. This was combined with the inclusion of Patterson within TID's service area, elimination of PG&E's obligation to serve within that area, and a 25-year two-way service area agreement between PG&E and TID. The agreement was submitted to the CPUC in 2002 and approved in 2003 (see D.03-04-032). Part of the agreement included annual payment by TID to PG&E to reflect the non-bypassable charges ("NBCs") owed by existing and expected new electric customers within the Patterson area.

TID currently serves approximately 95,000 electric customers, representing 600 MWs of load.[14]

Merced Irrigation District (MerID): MerID is an irrigation district serving several communities within and around Merced, California. It began generating hydroelectric power in the 1920s but did not serve as an electric delivery service provider until the 1990s.

In 1996, MerID began working with Turlock Irrigation District ("TID," described above), which had an exclusive service area to the north of Merced, to begin providing electric delivery service. MerID and TID constructed a transmission tap and dedicated substation at the site of a large former PG&E agricultural customer. MerID then constructed a 115 kV distribution loop that extended southwards through the communities of Livingston, Atwater and Merced – all within PG&E's service area – to provide electric service to existing and new customers. MerID also acquired the electric facilities on the former Castle Air Force Base as it went through base closure and retrocession.

MerID currently serves approximately 13,300 electric customers that were former or prospective PG&E customers, representing 125 MWs of load.[15]

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[14] Turlock Irrigation District, 2024 Annual Report, available at https://www.tid.org/wp-content/uploads/2025/08/TID-Annual-Report-2024.pdf/.

[15] Merced Irrigation District, "About Merced Irrigation District," available at https://mercedid.org/about-merced-irrigation-district/.

Lathrop Irrigation District ("LID"): LID is an irrigation district in Lathrop in San Joaquin County. It formed in 2002 and received approval from the San Joaquin County Local Agency Formation Commission ("LAFCO") to provide electric delivery services. In fact, one of its primary purposes in forming was to provide electric delivery services.

Originally, LID's irrigation service area was a relatively small portion of the City of Lathrop. In 2005, LID approached LAFCO for approval to annex and provide electric delivery service in a large adjacent area that was to be redeveloped into a new community (which later became "River Islands"). LAFCO granted its approval in 2006, and LID began providing retail electric service in 2013. LID currently provides electric delivery service to approximately 4,000 residential accounts in River Islands, representing approximately 10 MWs, and is eventually projected to grow to over 11,000 customers.

Kirkwood Meadows Public Utility District ("KMPUD"): KMPUD is a public utility district in the Sierra Nevada mountains within Alpine, Amador, and El Dorado Counties. It was formed in 1985, initially to provide water and other services. In 2011, KMPUD acquired the electric facilities from Mountain Utilities, a then-existing IOU. The sale was approved by the CPUC in D.11-06-032. In addition to the electric distribution facilities, the sale also included generation and propane.

Pittsburg Power Company: Pittsburg Power Company ("PPC") is a municipal joint powers agency operating as an electric and natural gas municipal utility in Contra Costa County, California. The City of Pittsburg and its redevelopment agency formed the PPC in 1997. Shortly thereafter, PPC acquired the electric delivery facilities on Mare Island, a former military base within the City of Vallejo (approximately 33 miles from Pittsburg), and began providing electric delivery service under the name "Island Energy."[16] It currently provides electric delivery to over 1,200 single family homes plus several commercial and industrial businesses on Mare Island. PPC does not provide electric delivery service within the City of Pittsburg.

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[16] Pittsburg Power Company, "Island Energy," available at https://pp.islandenergy.com/island-energy/.

Hercules Municipal Utility ("HMU"): HMU was a municipal utility within the City of Hercules. It was formed in 2001 to provide electric service in new growth areas within the city. It acquired electric delivery facilities from developers installing such facilities to serve new residential and commercial buildings. At its peak, HMU served approximately 800 residential and commercial customers within Hercules. However, as further described in Section D.3 below, PG&E acquired HMU's assets in 2011 after the city put them up for sale.

Port of Oakland: The Port began providing electric delivery service in 1927. Its legacy customers include the Oakland Airport and a number of maritime tenants located on its port facilities. It currently serves an expanding base of customers and redevelopment areas within the Oakland Seaport, including the Outer Harbor and other maritime and logistics facilities.

City of Redding: Following the annexation of land adjacent to the City's historic boundaries in 2000, a number of customers embedded within the expanded City boundaries continued to receive PG&E electric service. Redding made a formal offer to acquire the assets serving these customers in 2006; PG&E countered at a price that was unacceptable to the City. Redding subsequently moved forward with an eminent domain action in Superior Court in December 2006. The parties eventually settled in 2008.

Lassen Municipal Utility District: The Lassen Municipal Utility District ("LMUD") was first formed in 1931 to provide electric service in Susanville.[17] It attempted to take over the electric facilities of the then-existing provider, but this effort failed. The Board then decided to build power generation and transmission facilities but was unable to convince voters to pass the bond measure. In 1937, LMUD dissolved. Nearly a half-century later in 1986, voters created the current Lassen Municipal Utility District. In 1988, LMUD acquired the local electric facilities from CP National Corporation, a privately-owned utility company.

Trinity County PUD and Hayfork Valley PUD: In 1982, Trinity County PUD formed to acquire the electric distribution assets of CP National Corporation, a

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[17] Exploring Lassen County's Past, "LMUD To Lower Rates," available at https://tipurdy.org/lmud-to-lower-rates/.

privately-owned utility within Trinity County. PG&E served the remainder of the County. In 1984, the Hayfork Valley PUD took steps to condemn some of PG&E's electric delivery assets serving the more attractive load in Hayfork, leaving PG&E to serve the remaining higher-cost customer base. Trial was held in 1987, and while PG&E's subsequent appeal was pending, Hayfork Valley PUD moved ahead and started to serve the customers. Costs turned out to be higher than expected for Hayfork Valley PUD and for PG&E's service to the remainder of the customers within the County. Ultimately, Trinity County PUD stepped in and offered to support Hayfork Valley PUD and also to acquire PG&E's remaining electric delivery facilities within the County. The sale was conducted as a friendly condemnation and approved by the CPUC in D.95-04-061.

2. Additional POUs Have Attempted to Enter the Market for Electric Utility Property.

In addition to the successful efforts by POUs to establish or expand electric service within PG&E's footprint, there have been a number of additional attempts by POUs to acquire electric utility property and establish or expand their electric service. Some of these efforts are ongoing, such as CCSF's current effort to value the Subject Assets in this proceeding. In other instances, POUs suspended their acquisition efforts but retain their ability to resuscitate those efforts in the future. The San Francisco-Brisbane MUD, discussed earlier in this testimony chapter, is one example. Other examples include the following:[18]

Sacramento Municipal Utility District ("SMUD") Expansion into Eastern Yolo County: SMUD is an existing municipal utility that began providing electric service in Sacramento County in 1946. In 2004, SMUD initiated an effort to extend electric delivery service into eastern Yolo County. While a public vote was required in Yolo County, none was legally required in Sacramento County at that time. PG&E collected signatures within Sacramento County to create an advisory (not compulsory) vote in Sacramento County in late 2005. SMUD decided to make the vote compulsory in early 2006. Sacramento County voters subsequently rejected the takeover later that year.

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[18] This is not an exhaustive list.

South San Joaquin ID ("SSJID"): SSJID is an irrigation district in San Joaquin County, California. In addition to its irrigation services, it has been generating and selling wholesale hydroelectric power as part of the Tri-Dam Joint Powers Authority since the late 1950s.

SSJID has been interested in replacing PG&E as the electric distribution provider in its irrigation service area, which includes parts of Escalon, Manteca, and Ripon, for several decades. In 2004, SSJID applied to the San Joaquin County LAFCO ("SJLAFCO") to expand its services to include electric delivery service within its ID boundaries by taking over PG&E's electric distribution facilities. The SJLAFCO Commissioners denied the request. SSJID reapplied to SJLAFCO in 2009. In December 2014, the SJLAFCO voted to support it, with conditions. As such, SSJID now has conditional SJLAFCO approval to provide retail electric service within its territory.

In pursuit of its desire to provide retail electric service, on May 12, 2016, SSJID offered $116 million to acquire PG&E's electric distribution assets within the ID boundaries; PG&E rejected this offer. SSJID proceeded to file an eminent domain action in 2016, which most recently has been on hold in San Joaquin County Superior Court pending a California Supreme Court decision concerning the trial court's evaluation of the public interest of the proposed taking. The California Supreme Court issued a decision on August 24, 2026.[19]

East Bay MUD ("EBMUD"): EBMUD is the municipal utility district providing water and sewage treatment services across multiple towns and counties in the east San Francisco Bay Area. In 2001, EBMUD hired an external consultant to evaluate three potential pathways for EBMUD to participate in the electricity business: i) create an aggregation entity; ii) procure renewables such as solar and wind; iii) create a vertically integrated utility by taking over PG&E's electric delivery facilities within its MUD service territory. The report recommended proceeding to the next step in evaluating the third option, as did the staff report presented to the Board in 2002. The Board considered the recommendation but decided to defer any action.

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[19] PG&E and SSJID will return to the Superior Court for a status conference on January 13, 2027.

City of Davis: In December 2013, the Davis City Council passed Resolution 13-169, which charted a course for the City to acquire PG&E's electric delivery facilities serving the City's residents and businesses. PG&E and City staff engaged in numerous subsequent discussions. The City ultimately decided to pursue alternative approaches.

City of San Jose: In 2023, the San Jose City Council received a report from the City Manager that advocated the creation of a municipal utility to serve new large customers, particularly data centers, that are expected to locate within the City's boundaries over the next few years. It had hired external consultants to evaluate potential cost savings and potential generation of revenue associated with City service and electric connection to 230 kV lines proposed for that area. The City ultimately tabled the development of the municipal utility.

McAllister Ranch Irrigation District ("MRID"): In 1998, MRID formed for the purpose of providing multiple utility services, including electric delivery, within a 2,100-acre development in unincorporated Kern County. The development, initially slated for 6,000 homes, languished for a number of years; property ownership changed in 2005, and the City of Bakersfield annexed the development. The property ultimately went into foreclosure and was purchased in 2011 by the Buena Vista Water District and Rosedale-Rio Bravo Water District.[20] In 2026, MRID filed an application with PG&E for wholesale service with the intent to provide retail electric service to the Buena Vista Water District groundwater facility, which occupies approximately 600 acres of the development. That application remains pending.

City of Lincoln: In the late 1990s, the City of Lincoln received an analysis by an external consultant that promoted the development of a "spot muni" to serve significant anticipated growth in new residential and commercial developments. The consultant's analysis suggested that the City could generate a significant revenue stream that the City could use to fund unrelated municipal purposes. The Council considered the proposal and in February 2000 voted 3-2 to table the initiative.

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20 SJV Water, "Twisted saga of failed McAllister Ranch development takes another turn," available at https://sjvwater.org/twisted-saga-of-failed-mcallister-ranch-development-takes-another-turn/. Buena Vista Water District subsequently purchased the share of MRID owned by Rosedale-Rio Bravo Water District.

City of Oroville: The Oroville City Council started exploring various public power options in 2025, including adopting a resolution authorizing the creation of the OroVerde Public Utility in November. The key options evaluated for possible future pursuit were the utilization of existing PG&E facilities or the development of parallel facilities to serve the City's industrial area. Both were determined to be financially infeasible. However, staff is continuing to evaluate the development of an energy system independent of the existing electric grid to serve future greenfield development.

3. IOUs Are Less Active than POUs in the Market for Electric Utility Property.

In contrast to the POU expansion described above, there have been very limited purchases of electric transmission and distribution assets by IOUs in Northern and Central California. In fact, with the exception of Calpeco LLC (now Liberty Utilities) acquiring the assets of Sierra Pacific Power Company near Lake Tahoe, the only recent instances of IOU expansion within Northern and Central California involved PG&E purchasing additional electric utility property and expanding its customer base. No other IOU has purchased electric assets in or otherwise expanded into PG&E's service territory in recent history.

PG&E's Acquisition of Hercules Municipal Utility Electric Facilities: More than a decade after its creation, HMU had driven the City of Hercules to the brink of insolvency, having run up over $13 million in debt in a town with an annual budget of $14 million. HMU electric rates were significantly higher than those of PG&E, and Hercules' credit rating was downgraded. The City Council and Hercules' citizens ultimately voted to sell the assets, and PG&E was the successful bidder. This transaction was submitted to and approved by the CPUC in D.14-01-009.

E. Critique of CCSF Testimony

In testimony submitted on April 20, 2026, CCSF's expert witness Grant Rabon was asked to respond to the question: "If not the City specifically, why not assume the hypothetical buyer is some other municipal or public entity?"[21] In

[21] Ex. CCSF-004C – Prepared Direct Testimony of Grant Rabon, ASA on Behalf of the City and County of San Francisco at 12:21–22 (Apr. 20, 2026). CCSF submitted an errata to Mr. Rabon's testimony on May 21, 2026, but this section was not amended.

response, Mr. Rabon testified: "There are no other municipal or public entities that are likely to be purchasers of the Subject Property."[22]

PG&E subsequently served several data requests related to this testimony. One of them asked Mr. Rabon to "[i]dentify all entities that" he considered "likely to be purchasers" of the Subject Assets.[23] The response identified a list "of investor-owned utilities or private investment firms may be interested in acquiring the Subject Property" including, "[f]or example, the following publicly traded companies . . . identified by Value Line, Inc. as owning electric utility assets in the Western United States (excluding PG&E): Avista Corp; Black Hills Corp; Edison International; Hawaiian Electric Industries Inc; IDACORP Inc; NorthWestern Energy; Pinnacle West Capital Corp; Portland General Electric Company; Sempra; TXNM Energy Inc.; Xcel Energy Inc."[24] Mr. Rabon further answered that such "[p]rofit-motivated investors and companies could desire the Subject Property for much the same reason PG&E wants to own them. The rate base associated with the Subject Property allows for a return that some entities would find attractive on a risk-adjusted basis."[25]

PG&E also asked CCSF for "all documents, data, information, work files, workpapers, and analyses, on which [Mr. Rabon] based [his] conclusion that there are no other municipal or public entities that are likely to be purchasers."[26] Mr. Rabon responded:

> Municipally-owned utilities tend to own electric distribution assets within or nearby their corporate boundaries. Therefore, it would be unusual for another municipality (other than the City and County of San Francisco) to desire to purchase, at Fair Market Value, the Subject Property. Further, public entities generally have a region in which they have interests and often have a non-profit motivated purpose behind their investments (*e.g.*, improve reliability via investment in transmission assets). Therefore, it is unlikely that a public agency or district would desire to purchase, at Fair Market Value, the Subject Property since there is unlikely to be a geographic fit or purpose-driven benefit of acquiring electric distribution assets in San Francisco.[27]

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22 *Id.* at 12:23–24.

23 PG&E DR Set 14, No. 16a.

24 CCSF Response to PG&E DR Set 14, No. 16a.

25 CCSF Response to PG&E DR Set 14, No. 16c.

26 PG&E DR Set 14, No. 16b.

27 CCSF Response to PG&E Data Request Set 14, No. 16b.

Mr. Rabon's logic for excluding such buyers is flawed. His assertion that "[m]unicipally-owned utilities tend to own electric distribution assets within or nearby their corporate boundaries" ignores the fact that a number of California POUs have, in fact, initiated electric delivery service in areas that are a significant distance from their corporate or geographic boundaries. Examples include the City of Pittsburg's service to Mare Island (a distance of approximately 33 miles) and Modesto Irrigation District's service to the Community of Mountain House (a distance of approximately 38 miles).

Mr. Rabon's assertion that "public entities . . . often have a non-profit motivated purpose behind their investments" into electric assets likewise ignores the fact that a number of POU initiatives have been driven by a desire to acquire load in order to generate a revenue stream—and not solely a "non-profit motivated purpose." The Merced Irrigation District's expansion efforts in and around the cities of Merced, Atwater and Livingston is but one example.

Finally, Mr. Rabon's analysis of the "likely" buyers both asks the incorrect question and gives the incorrect answer. As noted above, I am instructed by counsel that the legal standard for a "hypothetical" buyer need not consider whether a particular entity is a *likely* buyer, but whether it is possible, in a hypothetical sense, for an entity to purchase the Subject Assets. Merriam Webster defines hypothetical as: "involving or being based on a suggested idea or theory: being or involving a hypothesis: conjectural." Mr. Rabon's analysis does not apply this standard and instead ventures into providing an unsupported judgment regarding the probability of such an acquisition. The fair market value standard does not require proof that a named buyer was preparing an actual bid. Rather, it requires the appraiser to consider buyer classes that were legally capable market participants as of the valuation date. There were multiple public utilities that met these criteria.

But even if the standard in the proceeding did consider whether a particular buyer was *likely,* Mr. Rabon's answer would still not be correct, as he provides no evidence that any of the "investor-owned utilities or private investment firms" he lists are likely buyers. The facts indicate that none of those entities operate within or have made any recent attempts to expand into PG&E's service territory. Some of them operate exclusively in different states; for example, Hawaiian Electric Industries operates only in Hawaii, as the name suggests, and

is separated from PG&E's service territory by more than 2,000 miles of ocean. If, according to Mr. Rabon, potential expansion beyond an existing footprint is enough to include western IOUs and investment firms as potential buyers, then geographic separation cannot reasonably nor categorically exclude public utilities with legal power to expand, demonstrated acquisition activity, and direct experience serving former PG&E load.

Regardless of how likely or not it is that they would be purchasers, municipal and public entities are legitimate hypothetical buyers of the Subject Assets that must be considered as part of the evaluation. Ultimately, Mr. Rabon's testimony does not merely suggest a debatable conclusion. Instead, he appears to have excluded an entire buyer class without conducting any sort of market analysis or providing any data or evidence supporting his proposed exclusion.

F. Conclusion

Based on my experience and research, I conclude that there are a number of public entities that could represent a hypothetical buyer of the Subject Assets. In fact, based on activity within the past four decades within Northern and Central California, there are significantly more public entities that have entered or expanded their presence in the electric delivery market than has been the case for private entities. Accounting for POU buyers in this way does not improperly value the assets based on CCSF's unique circumstances as a buyer or based on the specifics of CCSF's proposed taking. Instead, it simply recognizes the presence of an established class of hypothetical POU buyers. As such, any determination of the fair market value of PG&E's assets must account for the presence of hypothetical POU buyers in the market.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

BUSINESS SEVERANCE DAMAGES OVERVIEW

WITNESS: DAVID RUBIN

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
BUSINESS SEVERANCE DAMAGES OVERVIEW
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
BUSINESS SEVERANCE DAMAGES OVERVIEW

A. Introduction

My name is David Rubin. I am an outside consultant for Pacific Gas and Electric Company ("PG&E") and a retired employee of PG&E, where I was, among other positions, the Director of PG&E's Service Analysis Department (1995 to 2018) and Director of Strategy Formulation (2018 to 2020).

In this chapter of testimony, I present an overview of the evidence demonstrating that the City and County of San Francisco's ("CCSF" or "the City") proposed taking of PG&E's electric delivery assets within and serving San Francisco ("Subject Assets") would cause $7.61 billion[1] of business severance damages as of July 27, 2021 ("Petition Date"), comprised of $5.32 billion in damages, $1.83 billion to gross-up for taxes that the severance would cause PG&E to incur, and $0.47 billion connected with income taxes and operative reserve associated with the trust that would return the customer damages through rates. The vast majority of these costs would impact PG&E's remaining customers.[2] CCSF must pay this amount to prevent its proposed takeover from unfairly shifting these damages onto PG&E's remaining customers.

This chapter of my testimony summarizes PG&E's testimony on business severance damages, including the more detailed business severance damages testimony that I developed in coordination with witnesses Marcus Keller, Shaun Hoppes, and Tim Wedlake. This testimony chapter provides an overview of the key aspects of PG&E's business severance damages calculations; Chapter 8.1 contains the full detail of my inputs to these calculations and the relationship between my inputs and those of the above witnesses.

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1 Throughout this testimony chapter, I generally round my calculations to two decimal places; due to this rounding, individual amounts may not sum exactly to the stated total.

2 The tax gross-up is associated with the customer-impacting elements of the business severance damages. As described in further detail in Chapter 8.1, approximately 96% of the business severance damages (as determined as of the Petition Date) are designed to maintain neutrality for PG&E's customers outside of San Francisco. The remaining 4% that is attributable to shareholders consists of Construction Work in Progress and Accounts Receivable.

I have prepared and submit this chapter of testimony in compliance with the California Public Utilities Commission's ("Commission" or "CPUC") Interim Decision Sections 7.2(e) and (i), which require PG&E to present, among other things, "a specific sum that represents PCIA, safety, reliability, wildfire mitigation, public benefit, stranded asset costs, joint and common costs, public purpose charges, and other pass-through costs, stranded costs and stranded assets,"[3] and to account for which portion, if any, would be recovered via the Transferred Municipal Departing Load ("TMDL") Tariff.[4] Consistent with this direction, the damages presented herein include costs associated with public policy programs and other charges that, although not directly related to operating the electric system, must nevertheless be included to avoid reallocating costs to PG&E's remaining customers that otherwise would have been borne by customers in San Francisco.

I have laid out my testimony as follows:

- In Section B, I provide an overview of PG&E's business severance damages calculations;
- In Section C, I describe the methodology of those calculations, including the relationship of this testimony chapter to other testimony chapters;
- In Section D, I provide the amount of the tax gross-up required to make PG&E whole for the tax consequences of receiving CCSF's just compensation payment for business severance damages;[5]
- In Section E, I explain why PG&E cannot feasibly recover significant amounts from departed customers pursuant to the TMDL tariff;
- In Section F, I explain why the Commission should update severance damages at the time of the actual asset transfer date; and
- I conclude the chapter in Section G.

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[3] Decision Establishing Methods and Standards for Just Compensation and Valuation, D.25-10-039 at 35–36 (Oct. 30, 2025) ("Interim Decision").

[4] The E-TMDL Tariff applies to former PG&E customers who subsequently take electric delivery service from a publicly owned utility ("POU") like the San Francisco Public Utilities Commission ("SFPUC").

[5] The specifics regarding this tax gross-up are sponsored by witness Tim Wedlake in Chapter 8.1.

B. Overview of Findings and Conclusions

CCSF's proposed taking would cause PG&E both to lose revenues from its San Francisco customers and to avoid certain costs. The net financial impacts of CCSF's proposed taking on PG&E and its remaining electric business constitute business severance damages. Unless CCSF pays these damages in full, including related tax consequences, PG&E's remaining customers would incur the majority of these costs in the form of higher rates: they would not be left "neutral to the acquisition."[6]

In Table 8-1, I summarize the key components of PG&E's business severance damages as of the Petition Date.[7] I provide greater detail on each component's calculation in Section C and in Chapter 8.1.

TABLE 8-1
SUMMARY OF BUSINESS SEVERANCE DAMAGES JULY 27, 2021 THROUGH 2051

Line No.	Business Severance Damage Category	July 27, 2021-2051 ($ millions)
1	Forecasted Lost PG&E Revenues	$28,865
2	Plus: Additional Assets (wildfire mitigation and catastrophic event, flow-back deferred taxes, construction work in progress ("CWIP"), accounts receivable)	$548
3	Less: PG&E's Avoided Costs (costs PG&E would no longer incur)	($24,096)
4	Net Business Severance Damages	$5,317
5	Tax Gross-Up on Business Severance Damages	$1,826
6	Grossed-Up Business Severance Damages	$7,144
7	Trust Income Tax & Operative Reserve	$470
8	Total	$7,614
9	Amounts Potentially Collectible from MDL Tariffs, Net of Billing Costs (shown separately; not collectible in practice)	($344)

The first row in Table 8-1 shows the revenues that PG&E would lose if CCSF's proposed taking proceeds, starting with actual revenues from San Francisco customers as of the Petition Date. These revenue streams fund utility obligations (including the costs of distribution and transmission services), infrastructure investments, safety programs, and statewide policy initiatives.

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6 Interim Decision at 22.

7 Throughout this testimony and Chapter 8.1, I have evaluated business severance damages from the Petition Date through 2051, capturing a 30.43-year period. For ease of discussion, I will refer to this as a 30-year analytic timeframe.

They include important energy policy and related commitments that the California Legislature and the Commission have mandated.[8] As further described in Chapter 8.3, they also include revenues from non-tariff products and services ("NTP&S") that PG&E provides to third parties and selected retail customers.[9] Unless PG&E receives the full amount of its business severance damages, CCSF's condemnation would shift the costs of these utility operations and energy policy initiatives to PG&E's non-San Francisco customers. In addition, the taking would leave PG&E unable to recover from its San Francisco customers various costs that it has recorded in balancing and memorandum accounts for future recovery.[10]

To develop an accurate quantification of its business severance damages, I also have assessed the costs that PG&E would not incur (*i.e.*, avoided costs) if it no longer serves its San Francisco electric customers. These include avoided capital recovery (both for then-existing net plant plus ongoing capital investments), avoided operating and maintenance expenses, generation service costs, direct program benefits delivered to San Francisco customers, NTP&S expenses, and other items such as electric franchise fees and local taxes.

The sum of lost revenues and additional PG&E assets (Wildfire Mitigation and Catastrophic Events ("WMCE"), deferred taxes, CWIP, and accounts receivable) minus avoided costs translates into net business severance damages of $5.32 billion as of the Petition Date.

Ensuring that PG&E and its remaining customers are in fact kept neutral after a taking would also require a tax gross-up on PG&E's net business severance damages. Otherwise, PG&E and its customers would recover far less than the actual business severance damages. As PG&E witness Tim Wedlake further describes in Chapter 8.1, the tax gross-up amount is $1.83 billion. Finally, the trust structure that PG&E is proposing in Chapter 10 would

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8 *See, e.g.*, PG&E Testimony, Chapter 8.1 (Rubin *et al.*), § C.2.d & App'x II.

9 *See generally* PG&E Testimony, Chapter 8.3 (Delaney).

10 Additional business severance damages include higher costs for customers of PG&E's gas business in San Francisco due to post-taking coordination challenges with the City and lost economies of scale between PG&E's electric and gas businesses. *See* Ch. 8.1, § C.4.

result in taxable earnings and operative reserves, resulting in an additional $0.47 billion, bringing the total to $7.61 billion.

PG&E could not practically recover these amounts directly from departing San Francisco customers through the E-TMDL tariff, which requires consumers located within PG&E's service territory who become electric delivery service customers of a publicly owned utility ("POU") to pay certain so-called "non-bypassable charges" ("NBCs"). First, the tariff does not account for the full costs and charges that CCSF's taking would shift to remaining PG&E customers; it only covers a modest subset of the charges within PG&E's forecasted lost revenues. Specifically, the E-TMDL tariff does not include Distribution, Transmission, Generation and the Public Purpose Program Charges, which collectively represent approximately 67% of the damages.

Moreover, pursuing recovery on a customer-by-customer basis in a city the size of San Francisco is wholly impractical, particularly as the vast majority of customers who no longer receive electric service from PG&E will not pay separate PG&E bills for electric charges. And PG&E would lack any meaningful enforcement mechanism to promote payment. Commonly, the expectation that a customer will lose service due to failure to pay for service promotes payment; this would not exist for these departed San Francisco customers.[11] This would create the need for a significant collections program and acknowledgement of bad debt.

Finally, it is important to note that PG&E's business severance damages will require updating to correspond to the actual date of the asset transfer. Much has changed since the Petition Date, with additions, removals, and material changes to the relevant charges,[12] and San Francisco customers have continued to pay revenues already captured in the Petition Date-based forecast. To be accurate and truly achieve its stated purpose—to maintain neutrality for PG&E and its non-San Francisco customers—the calculation of PG&E's

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[11] The same is true with respect to Accounts Receivable as of the Petition Date.

[12] For example, as of the Petition Date, the Diablo Canyon Power Plant was slated for retirement in 2024 and 2025. It has since been authorized to operate through at least 2030 with associated costs recovered through the Public Purpose Program ("PPP") Charge.

business severance damages will need to be updated to reflect damages as of the date of transfer.

C. Background and Methodology

PG&E serves a mix of customer categories within San Francisco, distinguishable primarily by (a) whether they receive retail or wholesale service and (b) whether they receive their generation supply from PG&E or another provider. The retail categories include: (i) customers who take generation, distribution, and transmission from PG&E (bundled customers); (ii) customers who receive distribution and transmission from PG&E but obtain generation through CCSF's community choice aggregation ("CCA") program, CleanPowerSF; and (iii) direct access ("DA") customers who receive distribution and transmission from PG&E but obtain generation from a third-party energy service provider ("ESP"). Together, these retail categories make up the majority share of consumption in San Francisco. The remaining, smaller share consists of wholesale and hybrid arrangements: (iv) BART, which procures its own wholesale power and pays a mix of state and federal jurisdictional charges; (v) the San Francisco Public Utilities Commission ("SFPUC"), which receives distribution service from PG&E under PG&E's Wholesale Distribution Tariff ("WDT") in order to serve several thousand customers throughout San Francisco; and (vi) the Presidio Trust, which independently serves residents and businesses within the former Army base.

PG&E's revenues derive from various discrete electric rate components (*i.e.*, charges) including generation, distribution, transmission, wildfire-related charges, public purpose program, nuclear decommissioning, competition transition charge, and power charge indifference adjustment ("PCIA"), among others. Each of these charges represents revenues that fund critical infrastructure, safety programs, and statewide policy initiatives—revenues that PG&E would lose and costs that CCSF's taking would shift to PG&E customers outside of San Francisco. In this regard, it is important to consider that California law requires PG&E to charge rates that are geographically uniform, pooling the costs of serving customers and recovering them through rates that do not vary by locality. As the Interim Decision explains, the revenues that an IOU collects in a dense, urban area can exceed the costs of serving it, and the difference helps ensure reasonable rates elsewhere in the IOU's service

territory.[13] Without that lower-cost urban area's financial contribution, the rates for remaining customers would necessarily increase. This effect is particularly pronounced with respect to wildfire mitigation charges: PG&E incurs far greater wildfire-related costs in its more remote service locations yet collects relatively less revenue from those areas.

The methodology described in Chapter 8.1 of PG&E's testimony measures the financial harm that CCSF's proposed taking would impose on PG&E's non-San Francisco customers. Business severance damages reflect the amount that CCSF must compensate PG&E to make PG&E's customers whole—that is, to ensure that PG&E and its non-San Francisco customers do not bear the financial consequences of CCSF's municipalization. As discussed in Chapters 1 and 10, such damages constitute one component of the overall just compensation formula.[14]

The underlying formula for total business severance damages is:

Total Business Severance Damages (BSD) =
Lost Revenues (LR) +
Additional Assets (AA) –
Avoided Costs (AC) +
Tax Gross-Up (T)

I describe the results of my business severance damages analysis by revenue component in Table 8-2 below.

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13 Interim Decision at 25 ("The customer accounts, and the revenues they produce, are a major part of what is being taken. One of the highest density portions of PG&E's system is being removed from PG&E's whole system, where the revenues may be greater than the cost to serve, helping to offset costs in rural regions.").

14 *See* PG&E Testimony, Ch. 1 (Peterman) at 3.

TABLE 8-2
SUMMARY OF BUSINESS SEVERANCE DAMAGES BY REVENUE COMPONENT JULY 27, 2021 THROUGH 2051
(MILLIONS OF DOLLARS)

Line No.	Revenue Component	Lost Revenues	Avoided Costs	Net Damages
1	Generation	$1,475	($1,354)	$121
2	Distribution	$18,089	($15,886)	$2,203
3	Transmission	$4,539	($5,087)	($548)
4	Public Purpose Program Charge	$2,018	($104)	$1,913
5	Nuclear Decommissioning	$38	-	$38
6	Competition Transition Charge	$0.4	-	$0.4
7	Energy Cost Recovery Amount	$5	-	$5
8	Wildfire Fund Charge	$273	-	$273
9	New System Generation Charge	$39	-	$39
10	Wildfire Hardening Charge	$316	-	$316
11	Recovery Bond Charge	$797	-	$797
12	Recovery Bond Credit	($797)	-	($797)
13	Power Charge Indifference Adjustment	$1,061	-	$1,061
14	Non-Tariff Products and Services	$1,011	($722)	$289
15	Additional Assets	$548	-	$548
16	Local Taxes and Fees	-	($942)	($942)
17	Net Business Severance Damage Subtotal	$29,413	($24,096)	$5,317
18	Tax Gross-Up	-	-	$1,826
19	Trust Income Tax & Operative Reserve	-	-	$470
20	Total Business Severance			$7,614

I have converted all annual amounts to the value as of the Petition Date. As explained in Chapter 10, PG&E proposes to place the portion of damages designed to maintain neutrality for PG&E's remaining customers (after payment of taxes) into a trust to protect these funds and ensure that they are available and applied annually to prevent shifting of costs to PG&E's customers outside of San Francisco.[15] The appropriate rates used for converting future revenue streams to a value as of the Petition Date are the rates of return (as of the Petition Date) that the annual business severance damage amounts would earn during the period of time that they are returned to PG&E's non-San Francisco

[15] *See* PG&E Testimony, Ch. 10 (Rogers), § D.

customers through the rates that they pay.[16] PG&E's analysis applies Treasury rates to ensure capital preservation since PG&E would credit these funds to customers over 30 years. The trust would earn interest on the funds over this time frame and incur certain costs. These amount to an additional $0.47 billion, which has been added to the damages determination.

As explained in Chapter 8.1, PG&E also proposes to handle damages from certain charges on a collect and remit basis as opposed to a lump sum, which would reduce the total lump sum and associated tax gross-up amounts; however, because the Commission is required by law to set a simple sum for severance damages, PG&E has calculated such a sum. Further, as described in Section F, more than five years already have passed since the Petition Date, and there is a compelling need to eventually update key input values.

As discussed below and described in further detail in Chapter 8.1, CCSF's proposed taking would impose a significant cost shift on PG&E's non-San Francisco customers: $5.02 billion, measured over a 30-year period and using Treasury rates as of mid-2021. With an incremental $0.30 billion of damages due to shareholders for certain additional assets (namely CWIP and accounts receivable), along with a tax gross-up of $1.83 billion and $0.47 billion in trust interest and operating reserve, the total business severance damage amount is $7.61 billion.[17]

The following sections describe in further detail how I determined each component of the formula for business severance damages.

1. Lost Revenues

The lost revenues reflect the utility charges that PG&E's San Francisco customers would pay absent a CCSF taking, which I have measured as a forecasted stream over a 30-year time horizon.

To forecast the revenues from PG&E's San Francisco electric customers for each revenue component from July 27, 2021 through 2051, I relied on the revenue requirement and electric consumption information that

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[16] *See id*. For the two securitized charges, Wildfire Hardening Charge and Recovery Bond Charge/Recovery Bond Credit, I have used the 2021 rate of return earned by the Special Purpose Entities established to manage these funds.

[17] The treasury rate as of the Petition Date was approximately 1.82%. Rates as of the time of the submission of this testimony are approximately 4% after tax.

was available at or around the time of the Petition Date. I took most of the information for the first decade of the forecast period (2022 through 2032) directly from PG&E's submission in the California Energy Commission's ("CEC") 2021 Integrated Energy Policy Report ("IEPR") proceeding. Since the 2021 IEPR Submission included forecasted values through 2032, I extended the revenue requirement and PG&E system energy consumption forecasts for the period 2033 through 2051 consistent with the compound annual growth rate ("CAGR") for the final five years (2027-2032) for each of these categories.

I conservatively assumed that retail electricity consumption growth in San Francisco, along with consumption growth in the Presidio, would match that of the PG&E system for the entire 30-year timeframe. The CEC's 2022 IEPR Update forecast presented a more aggressive growth rate for consumption served by CleanPowerSF, CCSF's CCA.[18] Employing this CEC forecast would produce a significantly greater level of lost revenues, leading to a much larger value for business severance damages. For wholesale consumption served by CCSF under the WDT, I relied on the 2022-2035 forecast for the Power Enterprise of the SFPUC from the CEC's 2022 IEPR Update[19] and extended this forecast through 2051 using the CAGR of 2.4% from the last five years (2030-2035) of that forecast. I also relied on the 2022-2035 forecast for BART from the CEC's 2022 IEPR Update[20] and extended it through 2051 using the CAGR of 0% from the last five years of that forecast.

2. Additional Assets

The Additional Assets I consider in the business severance damages formula include the San Francisco pro rata share of certain regulatory account balances and other assets that reflect costs that PG&E had incurred

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18 *See* Cal. Energy Comm'n, *CED 2022 LSE and BA Planning Forecast Tables,* Form 1.1c, row 10. available at https://www.energy.ca.gov/data-reports/california-energy-planning-library/forecasts-and-system-planning/demand-side-0.

19 Row 37, Form 1.1c, *supra* n.18. The Power Enterprise of SFPUC included consumption both within and outside of San Francisco (*e.g.*, San Francisco International Airport). I assumed that the implied growth percentages for the total would apply equally to consumption within San Francisco.

20 Row 7, Form 1.1c, *supra* n.18.

as of the Petition Date but had not yet been incorporated into customer rates. Specifically, this includes various regulatory accounts related to wildfire mitigation and catastrophic events, deferred flow-through taxes, CWIP[21] and accounts receivable.

Table 8-3 represents the amounts of Additional Assets as of the Petition Date included within PG&E's business severance damages.

TABLE 8-3
SF SHARE OF ADDITIONAL ASSETS AS OF PETITION DATE
(JULY 2021, MILLIONS OF DOLLARS)

Line No.	Additional Asset	Amount
1	Wildfire Mitigation and Catastrophic Events Accounts	$81
2	Deferred Taxes	$166
3	Construction Work in Progress	$175
4	Accounts Receivable	$127

3. Avoided Costs

Avoided Costs are those costs that PG&E would no longer incur if it did not serve as the electric delivery provider in San Francisco. I subtracted these costs from Lost Revenues and Additional Assets to arrive at net business severance damages, prior to calculating and adding the tax gross-up.

Avoided Costs include the annual revenue requirements and expenses associated with PG&E's July 27, 2021 rate base in San Francisco, distribution and transmission capital investments that PG&E would no longer make, and operating costs that PG&E would no longer incur if it ceased serving electric customers in San Francisco. They also include direct financial incentives or other benefits that PG&E provides its customers in San Francisco, among other items.[22] Finally, I have added various fees

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21 For the purposes of this testimony, PG&E assumes that CCSF will not take CWIP as part of its taking. In response to a data request as to whether CCSF will acquire CWIP, CCSF confirmed that its testimony "does not identify or assign a separate value to CWIP" and responded that whether CCSF will acquire CWIP "will be made on a project-by-project basis at the time of acquisition and may be subject to a future determination." CCSF Response to PG&E's Data Request Set 26, No. 1. Any project-by-project decisions CCSF makes if it proceeds with its taking can be addressed in the update proceeding, which I discuss further in Section F.

22 *See* Ch. 8.1, § E.

and taxes associated with electric service in San Francisco that PG&E pays to CCSF but would no longer contribute were a taking to occur.[23]

In those areas where PG&E would realize avoidable operating costs, I have deducted them as part of my determination of business severance damages.[24] I base this part of my analysis on the avoided cost study that witness Whitney Alary conducted on the electric delivery grid and operations in San Francisco.[25] As described in further detail in Chapter 8.2, Ms. Alary performed a comprehensive review and quantification of operational costs that PG&E would no longer incur if it no longer owned and operated the Subject Assets.

Table 8-4 represents the July 27, 2021 value of the costs that PG&E would avoid from July 27, 2021 through 2051 as a result of CCSF's taking.

TABLE 8-4
VALUE OF AVOIDED COSTS FROM JULY 27, 2021 THROUGH 2051
(2021, MILLIONS OF DOLLARS)

Line No.	Avoided Cost	July 27, 2021 Value
1	Generation	($1,354)
2	Distribution	($15,886)
3	Transmission	($5,087)
4	Public Purpose Program	($104)
5	Non-Tariff Products and Services	($722)
6	Local Fees	($942)
7	Subtotal	($24,096)

23 Included are Franchise Fees, the San Francisco Business Tax, the San Francisco Sales/Use Tax, and property taxes. Property taxes associated with PG&E's distribution and transmission assets in San Francisco are reflected in the distribution and transmission avoided costs, respectively.

24 A number of charges—such as Nuclear Decommissioning, Competition Transition Charge, Wildfire Fund Charge, Power Charge Indifference Adjustment—are already expressed as an amount that is net of avoided costs, or there are no costs that are deemed avoidable. For these charges, the entirety of the lost revenue constitutes harm to PG&E's remaining customers, with no offset.

25 *See generally* PG&E Testimony, Ch. 8.2 (Alary).

D. Tax Gross-Up on Business Severance Damages

The business severance elements that I describe in Section C measure the "net" (pre-tax) economic harm to PG&E and its remaining customers, but they do not make PG&E and its other customers whole. True neutrality necessitates that CCSF also cover the associated tax consequences that its taking would cause. Specifically, because CCSF's severance payment for the customer-impacting damages will constitute taxable income to PG&E in the year received, my overall business severance damages determination includes a separately calculated tax gross-up on those net business severance damages.[26] Without the gross-up, CCSF's payment necessarily will leave a gap, resulting in a cost shift to PG&E and its non-San Francisco customers.

The amount of the tax gross-up associated with the customer-impacting net business severance damages amount is $1.83 billion.[27]

E. The TMDL Tariff Does Not Provide an Adequate Mechanism for Recovery of Severance Damages

Chapter 8.1 evaluates in detail whether the TMDL tariff[28] would make PG&E's non-San Francisco customers whole through the collection of certain NBCs. In summary, although the TMDL tariff provides a theoretical path to recover some charges from POU customers located within PG&E's service

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26 *See* Ch. 8.1, § G (Wedlake). I am assuming that the Commission ultimately approves a collect and remit approach for the securitized charges (Recovery Bond Charge, Recovery Bond Credit and Wildfire Hardening Charge), so they are excluded from the tax gross-up.

27 This amount will change due to updates to the business severance damages that will be necessary if CCSF continues with this proceeding and the taking of the Subject Assets. PG&E has estimated the tax gross-up in this testimony and asks that the Commission rule that a tax gross-up will be necessary as part of the just compensation award for severance damages, but that the Commission update the final calculation of the tax gross-up (and the treatment of any potential future tax deductions) during the update phase when more precise information will be known.

28 There is also a companion tariff (E-NMDL) for new energy consumers that locate within PG&E's service area as it existed on February 1, 2001, but that immediately receive electric delivery service from a POU (i.e., they were not transferred from PG&E to another entity). While E-NMDL would technically apply to new consumers locating within San Francisco subsequent to any CCSF taking, the NBCs within E-NMDL are essentially the same as those within E-TMDL. Since PG&E's determination of lost revenues is based on a kWh consumption forecast applied to specific charges, there is no meaningful distinction between a kWh of consumption growth attributable to a former versus prospective consumer. Throughout this chapter, I refer to both "the TMDL tariff" and "the MDL tariffs."

territory, it is neither a sufficient nor practical remedy for the harm that CCSF's proposed taking would cause.

First, the TMDL tariff as of the Petition Date addressed only a limited subset of the relevant charges.[29] The applicable charges represent only approximately 6% of the total damages. That percentage increases to approximately 27% if I include two *conditionally*-applicable charges,[30] and it grows to a maximum of 33% with the addition of two securitized charges that were added to the MDL tariff within a year of the Petition Date.[31] However, approximately 67% of the net business severance damages would not be within the scope of the TMDL tariff under any circumstance.

Second, it would be wholly impractical for PG&E to collect this subset of damages directly from San Francisco customers who no longer receive electric service from PG&E; and it would be unrealistic to assume that such a difficult and costly effort would prove productive. Indeed, PG&E's historical experience shows that the MDL tariffs do not function as meaningful practical safeguards against cost shifting because they require PG&E to bill and collect from individuals and businesses that no longer receive electric service from PG&E and commonly do not understand why PG&E is sending them a bill. Further, because MDL customers would not be expected to pay electric bills that PG&E issues, and because PG&E would lack any meaningful enforcement mechanism, such as shutoff for failure to pay their bills, employing the MDL tariffs would only serve to increase bad debt and uncollectibles. PG&E witness Shaun Hoppes discusses this more extensively in his testimony in Chapter 8.1.[32]

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29 Included were the Competition Transition Charge, Energy Cost Recovery Charge, Nuclear Decommissioning Charge and Wildfire Fund Charge.

30 These two charges are the Vintaged Power Charge Indifference Adjustment and the New System Generation Charge/Cost Adjustment Mechanism. MDL is exempt from paying these charges, unless and until the IOU demonstrates through an application that the POU effort represents a "large municipalization." *See* D.08-09-012.

31 The Legislature authorized the two charges—the Wildfire Hardening and Recovery Bond Charge/Recovery Bond Credit—in 2019. The relevant CPUC proceedings were substantially complete as of the Petition Date, and the CPUC implemented them within a year of the Petition Date. I have included them as part of business severance damages and therefore also include them as part of the theoretical maximum that could be recovered via the MDL tariffs.

32 *See* Ch. 8.1, §§ H.3–H.4 (Hoppes).

Third, implementation of the TMDL tariff would increase PG&E's costs, as the tariff contains customer-notification and communications provisions and would require PG&E to perform unproductive billing and collections operations, all of which carry incremental cost. The objective is to make customers whole, which these various shortcomings in the TMDL process would undermine. As described in detail in Chapter 8.1, the costs associated with pursuit of collection of the NBCs in the MDL tariffs would exceed expected revenues by approximately $344 million.

Commission precedent strongly supports this conclusion. In opining on Modesto Irrigation District's service to Mountain House Community Services District, the Commission found that direct collection from departing customers "would be far more difficult and would involve a greater risk of non-payment."[33] When the Modesto and Merced Irrigation Districts later approached new subdivisions about providing electric service in PG&E's service area, PG&E's efforts to collect departing load charges generated significant controversy and high uncollectible rates. The Commission supported and approved a collect-and-remit agreement with the two Irrigation Districts, observing that:

> Without an agreement, PG&E will continue to experience a high rate of uncollectibles and incur significant additional administrative and legal costs to collect unpaid NBCs. It is unreasonable for PG&E to incur costs to collect unpaid NBCs that exceed the value of the unpaid NBCs being collected.[34]

Chapter 8.1 describes similar billing challenges following additional municipalization events.[35] In each of these instances, the best solution was a collect-and-remit arrangement in which the POU collected charges from its newly-acquired customers on PG&E's behalf and remitted those amounts to PG&E. These precedents show that attempting to collect NBCs directly from non-customers is fraught, expensive, and leads to little, if any, actual cost recovery. And because the amounts that would remain uncollected under any other approach would inevitably fall upon PG&E's remaining customers, such approaches contradict the Interim Decision's mandate that CCSF pay severance

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33 D.04-03-036 at 21.

34 D.10-11-011, 2010 Cal. PUC LEXIS 533, at *49 (Nov. 19, 2010).

35 *See* Ch. 8.1, § H.5.

damages that leave PG&E's remaining customers "neutral to the acquisition."[36] In stark contrast, CCSF's proposal that PG&E apply TMDL across a metropolis like San Francisco would exacerbate the financial harm that CCSF's proposed taking would cause these customers.

Accordingly, PG&E submits that the appropriate mechanism by which to keep its remaining customers whole is for CCSF to pay a lump-sum amount for the entirety of the damages presented in this Chapter.[37]

F. The Commission Should Update Severance Damages as of an Actual Asset Transfer Date

PG&E requests that the Commission expressly note in its valuation decision that it will have to update its business severance damage findings in this case to reflect PG&E's business severance damages as of the date of any actual asset transfer, rather than the Petition Date. This is so because (1) PG&E's actual business severance damages will differ from those on the Petition Date, as charges have been added, removed, or materially changed over the past five years; (2) customer consumption patterns have evolved; and (3) the severance damage calculation as of the Petition Date presented in this testimony necessarily includes amounts that San Francisco customers already have paid. Moreover, the Legislature and/or the CPUC may also authorize additional programs prior to or following any asset transfer date, such that PG&E's severance damages also should include those associated costs. CCSF also has acknowledged the prospect for updating values prior to any asset transfer.[38]

G. Conclusion

CCSF's proposed taking of the Subject Assets would cause substantial financial harm to PG&E and its customers outside of San Francisco. The taking would result in a sizeable reduction in revenues that far exceeds the costs that

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36 Interim Decision at 22.

37 The Commission must calculate a single lump sum for business severance damages. However, a one-time payment for the securitized charges (Wildfire Hardening Charge and Recovery Bond Charge/Recovery Bond Credit) is currently not enabled under the special purpose entity structure. PG&E recommends that the Commission reserve the right to impose an ongoing collect-and-remit mechanism in a future proceeding..

38 *See, e.g.*, CCSF Response to PG&E Data Request Set 26, No. 1; CCSF Response to PG&E Data Request Set 20, Nos. 6, 9.

PG&E would avoid, producing business severance damages of approximately $7.61 billion as of the Petition Date, consisting of $5.32 billion in net damages plus an associated tax gross-up of $1.83 billion and $0.47 billion in income taxes and operative reserve associated with the trust that would manage the return of the customer portion of the damages. Pursuant to the Commission's Interim Decision, CCSF must pay the full amount of these severance damages to protect PG&E and its non-San Francisco customers from cost shifts.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8.1

BUSINESS SEVERANCE DAMAGES

WITNESSES: DAVID RUBIN, MARCUS KELLER, SHAUN HOPPES, AND TIM WEDLAKE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8.1
BUSINESS SEVERANCE DAMAGES
WITNESSES: DAVID RUBIN, MARCUS KELLER, SHAUN HOPPES, AND TIM WEDLAKE

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8.1
BUSINESS SEVERANCE DAMAGES[1]

A. Introduction (Sponsored by David Rubin)

My name is David Rubin. In this chapter of testimony, Marcus Keller, Shaun Hoppes, Tim Wedlake, and I describe the business severance damages that Pacific Gas and Electric Company ("PG&E") would incur if the City and County of San Francisco ("CCSF")[2] takes PG&E's electric delivery assets in San Francisco. We first provide an overview of our approach to defining and calculating business severance damages and then describe the annual revenue components and other assets, net of avoided costs, that constitute business severance damages that CCSF must pay PG&E to prevent its takeover from harming PG&E and its customers outside of San Francisco.[3]

We then detail our calculation of business severance damages as of July 27, 2021, *i.e.*, the date that CCSF filed its petition in this proceeding

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1 David Rubin is the designated witness for the entirety of Chapter 8.1, with the exception of the following subsections: Marcus Keller addresses lost revenues related to certain generation-related components, such as bundled generation, Competition Transition Charge, New System Generation Charge, and the Power Charge Indifference Adjustment in Sections C.2.f, C.2.i, C.2.m, D.6, D.9, and D.11. Shaun Hoppes addresses the billing challenges associated with Accounts Receivable in Section C.3.d, as well as the Municipal Departing Load Tariffs in Sections H.3 and H.4.a. Tim Wedlake addresses tax issues in Sections C.3.b and G.

2 Pursuant to Section 7.2(e) and (i) of the Decision Establishing Methods and Standards for Just Compensation and Valuation, D.25-10-039 (Oct. 30, 2025) ("Interim Decision"), this chapter provides among other things "a specific sum that represents PCIA, safety, reliability, wildfire mitigation, public benefit, stranded asset costs, joint and common costs, public purpose charges, and other pass-through costs, stranded costs and stranded assets, and account for which portion, if any, would be recovered in TMDL tariff." Interim Decision at 35–36.

3 *See infra*, § B, at 3. Note that approximately 96% of the business severance damages (as determined on the Petition Date) are associated with items that would impact PG&E's customers outside of San Francisco; the remaining 4% would impact PG&E's investors.

("Petition Date").[4] We base this calculation on a 30-year[5] forecast of the revenues that PG&E would lose (starting with actual 2021 revenues)[6] and the costs that it would avoid[7] due to CCSF's proposed taking. The net business severance damages also include additional assets in the form of San Francisco's *pro rata* share of certain regulatory account balances and other assets that reflect PG&E costs incurred as of the Petition Date but not reflected in rate forecasts available at that time. Our calculation reflects net business severance damages of $5.32 billion. After calculating the net business severance damages, we have added a tax gross-up associated with the damage amount of $1.83 billion[8] and included $0.47 billion in income taxes and operative reserve associated with the trust structure designed to ensure rate neutrality. After including these amounts, PG&E's total business severance damages are $7.61 billion. CCSF will need to pay this amount as part of PG&E's just compensation to ensure that PG&E and its customers are made whole and remain neutral following a taking.

We also estimate the revenues, net of billing and collection costs, that PG&E might practically recover from departing San Francisco customers via the Transferred Municipal Departing Load ("TMDL") and New Municipal Departing Load ("NMDL") tariffs (together, the "MDL tariffs") as of the Petition Date.[9] Given the limited scope of the tariffs, the theoretical MDL-collectible amount is $1.73 billion, only 33% of the pre-tax customer damages; furthermore, collection

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4 Public Utilities Code § 1417 provides for subsequent proceedings to adjust the amount of compensation due to PG&E to reflect changed circumstances and costs subsequent to the Petition Date.

5 The time-frame runs from July 27, 2021 until year-end 2051; therefore, it is 30.43 years. Throughout this chapter of testimony, we will refer to the time-frame as "30 years."

6 *See infra*, § D, at 32.

7 *See infra*, § E, at 44.

8 *See infra*, § G, at 50.

9 *See infra*, § H, at 51. Our approach is generally consistent with CCSF witness Mark Fulmer's suggestion: "If PG&E believes that it cannot reasonably expect to fully collect TMDL from former customers who depart to City service, PG&E should calculate a net present value, as of July 27, 2021, of the TMDL charges that existed as of the time of the Petition and propose to include that amount as part of business severance damages in its October 20, 2026 testimony." Ex. CCSF-006 – Prepared Direct Testimony of Mark Fulmer on Behalf of City and County of San Francisco at 21 (Apr. 20, 2026) ("Fulmer Testimony").

would be extremely challenging, costly, and—based on PG&E's historical experience—largely unsuccessful.

Finally, we explain in this Chapter why it is essential that the Commission (1) update its business severance damages finding after the close of this proceeding to coincide with the date of asset transfer; and (2) impose on CCSF the obligation to pay these amounts to ensure rate neutrality for PG&E and its remaining customers.

B. Overview of Business Severance Damages Methodology (Sponsored by David Rubin)

CCSF's proposed taking would cause significant financial harm.

To determine business severance damages, I first forecast "lost revenues," or the annual amounts that PG&E would expect to receive from its existing and future electric customers (both retail and wholesale) within San Francisco over a 30-year time horizon starting with the Petition Date. I then add "additional assets" in the form of regulatory account balances and other assets associated with costs incurred prior to the Petition Date but not forecasted in rates. I then subtract "avoided costs," or forecasts of the annual expenses and revenue requirements associated with the rate base as of the Petition Date and ongoing capital investments that PG&E would avoid if it were no longer the owner and operator of the San Francisco electric transmission and distribution assets that CCSF proposes to take. I converted all annual amounts back to the Petition Date by applying the trust rates of return that the funds would be expected to earn while awaiting incorporation into the rates that PG&E's non-San Francisco customers would pay.[10] We also include a tax gross-up to ensure that the tax

[10] The exceptions are the Wildfire Hardening Charge and Recovery Bond Charge/Recovery Bond Credit, which are discounted using the 2021 returns realized by the Special Purpose Entities that manage these funds.

consequences of the business severance damages award CCSF must pay to PG&E do not adversely impact PG&E's non-San Francisco customers.[11]

The result of this calculation constitutes the total business severance damages necessary to make PG&E and its customers outside of San Francisco whole.

I summarize this methodology in Figure 8.1-1 and describe it immediately below.

FIGURE 8.1-1
TOTAL BUSINESS SEVERANCE DAMAGES FORMULA

Total Business Severance Damages = (LR + AA – AC) + T

Where:

LR = Lost Revenues

AA = Additional Assets

AC = Avoided Costs

T = Tax Gross-up

Lost Revenues. To calculate PG&E's lost revenues from existing and future San Francisco electric customers, I started with the amounts that PG&E billed to its retail and wholesale customers in San Francisco in 2021 and forecasted these amounts over 30 years. Table 8.1-1 provides these figures by revenue component or charge. I based my forecast primarily on information that PG&E provided to the California Energy Commission ("CEC") in its 2021 Integrated Energy Policy Report ("IEPR"), along with other data sources described below. The loss of these revenues would financially harm PG&E's

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11 CCSF witness Mark Fulmer opines that PG&E's balance sheet and credit profile could improve following the acquisition. *See* Fulmer Testimony at 22. Yet CCSF subsequently confirmed that Mr. Fulmer had not identified any additional analyses supporting this proposition. *See* CCSF Response to PG&E Data Request Set 16, No. 10; CCSF Response to PG&E Data Request Set 17, Nos. 22, 23. CCSF identified no rating-agency review, capital-market analysis, utility precedent study, debt-capacity analysis, or other investigation demonstrating that a utility experiencing the loss of a substantial portion of its customer base and asset footprint would necessarily experience an offsetting reduction in financing costs. To ensure that customers receive full protection from cost-shifts, PG&E has not included any such speculative benefit in calculating its business severance damages.

customers outside of San Francisco because these revenues cover costs that non-San Francisco customers would bear after CCSF's taking. I also included revenues earned through PG&E's Non-Tariff Products and Services ("NTP&S") in San Francisco, as the associated net income benefits all retail electric customers.

TABLE 8.1-1
AMOUNTS BILLED TO PG&E'S CUSTOMERS IN SAN FRANCISCO IN 2021 BY REVENUE COMPONENT (MILLIONS OF DOLLARS)

Line No.	Revenue Component	2021 Electric Amounts Billed
1	Generation	$49
2	Distribution	$271
3	Transmission	$121
4	Public Purpose Program Charge	$56
5	Nuclear Decommissioning	$4
6	Competition Transition Charge	$0.4
7	Energy Cost Recovery Amount	$1
8	Wildfire Fund Charge	$22
9	New System Generation Charge	$14
10	Wildfire Hardening Charge	$0.1
11	Recovery Bond Charge	N/A
12	Recovery Bond Credit	N/A
13	Power Charge Indifference Adjustment	$137
14	Green Tariff Shared Renewables	$4
15	Climate Credit	$14
16	Non-Tariff Products and Services	$27
17	Total San Francisco Billed Revenues	$719

Additional Assets. I then added pro rata amounts[12] representing San Francisco electric customers' share of the July 2021 balances for various Wildfire Mitigation and Catastrophic Event ("WMCE") regulatory accounts, and deferred taxes associated with flow through / flow back tax accounting. These accounts included costs incurred as of the Petition Date but that were not reflected in the 2021 IEPR revenue requirements. I also included Construction Work in Progress ("CWIP") associated with specific San Francisco projects that were incomplete and not included in rate base as of July 27, 2021. Finally, I've added Accounts Receivable associated with the amounts that PG&E billed to its customers in San Francisco, as well as energy consumed but not yet billed as of

[12] The specific San Francisco percentages vary based on the characteristics of the account. This is explained further in Section C.3.

the Petition Date. Like lost revenues generally, these amounts represent financial harm that would be borne by PG&E and its non-San Francisco customers and that require compensation from CCSF to keep them neutral to the proposed taking.

TABLE 8.1-2
CCSF'S SHARE OF ADDITIONAL ASSETS AS OF PETITION DATE
(MILLIONS OF DOLLARS)

Line No.	Asset	Total Account Balance	CCSF Share
1	Wildfire Mitigation and Catastrophic Event	$1,815	$81
2	Deferred Taxes	$1,850	$166
3	Construction Work in Progress	N/A	$175
4	Accounts Receivable	N/A	$127

Avoided Costs. I then subtracted the costs that PG&E would not incur were it no longer providing electric service to its San Francisco customers. To determine these avoided costs, I started with PG&E's annual revenue requirements for the rate base of the distribution and transmission assets that CCSF proposes to take.[13] As reported in Chapter 6, the rate base as of the Petition Date was $2.44 billion.[14] I then deducted the following:

1) the annual revenue requirements tied to the capital investments that PG&E would no longer make in distribution and transmission facilities in San Francisco;[15]
2) PG&E's annual operating costs for the distribution and transmission assets and associated customer service costs that it would no longer incur;[16]
3) the annual direct benefits that PG&E's electric customers in San Francisco would no longer receive via the various public policy programs that PG&E's electric rates support (such as those in the Public Purpose Program and Distribution charges);

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13 The specific values are the same as those used as part of the Income Approach described in Chapter 5.

14 *See* PG&E Testimony, Ch. 6 (Hegarty *et al.*) at 3.

15 The specific values are the same as those used as part of the Income Approach described in Chapter 5.

16 *See* PG&E Testimony, Ch. 8.2 (Alary) at 3.

4) the annual costs for PG&E to provide generation service to its bundled customers in San Francisco;
5) the annual costs associated with PG&E's Non-Tariff Products and Services offerings in San Francisco; and
6) the annual local fees and taxes associated with PG&E's electric service in San Francisco that it would no longer contribute to CCSF were the taking to occur.[17]

The value of the avoided costs as of the Petition Date is shown in Table 8.1-3.

TABLE 8.1-3
VALUE OF AVOIDED COSTS FROM JULY 27, 2021 THROUGH 2051
(MILLIONS OF DOLLARS)

Line No.	Revenue Component	2021–2051
1	Generation	($1,354)
2	Distribution	($15,886)
3	Transmission	($5,087)
4	Public Purpose Program	($104)
5	Non-Tariff Product and Services	($722)
6	Local Fees and Taxes	($942)
7	Subtotal	($24,096)

The sum of lost revenues and other assets, net of avoided costs, measures the *pre-tax* economic harm to PG&E and its non-San Francisco customers; however, it does not ensure neutrality. True just compensation requires CCSF to compensate PG&E for the associated tax consequences so that PG&E is "in as good [a] position pecuniarily" as if the Subject Assets had not been taken.[18] Because most of CCSF's severance payment will constitute taxable income to PG&E in the year it is received, my calculation includes a separately determined tax gross-up on PG&E's net business severance damages. This gross-up is necessary to ensure that, after taxes are paid on CCSF's damage award, the full

[17] This includes Franchise Fees, the San Francisco Business Tax and San Francisco Sales/Use Tax. Property Taxes associated with distribution and transmission assets in San Francisco are reflected in those avoided revenue requirements. The July 27, 2021 amounts for each of distribution and transmission property taxes were $1.12 billion and $0.54 billion, respectively.

[18] Interim Decision at 25 (citation omitted).

amount of business severance damages remains available to offset the cost shift to PG&E and its non-San Francisco customers due to CCSF's taking.

The amount of the tax gross-up associated with the net business severance damages amount is $1.83 billion. Finally, I have added the Trust Income Tax and Operative Reserve associated with the trust structure proposed to return the customer damages through rates.[19]

Table 8.1-4 summarizes PG&E's total business severance damages.

TABLE 8.1-4
BUSINESS SEVERANCE DAMAGES BY RATE COMPONENT JULY 27, 2021 THROUGH 2051
(MILLIONS OF DOLLARS)

Line No.	Revenue/Cost Component	SF Customer Lost Revenues	SF Customer Avoided Costs	Total Business Severance Damages
1	Generation	$1,475	($1,354)	$121
2	Distribution	$18,089	($15,886)	$2,203
3	Transmission	$4,539	($5,087)	($548)
4	Public Purpose Program	$2,018	($104)	$1,913
5	Nuclear Decommissioning	$38	-	$38
6	Competition Transition Charge	$0.4	-	$0.4
7	Energy Cost Recovery Amount	$5	-	$5
8	Wildfire Fund Charge	$273	-	$273
9	New System Generation Charge	$39	-	$39
10	Wildfire Hardening Charge	$316	-	$316
11	Recovery Bond Charge	$797	-	$797
12	Recovery Bond Credit	($797)	-	($797)
13	Power Charge Indifference Adjustment	$1,061	-	$1,061
14	Non-Tariff Products and Services	$1,011	($722)	$289
15	Wildfire Mitigation Catastrophic Event	$81	-	$81
16	Deferred Taxes	$166	-	$166
17	Construction Work in Progress	$175	-	$175
18	Accounts Receivable	$127	-	$127
19	Local Fees and Taxes	-	($942)	($942)
20	Total	$29,413	($24,096)	$5,317
21	Tax Gross-Up	-	-	$1,826
22	Grossed-Up Business Severance Damages			$7,144
23	Trust Income Tax & Operative Reserve			$470

[19] *See generally* PG&E Testimony, Ch. 10 (Rogers).

24	Total Business Severance Damages			$7,614

Municipal Departing Load Tariffs. We also forecast the revenues, net of the associated billing and collection costs, that PG&E might recover, if any, directly from departing San Francisco customers.

The Legislature and the CPUC have, in some instances, declared certain State policy charges to be eligible for recovery from so-called "municipal departing load" ("MDL") consumers, *i.e.*, those consumers located within PG&E's service territory who receive their electric delivery service from a publicly owned utility ("POU"). These charges are deemed to be "non-bypassable charges" ("NBCs") to MDL consumers. The relevant PG&E tariffs that identify these NBCs are E-TMDL (Transferred Municipal Departing Load) and E-NMDL (New Municipal Departing Load). TMDL customers are those who were initially connected to PG&E's electric transmission and distribution system prior to departing in order to receive POU service. NMDL customers are POU customers who never received service from PG&E but are located within PG&E's service area as it existed on February 1, 2001.

The specific charges included in the MDL tariffs as of the Petition Date were the Competition Transition Charge, Nuclear Decommissioning Charge, Energy Cost Recovery Amount, and Wildfire Fund Charge. The Vintaged Power Charge Indifference Adjustment and New System Generation Charge were and remain conditionally non-bypassable to MDL.[20] The Recovery Bond Charge/Recovery Bond Credit and Wildfire Hardening Charge were added shortly after the Petition Date.[21] Thus, only a fraction of the shifted costs is within the tariffs.

Importantly, and as Mr. Hoppes explains in detail in Section H, collecting these charges from San Francisco customers after CCSF's proposed taking would be extremely challenging: as PG&E has experienced in prior municipalizations, customers who do not receive electric service from PG&E will

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20 Specifically, in order for these latter two charges to apply to MDL, the IOU must file an application with the CPUC to demonstrate that the POU effort represents a "large municipalization."

21 *See generally* D.21-06-030 (Wildfire Hardening Charge) and D.21-05-015 (Recovery Bond Charge/Recovery Bond Credit); *see also* AL 6448-E (Wildfire Hardening Charge) and AL 6568-E (Recovery Bond Charge/Recovery Bond Credit).

generally not pay electric bills that they receive from it, and enforcement of outstanding payment obligations is highly impractical, if not impossible.

C. Background of PG&E's Customer Base and Electric Charges (Sponsored by David Rubin)

1. Description of PG&E's San Francisco Customer Base

PG&E provides tariffed electric delivery services to six categories of customers within the footprint of San Francisco, largely distinguishable based on their jurisdictional status (retail vs wholesale) and their source of generation supply (PG&E vs third parties). These categories are:

1) **Bundled Customers:** Retail customers who receive distribution, transmission,[22] and generation supply from PG&E. In 2021, this category represented 535 gigawatt-hours ("GWh") of consumption.
2) **Community Choice Aggregation ("CCA") Customers:** Retail customers who receive electric distribution and transmission services from PG&E but receive generation supply from CCSF's CCA, CleanPowerSF. In 2021, this category represented 2,871 GWh of consumption.
3) **Direct Access ("DA") Customers:** Retail customers who receive distribution and transmission services from PG&E but receive their generation supply from a third-party Energy Service Provider ("ESP"). In 2021, this category represented 540 GWh of consumption.
4) **Bay Area Rapid Transit ("BART"):** BART is able to acquire its own power in the wholesale market and arranges transmission services with the California Independent System Operator ("CAISO") due to special legislation passed in 1995.[23] At the time of the Petition, BART paid CPUC-jurisdictional retail Distribution, Public Purpose Program, and Nuclear Decommissioning charges. The Wildfire Hardening Charge and

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[22] Technically, the California Independent System Operator ("CAISO") provides transmission service, primarily relying on transmission assets that PG&E and other California Participating Transmission Owners ("PTO") own. To date, CCSF has not stated whether it will certify as a PTO. *See* CCSF Response to PG&E Data Request Set 3, No. 4; Set 15, No. 10e.

[23] Senate Bill 184 (Chapter 681, Statutes of 1995).

Recovery Bond Charge/Recovery Bond Credit were added subsequently.

5) **Wholesale Distribution Tariff ("WDT") Customers:** PG&E provides wholesale distribution to the San Francisco Public Utilities Commission ("SFPUC") for service to approximately 6,000 delivery points throughout San Francisco as of 2024.[24] The SFPUC then arranges transmission service with the CAISO and provides generation services. In 2021, this category represented approximately 580 GWh of consumption.[25]

6) **The Presidio*:*** The Presidio Trust provides electric delivery and supply services to approximately 3,000 residents and businesses in the Presidio.

PG&E serves the first three categories of customers—which collectively constitute retail load—pursuant to CPUC-jurisdictional rates, terms, and conditions. The fourth category, BART, pays a hybrid of CPUC- and Federal Energy Regulatory Commission ("FERC")-jurisdictional charges. The fifth and sixth categories constitute wholesale load and are subject to FERC jurisdictional tariffs. In 2021, retail load was 86% of total consumption within San Francisco. The remaining 14% was a combination of BART, CCSF wholesale load and the Presidio.

Finally, as part of Non-Tariff Products and Services ("NTP&S"), PG&E provides products and services to third parties using Subject Assets, such as telecommunications companies who connect their facilities to PG&E's assets, occupy space in underground conduits, and utilize available fiber. As described in Chapter 8.3, the vast majority of the revenues associated with NTP&S benefit all electric customers via a credit to Distribution revenue requirements.[26]

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24 *See* Overview of Hetch Hetchy Power and CleanPowerSF (March 22, 2024), Rate Fairness Board at 2, available at https://www.sfpuc.gov/sites/default/files/agendas-minutes-rate-fairness-board/Item5_RFB_Overview_CleanPowerSF_HetchHetchy_Power2024.03.22.pdf.

25 Since PG&E currently bills CCSF's customers for distribution service under the WDT based on demand (kW), I have estimated total GWhs for 2021 based on historical consumption patterns.

26 *See* PG&E Testimony, Ch. 8.3 (Delaney) at 3–4.

2. Description of Electric Charges Billed to Customers[27]

PG&E incurs costs and collects revenues to recover those costs through several discrete revenue components ("charges"). In some instances, the charge targets a narrow need. For example, the Wildfire Hardening Charge ("WHC") and Recovery Bond Charges ("RBC") are collected by PG&E, on behalf of special purpose entities, to service debt payments owed by the special purpose entities for debt previously issued by the special purpose entities. The WHC and RBC charges are related to specific debt obligations to repay principal and interest due on bonds that have already been issued by the special purpose entities. The proceeds from those bond offerings were used to fund investments related to preventing and mitigating catastrophic wildfires. In other instances, the charge may fund a broad range of utility activities and programs. The Public Purpose Program ("PPP") Charge supports market energy efficiency, research and development, low-income energy efficiency and low-income rate support. It also supports other California energy policy initiatives such as power procurement from various non-traditional sources (such as biomass), residential undercollections, and electrification for disadvantaged communities.[28]

It is important to note that PG&E's retail rates are geographically uniform throughout its service territory regardless of the different costs to serve each area.[29] PG&E generally pools the costs to serve all of its 5.6 million electric customers throughout Northern and Central California, and then sets rates uniformly across this broad geography to recover those costs, distinguishing rates only by customer class (residential, commercial, industrial, agricultural,

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27 As described in Section C.1, PG&E serves both retail and wholesale customers in San Francisco. Much of the discussion that follows relates to those charges applicable to retail customers that PG&E serves pursuant to CPUC jurisdictional terms and conditions. PG&E's wholesale rates are set at FERC, and while the revenues that PG&E receives for wholesale distribution service are included in the determination of business severance damages, the following descriptions focus on CPUC jurisdictional rates.

28 *See* Appendix II for a description of the programs funded by the Public Purpose Program Charge as of the Petition Date.

29 The only exception to this geographic uniformity is PG&E's tiered rate design for residential customers, where rates increase based on consumption thresholds. The consumption threshold varies by climate zone.

streetlights), seasonality, and time of use. Accordingly, the actual revenues that PG&E charges and collects from its customers in San Francisco, or for that matter anywhere else throughout PG&E's service area, do not match the actual underlying costs associated with providing service in that particular area. The Commission acknowledged this fact in the Interim Decision:

> "…[O]n the theory that the cities and towns of California profit by the orderly development of the entire state, it has long been the Commission's practice, in so far as practical, to level rates throughout a utility's territory in order that the rural areas might benefit through service at reasonable rates. This practice has, of course, often resulted in rates of return from congested areas which consistently were above the average return for the entire system."[30]

Based on this, the Commission went on to find:

> "The customer accounts, and the revenues they produce, are a major part of what is being taken. One of the highest density portions of PG&E's system is being removed from PG&E's whole system, where the revenues may be greater than the cost to serve, helping to offset costs in rural regions."[31]

This is particularly significant with respect to charges that fund wildfire-related activities. In that context, wildfire risk and the costs to mitigate that risk, are far greater in rural areas than in highly-urban, more densely-populated areas like San Francisco.

In the remainder of this section, I describe each charge that I have included in my business severance damages calculation. I identify those charges that have been deemed by the Legislature and/or Commission as a non-bypassable charge to municipal departing load ("MDL"). However, this distinction is not relevant to my inclusion of particular charges as part of business severance damages, consistent with the direction provided in the Interim Decision.[32] It is only material as to whether they are part of the

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30 Interim Decision at 24 (quoting D.35985 (1938 App. No. 21960) at 17–18).

31 *Id.* at 30.

32 *See id.* at 35–36 ("In addition, business severance damages must provide a specific sum that represents PCIA, safety, reliability, wildfire mitigation, public benefit, stranded asset costs, joint and common costs, public purpose charges, and other pass-through costs, stranded costs and stranded assets, and account for which portion, if any, would be recovered in TMDL tariff[.]").

amounts that could theoretically be collected under the TMDL tariff—as discussed further in Section H.

I also report the revenues that PG&E billed to San Francisco retail and wholesale electric customers for each charge in 2021. I then present forecasted revenues that would be billed to San Francisco customers for each charge in Section D. Consistent with the Interim Decision, CCSF should be required to pay a business severance damage that includes the forecasted lost revenues associated with these charges, plus San Francisco's pro-rata share of various regulatory accounts and assets, net of avoided costs (forecasted in Section E), to avoid harming PG&E's other customers. And as described in Section G, this amount should be grossed-up to include taxes in order to ensure that PG&E and its non-San Francisco customers are held harmless.

a. Generation Charge

The Generation Charge recovers the costs of generating and/or procuring electric energy, capacity, and related services. As described in Section C.1, PG&E's San Francisco electric customers largely receive their generation supply from non-PG&E market participants. These include CCSF's Community Choice Aggregation Program ("CleanPowerSF") and Energy Service Providers for retail customers, and Hetch Hetchy Power for CCSF's wholesale customers. The percentage of the load within San Francisco that received its generation supply from PG&E in 2021 was 11%. PG&E billed $48.7 million to its San Francisco customers for this generation supply through the Generation Charge in 2021.

b. Distribution Charge

The Distribution Charge supports the costs of designing, engineering, financing, installing, operating, and maintaining PG&E's electric distribution grid throughout its Northern and Central California service territory. At the time of the Petition, this charge covered:

- The costs associated with PG&E's ownership and maintenance of the foundational infrastructure that delivers electricity to homes and businesses (poles, cables, conduits, transformers, etc.)

- Subaccounts for recovering various wildfire mitigation costs
- Costs of the following energy policy programs, some of which I discuss in more detail in Appendix I:
  - Electric vehicle infrastructure;
  - Demand response;
  - Microgrid support;
  - Mobile home park conversions;
  - PG&E's Self-Generation Incentive Program, which provides tailored rooftop solar, on-site battery, and electrification; and
  - Community renewable programs, which provide clean energy, resiliency and bill savings to qualifying low-income customers.
- The CPUC Fee that supports funding for the Commission.[33]

PG&E billed its San Francisco customers $270.9 million in 2021 through the Distribution Charge, comprised of $257 million to retail customers and $13.9 million to wholesale customers.

c. Transmission Charges

The Transmission Charge supports the costs of designing, engineering, financing, installing, operating, and maintaining the high voltage and low voltage transmission grid ("Transmission Costs"). FERC sets transmission rates and, since 1998, the CAISO has had operational control over the transmission grid. PG&E recovers its related costs via two charges that the CAISO administers:

- **High Voltage TAC**. PG&E recovers the Transmission Costs associated with its high voltage assets—*i.e.*, those with voltage ratings at or above 200 kilovolts ("kV")—via the High Voltage Transmission Access Charge ("HVTAC"). The HVTAC includes recovery of high voltage Transmission Costs on a uniform cents/kWh basis. Customers throughout the broader CAISO region pay the same HVTAC rate, with the CAISO distributing revenues to the Participating Transmission Owners ("PTOs") based on the

[33] The WDT charge that CCSF and the Presidio Trust pay to PG&E does not include any of these state energy policy programs, nor the CPUC Fee.

revenue requirements associated with their respective high-voltage transmission facilities.

- **Low Voltage TAC**. PTOs recover the costs of their low-voltage transmission assets (voltages below 200 kV) only within their respective geographic regions (so-called "Planning Areas"),[34] via a PTO-specific Low Voltage Transmission Access Charge ("LVTAC"). PG&E's retail customers, including those in San Francisco, represented 87% of the total amount of energy consumed over PG&E's LV grid in 2021.

PG&E billed $104.1 million to its San Francisco retail customers for transmission in 2021. The estimated amount that CCSF, BART and the Presidio paid to the CAISO for combined High Voltage and Low Voltage TACs was $17.3 million, yielding a total of $121.4 million.[35]

d. Public Purpose Program Charge

The PPP Charge initially included funding for programs promoting energy efficiency, renewables, low-income energy efficiency, low-income rate discounts, and research, development and demonstration.[36] The PPP Charge has expanded significantly over the past several decades to include additional programs, including various procurement tools relying on preferred resources, as well as residential uncollectibles and electrification programs for disadvantaged

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34 The PG&E Planning Area includes the following entities: Alameda Municipal Power, Biggs Municipal Utilities, Calaveras Public Power Agency, Gridley Electric Utility, City of Healdsburg, Kirkwood Meadows Public Utility District, Lassen Municipal Utility District, Lathrop Irrigation District, Lodi Electric Utility, City of Lompoc, City of Palo Alto, City of Pittsburg, Plumas-Sierra Rural Electric Cooperative, Power and Water Resource Pooling Authority, Port of Oakland, Port of Stockton, Power Enterprise of SF PUC, Silicon Valley Power, Tuolumne County Public Power Agency, and the City of Ukiah.

35 PG&E is not directly involved in the transaction connected to payments made by these wholesale entities and the CAISO. Therefore, it has relied on actual or estimated energy consumption information, and the relevant HV and LV charges in effect as of the Petition Date in order to calculate the amounts paid.

36 The Legislature created the PPP Charge in 1996 and the Commission implemented it through its Phase I Unbundling Decision. *See generally* AB 1890 (1996); D.97-08-056, 74 CPUC 2d 1, 1997 WL 473091 (1997). Appendix II provides additional detail on programs covered by the PPP Charge.

communities.[37] Appendix II provides additional details regarding the composition of the PPP. PG&E billed $56.0 million in 2021 through the PPP Charge to its San Francisco customers.

e. Nuclear Decommissioning Charge

The Nuclear Decommissioning ("ND") Charge collects revenues for recovering nuclear-decommissioning costs. The creation of the ND Charge stems from the Legislature's recognition that all customers on whose behalf the IOUs constructed carbon-free, base-load nuclear power facilities should contribute to the ultimate retirement of those facilities.[38] As a result, it was deemed to be an NBC applicable to all MDL customers. Through this charge, PG&E collects funds for restoring the sites of PG&E's nuclear power plants following their removal from service. PG&E files an application, called the Nuclear Decommissioning Cost Triennial Proceeding, every three years to present detailed, site-specific decommissioning cost estimates for the Diablo Canyon Power Plant ("DCPP") Unit 1 and 2 and the remaining decommissioning activities at Humboldt Bay Power Plant ("HBPP").[39] These costs are not avoidable if PG&E ceases to serve San Francisco customers.

PG&E billed $3.8 million to its San Francisco customers through the ND Charge in 2021.

f. Competition Transition Charge (Sponsored by Marcus Keller)

The Competition Transition Charge ("CTC") supports IOU recovery of above-market costs that IOUs incurred through power supply contracts with "Qualifying Facilities," *i.e.*, independent power producers using specific technologies identified in federal law. The Legislature and the Commission developed and implemented the charge in connection with the transition to a market structure that gave customers the choice

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37 For PG&E, the total revenue requirement forecast for the PPP in 2021 was $0.97 billion, representing 7.0% of PG&E's electric revenue of $13.80 billion for that year. By contrast, PG&E's PPP in 1997 was $0.27 billion, representing roughly 3% of PG&E's electric revenue requirement.

38 The California Legislature allowed for recovery for such costs in AB 1890 (1996). *See also* Pub. Util. Code § 379.

39 The last decision that the Commission issued on the ND Charge was D.21-09-003.

of alternative retail generation suppliers.[40] The Legislature's objective was to ensure recovery of these above-market costs of defined power supply commitments incurred by IOUs before customers could choose these alternative suppliers. The CTC applies broadly to MDL as an NBC.[41] These costs, comprised of longstanding power purchase commitments, are not avoidable if PG&E ceases to serve San Francisco customers.

PG&E billed $0.4 million to its San Francisco customers through the CTC in 2021.

g. Energy Cost Recovery Amount

The Energy Cost Recovery Amount ("ECRA") Charge was originally implemented to replace the Regulatory Asset Charge that helped resolve PG&E's 2001 Chapter 11 proceeding.[42] It currently reflects the amounts that PG&E collects from third parties and conveys to customers as a result of settlement agreements with sellers of energy to resolve claims related to the 2000-2001 Energy Crisis. In any given year, the amounts may be positive or negative, depending on the operation of balancing accounts. It is included as an NBC to MDL.

PG&E billed $1.2 million to its San Francisco customers through the ECRA Charge in 2021.

h. Wildfire Fund Charge

The Wildfire Fund Charge ("WFC") originated from the Legislature's determination that it is in the public interest to establish a Wildfire Fund as a means of managing future wildfire claims.[43] The Wildfire Fund is capitalized with contributions from both ratepayers and shareholders of large electric corporations, including PG&E.

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40 *See generally* AB 1890 (1996); *see also* D.95-12-063, 166 P.U.R. 4th 1, 1996 WL 47921, at *1 (1996) ("Our objective continues to be the collection of transition costs through the imposition of a non-bypassable Competitive Transition Charge (CTC).").

41 There are limited load-specific exemptions for self-generation and cogeneration, historical irrigation and water district allocations, among others. *See, e.g.*, Pub. Util. Code §§ 372, 374.

42 *See generally* D.04-11-015.

43 *See* AB 1054 (2019); *see also* Pub. Util. Code § 3289(a); *see also generally* D.19-10-056, D.20-07-014, D.20-09-005 and D.20-09-023 (imposing the WFC).

The WFC commenced on October 1, 2020 and replaced the California Department of Water Resources ("DWR") Bond Charge on customers' bills. The WFC is the property of the California Department of Water Resources for all purposes under California law. It is non-bypassable to all categories of customers that previously paid the DWR Bond Charge, including MDL. Notable exceptions include CARE and Medical Baseline customers, as well as continuous Direct Access customers. In D.19-10-056, the Commission established an annual revenue requirement for PG&E of $404.6 million for the WFC. The Commission ordered this revenue requirement to remain in effect until January 1, 2036.

PG&E billed $21.5 million through the Wildfire Fund Charge to its San Francisco customers in 2021.

i. New System Generation Charge / Cost Adjustment Mechanism (Sponsored by Marcus Keller)

The New System Generation Charge ("NSGC"), also called the Cost Adjustment Mechanism ("CAM"), was adopted by the Commission in D.06-07-029 so that IOUs could collect costs associated with new generation determined by the Commission to be needed to meet system and/or local reliability. In D.20-06-002, the Commission established that PG&E and SCE would serve as the Central Procurement Entity ("CPE") in order to provide local capacity for all CPUC-jurisdictional Load Serving Entities throughout their respective distribution service areas. Overall, there are three specific types of capacity necessary to ensure reliable operation of the electric grid: (i) system; (ii) flexible; and (iii) local.[44] Each form of capacity plays an important role in ensuring that overall supply can instantaneously meet demand.

Prior to the Commission establishing PG&E as the CPE for its distribution service area, the Commission had authorized PG&E to

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[44] System capacity ensures that there is sufficient generating capacity to meet forecasted system-wide demand with an adequate reserve margin to capture forecasting error, unit outages, and other foreseen conditions. Flexible capacity ensures that there is enough generating capacity available to ramp up quickly to balance intermittent generation and load changes throughout the day. Local capacity ensures that there is sufficient capacity in transmission constrained areas or load pockets.

recover costs through its NSGC/CAM for procurement that it identified as necessary to support reliability, including procurement directed by the Commission in Resolution E-4909 to meet specific local area needs in three of PG&E's local subareas. After the Commission directed PG&E and SCE to serve as the CPE for all local capacity or Resource Adequacy ("RA") requirements within their respective distribution service areas, procurement costs recovered through the NSGC/CAM expanded to include both long-term commitments for new resource development within their respective local areas as well as procurement with existing resources needed to ensure compliance with local reliability requirements.

In D.08-09-012, the Commission established a test by which it would determine whether MDL customers were required to pay this charge as a departing load charge under E-TMDL and E-NMDL. Specifically, the Commission found that MDL customers must pay the NSGC/CAM if the IOU demonstrates that the particular municipalization effort is large enough that it was not reflected in the IOU's forecast underpinning its energy procurement activities.[45] In Appendix III, Mr. Rubin describes his investigation regarding whether either party—PG&E or CCSF—provided a forecast that reflected a CCSF municipalization effort as part of any long-term procurement proceeding. In short, Mr. Rubin found no such evidence.

PG&E billed $13.6 million to its San Francisco customers through the NSGC/CAM in 2021.

j. Wildfire Hardening Charge

The Legislature has provided that the three large IOUs' first $5 billion of fire risk mitigation capital expenditures in approved wildfire mitigation plans will be excluded from the utilities' equity rate base and instead financed with debt, and that such capital expenditures and associated debt may be financed through securitization.[46] PG&E's

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[45] *See* D.08-09-012 at 29 ("The IOU has the burden to show the departures are within the definition of a large municipalization, especially as it relates to how the large municipalization is or is not reflected in the adopted LTPP load forecasts.").

[46] *See generally* AB 1054 (2019); *see also* Pub. Util. Code § 8386.3(e).

current share of such expenditures is $3.21 billion; pursuant to three Commission financing orders,[47] a special purpose entity, wholly-owned by PG&E, has issued Recovery Bonds in that amount to securitize fire risk mitigation capital expenditures.

The Commission's Financing Orders authorizing securitization of fire risk mitigation capital include the Commission's irrevocable commitment to permit rate recovery of principal and interest on the Recovery Bonds over their terms (generally, 30 years) via a non-bypassable Wildfire Hardening Charge (WHC) on all non-CARE and non-FERA customers' bills.[48] For financial accounting purposes, the right to receive the WHC is recorded as a regulatory asset. The Commission should follow the same approach for the fire risk mitigation capital securitization as it does for the Recovery Bond securitization described in Section C.2.k below.

The Financing Orders authorizing the securitization of fire risk mitigation capital also irrevocably commit the Commission, in the event of a condemnation of utility assets, to authorize recovery of the amounts by the new asset owner either through a collect-and-remit process or by an up-front payment.[49] PG&E believes that a collect-and-remit process is a better approach.

This monthly remittance approach is more consistent with the enabling legislation, the Commission's decisions and financing orders, and securitization contracts, and avoids benefiting current ratepayers at the expense of future ratepayers and minimizes regulatory and rating-agency risks. The financing orders and the servicing agreement both require that true-up of collections—remitted versus collections actually received—must occur at least semi-annually. Under the servicing agreements, collections are remitted to the collection accounts and reconciliations must be completed within 60 days of the payment date under the servicing agreements. The securitizations were structured

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47 *See generally* D.21-06-030, D.22-08-004, and D.24-02-011.

48 D.21-06-030 at 115, 119 (Ordering Paragraph (OP) 1, 11); D.22-08-004 at 110, 114–15 (OP 1, 11).

49 D.21-06-030 at 108, 120 (Conclusion of Law (COL) 47, OP 13); D.22-08-004 at 103–04, 115 (COL 47, OP 13).

around ongoing collections, semi-annual true-up adjustments and 60-day reconciliations. An up-front payment could significantly reduce or temporarily suspend charges during future true-up periods because the excess collections would affect the true-up calculations. This creates an inequitable rate impact: current ratepayers receive the benefit of the up-front payment, while future ratepayers are asked to subsidize current ratepayers by paying disproportionately higher rates in the future.

The monthly remittance approach is also consistent with the objectives underlying the State Pledge.[50] Under the State Pledge, the State of California committed that it will not take actions that will limit, alter, or impair the collection of the fixed recovery charges until the recovery bonds have been paid in full. Requiring a successor public owner to continue collecting the applicable charges from municipal departing customers and remitting those amounts for bond repayment preserves the existing collection framework, reduces under-collection risk, and helps protect the stability of the Wildfire Hardening Charge and bondholder interests, which was the objective of the State Pledge.

In this phase of the proceeding, the Commission's order should identify the up-front payment amount as a severance damage but should state that the Commission would remove the up-front payment from the up-front severance damage award if and when the Commission orders CCSF to collect and remit the charges.

PG&E billed $0.1 million through the WHC to its San Francisco customers in 2021.

k. Recovery Bond Charge (Fixed Rate Charge)

Pursuant to SB 901 (2018), as implemented by D.21-04-030 and D.21-05-015, a special purpose entity, wholly owned by PG&E, has issued $7.5 billion of rate-neutral securitized bonds to retire temporary debt that it incurred to finance its Plan of Reorganization and to fund deferred payments to the Fire Victims Trust. The special purpose entity completed the Rate-Neutral Securitization and issued two series of debt financings: $3.6 billion in May 2022 and $3.9 billion in July 2022.

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50 *See* Pub. Util. Code § 850.1(e).

Based on customer consumption estimates and growth projections, the Commission approved, in D.21-05-015, a 30-year plan through which all non-CARE and non-FERA PG&E customers[51] repay the principal and interest due on the bonds via the Recovery Bond Charge ("RBC"). If customers within a defined geography no longer take transmission and distribution retail service from PG&E, they nonetheless remain obligated to continue to pay the RBCs.[52] To prevent PG&E from losing RBC revenues from San Francisco customers, which would shift those revenue obligations to other PG&E customers, the Commission should require CCSF to "bill and collect" from San Francisco customers "and remit such collections to PG&E."[53]

D.21-05-015 affirms this conclusion and includes an irrevocable commitment by the Commission to ensure that the new asset owner, in the case of condemnation, either provides an upfront payment or continued collection of the charges by the new asset owner (here, CCSF) with remission to PG&E.[54] As described in Section C.2.j above regarding the Wildfire Hardening Charge, PG&E prefers the latter method because, based on the size and complexity of the financing, this would be simpler and more effective than requiring an upfront, lump sum payment. PG&E will likely ask for a collect-and-remit method at the appropriate time. However, since the CPUC's task in this proceeding is to value the just compensation for severance damages in a single sum, this Chapter contains the information necessary for the Commission to value a one-time payment.

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51 Non-CARE/non-FERA customers represented approximately 93% of CPUC-jurisdictional consumption in San Francisco in 2021.

52 D.21-05-015 at 102–03 (OP 15).

53 D.21-05-015 at 90–91 (COL 65 (footnotes omitted)).

54 D.21-05-015 at 90–91, 113 (COL 65 (footnotes omitted), OP 55).

l. Recovery Bond Credit

The Commission established the Customer Credit Trust ("CCT") to serve as a source of revenues to fund credits to customers that offset the Recovery Bond Charge.[55]

In D.21-05-015, the Commission deferred addressing how the Customer Credit would be applied to departing load customers in a municipalization scenario.[56] As noted, PG&E proposes a collect and remit approach to the Recovery Bond Charge and Recovery Bond Credit, in which the customers who pay the RBCs on an ongoing basis (via CCSF) should receive the same credit from the CCT as PG&E's customers outside of San Francisco. If a collect and remit process is not ordered for the Recovery Bond Charge and Recovery Bond Credit, then PG&E proposes that the Commission decide how to address the Recovery Bond Credit as part of the update process in this proceeding.

m. Vintaged Power Charge Indifference Adjustment (Sponsored by Marcus Keller)

The Vintaged Power Charge Indifference Adjustment ("PCIA") ensures that customers receiving their energy supplies from third party providers—including ESPs and CCAs—would be financially responsible for energy supply commitments undertaken on their behalf and that the Commission approved.[57] The PCIA captures the above-market costs associated with renewable resources tied to PG&E's Renewable Portfolio Standard ("RPS") obligations, as well as above-market costs associated with large hydroelectric GHG-free and conventional power

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55 *See generally* D.21-05-015.

56 *Id.* at 74 n.43.

57 The Commission implemented the Vintaged PCIA in 2008 in its Decision on Non-Bypassable Charges for New World Generation and Related Issues. *See generally* D.08-09-012. Subsequent litigation regarding the elements, methodology, and applicability of the PCIA led to several additional CPUC decisions on these matters most recently in D.18-10-019 and D.19-10-001, prior to the Petition Date. PG&E's MDL Tariffs provide a reference to the Power Charge Indifference Adjustment, which was associated with the power contracts executed by the Department of Water Resources during the energy crisis. The Vintaged Power Charge Indifference Adjustment was introduced in 2008 and is referenced in the MDL tariffs in Special Condition 2e.

supply commitments that help ensure PG&E's and the State's reliable and balanced operation of the power grid.

Most of PG&E's customers in San Francisco already pay a Vintaged PCIA. As described in Section C.1, CCSF operates a CCA, CleanPowerSF, which served over 70% of the retail load in San Francisco in 2021; CleanPowerSF customers have a vintage PCIA consistent with CleanPowerSF's phase-in. The same is true for DA customers within San Francisco that receive their power supply from ESPs. The rest of the retail load in San Francisco—that is, PG&E customers within San Francisco that received generation from PG&E—paid a "Bundled" PCIA in 2021.[58]

Similar to the NSGC/CAM,[59] the Commission determined in D.08-09-012 that the Vintaged PCIA would apply to MDL if the IOU demonstrates that a particular municipalization effort is large enough that it was not reflected in the IOU's forecast underpinning its energy procurement activities. In Appendix III, Mr. Rubin indicates that he found no evidence that either party—PG&E or CCSF—provided a forecast that reflected a CCSF municipalization effort as part of any long-term procurement proceeding.

The total Vintaged PCIA that PG&E billed in 2021 to its San Francisco customers was $137.1 million.

n. Green Tariff Shared Renewables

PG&E offers an optional rate for customers who seek to procure power from designated renewable projects located generally within its service area. Rates for this service are designed to ensure that participating customers cover the costs associated with the specific projects that supply the power that they consume.

PG&E billed $3.4 million through this tariff option to its San Francisco customers in 2021.

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58 In calculating its PCIA-related severance damages, PG&E has applied the vintage inputs for the portion of load that CleanPowerSF and Direct Access providers serve in San Francisco, as well as a 2021 vintage for bundled customers.

59 *See supra*, § C.2.i.

o. California Climate Credit

The California Climate Credit is a semi-annual bill credit associated with the sale of greenhouse gas emission allowances allocated to load serving entities by the California Air Resources Board. It is available almost exclusively for retail residential customers. CCSF witness Mark Fulmer stated: "[T]he departure of the City's load will not affect the remaining ratepayers. This is because the departure would both reduce the allowance allocations per the CARB formulas to PG&E and also the number of remaining PG&E customers over whom the credits are allocated. Overall, the two effects will offset each other, keeping the remaining PG&E customers who receive the credits indifferent."[60] To reflect this indifference in my damages forecast, I added the amount of the California Climate Credit received by PG&E's San Francisco residential customers in 2021 ($13.7 million) to the billed distribution revenues in that year, since billed distribution amounts in April and October reflected these credits. This set the 2021 starting point distribution revenue amount at the appropriate level.

p. Non-Tariff Products and Services

As described further in Chapter 8.3, PG&E is able to use its energy assets to provide various non-tariff products and services.[61] Examples include allowing telecom companies to attach their devices to PG&E's poles and/or streetlight facilities and allowing data transmission companies to place their fiber in PG&E's underground conduit. The Commission regulates services connected to distribution assets and FERC regulates services connected to transmission facilities. As explained more fully in Mr. Delaney's testimony in Chapter 8.3,[62] the net revenues associated with the CPUC jurisdictional services are credited to PG&E's customers via "Other Operating Revenue." The after-tax net revenues associated with the FERC jurisdictional services are split 50:50 between PG&E's customers and its shareholders.

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60 Fulmer Testimony at 19.

61 *See* Ch. 8.3 at 1–3.

62 *See id.* at 3.

In 2021, PG&E generated revenue of $27.2 million from NTP&S in San Francisco. Only a de minimis amount of this total (approximately $5,000 in net income) was tied to FERC-jurisdictional assets.[63] As a result, and as explained more fully in Mr. Delaney's testimony, I treat all NTP&S net revenue as CPUC-jurisdictional for purposes of my calculation of damages amounts.

3. Description of Additional Business Severance Components

As of the Petition Date, there were a number of financial assets on PG&E's books representing costs incurred that would be recovered through rates over time, but were not reflected in forecasts submitted to the CEC as part of the 2021 IEPR. These are described below, along with associated amounts that would be included in the severance damages total.

a. Wildfire Mitigation and Catastrophic Event

Wildfire Mitigation and Catastrophic Event ("WMCE") accounts track costs associated with the wildfire events that occurred in 2017–2019. As of the Petition Date, a significant portion of the costs reflected in these accounts were not yet approved for recovery in PG&E's rates, and not part of the revenue requirement forecast submitted as part of the 2021 IEPR. In order to hold harmless PG&E's customers outside of San Francisco, a pro-rata share of the adjusted July 27, 2021 account balances would need to be allocated to CCSF and paid as a severance damage. To develop the relevant amounts, I interpolated between the balances as of June 30, 2021 and September 30, 2021 to arrive at an imputed Petition Date balance. I then subtracted the amounts that were reflected in lines 54 and 55 of Form 8.1a of the 2021 IEPR Submission. I also reduced the Wildfire Mitigation Plan Memorandum Account balances by the revenue requirements tied to capital investments, as these were likely subsequently included in the Wildfire Hardening Charge.

The net amount included in these accounts as of the Petition Date after the aforementioned adjustments was $1.82 billion.

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63 *See id.* at 4.

b. Deferred Taxes[64] (Sponsored by Tim Wedlake)

Under cost of service ratemaking principles, tax expenses are included in the revenue requirement paid by PG&E's customers. If deductions against taxable income align with those used to determine book value, then the tax expense calculation in the revenue requirement for ratemaking purposes is merely book income times the tax rate. However, tax law permits regulated utilities to accelerate certain tax deductions, which causes the timing recognition of expenditures for tax and book to diverge, creating what is called a "tax and book timing difference." For example, depreciation lives and methods for tax are often shorter and more accelerated than those used for book purposes, resulting in greater tax depreciation than book depreciation in the early years of an asset's life cycle.

Flow-through tax accounting reduces the revenue requirement by the full benefit of lower tax expenses as compared to the book expense[65] with a corresponding increase in the revenue requirement in the later years when tax expense is greater than the book expense. Ultimately all amounts flowed through to customers are eventually flowed back from customers. Until that happens, the utility records the amount of tax flow-back still owed from customers (*i.e.*, the additional revenue requirement for future tax) as a regulatory asset under the Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 109 ("FAS 109").[66] Examples of tax adjustments that use flow-through tax accounting include fiscal/calendar

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64 PG&E applies two tax accounting methods to take account of the book and tax timing differences when calculating the revenue requirement that customers pay: (i) flow-through tax accounting and (ii) normalized tax accounting. For purposes of determining business severance damages due to lost revenue from the proposed taking of the Subject Assets, flow-through tax accounting treatment of these timing differences is relevant, as discussed below.

65 The statutory tax rate times the tax and book timing difference.

66 The naming convention and numbering has been updated from FAS 109 to ASC 740; the substantive content of the guidance is unchanged.

year property tax adjustment, operating expense adjustments, and repairs deductions, among others.[67]

If CCSF takes the Subject Assets, then PG&E would not collect the share of the regulatory asset from San Francisco customers to cover the future flow-back tax expense. Absent recovery as part of business severance damages, remaining PG&E customers would pay the tax (*i.e.*, the flowback that would have been collected in the future from SF customers). CCSF therefore should compensate PG&E for the tax expense that PG&E would have collected from customers in future rates, which is equivalent to the portion of the regulatory asset associated with the Subject Assets that CCSF would condemn.

I determined the system-wide amount as of the Petition Date by interpolating between the year-end 2020 and 2021 levels. As of the Petition Date, that amount was $1.85 billion.

c. Construction Work in Progress

Construction Work in Progress (CWIP) is a category of electric assets that are at various stages of construction/installation at any given point in time. Because they are only partially completed and therefore not in-service, they are not included in rate base. In response to a data request, CCSF conceded that it did not identify nor assign a value to CWIP projects in San Francisco in its testimony and instead deferred the question of whether it would take any CWIP "at the time of acquisition and may be subject to a future determination . . . at the request of the CITY or PG&E."[68]

Since these facilities are neither included in CCSF's nor PG&E's valuation as part of rate base, nor reflected as part of going forward capital additions, they represent a stranded cost. In order to ensure that PG&E's shareholders are not harmed by the proposed taking (since CWIP was not included in the starting point net plant), the CWIP amounts as of the Petition Date should be included as a business

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67 *See* PG&E 2023 GRC, Exh. PG&E-10, Ch. 13 (summarizing each tax and book timing difference and which are treated under flow-through tax accounting and which are treated under normalized tax accounting).

68 *See* CCSF Response to PG&E Data Request Set 26, No. 1.

severance damage. In the event that there is a subsequent determination by CCSF that it will acquire some or all of these assets, the appropriate amounts would then be reflected in a revised Fair Market Value of the assets taken and removed from the business severance damages amount.

d. Accounts Receivable (Sponsored by Shaun Hoppes)

Accounts Receivable are the amounts that PG&E had billed to customers but that customers had not yet paid. Additionally, customers would have owed amounts associated with any energy that they had consumed subsequent to their prior bill. This is because, at the point of any transfer of assets, PG&E would calculate and mail a final bill for each PG&E customer in San Francisco.

As discussed in Section H, once PG&E ceases to provide electric service to customers, it encounters significant difficulty in collecting revenues from these customers. Upon transfer, PG&E will have little, if any, recourse to compel payment of the accounts receivable amounts from its former customers. This is because CCSF's taking would remove PG&E's "ability to enforce payment[s] . . . through refusal to furnish services," which is the only practical way PG&E could compel payment across the tens of thousands of accounts at issue.[69] The amounts outstanding as of the Petition Date are therefore appropriate as a severance damage.[70]

The Commission should award the accounts receivable balance as of the transfer date as severance damages to avoid shifting the costs of uncollected accounts receivable to PG&E's investors.[71] Any amounts that PG&E would receive based on bills that would have been sent out as of the closing date could be credited back to CCSF, either through a lockbox or some other mechanism.

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69 *S. Bay Irr. Dist. v. Cal.-Am. Water Co.*, 61 Cal. App. 3d 944, 1000 (1976).

70 *Id.* at 1001.

71 The lost recoverability of accounts receivable impacts investors as they flow into working capital, which is funded by investors.

4. Gas Impacts

CCSF's taking may lead to business severance damages specifically for PG&E's gas customers. Gas-related business severance damages are distinct from gas-related damages addressed in Chapter 9, which describes the physical severance damages arising from the effect of the separation on the physical infrastructure supporting PG&E's gas operations, among others. Gas-related business severance damages may include (1) increased coordination costs with CCSF after the taking and (2) cost inefficiencies due to lost economies of scope between PG&E's gas and electric businesses. Because the existence of such business severance damages relies, in part, on negotiated terms of coordination with CCSF, and given the significant changes that have occurred since the Petition Date, PG&E reserves its right to provide figures identifying such damages in a future valuation proceeding at the actual time of acquisition, and following further negotiation and clarification of shared roles with CCSF.[72]

a. Coordination Costs

CCSF's proposed taking could lead to coordination issues between PG&E's gas business and CCSF's electric operations. These coordination issues result in increased expenditures and hours worked to accomplish tasks that previously benefitted from the efficiency of related business entities operating under a single corporate umbrella. There are numerous contexts in which gas personnel require coordination with electric operations. Examples include:

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[72] PG&E did not learn of the full scope of CCSF's proposed condemnation, including its intent to take additional assets such as the Martin Substation and the Martin Triangle, until CCSF served its amended and restated testimony in April 2026. As PG&E explained in prior filings, PG&E will need at least eight months to prepare its responsive testimony given the number of issues raised in this proceeding and their complexity. E.g., PG&E Comments on ALJ's Ruling Soliciting Comments Regarding Schedule at 9–11 & n.24 (Feb. 2, 2026); PG&E's Comments on Proposed Interim Decision at 10 (Oct. 16, 2025). Because the Scheduling Order provided less time, PG&E's testimony on certain issues (*e.g.*, the interaction between gas and electric) necessarily reflects the analysis that it could reasonably develop within the time provided. PG&E respectfully reserves the right to augment or otherwise supplement this testimony as appropriate and permitted by the Commission.

- Joint trenching. This includes navigating support and work around ("SAWA") agreements in the case of construction or maintenance near gas and electric distribution assets.
- Power operation during combustible gas indicators ("CGI").
- Connection and powering of Supervisory Control and Data Acquisition ("SCADA") assets.
- Site visits, including access to gas transmission assets if they are within an electric substation fence.
- Cathodic protection systems (*i.e.*, electric usage for rectifiers) for pipelines.
- Power drops with respect to electricity for PG&E gas ops facilities and attachments.
- Cross-bore agreements (*e.g.,* negotiating allocation of liability for boring through a neighboring underground structure).
- Any changes in standards associated with new electric ownership (*e.g.,* proximity of gas/electric meters).

Use and application of all of these systems requires coordination with the electric utility. PG&E has experienced these coordination issues with other governmental owned electric utilities. Historically, the costs associated with coordination are less significant and easier to manage when both sides are under a single corporate umbrella.

b. Lost Economies of Scope

"Diseconomies of scope" may arise from CCSF's taking because PG&E's gas and electric operations currently share assets, services, and personnel. After CCSF takes PG&E's San Francisco electric assets, costs associated with certain shared electric and gas activities will no longer be split between gas and electric and will become fully allocated to gas. The result is increased gas costs for PG&E's gas customers. These effects involve both PG&E's field operations and corporate and main office functions. Examples include:

- Locate and mark activities as part of its gas business, which entail locating pipes and cables.
- Equipment and storage costs at certain sites.
- Customer service functions that serve both gas and electric.

- Billing functions that currently provide combined monthly statements for gas and electric customers but would afterwards only reflect gas.
- Corporate services and support (*e.g.*, human resources, marketing and advertising, technological infrastructure, finance, insurance, real estate, safety, environmental, health, legal, regulatory).

D. Forecasted Lost Revenues (Sponsored by David Rubin)

This section discusses the determination of the lost revenues associated with the Charges and Accounts described in Section C that would result were CCSF to proceed with the proposed takeover. Pursuant to the statutory requirement that the Commission determine just compensation "as of the day on which the petition was filed with the commission,"[73] I have calculated these amounts as of the Petition Date. I recognize that the value of these financial severance costs will be different at the time of condemnation (if condemnation indeed occurs), and that it would be appropriate to provide an updated business severance damage value at that time.

1. General Methodology

My general approach in forecasting the revenues from PG&E's San Francisco electric customers from July 27, 2021 through 2051 for each revenue component was to rely on revenue requirement and electric consumption information that was available at or around the time of CCSF's Petition. Much of that information for the first decade of the forecast period (2022 through 2032) was taken directly from PG&E's submission in the California Energy Commission's 2021 Integrated Energy Policy Report proceeding ("PG&E's 2021 IEPR Submission"), provided to the CEC around the time of the Petition. This submission included forecasts for PG&E system-wide revenue requirements associated with various revenue components and system-wide energy consumption from 2021-2032.[74]

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73 Pub. Util. Code § 1411.

74 *See* PG&E, Electric Demand Form 8.1a ("IOU Revenue Requirements by Major Cost Categories/Unbundled Rate Component"), https://efiling.energy.ca.gov/GetDocument.aspx?tn=239544&DocumentContentId=72985

I started with actual 2021 billed revenues for retail and wholesale consumption in San Francisco by revenue component.[75] The annual changes in IEPR revenue requirements, divided by the annual changes in IEPR system-wide energy consumption, were multiplied by the prior year's amounts for each revenue component, and this product was then multiplied by the year-over-year forecasted change in total energy consumption in San Francisco.

I assumed that retail consumption growth in San Francisco would match that of the PG&E system. This is conservative in light of the fact that there was a forecast in the CEC's 2022 IEPR Update for load served by CCSF's CCA, CleanPowerSF – representing close to 75% of retail consumption in San Francisco that showed significantly greater year-over-year consumption growth.[76] Higher consumption, all other things being equal, would yield larger business severance damages. Thus, the formula described above simplifies to escalating the year-over-year lost revenues for retail load by the year-over-year change in revenue requirements. For wholesale consumption served by CCSF under the WDT, I relied on the forecast for the Power Enterprise of SFPUC.[77] I relied on the BART forecast for BART consumption.[78] I assumed that the Presidio consumption growth would match that of PG&E's retail consumption.

Since PG&E's 2021 IEPR Submission only forecasted values through 2032, I extended the revenue requirement and PG&E system energy consumption forecasts (along with the San Francisco retail consumption growth forecast) beyond 2032 and through 2051 consistent with the

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75 *See supra* Table 8.1-1. As discussed in Section C.2.o, I adjusted the 2021 retail distribution revenue amounts by $13.7 million to account for the California Climate Credit, which reduced the billed distribution charges paid by residential customers.

76 *See* Cal. Energy Comm'n, *CEDU 2022 LSE and BA Planning Forecast Tables,* Form 1.1c, available at https://www.energy.ca.gov/data-reports/california-energy-planning-library/forecasts-and-system-planning/demand-side-0.

77 *Id.* (Row 37). Power Enterprise of SFPUC included consumption both within and outside of San Francisco (*e.g.*, San Francisco International Airport). I assumed that the implied growth percentages for the total would apply equally to consumption within San Francisco.

78 *Id.* (Row 8).

compound annual growth rate ("CAGR") for the final five years (2027-2032) for each of these items.

To extend the wholesale load forecast, I applied the 2.4% CAGR of the Power Enterprise of SFPUC for 2030-2035. I also extended the BART-load forecast using BART's projected CAGR of 0% for the same time period.

I modified this general approach as appropriate when the information described above was not readily available. This was the case for Transmission, Recovery Bond Charge/Credit, Wildfire Hardening Charge, CARE portion of the PPP, Vintaged PCIA, and NSGC, as described below.

2. Generation Charge

To forecast the Generation revenues associated with bundled load in San Francisco, I relied on the generation revenue requirement forecast and bundled load forecast from PG&E's 2021 IEPR Submission.[79] I multiplied the year-over-year percentage change in PG&E's generation revenue requirement by the amount of generation revenues billed to PG&E's bundled San Francisco customers in 2021, and divided the resulting amount by the year-over-year percentage change in PG&E's systemwide bundled load. Both inputs showed very little net growth over the 2021-2032 forecast period: PG&E's generation revenue requirement increased from approximately $3.5 billion to $3.52 billion and system bundled load increased from approximately 30.7 TWh to 31.6 TWh. I then multiplied this ratio by the year-over-year change in PG&E retail consumption as a proxy for retail consumption in San Francisco.

3. Distribution Charge

To forecast the Distribution revenues, I began with the amounts billed through the Distribution Charge to PG&E's retail customers and BART, and to CCSF and the Presidio under the WDT in 2021. I then added the $13.7 million associated with the California Climate Credit that was applied against Distribution revenues for San Francisco retail residential customers. PG&E's 2021 IEPR Submission forecasted a modest increase in its

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79 *See* Form 8.1b (Bundled), https://efiling.energy.ca.gov/GetDocument.aspx?tn=239543&DocumentContentId=72986; Form 1.1b, available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=239106-1&DocumentContentId=72554.

Distribution revenue requirement from 2021 to 2022, followed by a significant increase in 2023, consistent with PG&E's request in its 2023 General Rate Case. The 2021 IEPR Submission forecasted a 10% decrease in 2024, reflecting the amortization of certain wildfire and catastrophic related accounts, followed by relatively consistent annual growth of between approximately 4.5% to 5.5%. The CAGR from the 2027-2032 time frame in the 2021 IEPR Submission was 4.7%. I applied that rate to the 2033-2051 forecast period.

4. Transmission Charges

As described in Section C.2.c, PG&E's customers pay transmission charges for CAISO-wide high voltage assets via the CAISO HV TAC Rate, and PG&E's low-voltage assets via PG&E's LV TAC Rate. Thus, PG&E's transmission revenue requirement forecast from its 2021 IEPR Submission does not precisely reflect the amounts that PG&E's customers, including those in San Francisco, would be assessed. Specifically, the CAISO-wide HV TAC reflects a composite of the high voltage transmission facilities owned by PTOs throughout the CAISO's transmission control area. The blended revenue requirement forecast presented in PG&E's 2021 IEPR Submission reflects the total amount that PG&E would recover for its high voltage assets (paid by all CAISO-wide customers), as well as its low voltage assets (paid by all retail and wholesale customers located within PG&E's Planning Area).

To determine the amount that would be assessed to PG&E's retail and wholesale San Francisco customers under the existing arrangement ("current case"), as well as the amount that would be assessed to CCSF under its proposed takeover ("takeover case"), I needed separate forecasts for the CAISO HV TAC and for PG&E's LV TAC. This is because, as described further below, a CCSF taking would not produce any change in the revenues received by the CAISO for the HV TAC, but it would create a significant reduction in the revenues received by PG&E for the LV TAC.

Around the time of the Petition Date, there was a CAISO forecast for its HV TAC Rate,[80] but no such forecast was available for PG&E's LV TAC Rate. Therefore, I used information contained within the CAISO's 2020-2021 HV TAC Rate model and CAISO's January 1, 2021 Tariff Sheet[81] to unbundle PG&E's blended HV and LV revenue requirement from the 2021 IEPR Submission, and to produce a forecast of PG&E's LV revenue requirement and LV TAC Rate. Specifically, the Tariff Sheet showed $845.9 million for PG&E's HV revenue requirement and $1,154 million for its LV revenue requirement, for a total of approximately $2 billion.[82] Since PG&E's 2021 IEPR Submission had a slightly different total of $2,037 million, I applied the HV and LV shares of the total in the Tariff Sheet[83] to the 2021 blended revenue requirement from the 2021 IEPR Submission.

I then applied the HV TAC year-over-year revenue requirement percentage change shown on the CAISO's 2020-2021 HV TAC Rate Model[84] to this imputed 2021 HV revenue requirement, based on my assumption that PG&E's annual HV revenue requirement change would mirror that of the broader CAISO HV revenue requirement. I then determined PG&E's LV revenue requirement as the difference between this calculated HV revenue requirement and PG&E's total transmission revenue requirement from the 2021 IEPR Submission. Finally, I created a PG&E LV TAC Rate forecast by multiplying PG&E's 2021 LV TAC Rate[85] times the year-over-year change in this imputed LV TAC revenue requirement, and then divided the result by the year-over-year change in the PG&E Planning

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80 CAISO, Transmission Access Charge Forecast Model 2020–2021, https://www.caiso.com/Documents/2020-2021transmissionaccesschargeforecastmodelwithnewcapital.xlsx (Row 18).

81 CAISO, January 01, 2021, TAC Rates Based on Filed Annual TRR/TRBA and Load Data (Mar. 10, 2021), https://www.caiso.com/documents/highvoltageaccesschargerateseffectivejan01_2021revised03112021.pdfHighVoltageAccessChargeRatesEffectiveJan01.

82 *Id.*

83 The Tariff Sheet reflected 42.3% for HV and 57.7% for LV, respectively.

84 CAISO, Transmission Access Charge Forecast Model 2020–2021, *supra* note 80 (Line 15).

85 This amount is $13.30/MWh.

Area Consumption.[86] For the period extending beyond the time-frame associated with these forecasts, I relied on the CAGR for the final five years of the forecast horizons.

With these forecasts for the CAISO's HV TAC Rate and PG&E's LV TAC Rate, I was able to determine the change in TAC revenues that would occur under CCSF's proposed takeover. I first describe the HV and LV TAC revenues that would be collected in the current case and then describe the HV and LV TAC revenues that would be collected under CCSF's takeover.

Current Case: Since all of the retail and wholesale customers located within San Francisco are served at or below 115 KV, the CAISO HV TAC Rate and PG&E's LV TAC Rate collectively apply to all consumption. Therefore, I multiplied the forecasted retail and wholesale consumption times the sum of the forecasted HV and LV TAC Rates in order to determine the annual revenues that would be contributed by customers in San Francisco to recover costs associated with the CAISO's HV assets and PG&E's LV assets.

Takeover Case: Were CCSF to proceed with a takeover consistent with its Separation Plan, it would acquire PG&E's in-City HV and LV transmission facilities, as well as the Martin Substation. Since CCSF is not now nor has it committed to becoming a PTO subsequent to the proposed taking,[87] I am assuming that these facilities and the associated revenue requirements[88] would be removed from the CAISO control.[89] CCSF would be metered at the high-side of Martin, which is currently fed by two 230 kV lines and six 115 kV lines.[90] In 2021 approximately 69% of the power delivered to consumers in San Francisco came through Martin. Of the power delivered to Martin, 58% arrived over the 230 kV lines while the remaining 42% was delivered over the 115 kV lines. The remainder of the power consumed in

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86 Cal. Energy Comm'n, Form 1.1c, *supra* note 76 (Row 43).

87 CCSF has not confirmed that it will become a PTO in response to data requests. *See* CCSF Response to PG&E Data Request Set 3, No. 4; Set 15, No. 10e.

88 The impact of removing the revenue requirements is discussed in the avoided cost section.

89 The resulting reduction is reflected in the avoided costs. *See infra*, § E.

90 *See* PG&E Testimony, Ch. 9 (Teran *et al.*) for more detail. Note that there are actually eight 115 lines, two of which deliver power to customers in San Mateo County.

San Francisco in 2021 (31%) was transmitted via the Transbay 330 kV Cable, the costs of which are recovered through the CAISO's HV TAC. Transbay does own LV transmission facilities, with a 2021 revenue requirement of $9.5 million[91] which is recovered as part of PG&E's LV TAC. I am assuming that, were a takeover to proceed, Transbay's HV revenue requirement would continue to be recovered via the CAISO's HV TAC, but that its LV revenue requirement would no longer be recovered as part of PG&E's LV TAC (it would likely become the responsibility of CCSF).

In its Separation Plan, CCSF has proposed providing PG&E with a substation that would connect to the 115 kV lines so that PG&E could continue to serve its customers in San Mateo County that are currently served via Martin (or other facilities emanating in San Francisco). This essentially means that the power to serve PG&E's customers south of San Francisco would be "diverted" from the 115 kV lines that currently deliver power into Martin (and not the 230 kV lines). Based on this changed configuration that would occur as part of the CCSF takeover, a greater percentage of the power arriving to the Martin Substation would be delivered over the 230 kV lines. I estimate that 80% of the power consumed within San Francisco would be delivered to CCSF through a combination of the Transbay Cable and the 230 kV lines coming into Martin and charged accordingly. The remaining 20% would be delivered over the 115 kV lines coming into Martin.

As a result, while the revenues paid to the CAISO for the HV TAC revenue requirements wouldn't change relative to the current case, only 20% of the power delivered to CCSF (the amounts delivered over the 115 kV lines feeding Martin) would be assessed PG&E's LV TAC. With the exception of the removal of the HV and LV facilities that CCSF would condemn, there would not be any reduction in the use and cost of the PG&E LV grid. Thus, my Lost Revenues calculation for Transmission reflects this ongoing reduction in payments for PG&E's LV TAC.

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91 CAISO, Transmission Access Charge Forecast Model 2020–2021, *supra* note 80.

Finally, since PG&E's remaining customers represent 83% of the LV consumption after the proposed takeover,[92] I've multiplied this Lost Revenue amount by 0.83 to determine the impact on PG&E's other customers.

5. Public Purpose Program Charge

As described in Section C.2.d and Appendix II, the PPP Charge is a composite charge that funds a sizeable number of State public policy programs. The most significant portion of the PPP Charge is support for rate discounts to qualifying low-income customers under the CARE program. In order to produce a forecast for the PPP Charge that would be billed to PG&E's San Francisco customers, the revenues associated with non-CARE programs under the PPP must be separated from the amounts paid to support the CARE program.[93] This is because the revenue requirement forecast included in PG&E's 2021 IEPR submission did not reflect the CARE Surcharge, or the mechanism by which non-CARE customers fund a rate transfer to produce a bill discount for CARE customers. Since it is an inter-class rate transfer, it is not considered a revenue requirement *per se*, with the exception of the costs of administering the program.

To forecast the portion of the PPP Charge used to fund the CARE discount, I multiplied the CARE Surcharge in effect as of mid-2021—$0.01037/kWh[94]—by the 3,752 GWh consumed by non-CARE customers in SF during 2021. This calculation yielded approximately $38.9 million. I then adjusted the $38.9 million using the ratio of (1) the annual percentage changes in PG&E's total Bundled Customer Revenue Requirement, as reported in PG&E's 2021 IEPR submission,[95] to (2) the annual percentage changes in PG&E's systemwide sales to bundled customers.[96] This ratio is

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92 The remaining 17% is represented by pre-existing governmental utilities, as well as the retail load within San Francisco.

93 CARE customers are exempt from paying the charge that provides the discount.

94 *See* Preliminary Statement I, AL 6004-E-C.

95 *See* Form 8.1b (Bundled), *supra* note 79.

96 *See* Form 1.1b, *supra* note 79.

a proxy for the year-over-year change in bundled rates. Because the discount received by CARE customers in 2021 was determined as a percentage off the total bundled rate, the year-over-year change in the bundled rate is the most appropriate basis for escalating the CARE Surcharge. I then multiplied the resulting annual amounts by the year-over-year change in the PG&E retail consumption forecast. This methodology assumes that the relative proportions of CARE and non-CARE consumption in San Francisco remain constant throughout the forecast period. For 2033 through 2051, I applied the respective compound annual growth rates calculated over the final five years of the forecasts for bundled revenue requirements and bundled-system sales.

To forecast the remainder of the PPP revenues to be collected from PG&E's San Francisco customers, I subtracted the 2021 CARE Surcharge portion described above ($38.9 million) from the total 2021 PPP revenues billed to SF customers ($56.0 million), and then multiplied the difference ($17.1 million) by the year-over-year change in PPP revenue requirements from PG&E's 2021 IEPR submission.

6. Nuclear Decommissioning and Competition Transition Charges (Sponsored by Marcus Keller)

I followed the general methodology described in Section D.1 for the ND and CTC Charges. In the 2021 IEPR submission, the system-wide ND was above $100 million through 2027 but then dropped to a relatively insignificant amount starting in 2028. Therefore, I terminated it at that point for purposes of this analysis. The CTC was forecast to decline significantly at the end of 2026 due to the expiration of a sizeable contract, but then continue at a modest level—largely negative—for the remainder of the forecast horizon.

7. Energy Cost Recovery Amount

The 2021 IEPR Submission did not include a forecast for ECRA. Since the 2021 amounts were relatively small, I maintained the revenue requirement at the same level as 2021. Furthermore, I assumed that the ECRA would sunset in 2027.

8. Wildfire Fund Charge

The 2021 IEPR Submission showed a constant DWR Bond / Wildfire Fund Charge revenue requirement at $403.4 million through the forecast horizon (2032). At the time of the Petition Date, the Wildfire Fund Charge was set to expire per enabling legislation at the end of 2035. Even though it has subsequently been extended pursuant to recent legislation, I terminated the charge starting in 2036 consistent with the expectation as of the Petition Date.

9. New System Generation Charge (Sponsored by Marcus Keller)

Given the lack of historical data for procurement by the Central Procurement Entity (CPE), PG&E's 2021 IEPR submission presented a forecast for the NSGC that reflected a presumption that load serving entities ("LSEs") would self-provide Local Resource Adequacy ("LRA") to the CPE as part of the CPE meeting its LRA requirements. Since PG&E's 2021 IEPR submission, the CPE has subsequently entered into agreements with multiple generators located in LRA areas that incur procurement costs recovered from PG&E's service area customers. While not fully representative of the expected costs based on actual (vs predicted) CPE activity,[97] the cost forecast from PG&E's 2021 IEPR submission that is provided focuses specifically on firm commitments that were undertaken up to the Petition Date[98] to produce a NSGC charge applied to load growth through 2032. There were no residual costs beyond this point.

Mr. Fulmer incorrectly asserts that there would not be a damage associated with the NSGC, because "When the City begins full electric service, the capacity that had been allocated to CleanPowerSF and other DA load in San Francisco will be re-allocated to all remaining Commission jurisdictional LSEs in PG&E's territory. Therefore, while the costs that must be collected via the NSGC rate will increase with the departure of the City's

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97 AL 6386-E; AL 6706-E; AL 7026-E, AL 7365-E, and AL 7704-E.

98 Unlike the PCIA, the NSGC/CAM is not vintaged based on the date of the customer's departure. However, since CCSF would become responsible for RA costs were it to proceed with the takeover, PG&E conservatively limited the departing load charge to those firm unavoidable commitments that had been undertaken prior to the Petition Date.

load, this will be offset by proportionate increase in the RA allocated to each remaining LSE outside of San Francisco."[99] This is incorrect since PG&E had unavoidable fixed costs that would be above market were the San Francisco load to be removed from PG&E's service area as of the Petition Date. This is similar to the approach employed to determine the Vintaged PCIA, where fixed commitments undertaken consistent with a service obligation, net of avoided costs, need to be recovered from those on whose behalf the commitments were made.

10. Recovery Bond Charge/Recovery Bond Credit and Wildfire Hardening Charge

I developed San Francisco's share of the securitized financings described in Section C.2 by dividing the non-CARE/non-FERA[100] portion of San Francisco's 2021 consumption by the non-CARE/non-FERA PG&E system-wide energy consumption, and multiplying this "SF Consumption Share" times the annual debt service amounts associated with the financings.[101] In 2021, San Francisco non-CARE/non-FERA consumption was 3,734 GWhs, while for the PG&E retail system it was 68,901 GWhs, producing a ratio of 5.42%. This was applied throughout the remaining time-frame. The future streams were converted to a value as of the Petition Date using the return rate earned by the Special Purpose Entity in 2021. That rate was 0.01%.

The July 2021 value associated with San Francisco's share of the Wildfire Hardening Charge is $316 million. The July 2021 value associated with San Francisco's share of the Recovery Bond Charge is $797 million. As noted above, PG&E recommends a collect and remit process for these charges. For the purposes of this testimony, I am assuming that sufficient funds will be available in the CCT to offset the RBC in the form of the Recovery Bond Credit as of July 2021, resulting in zero net charges.[102]

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[99] Fulmer Testimony at 16.

[100] Since CARE and FERA customers do not owe the RBC and WFC.

[101] The filings provide the annual amounts associated with these financings.

[102] However, the Commission's decisions authorizing the CCT make clear that the collection of the RBC in customer rates is independent of the availability of credits from the CCT.

11. Vintaged PCIA (Sponsored by Marcus Keller)

PG&E's 2021 IEPR Submission included a forecast of the generation revenue requirements that form the basis for the Vintaged PCIA. For 2021, I subtracted the 2021 "market price value" provided by the CPUC as part of the ERRA proceeding in 2021 to arrive at the appropriate above-market portions for the portfolios that reflect the obligations of "departed load" and "bundled load." I compared the forecasted generation revenue requirement with an internal PG&E market forward forecast to determine the PCIA for the time-frame through 2032. To extend these amounts from 2032 through 2051, I applied a 2% per year escalation rate, while at the same time making adjustments as appropriate to remove the forecasted above-market costs for energy supply resources from the portfolio consistent with their expected expiration dates.

12. Green Tariff Shared Renewables

As described in Section C.2.n, this optional rate schedule is designed to recover incremental costs associated with the specialized nature of the power supply provided to participating customers. I have therefore assumed that the avoided costs for this rate option would essentially offset the revenues, therefore producing $0 in business severance damages.

13. Non-Tariff Products and Services

As presented in further detail in Chapter 8.3, the net income that PG&E received from the NTP&S agreements in place as of the Petition Date was $7.8 million. This net income grew by a CAGR of 4.1% per year from 2018 through 2021. As described further in Chapter 8.3, PG&E conservatively forecasts this to grow at 3.1% from 2022 onwards.

14. Additional Business Severance Damages

As described in Section C.3, there are a number of assets that were on PG&E's books at the time of the taking that reflected values not yet placed into rates, but for which there was a reasonable expectation that they would be approved for recovery. I have developed the appropriate share of PG&E's San Francisco customers' responsibility for these 2021 costs based on the most logical allocation basis. Included are the following:

Wildfire Mitigation and Catastrophic Event: I determined San Francisco's share of the net amount of $1.82 billion based on the percentage of total system-wide distribution revenues billed to PG&E's San Francisco customers in 2021. This percentage was 4.4%, producing a San Francisco amount of $80.7 million as of the Petition Date. For purposes of recovery, I am assuming that these amounts would be reflected in rates in 2024 through 2026.

Flow-Through Taxes: To determine this value as of the Petition Date, I multiplied the total deferred tax amounts under FAS 109 for PG&E's system-wide transmission and distribution assets as of the Petition Date ($1.85 billion) times the percentages of total system T&D gross plant represented by PG&E's SF T&D assets. The result is $166 million. The recovery period for these amounts would be tied to the remaining life of the underlying assets (17 years for distribution and 35 years for transmission).

Construction Work in Progress: As described in Chapter 6, the amount of San Francisco projects that were partially completed and not reflected in rate base as of the Petition Date was $175 million.[103]

Accounts Receivable: As of the Petition Date, PG&E's Accounts Receivable owed by San Francisco customers was $73.5 million. Of this total, $28 million is associated with accounts that were 31 days or greater in arrears, while the remainder was for bills sent within the prior 30 days. I also determined the amount of energy consumed but not yet billed for PG&E's electric customers in San Francisco to be $53.4 million as of the Petition Date, bringing the total to $126.9 million.

E. Avoided Cost Forecast (Sponsored by David Rubin)

Many of the charges discussed in Section D are so-called "pass through" charges. Included are ECRA, ND, CTC, WFC, WHC, RB Charge/RB Credit, Vintaged PCIA, and NSGC. They are either not associated with any avoided costs or are already calculated as an amount that is net of avoided costs. Thus, the lost revenues tied to these charges are presented as net business severance damages, without any needed adjustment. The same is true for the Additional Assets. The charges for which avoided costs do exist include

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103 *See* Ch. 6 at 24.

Generation, Distribution, Transmission, portions of the Public Purpose Program Charge, and Non-Tariff Products and Services. These are discussed below.

1. Generation Charge (Sponsored by Marcus Keller)

As described in Section C.1, approximately 11% of the total load within San Francisco in 2021 is so-called bundled load, which received its generation supply from PG&E. The generation billed amounts for this load were $48.7 million in 2021. The costs incurred to provide that supply were calculated at $44 million. This included the energy and capacity costs required to serve this load in 2021, along with all procurement characteristics needed to meet California's clean energy standards. The difference between the revenues and costs reflects the fact that San Francisco's consumption characteristics are less expensive to serve than the bundled system average, driven by San Francisco's cooler summer climate and consequently smaller share of consumption that occurs during the more costly peak consumption hours. I developed a forecast of the energy and capacity costs that would be avoided were this customer base no longer served by PG&E using market price forwards that supported PG&E's 2021 IEPR submission.

2. Distribution Charge

The avoided costs associated with the Distribution Charge are comprised of four specific components: (a) annual revenue requirements associated with the distribution rate base as of July 2021; (b) annual revenue requirements associated with forecasted capital investments tied to the upgrading and expansion of PG&E's San Francisco distribution infrastructure that PG&E would no longer undertake were CCSF to take these assets; (c) expenses associated with the operation and maintenance of PG&E's San Francisco distribution infrastructure and related customer service costs that PG&E would no longer incur were CCSF to take these assets; and (d) direct financial incentives and/or rate benefits funded through the Distribution Charge that PG&E provides its electric customers in San Francisco that PG&E would no longer provide were CCSF to take these customers.

Regarding the first component, a central part of the Just Compensation amount to be determined in this proceeding will be associated with the Fair Market Value ("FMV") that the Commission assigns to the transmission and distribution assets that CCSF wishes to take. A portion of this FMV would benefit PG&E's remaining customers through the removal of the Subject Assets from PG&E's distribution and transmission rate bases. I adopted the annual revenue requirement associated with the starting point distribution rate base from the Income Valuation presented in Chapter 5. I then included property taxes associated with these assets, as they would need to be reflected as an avoided cost.[104]

For the second component, similar to the starting point rate base, I have incorporated the annual revenue requirements for each investment year from the Income Valuation presented in Chapter 5, along with the inclusion of property taxes.

For the third component, I relied on the avoided distribution expense analysis presented in Chapter 8.2.[105]

For the fourth component—costs associated with those programs that help fund specific customer measures (*e.g.*, self-generation incentive program) or provide rate benefits (demand response) to customers located in San Francisco—I relied on PG&E's records regarding the actual benefits received by PG&E's San Francisco electric customers during the years immediately preceding and including the Petition Date. If the 2021 data was representative of the time-period, I used it directly. If the 2021 data was not representative for the time-period (*e.g.*, there were wide swings amongst the immediately preceding years), I developed an average over the prior years. I escalated the direct financial benefit amounts using revenue requirements for the relevant programs reflected in the 2021 IEPR, system sales, and San Francisco specific sales as described above for the lost revenues.

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104 As described in Chapter 6, the starting point rate base for both distribution and transmission includes IRS ADIT, but not excess ADIT. Excess ADIT is reflected in the 2021 Transmission and Distribution revenues (*i.e.*, they were lower than they otherwise would be to reflect these amounts), so no adjustment to the lost revenue calculation is required. *See* Ch. 6 at 20–23.

105 *See generally* Ch. 8.2.

3. Transmission Charge

The avoided costs associated with transmission are comprised of three specific components: (a) annual revenue requirements associated with PG&E's San Francisco transmission rate base as of the Petition Date; (b) annual revenue requirements associated with forecasted capital investments tied to the upgrading and expansion of PG&E's San Francisco transmission infrastructure that PG&E would no longer undertake were CCSF to take these assets; and (c) expenses associated with the operation and maintenance of PG&E's San Francisco transmission infrastructure that PG&E would no longer incur were CCSF to take these assets.

For the first component, I adopted the annual revenue requirement associated with the starting point transmission rate base used in the Income Valuation in Chapter 5. I included property taxes associated with these assets, as they would need to be reflected as an avoided cost. A portion of these avoided costs would impact non-PG&E users of the CAISO's high voltage grid, since a subset of the assets are in the form of 230 kV transmission facilities and the associated costs are currently collected broadly across the CAISO's transmission control area. The share of these high voltage avoided costs that would impact PG&E's remaining customers is 37%. The share of the low voltage avoided costs that would impact PG&E's remaining customers is 83%. Therefore, I multiplied the annual amounts described above times these percentages to develop PG&E's customers' share of the avoided costs.

For the second component, I incorporated the annual revenue requirements for each investment year from the Income Valuation in Chapter 5, with the inclusion of property taxes. As is the case with the revenue requirements associated with the July 2021 transmission rate base, a portion relates to high voltage facilities and the impacts would be spread more broadly across the CAISO's transmission control area. I used the same fractions described above to reflect PG&E's remaining customers' shares of the avoided costs.

For the third component, I relied on the avoided transmission expense analysis presented in Chapter 8.2.[106] I used the same fractions described above to reflect PG&E's other customers' shares of the avoided costs.

4. Public Purpose Program Charge

As described in Section C.2.d, the PPP Charge includes a significant number of policy programs, some of which provide direct financial support to end-use customers, including those in San Francisco. For those programs that help fund specific investments (e.g., energy efficiency rebates), I relied on PG&E's records regarding the actual benefits received by PG&E's San Francisco electric customers during the years immediately preceding and including the Petition Date. I escalated the direct financial benefit amounts using revenue requirement, system sales and San Francisco specific sales as described above for the lost revenues. Since there are a significant number of programs included in the PPP, not all of them are reflected in the PPP portion of the 2021 IEPR Submission. For those that were not, I applied the percentage change from the "other" line.

Regarding PG&E's low-income rate (CARE), the bill discount received by CARE customers at the time of the Petition was comprised of exemptions from the CARE Surcharge and Wildfire Fund Charge (and subsequently the Wildfire Hardening Charge and Recovery Bond Charge/Recovery Bond Credit), as well as a reduction to the Distribution Charge. As this latter discount was reflected in the billed Distribution revenues in 2021 and carried forward formulaically via the forecasting approach that I employed, I concluded that no additional avoided cost adjustment is required.

5. Non-Tariff Products and Services

NTP&S categories have varying levels of costs that would be avoided were these services no longer provided. The avoided costs tied to PG&E's San Francisco NTP&S in 2021 were $19.4 million. As described in Chapter 8.3, they are escalated at 3.1% (the same escalation rate for NTP&S revenues) through 2051.

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106 *See* Ch. 8.2 at 3, 9–10.

6. Local Fees and Taxes

There are a number of fees and taxes associated with electric service that PG&E pays to San Francisco that would no longer be contributed were the takeover to proceed. Included are franchise fees (including the franchise fee surcharge), the San Francisco Business Taxes, the San Francisco Sales/Use Tax and property taxes.

- The franchise fees are based on the franchise fee percentage included in the franchise agreement between PG&E and San Francisco (0.78%), multiplied times total forecasted electric revenues for each year of the 30-year time-frame. The July 27, 2021 value is $226 million.
- The San Francisco Business Tax is determined as 1.125% (the rate in effect as of the Petition Date) times total forecasted electric revenues. The July 27, 2021 value is $326 million.
- The San Francisco Sales/Use Tax is 8.625% (the tax rate in effect as of the Petition Date) times the non-labor (equipment) portion of electric capital investments. The July 27, 2021 value is $390 million.
- Finally, property taxes are determined as 1.28% (the factor in effect as of the Petition Date) times the net book value of electric distribution and transmission facilities for each and every year of the 30-year time-frame. The July 27, 2021 value is $1.12 billion for distribution and $0.54 billion for transmission. These amounts are embedded within the distribution and transmission avoided costs.

F. Business Severance Damages as of July 27, 2021 (Sponsored by David Rubin)

Based on the calculations described in Sections D and E, I have determined business severance damages as the difference between the revenues that PG&E would lose were the takeover to proceed and the costs that PG&E might avoid. The net result is $5.32 billion. In addition to the tax gross-up described in the next section, we also add $0.47 billion to reflect the income tax and operative reserve of the proposed trust described in Chapter 10.

G. Tax Gross-Up on Business Severance Damages (Sponsored by Tim Wedlake)

The payment by CCSF of severance damages will result in taxable income to PG&E at the time the payment is made.[107] To prevent remaining customers from bearing this tax expense through the reduction of the business severance damages payable to customers, I have included the tax gross-up needed to pay the tax on the customer portion of business severance damages.

The need for a tax gross-up is demonstrated by the following example. The current federal statutory income tax rate is 21%, while the applicable California tax rate is 8.84%. State taxes paid on business severance damages are deductible for federal taxes. As a result, PG&E will be required to pay a combined rate of 27.98% on all taxable revenues.[108] In the absence of the gross-up, if severance damages were $1 billion, there would only be $720.2 million (72.02% after taxes of 27.98%) after taxes to compensate for $1 billion of severance damages. In order to receive a net amount of $1 billion, the tax gross-up factor requires CCSF to pay $1.389 billion because the gross-up itself is also subject to tax.[109] This gross-up ensures that the full severance business damages calculated in this Chapter are realized as compensation and that the taking leaves PG&E and its customers in as good a position as they would have been if the taking did not occur, as required by the Interim Decision.[110]

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107 IRC Section 61(a) defines gross income broadly: "Except as otherwise provided in this subtitle, gross income means all income from whatever source derived[.]"

108 IRC Section 11 provides the federal tax rate for corporations: 21%. CRTC Section 23151 provides the California tax rate for corporations: 8.84%. As California taxes are a deduction against federal taxable income, there is also a calculation for that impact on the combined tax rate. The combined tax rate is calculated as follows: 21% + (8.84% times (1-21%)), or ~27.984%.

109 This is calculated as follows: $\frac{1}{1-0.2798} \approx 1.389.$

110 Interim Decision at 25.

The amount of the tax gross-up associated with the net customer business severance damages calculated in this testimony is $1.83 billion.[111]

H. Amounts that Could be Collected from the TMDL Tariff (Sponsored by David Rubin)

The Interim Decision requires PG&E to estimate the portion of the business severance damages, if any, that could be collected directly from the departing customers under the Transferred Municipal Departing Load (TMDL) tariff.[112] This tariff identifies various specified charges within PG&E's rate structure as "non-bypassable" to municipal departing load customers who transfer to electric delivery service from a POU. This section discusses the theoretical maximum amount that could be recovered via the TMDL tariff and then describes the various reasons why very little would likely be collected. It also quantifies the costs associated with any billing and collection effort.

1. Theoretical Maximum Amount

The TMDL tariff in effect as of the Petition Date included a modest subset of the charges discussed above—specifically the CTC, ND, ECRA and WFC. TMDL consumers have been, and remain, exempt from the Vintaged PCIA and NSGC, unless and until the Commission approves an IOU application demonstrating the activity in question constitutes a "large municipalization."[113] Within the year following the Petition, the Wildfire Hardening Charge and Recovery Bond Charge/Recovery Bond Credit were

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[111] This amount will change by the time of acquisition due to updates to the business severance damages that will be necessary if CCSF continues with this proceeding and the taking of the Subject Assets. PG&E has estimated the tax gross-up in this testimony and asks the Commission rule that a tax gross-up will be necessary as part of the just compensation award for severance damages, but that the Commission defer the final calculation of the tax gross-up (and the treatment of any potential future tax deductions) until the update phase when more precise information will be known.

[112] Interim Decision at 35–36.

[113] D.08-09-012 at 29.

added to the TMDL tariff.[114] I am including all of these charges as part of the theoretical maximum that could be collected via the TMDL tariff.[115]

There is also a companion tariff, E-NMDL, that applies to new energy consumers located within PG&E's service territory as it existed on February 1, 2001, but which immediately receive electric delivery service from a POU. This tariff includes the same charges as E-TMDL and has many of the same provisions. In forecasting lost revenues, I have applied a consumption growth forecast that indistinguishably reflects both consumption growth from existing customers as well as consumption from newly locating consumers. Since the charges in E-TMDL and E-NMDL (collectively "The Departing Load Tariffs") are expressed as a $/kWh amount and thus are based on consumption, it is not necessary to distinguish the number of customers or level of consumption that would be subject to each tariff separately for the purpose of quantifying the amounts that could theoretically be recovered via these Departing Load Tariffs.

Table 8.1-5 shows the value of these charges as of the Petition Date. This reflects the theoretical maximum of the amounts that might be recovered—representing approximately 33% of the net business severance damages.

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114 I consider these charges as part of business severance damages since the enabling legislation had passed and the CPUC proceedings approving these charges were close to conclusion. Therefore, I am also including them in the theoretical maximum amounts that could be recovered directly from end-use customers as part of E-TMDL and E-NMDL.

115 In response to a PG&E Data Request, Mr. Fulmer provided the following:

"Per the current Electric Schedule E-TMDL, TMDL customers are subject to the Wildfire Hardening Charge (WHC) and Wildfire Hardening Fixed Recovery Charge Balancing Account (WHFRCBA) rate; and the Recovery Bond Charge and Fixed Recovery Charge Balancing Account (FRCBA) rate, which were not in place at the time of the CITY's Petition. Depending upon the time of the associated Financing Orders and the time at which they become TMDL customers, they may also be exempt from all or portions of these two charges. *See* Electric Schedule E-TMDL, sections 8 and 9." CCSF Response to PG&E Data Request Set 22, No. 19.

TABLE 8.1-5
MDL THEORETICAL MAXIMUM AMOUNTS
(MILLIONS OF DOLLARS)

Line No.	Revenue Component	2021 Billed Amounts	2021-2051 Value
1	Wildfire Fund Charge	$22	$273
2	Competition Transition Charge	$0.4	$0.4
3	Nuclear Decommissioning	$4	$38
4	Energy Cost Recovery Amount	$1	$5
5	**Subtotal**	$27	$317
6	Power Charge Indifference Adjustment	$137	$1,061
7	New System Generation Charge	$14	$39
8	**Subtotal**	$151	$1,100
9	Wildfire Hardening Charge	$0.1	$316
10	Recovery Bond Charge	-	$797
11	Recovery Bond Credit	-	($797)
12	**Total**	$178	$1,733

2. General Challenges in Billing Municipal Departed Customers

As described above, E-TMDL and E-NMDL are very similar in most respects, with E-TMDL being applicable to existing PG&E customers who switch service to a POU, while E-NMDL is applicable to new customers within PG&E's service area who take immediate service from a POU. However, there is an important distinction that exists between the two categories of MDL that is relevant for our analysis. In almost every instance, TMDL customers are active participants in the transfer of service from PG&E to a POU. That is, they are typically approached by a POU wishing to replace PG&E as the electric delivery provider.[116] By contrast, NMDL customers are typically part of new developments, where the developer of a new subdivision deeds their electric line extension facilities over to the POU as opposed to PG&E. These customers are very likely unaware that PG&E service is an option, and/or given a choice of electric delivery service provider. In the current instance, were the takeover to proceed, PG&E's existing San Francisco customers would become passive and unengaged

[116] *See* E-TMDL, Special Conditions 3.a.

(and likely unaware) participants in the transfer—essentially the same as NMDL customers.

PG&E has tried to collect charges from NMDL customers in other parts of its service area, including when the Modesto and Merced Irrigation Districts extended electric facilities into PG&E's service area. However, the NMDL customers revolted at having to pay such charges to the electric utility that they had "departed." Thus, in developing an estimate of how much PG&E might collect from existing and new customers who would become served by CCSF under a takeover scenario, we believe that it is appropriate to consider them as passive participants in the process, and thus extremely unlikely to pay bills that they receive from an entity that is no longer providing any electric delivery service.

In order for PG&E to recover charges from these customers, PG&E would either need to generate separate electric bills or receive CPUC approval to include the charges on gas bills. The latter would miss a growing number of customers who receive electric service but not gas service, including conversions from gas to electric service, as well as EV charging. The former would represent a significant and unnecessary additional cost. And in either case, based on previous experience, confusion will ensue and recovery will be significantly compromised.

Accordingly, if PG&E is no longer the electric provider in San Francisco, collection of these critical policy-supporting funds would be excessively costly, likely generate significant confusion and frustration, and ultimately have limited or no success. PG&E will also not be in a position to shut-off electric service for non-payment—one of the few enforcement mechanisms that it possesses for typical electric customers that do not pay their bills.

Additionally, under current tariffs, the electric-consumption characteristics necessary to determine customers' NBC obligations would be based on historic billing data. Given the expected increases in electric load growth in San Francisco (*i.e.*, due to state and local programs encouraging gas-to-electric conversions and electric vehicle charging),[117] it

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117 *See* City & County of San Francisco, CleanPowerSF 2022 Integrated Resource Plan Compliance Filing, CleanPowerSF IRP Narrative, Rulemaking 20-05-003 (C.P.U.C. Nov. 1, 2022).

is very likely that actual consumption would significantly exceed the historic load otherwise used to assess customers' obligations. Thus, billing based on historical data would lead to artificially low revenue contributions.[118]

3. Practical Challenges and Associated Costs in Billing Municipal Departed Customers[119] (Sponsored by Shaun Hoppes)

Notwithstanding the above concerns, I have estimated the limited amounts that PG&E might reasonably collect after accounting for the practical challenges and associated costs described below. I also note that PG&E currently has 401 TMDL accounts. There are approximately 420,000 electric customers in San Francisco, with significant turnover. The process that PG&E employs to bill the existing TMDL accounts is manual and time intensive. It was not designed for, nor will it easily accommodate, a 1,000-fold increase in volume.

Step 1. Notification: Pursuant to Special Condition 3a of E-TMDL, PG&E initiates the process by sending a notification to the TMDL customer, advising them of their obligations under the tariff. The customers are then required to notify PG&E within 30 days "of their intention to take steps that will qualify their load as Transferred Municipal Departing Load." Special Condition 3a goes on to provide that: "The customer shall specify in its Notice of Departure the following: 1) The date on which the customer will reduce or discontinue its electric service (Date of Departure); 2) A description of the load that will qualify as Transferred Municipal Departing Load; 3) The PG&E account number assigned to this load; 4) The name of the POU from which the customer will take service; and 5) Its preferred method of selecting billing determinants (12-month or 36-month[, or customer provided usage amounts]) for its Reference Period Load Profile as described in Special Condition 5.a."[120]

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[118] This problem could be avoided to some degree if the governmental entity were to regularly provide actual billing data to PG&E to support these calculations. Both problems could also be avoided if CCSF collected and remitted these NBCs on PG&E's behalf.

[119] Mr. Hoppes sponsors Sections C.3.d (Accounts Receivable), H.3, and H.4.a.

[120] E-TMDL, Special Conditions 3.a.

The activities associated with sending this notification to departed load customers are performed manually and would cost approximately $7.28 per customer account.

Step 2. Account Set-Up: Upon receipt of a completed Notice of Departure from the customer, PG&E must perform a series of manual and resource-intensive activities to establish each departing customer account. This process involves tariff review, development of billing determinants, account creation, and quality assurance, all of which must be completed before billing can begin. While account set-up is typically initiated upon receipt of a completed Notice of Departure, PG&E would also need to establish accounts for customers that do not respond to calculate, bill, and pursue collection of any applicable departing load charges.

As part of this process, PG&E must develop a historical load profile to calculate ongoing charges. As mentioned above in step 1, customers indicate on the Notice of Departure form whether they prefer PG&E to use: 1) actual monthly usage from the prior 12-month period, which produces monthly billing quantities that vary throughout the year, 2) an average monthly usage amount based on the prior 36 months of historical consumption, or 3) customer-provided usage amounts. The selected methodology is then used to establish the billing determinants associated with the customer's departing load obligation.

Given that PG&E's customers in San Francisco are unlikely to take affirmative steps to qualify their load as Transferred Municipal Departing Load during the NOD process, as they are not initiating the proposed takeover, I expect that only a limited number of customers will return the required notifications within the 30-day timeframe prescribed by the tariff. For the remaining customers who do not respond, PG&E would establish the load profile using the lesser of the 12-month or 36-month average consumption to determine the departing load obligation. This analysis is not automated and must be performed before the account can be billed.

Once the load profile has been developed, whether through a customer's affirmative election or PG&E's default determination process, PG&E prepares and issues a Non-Bypassable Charge (NBC) statement to the customer. The TMDL tariff requires that the statement be provided

within 20 days of receipt of the required information (Special Condition 3b). For customers who do not submit the required notice, PG&E would determine the applicable billing quantities after the 30-day response period has expired and then prepare and issue the NBC statement. The activities associated with reviewing customer documentation, developing the load profile, preparing the NBC Statement, and communicating required information to the customer are performed manually and cost approximately $33.58 per account.

Following completion of the tariff and load-profile review, the account information is provided to PG&E's Billing organization, which establishes the departing load account in SAP. This process requires all customer information to be manually entered into the Departing Load Calculation Spreadsheet. Billing then calculates the dollar amount for each NBC, tax, and other applicable billing components based on the information provided by the Tariff Analyst. This activity costs approximately $39.45 per account.

Because the account setup and billing determination process involves multiple manual calculations and data-entry activities, PG&E performs an additional quality assurance review of the initial bill. Consistent with PG&E's internal controls supporting billing accuracy, including applicable Sarbanes Oxley ("SOX") controls, the initial invoice is returned to the responsible Tariff Analyst for verification before issuance. This review would cost approximately $13.15 per account. Once approved, the invoice is mailed to the customer.

Step 3. Account Billing: Even after departing load accounts are established, ongoing administration remains manual, inefficient, and costly. Departing load invoices are generated through a monthly batch process that requires manual initiation, monitoring, and oversight. TMDL invoices are issued separately from a customer's standard PG&E energy statement and are generated on an account-by-account basis. Unlike traditional utility billing, multiple accounts cannot be consolidated onto a single invoice. As a result, customers with more than one TMDL account receive a separate paper invoice for each account, increasing both administrative cost and customer burden.

For each monthly TMDL invoice issued, PG&E incurs approximately $1.02 for labor, printing materials and postage associated with producing and mailing each statement.

Step 4. Revenue Collection: Customers who receive departing load invoices and elect to pay have limited payment options. Payments must be remitted by check or money order and mailed to PG&E for processing. As a result, both customers and PG&E incur additional administrative costs associated with paper-based payment processing. The cost to process a departing load payment is approximately $0.13.

Beyond the lack of payment options associated with TMDL charges, the long-term collectability of these charges presents additional concerns. Departing Load charges may continue for many decades under the tariff, requiring customers to make payments long after they have stopped taking electric service from PG&E. Unlike a traditional retail electric customer, a departing San Francisco customer would receive electric delivery service from another provider, and PG&E would have no ability to disconnect electric service for non-payment of a PG&E departing load invoice.

Collection rates are expected to be significantly impacted by the circumstances surrounding the transition. Many customers may have not actively participated in the process that results in their designation as a TMDL customer and may have little understanding of why they are receiving a bill from PG&E after no longer taking service from PG&E. Some customers may not receive or recall the original notices, while others may view the charges as unexpected or assume they were sent in error. As a result, PG&E believes a substantial portion of customers will not make payments even in the first year. To reflect this risk, PG&E modeled a first-year collection rate of 40% for customers receiving TMDL invoices.

PG&E further modeled for an annual 40% decline in collections thereafter. This assumption reflects the expectations that customers will become increasingly removed from their prior relationship with PG&E and less likely to perceive a reason to continue paying charges associated with service they no longer receive. Customers who discontinue payments and experience no interruptions to electric service are likely to share that experience with neighbors, businesses, and community organizations.

Information regarding the limited consequences of non-payment can also be expected to spread through social media and other public forums, further reducing collections over time. Given that these charges could remain in place for many years, PG&E expects collection performance to deteriorate progressively as awareness of the charges, their purpose and the limited remedies available for non-payment evolve. Accordingly, PG&E believes a 40% annual decline in collections is a reasonable assumption.

Step 5. Recourse for Non-Payment of Charges: If a customer fails to pay, or subsequently discontinues payment of their departing load bill, PG&E's available remedies are limited and often uneconomic. PG&E may issue late payment notices at a cost of approximately $0.71 per notice and initiate outbound collection calls at a cost of approximately $11.52 per call. If the TMDL balances remain unpaid, PG&E may request a deposit equal to two times the customer's monthly TMDL bill (Special Condition 3.g). However, because customers no longer take electric service from PG&E, non-payment of either the monthly charge or the deposit does not result in the disconnection of electric service. As a result, the practical effectiveness of the deposit requirement as a collection tool is limited. Customers who are unwilling or unable to pay their ongoing TMDL obligation may also be unlikely to remit a separate deposit payment.

Step 6. Demand for a Lump Sum: For customers who fail to make required monthly payments or do not provide the requested deposit, PG&E may issue a lump-sum invoice for the accumulated departing load obligation. These invoices would likely be substantially larger than the monthly recurring charges and, therefore, may be even more difficult to collect. Given the limited remedies available to PG&E, the expected collection rates for such lump-sum invoices are low.

Step 7. Enforceability: Although the tariff permits PG&E to pursue legal remedies to recover unpaid balances, including filing suit in any court of competent jurisdiction (Special Condition 3.j), litigation or other collections efforts may be cost-prohibitive where collection costs exceed the amount owed. Accounts that remain unpaid and are determined to be uncollectible are ultimately written off in accordance with PG&E's standard accounting practices.

Step 8. Change of Party: The burdens described above will continue and repeat over time because TMDL accounts require manual maintenance when property ownership or occupancy changes. Under the tariff (Special Condition 3c), the existing customer must notify PG&E when it seeks to terminate responsibility for departing load charges, and the successor customer must separately notify PG&E of its intent to occupy the property and assume responsibility for future charges. If the required notifications occur, PG&E must then manually establish a new account and determine the appropriate billing determinant using historical usage information, where permitted under the tariff, or alternative supporting data provided by the customer.

In San Francisco, where customer move-in and move-out activity was approximately 24% in 2020, this requirement would create continuing account maintenance challenges. Each ownership or occupancy change would increase the risk of delayed billing, customer disputes, inaccurate account responsibility, or uncollectible balances.

Step 9. Public Affairs: In prior circumstances when PG&E has sent bills to departing customers, collective outrage has resulted in the need to communicate with customers and public officials through various public forums. While these costs could be significant, we have not attached a value to them as part of this analysis.

4. Estimate of Revenue Net of Costs that Might be Collected Through E-TMDL and E-NMDL

As discussed above, the theoretical maximum amount that could be recovered from E-TMDL and E-NMDL is $1.733 billion over the 2021-2051 timeframe. This includes not only the charges that were contained in the Departing Load Tariffs as of the Petition Date, but also charges added within the following year, plus charges that required an application and Commission approval.

It is very unlikely that PG&E would be successful in collecting much, if any, of this theoretical maximum amount, given the challenges described above. Furthermore, the costs associated with the Departing Load Tariff requirements would easily offset the limited revenues that might be recovered. I have approached my analysis as follows:

a. Costs (Sponsored by Shaun Hoppes)

1) I calculated the notification costs for the initial group of customers as of the Petition Date (approximately 420,000) as described in Step 1 of Section H.3 above. I then added the account set-up costs for this same group of customers, since all of them would require this next step—whether they are part of the estimated 20% that affirmatively respond to the notification, or are part of the remaining 80% that do not respond to the notice but nonetheless require account set-ups in order to pursue Steps 5 and 6 of Section H.3.

2) I then calculated the costs associated with preparing and issuing TMDL bills to 100% of the original customer population, as well as the cost of processing check and money order payments from the portion of customers expected to pay their TMDL charges. Consistent with the assumptions described in Steps 4 and 5, I modeled an initial collection rate of 40% and an annual collection decay rate of 40% to reflect customers who make payments initially but subsequently discontinue payments in future years. I then calculated the costs associated with escalated collection and recovery activities, including late-payment notices and collection calls, for customers who do not pay their TMDL charges. These costs increase over time as the population of non-paying customers grows due to the assumed collection decay. Conversely, payment-processing costs decline over time as fewer customer payments are received and processed.

3) I also relied on change-of-party data from the 2020 timeframe to estimate the annual turnover of customers within San Francisco, which was approximately 24%. This assumption reflects the replacement of existing customers by successor customers subject to the tariff. Using this assumption, I calculated the ongoing one-time costs associated with providing required notifications and establishing TMDL accounts for new customers occupying premises subject to TMDL charges. Consistent with the assumptions applied to the original population, I modeled an initial collection rate of 40% and an annual collection decay rate of 40% for each new customer. I calculated these costs through 2051 using the same methodology and assumptions.

b. Revenues

1) I started with the quantitative values of the MDL charges that were in effect as of the Petition Date for each customer class. As described above, I included the ND, CTC, ECRA and WFC, as well as the PCIA and NSGC. For the WHC, I relied on the value added to rates as of December 2021. For the Recovery Bond Charge and Recovery Bond Credit, I assumed that they would offset for the entire time-frame, consistent with how these Charges interact on a pay-as-you-go basis.

2) I then applied average monthly consumption levels in 2021 by customer class to the relevant charges in order to determine the average monthly billed amounts.

3) As described in Section H.4.a above, I assumed that 40% of customers would actually pay the TMDL bills during the first year. I further assumed that the percentage of customers paying the TMDL bills would drop by 40% each year thereafter.

4) I also factored in revenues from newly locating customers that might pay their TMDL bills. I assumed that, similar to the original customer group, 40% of these customers would pay their TMDL bills in the first year, which would decay at the same rate as described above.

5) I included the growth in customer consumption along with the changes in the various MDL NBCs that are reflected in the business severance damages calculation as annual inputs to the calculations of the monthly bills.

c. Revenues Net of Costs

I performed a calculation of the annual revenues generated through this process and subtracted the costs. The value of the net amount as of the Petition Date is approximately ($344 million).

5. Prior Agreements with POUs

The best practice where existing and prospective PG&E customers take POU delivery service has been for the POU to collect the various NBCs identified in the MDL tariffs from customers and remit the amounts to PG&E. PG&E has negotiated a number of agreements with POUs that initiated service to customers located within the footprint of PG&E's service area to

pay these amounts, typically through a collect-and-remit procedure that may later be terminated in a lump sum payment. The Commission has approved all of these agreements. They are discussed below.

Modesto Irrigation District (Mountain House): Per legislation passed in 2000,[121] the Modesto Irrigation District ("MID") became the exclusive service provider to existing and new customers in the newly developing community of Mountain House. PG&E was no longer allowed to serve electric customers in that area, but at the same time MID did not have the immediate ability to fulfill its service obligation, as it did not own any electric assets in the vicinity. In 2001, PG&E and MID negotiated an agreement whereby PG&E sold and leased electric distribution assets to enable MID to become the exclusive service provider in Mountain House.[122] As part of the arrangement, MID agreed to collect and remit revenues associated with the customers within the footprint of the new community.[123] In approving the agreement, the Commission concluded that: "[I]f [MID] had not agreed to pay these NBCs for departing customers, PG&E would have to collect these NBCs directly from departing customers, which would be far more difficult and would involve a greater risk of non-payment."[124]

Turlock Irrigation District (Patterson): In 2002, in response to the same legislation, PG&E and TID negotiated a limited sale of electric facilities, along with a Service Area Agreement in the City of Patterson.[125] This arrangement involved an agreement for TID to bill NBCs on behalf of the customers within Patterson, and remit them to PG&E. Similar to CCSF's proposal to take over PG&E service within a defined geographic area without the specific acquiescence of the individual customers, the transferred and new MDL customers were both included as part of the POU collect and remit approach.[126] TID continued to pay the agreed-upon

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[121] AB 2648 (2000).

[122] D.04-03-036 at 2–5.

[123] *Id.*at 9.

[124] *Id.* at 21.

[125] D.03-04-032 at 3–6.

[126] *Id.* at 23–25.

charges until 2016, at which time PG&E and TID negotiated a one-time lump sum payment from TID to PG&E to extinguish any future payment obligation by TID.

Modesto and Merced Irrigation Districts ("IDs"): In 2009, the Modesto and Merced IDs began aggressively approaching developers of new subdivisions in PG&E's service area to become the electric service provider of the soon-to-be new customers. Consistent with its tariffs, PG&E began sending bills for departing load charges to these customers. This resulted in significant local controversy. Pursuant to direction from local legislators, PG&E and the IDs subsequently negotiated an agreement that required the IDs to pay an amount on behalf of the customers that the IDs connected each year. It was submitted to the Commission and approved in November 2010.[127] In approving this agreement, the Commission stated: "Without an agreement, PG&E will continue to experience a high rate of uncollectibles and incur significant additional administrative and legal costs to collect unpaid NBCs. It is unreasonable for PG&E to incur costs to collect unpaid NBCs that exceed the value of the unpaid NBCs being collected."[128]

Power and Water Resources Pooling Authority ("PWRPA"): In 2008, PG&E had a good faith dispute with the PWRPA regarding PWRPA service to a number of customers within PG&E's service area. PWRPA operates as a POU and provides electric service to end-use customers as part of PG&E's agreement with the Western Area Power Administration ("WAPA"). PG&E and PWRPA disagreed regarding the components of bills that PG&E had sent to PWRPA customers. PG&E and PWRPA settled their dispute in 2009. This settlement involved a lump sum payment by PWRPA for specifically designated charges and customer load. The present value amount was to be paid in four quarterly installments, with any adjustment required due to changes in one of the charges to be reconciled. The Commission approved the agreement.[129]

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127 *See generally* D.10-11-011, 2010 Cal. PUC LEXIS 533 (Cal. P.U.C. Nov. 19, 2010).

128 *Id.* at *49.

129 *See generally* D.09-08-015.

These agreements teach at least two lessons. First, attempting to collect NBCs from non-customers is fraught and leads to very little cost recovery. Indeed, the Commission acknowledged in D.10-11-011, that it is unreasonable to incur collection costs that exceed the amounts actually collected. Second, these agreements show that an alternative procedure, wherein the new POU collects the charges from its customers on PG&E's behalf and remits those costs to PG&E, *can* lead to recovery.

PG&E would prefer this method of payment for the lost revenues described in this chapter related to the securitized charges. However, PG&E acknowledges that the Commission's objective in this proceeding is to value severance damages in a single sum. Therefore, PG&E asks the Commission to include all of the amounts described in this chapter in its severance damage calculation. But PG&E also requests the Commission to note in its decision that the amounts may be removed from this valuation if the Commission later orders, or if CCSF and PG&E enter into a binding agreement, that CCSF collect these amounts from its customers over time and remit those revenues to PG&E.

I. The Commission Should Update Severance Damages to Correspond to the Actual Asset Transfer Date (Sponsored by David Rubin)

The relevant statutes governing the Commission's determination of Just Compensation for the assets that CCSF proposes to take require the Commission to calculate severance damages as of the Petition Date.[130] This chapter has provided such a valuation.

The Petition Date in this case, however, was more than five years ago. Much has changed since that time. For example, certain charges that existed as of the Petition Date no longer exist. The amount that PG&E collects through each Charge varies year by year and has changed significantly between the Petition Date and the present. As but one of many examples, the Diablo Canyon Power Plant (DCPP) was slated for retirement at the time of the Petition, but has now been authorized to operate through at least 2030. The costs associated with the operation of DCPP are currently recovered via the PPP Charge. Further, the severance damage calculation as of the Petition Date

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130 *See* Pub. Util. Code § 1411.

necessarily includes amounts that customers in San Francisco have already paid from the Petition Date to present. Much can be expected to change prior to any Commission decision in this proceeding. It would be appropriate—and indeed, necessary—for the Commission to update the severance damages to correspond to any asset transfer date.

One additional significant justification for updating business severance damages is that the Legislature and/or the CPUC may authorize additional programs prior to any asset transfer date. If this turns out to be the case, the associated costs should be included as part of a business severance damages determination connected with the taking. PG&E requests that the Commission expressly note, in its valuation decision, that business severance damage amounts will be updated based on new charges that come into effect (or are expected to come into effect) after the valuation date in these proceedings.

There are also good policy reasons for the costs associated with charges that might be implemented in the future to be incorporated into the business severance damage award. It is important to underscore that CCSF's proposal could stimulate a dangerous trend: one in which governmental agencies attempt to remove their geographic area from Commission oversight, and as a result, from funding the many important California energy policy programs that IOUs administer. If other municipalities follow suit, IOUs will be left with a shrinking customer base. This constrains the future revenue that the Legislature and Commission can consider when introducing new policy initiatives or expanding existing initiatives and jeopardizes the existing system of IOU-implemented energy programming in California.

J. Conclusion (Sponsored by David Rubin)

CCSF's proposed taking would cause a massive reduction in revenues that vastly exceeds the costs avoided. PG&E would experience prohibitively difficult challenges and costs if it were to try to bill any portion of these charges from departing customers after CCSF's proposed takeover. PG&E therefore requests that the Commission require that CCSF pay the amounts presented in Section F as business severance damages, as well as the amounts associated with the tax gross-up. PG&E also requests that the Commission authorize an update of these business severance damages closer to any asset transfer, in order to reflect any payments made by PG&E's San Francisco customers subsequent to

the Petition Date, as well as to update the forecasted amounts and include any new or recently foreseeable charges. Finally, PG&E requests that the Commission consider a “collect and remit” approach as opposed to a lump sum payment, for the securitized charges (Recovery Bond Charge, Recovery Bond Credit, Wildfire Hardening Charge) to accommodate the unique structure and requirements of those charges.

Appendix I: Public Policy Components of the Distribution Charge as of the Petition Date

This appendix describes some of the public policy components of the Distribution Charge as of the Petition Date. The Distribution Charge includes a variety of components intended to fund and support the development of renewable and distributed energy resources.

A. Electrification Infrastructure/Programs

Under extensive CPUC guidance and oversight, PG&E manages a number of different programs that help advance the State's goal of decarbonizing the transportation sector—which generates the largest share of California's greenhouse gas emissions. PG&E's programs include rate options to encourage electric vehicle ("EV") charging during the most advantageous hours (for customers and the grid), financial incentives to customers installing qualifying charging infrastructure for EVs, and vehicle-grid integration ("VGI") planning and investments. These programs are designed to jump-start and enable a growing market for EVs, a critical component of California's climate action plan. PG&E's foundational programs in this area have been primarily authorized through D.18-01-024 and D.19-11-017, with a number of more recent CPUC decisions expanding and extending these programs.[131] The associated costs are recovered via PG&E's distribution rate.

B. Demand Response Programs

PG&E's Demand Response ("DR") programs were initially authorized through CPUC Decision D.01-03-073, implementing AB 970 (2000). AB 970 directed the Commission to provide incentives for resources to reduce peak energy demand, largely in response to the California Energy Crisis. DR programs have existed at PG&E for several decades. Historically, these programs ensured grid reliability and enabled the deferral of new generation units, as well as transmission and distribution capacity enhancements, to meet rising energy demand.

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[131] The key CPUC decisions authorizing IOU funding for transportation electrification programs are available at this link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/transportation-electrification/key-cpuc-te-decisions-and-resolutions#:~:text=program%20at%20PG%26E.-,D.,combined%20budgets%20of%20%2442%20million.

Over the past few decades, these programs have evolved and expanded significantly. California's position as an international leader in advancing solutions to climate change leads to energy markets that are dynamic and continue to evolve. The growth in renewables, achieved through a combination of firm and intermittent resources, combined with growth in electric demand tied to the decarbonization of non-electric sectors, presents challenges to the dynamic management of the electric grid. DR is expected to play a critical role in meeting California's aggressive decarbonization goals by 2045. DR resources have also become increasingly important to addressing California's capacity shortfall and grid reliability issues, driven by wildfires and extreme weather caused by climate change. As an important tool to ensure that supply and demand can be kept in balance, and as a means of helping customers meet their energy needs at the lowest possible cost, PG&E offers a number of programs to help customers manage the time-of-use characteristics of their energy consumption, in exchange for financial compensation.[132]

The principal design consideration of these programs is to help maintain the balance between supply and demand at the system and local level at the lowest possible cost. For example, certain programs compensate customers who can reduce their demand by a particular percentage or amount when the reserve margin (the difference between supply and demand) hits a pre-determined level (*e.g.*, 5%). Other programs encourage customers to consume more energy when the system is "long" on supplies—*e.g.*, during the middle part of the day in the spring when solar production is peaking and hydro production reflects significant snowmelt. Programs within PG&E's portfolio are generally available for customers within all customer classes.

All grid customers benefit from these programs – as they are designed and approved according to cost-effectiveness criteria that ensure that they are amongst the lowest cost options to maintain the reliability of the electric system. Given the interconnected nature of California's transmission grid, the deployment of DR resources to address localized reliability issues in one area of the state can have a beneficial impact on energy consumers in other areas of

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132 D.16-09-056 at 46. ("Commission-regulated demand response programs shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, and enable customers to meet their energy needs at a reduced cost.").

California. This means that even if they no longer receive distribution services from PG&E, CCSF customers will benefit from the impact that the deployment of PG&E DR programs has on the transmission grid, even though they would no longer be eligible to participate themselves in PG&E's DR programs.

C. Self-Generation Incentive Program

The Legislature first directed the creation of the Self-Generation Incentive Program ("SGIP") in AB 970. It was initially authorized through CPUC Decision D.01-03-073. In addition to the Demand Response programs described above, AB 970 directed the Commission to provide incentives for distributed generation resources to reduce peak energy demand. Included were solar photovoltaic and fuel cell projects. Through legislative and CPUC efforts, the program has been revised and refined a number of times.[133] The most recent CPUC decision authorizing this program was D.20-01-021. The program in its current form is largely directed to supporting on-site battery storage to provide resiliency for critical infrastructure and low-income or medically vulnerable customers subject to outages associated with wildfires.

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[133] D.20-01-021 at 5 n.2 ("Notably, AB 1685 (Leno, 2003), AB 2778 (Lieber, 2006) and SB 412 (Kehoe, 2009) collectively shifted SGIP's focus from peak demand reduction towards reducing criteria pollutants and greenhouse gas (GHG) emissions. SB 861 and AB 1478 authorized SGIP collections through 2019 and administration through 2020 and required a number of other changes. AB 1637 (Low, 2016) authorized the Commission to double annual collections through 2019 as compared to calendar year 2008.").

Appendix II: Public Policy Components of the Public Purpose Program Charge as of the Petition Date

The Public Purpose Program (PPP) Charge is a composite charge that recovers costs associated with a number of state policy programs that are primarily supported by customers of investor-owned utilities. The general categories that were included in the PPP as of the Petition Date are described in detail below.

A. Energy Efficiency

The types of energy efficiency initiatives funded through the PPP include:

- Direct support for advancing state building codes and state and federal appliance standards through advocacy, and direct support for compliance with building codes and appliance standards. Codes and standards are developed and adopted by the CEC and apply across the entire State to achieve cost-effective energy savings in California.
- "Upstream" delivery channel programs that incentivize manufacturers and distributors to develop and stock energy efficient equipment.
- Information products that help direct consumers to more efficient products and homes, and other strategies to improve the efficiency of their energy consumption.
- Statewide new construction programs that leverage incentives, rebates, technical assistance, and stakeholder engagement to promote building decarbonization and increase adoption of new energy efficient technologies. The programs' education and training program elements train builders, developers, and other market actors who are expected to transfer their skills to projects across the state, increasing the stock of highly efficient buildings.

PG&E's energy efficiency portfolio provides direct benefits to all customers through the delivery of avoided cost benefits to California's electric system. This is measured through the Total System Benefit metric, which expresses the lifecycle energy, ancillary services, generation capacity, transmission and distribution capacity, and GHG benefits of energy efficiency activities.[134] Thus, PG&E's San Francisco customers benefit not only from codes and standards and market transformation efforts funded through the PPP, but also from energy

[134] Total System Benefit Technical Guidance, CPUC, v.1.2 (Oct. 25, 2021).

efficiency incentives provided to customers outside of San Francisco, such as the replacement of inefficient air conditioning systems with more efficient ones for PG&E's customers in the Central Valley.

A significant portion of the energy efficiency share of the PPP gets allocated directly to other governmental groups and organizations approved by the CPUC to also run energy efficiency programs in PG&E's territory, including in the City and County of San Francisco. These include Regional Energy Networks ("RENs") such as the Bay Area Regional Energy Network ("BayREN") and CleanPowerSF. Previously, this also included the Local Government Partnership program administered through San Francisco's Department of the Environment ("SFE").[135]

B. Low Income Support

The PPP also supports important programs to help address the energy needs of the most vulnerable members of its customer base – and specifically those defined as "low-income." Public Utilities Code § 739.1(a) requires the CPUC to establish an assistance program for low-income customers of IOUs with annual household incomes that are no greater than 200% of the federal poverty guideline levels.

PG&E's California Alternative Rates for Energy ("CARE") program provides a discount for low-income customers that meet defined eligibility criteria.[136] In 2021, that discount was 35% relative to the customer's otherwise applicable bill. All customers who do not receive CARE benefits ("non-CARE") fund this rate discount through the PPP charge. The CARE Program is only available to CPUC-jurisdictional customers. If CCSF's acquisition is consummated, CCSF electric customers will lose access to this vital program. Families whose household income slightly exceeds the CARE allowances qualify to receive a rate discount under the Family Electric Rate Assistance ("FERA") program, which applies an 18% discount on their electricity bill. FERA is available for IOU customers.

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[135] San Francisco Energy Watch program closed as of June 30, 2023.

[136] Specifically, eligible households are those with incomes at or below 200% of the Federal Poverty Guideline.

Additionally, PG&E's low-income customers are eligible to participate in direct-install energy efficiency programs ("Energy Savings Assistance", or ESA). As shown in Section C of this testimony, a portion of the costs of these programs is directed to San Francisco customers and hence would be avoidable if PG&E ceases to serve San Francisco. The revenue that PG&E collects from San Francisco customers for these programs, however, exceeds these revenue returns. That difference constitutes severance damages.

C. Procurement from Preferred Resources

The Commission also has directed the IOUs to implement additional procurement mechanisms to satisfy specific state objectives. These efforts include supporting the production of energy from non-traditional sources of methane (*e.g.*, dairy farms) via the Bioenergy Market Adjusting Tariff Non-bypassable Charge, woody biomass derived from dead and dying trees via the Tree Mortality NBC, and standard offer contracts. The CPUC directed these procurement efforts through D.20-12-038 and D.22-12-044. Per those decisions, the cost recovery for these procurement tools is included in the Public Purpose Program charge. Unlike the PCIA, these costs are not vintaged based on the date of departure for a particular group of customers.

D. Research and Development (EPIC)

The Electric Program Investment Charge ("EPIC") funds clean energy applied research and development, technology demonstration and deployment, and market facilitation. The Commission first authorized EPIC in D.11-12-025 and adopted a permanent framework for EPIC in D.12-05-037. It renewed the electric program investment charge prior to the Petition Date in D.20-08-042. In D.20-08-042, the Commission reaffirmed that EPIC investments yield benefits through "greater reliability, lower costs, and increased safety," and "broader benefits such as attracting additional investment and fostering innovation."[137] The Commission also noted that "many EPIC projects have benefited low-income and disadvantaged communities," as 65% of its technology and deployment funds have gone to projects located in and benefitting those communities.[138] The Commission concluded that EPIC "has benefitted

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[137] D.20-08-042 at 12.

[138] *Id.* at 16.

electricity IOU ratepayers and California in general, helping address wildfire risk, meeting climate goals, and creating job growth, among many other benefits."[139]

[139] *Id.* at 17.

Appendix III: Evidence that No Party Forecasted, Nor Did the Commission Adopt a Sales Forecast that Included SF Large Municipalization As Part of Any Long-Term Procurement Proceeding.

A. Summary

Virtually all of PG&E's retail customers in San Francisco currently pay the PCIA and NSGC.[140] Were CCSF to proceed with a takeover, these customers would become municipal departing load. Under current Commission rules and relevant PG&E tariffs, these customers would be exempt from the PCIA and NSGC/CAM, unless PG&E demonstrates that this takeover constitutes a "large municipalization," specifically that the load was not removed from a Commission adopted sales forecast in a Long-Term Procurement Proceeding ("LTPP").

I have reviewed all of the relevant documents associated with the LTPPs beginning in 2010 (immediately following the Commission's September 2008 Decision establishing how the IOUs may allocate the above-market costs of generation procured when customers leave bundled utility service),[141] as well as the successor Integrated Resource Plan ("IRP") proceeding beginning in 2018. This includes documents produced by PG&E, the CEC (as part of its biennial IEPR), CCSF (including SFPUC and CleanPowerSF), and the CPUC. As a result of this review, I have concluded that no party provided a sales forecast that reflected a "large municipalization" in San Francisco, and the CPUC did not adopt such a sales forecast in any LTPP or successor IRP that reflected a large municipalization in San Francisco.

B. Background

Per D.08-09-012, an IOU may file an application to impose charges if it shows that the departing load was included in an adopted forecast and that procurement costs were incurred for it. "The IOU has the burden to show the departures are within the definition of a large municipalization, especially as it relates to how the large municipalization is or is not reflected in the adopted LTPP load forecasts."[142]

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[140] The exception is the small number of customers that are exempt as a result of their status as "continuous direct access." These customers were served continuously under direct access prior to its suspension in 1999, and then through its reopening in 2002.

[141] D.08-09-012.

[142] *Id.* at 29.

"It is necessary that the affected IOU demonstrate on a case-by-case basis that the related annexation cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP forecasts."[143]

"In the application, the IOU should demonstrate how the loads of these customers were included in an adopted load forecast, establishing that the IOU reasonably incurred costs on behalf of such customers. The Commission will determine the fair share of these customers for paying the D.04-12-048 and D.06-07-029 costs based on a departure date established through a binding notice of intent or alternative process."[144]

In order to place this effort into context, it is important to frame the process that ultimately underpins the development and adoption of a load forecast for purposes of resource planning.

LTPPs were conducted biennially and concluded in even years. In the spring of the year preceding the LTPP (an odd-numbered year), the CEC collects forecasted load information from Load Serving Entities (including IOUs, CCAs and publicly owned utilities) as part of the biennial IEPR proceeding. The CEC then aggregates and processes these forecasts and publishes them as part of the IEPR report. The CPUC then directs LSEs to use the applicable forecast from the IEPR report as a "Commission-mandated" case in the upcoming LTPP/IRP proceeding in order to ultimately develop a procurement plan. LSEs have the option of proposing alternative cases. The CPUC-adopted load forecast and procurement plan is published at the conclusion of the proceeding.

To summarize, there are several points along this process where either PG&E, another LSE, the CEC or the CPUC could have reflected a reduction in PG&E's load associated with a so-called large municipalization effort. I have reviewed all of the relevant documents starting with the 2010 LTPP through the 2022 IRP, and have not found any such reduction. Obviously, CCSF's CCA, CleanPowerSF, was actively engaged in this process by the 2012 LTPP

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143 *Id.* at 93.

144 *Id.* at 107 (Order ¶ 3). D.08-09-012 defined a "Binding Notice of Intent" as a "commitment to a target date, at which point a CCA is responsible for its own energy procurement and resource capacity." *Id.* at App'x C.

proceeding, following CleanPowerSF's registration as a CCA in May 2010.[145] Its forecasts were associated with its CCA efforts, as well as load adjustments associated with its service to selected customers under PG&E's Wholesale Distribution Tariff ("WDT").[146] The former category of load owes a vintaged PCIA consistent with the rules established as part of D.08-09-012 and subsequent proceedings. The latter category of load does not owe the PCIA under current CPUC rules.

As shown in Table III.1, CCSF's estimates for the load that it serves under the WDT provided to the CEC as part of the IEPR process were essentially held flat or exhibited modest growth through the various forecasted time-frames. Clearly none of these forecasts reflected a "large municipalization" that is associated with the retail load in San Francisco (an incremental ~4,000 GWh/year). Moreover, during this same time-frame CleanPowerSF was providing forecasts of the load that it intended to serve as a CCA. This CCA load would then be reflected in the CPUC's mandated case in the LTPP and/or adjusted as part of that proceeding. In 2018, CCSF responded to an ALJ Ruling providing an opportunity for LSEs to modify their forecasts.[147] CCSF did in fact respond with a significant increase in its forecasted load relative to that of the IEPR. Were there to have been a forecasted municipalization of San Francisco, it would have resulted in a double-counting of much of the same load. It's noteworthy that this was true in 2019, 2021 and 2023, which overlaps with the time-frame that includes CCSF's current takeover effort.

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145 Res. E-4397 at 2.

146 WDT load includes customers within the City's boundaries as well as some additional service delivery points outside San Francisco.

147 R.16-02-007, ALJ's Ruling Finalizing Greenhouse Gas Emissions Accounting Methods, Load Forecasts, and Greenhouse Gas Benchmarks for Individual Integrated Resource Plan Filings (May 25, 2018).

TABLE III.1
CCSF ESTIMATES FOR LOAD

Line No.	Year of Submission (and First Year of the Forecast)	Final Year of Forecast	GWh Consumption in First Year	GWh Consumption in Final Year	CAGR
1	2009				
2	2011				
3	2013				
4	2015				
5	2017	2026	980	980	0%
6	2019	2030	1,013	1,365	2.8%
7	2021	2030	927	1,412	4.8%
8	2023	2034	937	1,481	4.2%

In addition, PG&E has never received a Binding Notice of Intent from CCSF associated with a takeover of PG&E's SF Electric System.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8.2

AVOIDED COST STUDY

WITNESS: WHITNEY ALARY

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CHAPTER 8.2
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WITNESS: WHITNEY ALARY

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Schedule 5 (and sub schedules): System-Wide Indirect Avoided CapEx

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8.2
AVOIDED COST STUDY

A. Introduction

1. Scope of Engagement

Pacific Gas and Electric Company ("PG&E") retained HKA Global, LLC ("HKA") to assist with financial, economic, accounting, and damages analyses related to the City and County of San Francisco ("CCSF") petition to the California Public Utilities Commission ("CPUC") for a determination of just compensation for acquisition of certain public utility property of PG&E in San Francisco,[1] and specifically to assist with PG&E's evaluation of business severance damages.

As part of this engagement, I was asked to determine certain operational costs that PG&E would no longer incur with a potential condemnation of PG&E's electric delivery assets in and around San Francisco (*i.e.*, avoided costs). I may also be asked to respond to opinions set forth by or on behalf of CCSF related to business severance damages and avoided costs.

This Report presents my analysis to date on this matter.[2] The Appendices and Schedules at the end of this Report are an integral part of this Report. I prepared this Report with the assistance of other HKA professionals working at my direction.

I based the opinions and analyses presented in this Report on currently available information. My work is ongoing, and I plan to analyze any new information presented by CCSF or its experts. I reserve the right to update my findings if new information is produced that affects my opinions. For

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[1] I understand the City of San Francisco and County of San Francisco share the same borders.

[2] My opinions in this Report are based on my education and experience (described in Section A.2 of this Report) and my analysis of the documents and information relating to the issues in this case. I understand that my analysis and opinions may relate to legal or regulatory issues in this case, however, I am not providing any legal or regulatory opinions.

example, if CCSF presents additional witness testimony or expert reports, I may supplement this Report.

If this matter proceeds to a CPUC hearing, I may prepare graphical or illustrative exhibits based on the contents of this Report and the attached Appendices and Schedules, the documents and information considered, and my analysis of the documents and information.

2. Qualifications

HKA is a business, economic, financial, and damages consulting company that provides services to business entities, individuals, and counsel. I am a Partner in HKA's Los Angeles office. Previously, I was employed by TM Financial Forensics, LLC since its inception in January 2010 and held different positions, including Vice President. Prior to joining TM Financial Forensics, LLC, I worked for Navigant Consulting, Inc., an international consulting firm, in the Disputes and Investigations practice. I graduated summa cum laude from the University of California, Los Angeles, with a degree in Business Economics and a minor in Accounting.

I have over 19 years of professional experience in the financial, economic, accounting, and damages concepts relevant to the scope of my work on this matter. Over the course of my professional career, I have consulted on numerous economic damages matters, including matters involving energy companies and other regulated industries and government contracts. I have studied economic damages in numerous business environments, including oil and gas, nuclear, finance and banking, insurance, telecommunications, transportation, tobacco, aerospace, defense, software, manufacturing and construction.

I have prepared and analyzed claims for lost revenue, avoided costs, lost profits, increased costs, loss of business value, and other financial and economic impacts. In that context, I have analyzed the financial performance and operations of many commercial entities and government contractors, including detailed studies of labor, material, equipment, overhead, general and administrative, and other types of costs, and profit and interest. I have also reviewed and evaluated cost estimates, bids and proposals, change orders, contract pricing information, and incurred costs on government contracts.

My CV is attached as Appendix A.

B. Executive Summary

I was asked to calculate PG&E's avoided costs from July 27, 2021 through 2051 as part of PG&E's business severance damages. I analyzed PG&E's avoided costs as a result of no longer operating and maintaining electric assets and serving associated customers in San Francisco.

As part of my analysis, I evaluated multiple categories of costs that would be impacted by the loss of San Francisco electric operations, including: (1) electric distribution operations and maintenance ("O&M") costs; (2) electric transmission O&M costs; (3) system-wide indirect O&M costs; and (4) system-wide indirect capital expenditures ("CapEx").[3] Table 8.2-1 below summarizes my calculation of PG&E's avoided costs by category, totaling $3.8 billion in avoided costs (in nominal dollars for 30 years).

TABLE 8.2-1
SUMMARY OF PG&E'S AVOIDED COSTS[4]
(MILLIONS OF NOMINAL DOLLARS)

Line No.	Cost Category	Avoided Costs (30 Years)	Percent of System-Wide Costs Avoided
1	Electric Distribution O&M	$1,606.0	1.69%
2	Electric Transmission O&M	105.8	0.39%
3	Indirect O&M	1,552.1	1.01%
4	Subtotal O&M	$3,263.9	1.19%
5	Indirect CapEx	534.3	1.11%
6	Total	$3,798.1	1.17%

[3] I did not analyze avoided direct CapEx for electric distribution or transmission, avoided costs for gas or energy supply, or avoided costs associated with various policy programs that provide direct benefits to end-use customers in San Francisco, as these costs are addressed in PG&E Testimony, Chapter 8.1 (David Rubin).

[4] Schedule 1. Any differences between totals and the sum of individual amounts in the tables in this Report are due to rounding.

C. Background[5]

1. CCSF's Petition and Business Severance Damages

On July 27, 2021, CCSF petitioned the CPUC for a determination of just compensation for acquisition of certain public utility property of PG&E within and adjoining the boundaries of San Francisco (the "Petition").[6]

I understand that CCSF seeks to take over, by way of eminent domain, electric delivery (transmission and distribution) in San Francisco that is currently provided by PG&E. Should CCSF succeed, it would be required to provide just compensation to PG&E for the value of the business taken. The standards for just compensation include the standard that PG&E ratepayers remain in the same financial position after the proposed acquisition.[7]

I understand that just compensation in this matter includes the value of PG&E's assets that CCSF seeks to acquire, as well as business severance damages and physical separation costs. PG&E's business severance damages represent the dollar amount necessary to compensate PG&E and its remaining electric and gas customers for the financial impact of CCSF's taking, including losing electric assets and customers in San Francisco. Business severance damages evaluate PG&E's lost revenues from no longer serving electric customers in San Francisco, less PG&E's avoided costs from not operating and maintaining or investing in PG&E's electric assets in San Francisco and from no longer providing service to the customers connected to those assets.

I understand that PG&E's witness David Rubin will testify to PG&E's calculation of business severance damages, including calculating PG&E's lost revenues and other avoided costs not addressed in my Report, such as customer benefits from various public policy programs. I also understand

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5 This Section is provided for context only and is not intended to represent a legal analysis of disputed facts.

6 California Public Utilities Commission proceeding, "Petition of the City and County of San Francisco for a Valuation of Certain Pacific Gas and Electric Company Property Pursuant to Public Utilities Code Sections 1401-1421" Petition ("P") 21-07-012 (July 27, 2021).

7 Decision Establishing Methods and Standards for Just Compensation and Valuation, D.25-10-039 at 42 (Oct. 30, 2025) ("Interim Decision").

that David Rubin incorporates the avoided costs from my Report to calculate total business severance damages.[8]

2. PG&E's Costs Supporting Electric Operations in San Francisco

PG&E incurs billions in costs annually to provide electric and gas services to customers in its territory. PG&E's costs include recurring O&M costs to perform daily operations and maintain equipment and facilities, as well as CapEx to invest in long-term physical assets, among other costs.

PG&E incurs O&M costs and CapEx that directly support its electric operations, including transmission and distribution. PG&E's 2023 General Rate Case ("GRC"), submitted on June 30, 2021, describes electric operations as "responsible for safely and reliably delivering electricity to PG&E's customers over a large and diverse service area through efficient and cost-effective planning, engineering, constructing, maintaining, and restoring of electric distribution assets."[9] Examples of costs that PG&E incurs to support electric operations work include costs to inspect and maintain overhead and underground distribution and transmission lines, and costs to trim trees around overhead lines as part of wildfire mitigation efforts.

PG&E also incurs indirect costs that support the entire PG&E system. These include costs to support customers and communications, shared services, information technology ("IT"), human resources, and administrative and general ("A&G") costs.

PG&E records all actual costs in its cost accounting system and maintains historical records for at least 10 years. Every cost record is assigned to a two-digit Major Work Category ("MWC"), and some costs are assigned a third digit subcategory Maintenance Activity Type ("MAT"). MWCs generally align to a particular direct or indirect cost category.[10] PG&E maintains separate MWCs for O&M (represented as two letters) and CapEx (represented as two numbers or a number and letter). For example, MWC JV is used for O&M costs to maintain IT applications and

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8 *See* PG&E Testimony, Chapter 8.1.

9 2023 General Rate Case Application of Pacific Gas and Electric Company (U 39 M) (June 30, 2021) ("PG&E 2023 GRC"), Exhibit 4, Chapter 1 Electric Distribution Policy and Introduction at 1-1.

10 PG&E 2023 GRC Application at 16 to 17.

infrastructure, while MWC 2F is used for CapEx to build IT applications and infrastructure.[11] As another example, MAT ICU (a subcategory of MWC IC) is used for O&M costs to maintain underground electric transmission facilities, while MWC 72 is used for CapEx to replace electric transmission underground lines.[12]

PG&E's cost accounting system also maintains other attributes for each cost record, such as the location where work was performed and the overseeing department.

3. PG&E's Electric Service in San Francisco

PG&E is one of the largest utility companies in the United States. It provides electric and gas service to customers across a 70,000 square mile territory, spanning from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada in the east.[13] PG&E has provided electric service to San Francisco since it was incorporated in 1905.[14]

I provide the following metrics from 2021 for frame of reference in evaluating PG&E's costs for San Francisco electric operations relative to PG&E's entire system.

- San Francisco accounts for approximately 0.067% of PG&E's 70,000 square mile territory.[15]

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[11] PG&E 2023 GRC, Exhibit 7 Shared Services and Information Technology, Chapter 8 Information Technology at 8-20.

[12] Transmission Expense 2022 Investment Plan (Dec. 14, 2021).

[13] PG&E Company Profile (https://www.pge.com/en/about/company-information/company-profile.html).

[14] 150 Years of Energy: The History of PG&E Corporation (https://web.archive.org/web/20120629010809/http://www.pgecorp.com/150_non_flash/index.html)

[15] 46.9 / 70,000 = 0.067%. San Francisco city, California Census Bureau Profile (https://data.census.gov/profile/San_Francisco_city,_California?g=160XX00US0667000). PG&E Testimony, Chapter 2 Overview of PG&E Electric System in San Francisco at 2-2.

- San Francisco electric customers account for approximately 7.55% of PG&E's 5.6 million electric customers.[16]
- San Francisco retail customers consume approximately 5.13% of PG&E's total retail electric consumption.[17]
- Approximately 1.40% of PG&E's 108,000 primary distribution line miles are in San Francisco, and approximately 0.38% of PG&E's 18,000 transmission line miles are in San Francisco.[18]

The metrics above demonstrate the variability in the percentage of PG&E's electric business related to San Francisco, which is primarily driven by the city's urban environment. San Francisco has a relatively denser population, smaller footprint, and harder landscape – *e.g.*, dominated by buildings, pavement, and other solid surfaces – compared to the rest of PG&E's territory.

As described in more detail below, I determined the percentage of system-wide costs for San Francisco electric service that PG&E would avoid for each category in PG&E's O&M and CapEx forecast. Each cost category may relate to one of the metrics above, and the overall weighted average avoided costs are 1.17% of PG&E's cost forecast.[19]

4. PG&E's Wildfire Prevention Programs

The CPUC maintains a fire-threat map that identifies areas designated as High Fire Threat Districts ("HFTD"), which are assigned Tiers 1, 2, and 3 based on increasing level of wildfire risk.[20] Approximately half of PG&E's territory is at high risk of wildfires (*i.e.*, designated as Tier 2 – Elevated risk

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16 421,774 / 5,584,482 = 7.55%. San Francisco electric customers are based on the number of customer meters and primary meters per the asset stipulation documents. 2021 Integrated Energy Policy Report, Form 2.3 Customer Count and Other Forecasting Inputs.

17 4.0 TWh / 78.2 TWh = 5.13%. PGE SF Revs 2017-2022.xlsx, tab "2021 Revenues by Class;" 2022 Integrated Energy Policy Report, Form 1.1c Electricity Deliveries to End Users by Agency (including all Pacific Gas & Electric Company, BART, and CCA).

18 1,511 / 108,000 = 1.40%. San Francisco distribution mileage per the asset stipulation documents; PG&E Testimony, Chapter 2 at 2-2. 68 / 18,000 = 0.38%. PG&E Testimony, Chapter 2 Overview of PG&E Electric System in San Francisco at 2-2 and 2-7.

19 Schedule 1.

20 CPUC Fire-Threat Map, Revised on August 19, 2021.

and Tier 3 – Extreme risk), and approximately one-third of PG&E's overhead assets are in these territories.[21]

PG&E is focused on reducing wildfire risk to keep customers and communities safe. PG&E incurs significant costs related to wildfire mitigation, including for:[22]

- Vegetation management – pruning or removing trees along distribution and transmission lines to mitigate wildfire risk;
- System hardening – installing stronger, more resilient poles and covered conductors on overhead lines and undergrounding lines in HFTDs;
- Public safety power shutoff ("PSPS") programs – proactively de-energizing portions of the PG&E electric system when there is a heightened risk of a catastrophic wildfire;
- Situational awareness – installing equipment (*e.g.*, weather stations and cameras) and utilizing advanced modeling to more precisely forecast and monitor weather;
- Inspections – inspecting assets to identify conditions that require repair or replacement prior to a failure that could lead to ignition; and
- Wildfire liability insurance – insuring the business should a wildfire occur.[23]

Wildfire threats and related costs to reduce wildfire risk have increased over time.[24] For example, PG&E's 2023 GRC identifies that "[a]pproximately 50% of the requested revenue requirement increase over 2022 adopted is for wildfire reduction work, including our vegetation management programs."[25]

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21 Pacific Gas and Electric Company 2021 Wildfire Mitigation Plan – Revised (June 3, 2021) at 3. PG&E 2023 GRC, Exhibit 4 Electric Distribution, Chapter 1 Electric Distribution Policy and Introduction at 1-6.

22 PG&E 2023 GRC, Exhibit 4 Electric Distribution, Chapter 1 Electric Distribution Policy and Introduction at 1-1 to 1-2.

23 PG&E paid high wildfire liability insurance premiums as of 2021. I understand that PG&E has since changed to a self-insurance model where it no longer pays premiums to third-party insurers.

24 PG&E 2023 GRC, Exhibit 4 Electric Distribution, Chapter 1 Electric Distribution Policy and Introduction at 1-6.

25 PG&E 2023 GRC, Application at 5.

San Francisco is not designated a HFTD,[26] and I understand that PG&E would not change its wildfire mitigation plan with the loss of San Francisco electric operations. Therefore, the significant and increasing costs that PG&E incurs for wildfire risk mitigation would not be avoided. See further discussion of wildfire-related costs in Section E.3 below.

D. Calculation of Avoided Costs

I calculated the costs that PG&E would avoid from the Petition date, July 27, 2021, through year-end 2051 (30 years).[27] I provided the results of my analysis to PG&E's witness David Rubin, who incorporated these avoided costs into his analysis of business severance damages in Chapter 8.1 of PG&E's testimony.

I understand that the Commission will determine just compensation in this matter, pursuant to Pub. Util. Code § 1411, as of the Petition date. Therefore, my analysis of PG&E's avoided costs is based on information available on or around the Petition date.[28]

To calculate PG&E's avoided costs, I performed the following four steps, described in more detail in Sections D.1 to D.5 below:

- **Step 1:** I reviewed all of PG&E's roughly $13.7 billion annual cost forecast (as of 2021), and I identified cost categories related to PG&E's electric

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26 CPUC Fire-Threat Map, Revised on August 19, 2021.

27 PG&E is evaluating business severance damages from the Petition date through year-end 2051. *See* PG&E Testimony, Chapter 8.1 at 8.1-1 to 8.1-2. While the period from July 27, 2021 to December 31, 2051 is 30.43 years, I generally refer to the avoided cost period as 30 years.

28 California Public Utilities Commission proceeding, "Petition of the City and County of San Francisco for a Valuation of Certain Pacific Gas and Electric Company Property Pursuant to Public Utilities Code Sections 1401-1421," Petition ("P") 21-07-012 (July 27, 2021). I understand that PG&E's cost structure has changed since July 27, 2021. To the extent that CCSF is successful in its Petition, I reserve the right to update the analysis to reflect PG&E's current cost structure and actual costs since the Petition date.

operations in San Francisco.[29, 30] San Francisco related costs relevant to my analysis include direct O&M costs for electric distribution and transmission operations and indirect O&M costs and indirect CapEx supporting PG&E's system-wide operations.

- **Step 2:** I obtained PG&E's contemporaneous total system-wide cost forecasts for those categories, and I extended those forecasts to estimate PG&E's total system-wide costs for 30 years.
- **Step 3:** Using historical data and interviews with PG&E subject matter experts ("SME"), I calculated the percentage of total system-wide costs in each category that support electric operations in San Francisco and determined the portion of those costs that would be avoided (*i.e.*, the "avoided cost percentage," described in more detail in Section V below). For all cost categories (with one exception), I conservatively assumed that 100% of the costs related to San Francisco electric operations would be avoided within the first year after separation and implemented such avoided costs immediately in modeling the 30 years of avoided costs.[31]
- **Step 4:** I applied the avoided cost percentage from Step 3 to the total system-wide cost estimate from Step 2 to calculate nominal avoided costs for 30 years.
- **Step 5:** For system-wide indirect avoided costs (both O&M and CapEx), I allocated them between electric transmission and electric distribution using the allocations to functional category in the 2023 GRC.

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29 Comprised of the 2021 forecast for expense ($5.0 billion) and capital ($6.5 billion), including electric distribution, gas, energy supply, and system-wide indirect costs (PG&E 2023 GRC, Exhibit 1, Chapter 2 at Table 2-2), electric transmission CapEx forecast [redacted], and electric transmission O&M forecast [redacted] (Schedule 3.12).

30 My analysis considered the electric distribution and electric transmission costs recovered through the GRC and Transmission Owner ("TO") Rate Case. I also considered cost categories identified in the 2023 GRC that are funded through other mechanisms, such as Advice Letters. I did not identify any avoided costs in the cost categories funded outside of the GRC and TO Rate Case.

31 Only the Law Organization would not avoid any costs for at least five years after separation. Therefore, I calculated no avoided costs for the Law Organization for five years after the Petition date and avoided costs using the relevant avoided cost percentage thereafter. *See* Section D.4 for further discussion.

Overall, I determined that PG&E would avoid 1.17% of its total system-wide costs (for categories related to San Francisco electric operations), equaling $3.8 billion (in nominal dollars), from July 27, 2021 through 2051.

Appendix B attached to this Report is a matrix of all the cost categories analyzed, including a description of the cost, source of PG&E contemporaneous forecast, avoided cost percentage method, and estimated avoided costs.

1. Step 1: Identify Cost Categories Related to Electric Operations in San Francisco

As an initial step, I analyzed PG&E's historical costs and contemporaneous cost forecasts to identify cost categories related to PG&E's electric operations.[32] These included both direct costs for electric transmission and distribution, and costs supporting PG&E's system-wide operations that indirectly benefit electric operations in San Francisco.

I first analyzed PG&E's 2023 GRC application, which was submitted to the CPUC on June 30, 2021, less than a month before the Petition date. PG&E submits a General Rate Case application to the CPUC every four years to set its electric and gas distribution rates.[33]

The 2023 GRC covers PG&E's cost forecasts for electric distribution, gas operations, and energy supply, as well as indirect costs for A&G, human resources, shared services, IT, customer support, and communications.[34] It includes detailed forecasts by cost category for 2021 to 2023.[35] I relied on the cost categorization and forecasts in the 2023 GRC to analyze PG&E's electric distribution O&M costs and system-wide indirect O&M costs and indirect CapEx. For example, the 2023 GRC is organized by exhibit (*e.g.*, electric distribution or A&G), chapter (*e.g.*, vegetation management or finance organization), and subcategories within each chapter, such as by MWC (*e.g.*, routine vegetation management (MWC HN) or bank fees).

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32 PG&E's historical data and forecasts segregate electric distribution and electric transmission direct costs from other direct operations costs, such as gas and energy supply.

33 PG&E 2023 GRC Application; PG&E General Rate Case (https://www.pge.com/en/regulation/general-rate-case.html).

34 PG&E 2023 GRC, Exhibits 3 through 9.

35 Certain cost categories are forecasted to 2026.

The 2023 GRC does not include electric transmission direct costs,[36] and I understand there is no similar public multi-year forecast for electric transmission O&M costs.[37] To identify the relevant cost categories for electric transmission O&M, I analyzed PG&E's internal Transmission Expense 2022 Investment Plan, prepared on December 14, 2021, forecasting electric transmission O&M costs for 2022 to 2026.[38] The Transmission Expense Investment Plan reflects the overall targets and forecasts for PG&E's electric transmission portfolio spending in certain categories of work. PG&E updates its Transmission Expense Investment Plan annually to include new projects and to update estimates for in-process work. It includes cost forecasts by MWC and MAT, and I analyzed PG&E's electric transmission costs by MWC/MAT.

I did not analyze PG&E's direct O&M costs or CapEx for gas operations or energy supply because I understand that CCSF is not seeking to take PG&E's gas or energy supply assets.[39] I did, however, consider costs incurred for shared assets, services, and personnel supporting both PG&E's electric and gas service in San Francisco, including identifying stranded costs for maintaining shared assets that must be retained for PG&E's gas business, such as service centers.[40]

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36 PG&E General Rate Case (https://www.pge.com/en/regulation/general-rate-case.html).

37 PG&E files publicly the TO Rate Case with the Federal Energy Regulatory Commission ("FERC") which details the O&M costs associated with its transmission facilities. However, PG&E's TO Rate Case only forecasts transmission costs for one year. *See, e.g.*, Pacific Gas and Electric Company Transmission Owner Annual Update Filing under the Formula Rate in Docket Nos. ER19-13-000, ER19-1816-000, and ER20-2265-000 (Consolidated) for the Rate Year 2021 (RY2021) (Dec. 1, 2020). PG&E also publicly files a five-year forecast of transmission CapEx in its Stakeholder Transmission Asset Review ("STAR") Process filing, however the STAR filing does not include transmission O&M costs. *See, e.g.*, PG&E June 1, 2021 Submission of Section 3.1 Material to Stakeholder Transmission Asset Review Process Stakeholders.

38 I also assessed the latest available pre-Petition data, prepared in August 2020, and concluded that its use in the avoided cost analysis would result in a nonmaterial difference. I used the December 2021 forecast because it was closer to the Petition date and accounted for information learned in the year prior to the Petition.

39 PG&E Testimony, Chapter 8.1 presents avoided costs associated with generation supply that PG&E would no longer provide to its bundled customers.

40 For the reasons explained in Section C.4 of Chapter 8.1, I reserve the right to further quantify the effects of the taking on PG&E's gas business in a future valuation proceeding at the actual time of acquisition. *See* Chapter 8.1, § C.4 & n.73.

I also did not analyze avoided costs for various policy programs that provide direct benefits to end-use electric customers in San Francisco or avoided costs for electric transmission and distribution CapEx in San Francisco. An analysis of avoided costs related to PG&E's policy programs and electric transmission and distribution CapEx is addressed in the witness testimony of David Rubin (*see* PG&E testimony Chapter 8.1).

2. Step 2: Forecast Total System-Wide Costs to 2051

Next, I forecasted PG&E's total system-wide costs for the identified categories from July 27, 2021 through 2051. I prepared a 30-year forecast consistent with the approach employed by the business severance analysis in Chapter 8.1.

I started with PG&E's contemporaneous forecasts for 2021 to 2023 (or 2026) for each category from the 2023 GRC and the Transmission Expense 2022 Investment Plan. The Transmission Expense 2022 Investment Plan does not include 2021 expenses. To estimate the costs in 2021, I analyzed the trend in PG&E's forecast for each MAT.[41] See schedule for each electric transmission cost subcategory titled "Estimate of July to December 2021 Costs with SF" for the 2021 cost methodology and forecast.

I escalated the annual cost forecasts starting in 2024 (or 2027) by applying annual escalation rates (described immediately below) to the prior year's forecast to 2051. The escalation factors account for inflation in future years.[42]

To determine the annual escalation rates, I relied on the escalation rates used in the 2023 GRC. The 2023 GRC includes O&M labor escalation rates for operating units and A&G, O&M non-labor escalation rates for each functional category, including electric distribution and administration, and

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[41] For example, if an MAT forecast was the same amount each year from 2022 to 2026, I assumed the same amount for 2021. If an MAT forecast increased each year from 2022 to 2026, I de-escalated the 2022 amount using the overall growth rate from 2022 to 2026 to determine the 2021 amount. In certain instances, when the 2022 forecast was different than the trend for 2023 to 2026, I accepted the 2022 amount for 2021.

[42] PG&E 2023 GRC, Exhibit 12 General Report, Chapter 3 Escalation Rates at 3-1 to 3-2.

CapEx escalation rates for each functional category, including electric distribution and common plant.[43]

While the 2023 GRC does not include escalation rates for electric transmission, the underlying data source for the non-labor escalation rates, IHS Markit, includes rates for electric transmission. I applied the IHS Markit rates for electric transmission to the electric transmission forecast consistent with the methodology in the GRC. Labor includes PG&E employees (both union and non-union), and non-labor includes contractor services and materials. Table 8.2-2 below shows the relevant escalation rates from the GRC and IHS Markit data.

TABLE 8.2-2
2023 GRC AND IHS MARKIT ESCALATION RATES[44]

Line No.	Category	2021	2022	2023	2024	2025	2026
1	Labor – Operating Units	3.0%	3.5%	3.5%	3.5%	3.5%	3.5%
2	Labor – A&G	3.1%	3.3%	3.3%	3.3%	3.3%	3.3%
3	Non-Labor – Electric Distribution	-0.4%	2.2%	2.4%	2.2%	2.0%	1.9%
4	Non-Labor – Electric Transmission	[redacted]					
5	Non-Labor – Administrative	1.4%	1.9%	2.3%	2.3%	2.1%	2.1%
6	CapEx – Common Plant	[redacted]					

As shown in Table 8.2-2 above, the 2023 GRC includes escalation rates through 2026. The underlying IHS Markit data for non-labor and CapEx escalation rates includes escalation rates through 2030. For purposes of the avoided cost analysis, I applied the escalation rate for the latest available year (2026 or 2030) for each category to all future years through 2051. The escalation rate of the latest year represents the best information available in 2021 about PG&E's future cost inflation.

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43 Labor escalation rates are based on PG&E's collective bargaining labor agreements for represented employees, and third-party salary survey data for non-represented employees. Non-labor and CapEx escalation rates are based on IHS Markit's First Quarter 2020 Power Planner forecast. IHS Markit's forecast is commonly used by utilities to escalate costs for inflation at the functional utility level.

44 PG&E 2023 GRC, Exhibit 8 Human Resources, Chapter 4 Compensation: STIP, Non-Qualified Retirement and Labor Escalation at 4-22 to 4-25. PG&E 2023 GRC, Exhibit 12 General Report, Chapter 3 Escalation Rates at 3-1 to 3-3. IHS Markit Q1 2020 Forecast.

Given that the 2023 GRC provides separate escalation rates for O&M labor and non-labor, I developed a blended escalation rate for each major cost category (*i.e.*, 2023 GRC chapter or MWC) consistent with the methodology employed by PG&E in the 2023 GRC. I started by splitting the latest year's contemporaneous forecast (2023 or 2026) between labor and non-labor.[45] I then applied the labor and non-labor escalation rates separately to the labor and non-labor forecasts to determine the following year's forecasts. I then compared the sum of the following year's labor and non-labor forecasts to the sum of the current year's forecasts to determine a blended escalation rate for the year. Table 8.2-3 below provides an example of the escalation rate calculation for the electric distribution O&M cost category Overhead and Underground Electric Asset Inspections for the first five years.

TABLE 8.2-3
EXAMPLE ESCALATION RATES
OVERHEAD AND UNDERGROUND ELECTRIC ASSET INSPECTIONS[46]

		Labor		Non-Labor		Total	
Line No.	Year	Forecasted Expense	Annual Escalation Rate	Forecasted Expense	Annual Escalation Rate	Forecasted Expense	Annual Escalation Rate
1	2023	$19,682		$69,782		$89,464	
2	2024	$20,375	3.52%	$71,288	2.16%	$91,663	2.46%
3	2025	$21,092	3.52%	$72,700	1.98%	$93,792	2.32%
4	2026	$21,834	3.52%	$74,090	[redacted]	$95,925	[redacted]
5	2027	$22,603	3.52%	[redacted]	[redacted]	[redacted]	[redacted]
6	2028	$23,399	3.52%	[redacted]	[redacted]	[redacted]	[redacted]
7	… to 2051						

Table 8.2-3 shows that, for example, the 2024 blended escalation rate is calculated by (1) multiplying the 2023 labor expense of $19,682 times the 2024 labor escalation rate of 3.52% to calculate a 2024 labor expense of $20,375; (2) multiplying the 2023 non-labor expense of $69,782 times the 2024 non-labor escalation rate of 2.16% to calculate a 2024 non-labor

45 *See* attached Schedule 2.10 for electric distribution, Schedule 3.9 for electric transmission, and Schedule 4.15 for system-wide indirect costs. CapEx does not have separate escalation rates for labor and non-labor.

46 Schedule 2.5D.

expense of $71,288; (3) adding the annual labor and non-labor expenses to calculate 2023 total expenses of $89,464 and 2024 total expenses of $91,663; and (4) dividing 2024 total expenses by 2023 total expenses to calculate a blended escalation rate of 2.46%. I performed the same calculation for each subsequent year until 2051. See schedule for each cost category titled "Escalation Rates" for the calculated blended escalation rates applicable to that category.

I applied the blended escalation rates for each major cost category to all costs in that category to account for inflation in estimating future years. See schedule for each cost subcategory titled "Costs With SF" for the escalated cost forecast through 2051.

3. Step 3: Determine the Percentage of Costs that Would Be Avoided

I then calculated the percentage of total system-wide costs in each category that support electric operations in San Francisco and determined the portion of those costs that would be avoided if PG&E no longer provided electric service in San Francisco (*i.e.*, the "avoided cost percentage"). I determined the avoided cost percentage using four different methods, depending on the type of cost and the location-specific information available (*i.e.*, data that is identifiable to a specific location, including San Francisco). The four methods include:

1) Using location-specific historical costs;
2) Using location-specific operational data;
3) Categories with no avoided costs; and
4) Efficiencies gained for general support costs.

I explain the high-level process of determining the avoided cost percentages here and describe additional details of my calculations and provide examples in Section E below.

I first analyzed PG&E's historical system-wide costs to distinguish costs incurred for electric operations in San Francisco from other areas of PG&E's service territory. I obtained an extract of five years of historical costs from PG&E's cost accounting system that included fields tagging costs to a specific location, such as county code, which aligns to the California counties that PG&E serves, and division code, which aligns to the

operational boundaries PG&E uses for the 19 divisions it serves. San Francisco is both a California county and a PG&E division.

I worked with PG&E Business Finance personnel to analyze multiple attributes of the cost data to identify historical costs for electric work in San Francisco and other locations. For each cost category with sufficient location-specific cost data, I calculated the percentage of costs incurred for San Francisco relative to PG&E's total system-wide costs to determine the historical percentage of costs for San Francisco (*i.e.*, method 1, using location-specific historical costs). See Section E.1 for additional detail.

For each cost category, I conducted interviews with subject matter experts to understand the type of work performed and costs incurred for the category, including confirming what portion of costs, if any, would be avoided if PG&E no longer provided electric service in San Francisco. Subject matter experts included PG&E personnel from both the finance and operational sides of PG&E's electric operations, as well as department heads supporting system-wide indirect cost categories. I confirmed with each subject matter expert that the percentage of costs for San Francisco based on historical cost data was a reasonable estimate of the costs PG&E would avoid.

Certain cost categories contained sufficient information in the historical data to determine the location. For example, most electric distribution O&M costs were identifiable to a location and were used to determine an avoided cost percentage.

However, while other cost categories include costs that are directly attributable to San Francisco, the historical data for these categories does not include sufficient level of detail to determine costs specifically for San Francisco. For these categories, I worked with PG&E subject matter experts to identify other operational metrics that would reasonably estimate the portion of costs for San Francisco. For example, I considered miles of underground lines in and outside of San Francisco for underground-related work.

For each cost category with location-specific operational data, I obtained historical data for the operational metric and calculated the percentage of San Francisco units relative to PG&E's total system-wide units to determine

the percentage for San Francisco. I used the operational percentage for San Francisco as a proxy for the percentage of costs incurred for San Francisco (*i.e.*, method 2, using location-specific operational data). I also considered whether the costs for a category are higher in San Francisco than other areas and adjusted the percentage to account for higher costs in San Francisco, as appropriate.[47] See Section E.2 for additional detail.

Subject matter experts also confirmed that certain cost categories would have no avoided costs (*i.e.*, method 3, categories with no avoided costs). These categories mainly relate to wildfire mitigation. As discussed in Section C.4 above, PG&E incurs significant costs for wildfire prevention in HFTDs, and San Fransico is not a high-risk area for wildfires. Therefore, I understand PG&E would maintain its existing wildfire mitigation programs and would not avoid any costs with the loss of San Francisco electric assets or customers.

PG&E also incurs system-wide indirect costs that support all of PG&E's operations, including its electric operations in San Francisco. I understand that many of these indirect costs are not associated with specific locations, and PG&E's historical indirect costs are not tagged by location. I also understand that many indirect cost categories would not avoid any costs (*e.g.*, would not reduce headcount) if PG&E no longer provided electric service in San Francisco.

I conservatively assumed that PG&E would gain some efficiencies from a decreased level of effort from no longer providing electric service in San Francisco. I assumed the avoided indirect costs from these efficiencies would be proportional to the overall percentage of avoided O&M costs for

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47 For example, to determine the avoided costs for maintenance of overhead electric poles, I first determined that 1.4% of PG&E's utility poles are in San Francisco. However, the average cost to replace a pole in San Francisco is over 2.6 times the cost to replace poles in other areas of PG&E's service territory because poles in San Francisco are more difficult to access and can require additional equipment, such as a crane, to replace. Therefore, to determine the percentage of avoided costs for San Francisco, I increased the 1.4% of poles in San Francisco by 2.6 times to account for the higher cost of pole replacement in the city, resulting in an avoided cost percentage of 3.68%. *See* Schedule 2.9B.4.

electric distribution and transmission (*i.e.*, method 4, efficiencies gained for general support costs) of 1.40%.[48]

Appendix B attached to this Report identifies the method for developing the avoided cost percentage for each cost category analyzed.

4. Step 4: Calculate Avoided Costs

For each cost category, I applied the avoided cost percentage from Step 3 to the total system-wide cost estimate from Step 2 to calculate avoided costs each year from July 27, 2021 through 2051.

For all cost categories (with one exception), I conservatively assumed that costs related to San Francisco would be avoided within the first year after separation and implemented such avoided costs immediately after separation (*i.e.*, starting on the day of the Petition) in modeling the 30 years of avoided costs.

For the Law Organization, I understand that PG&E would still be subject to legal claims related to its infrastructure for years after separation, and therefore PG&E would not avoid the costs to process, defend, and pay those claims for at least five years.[49] Therefore, I calculated no avoided costs for the law department for five years after the Petition date (through July 26, 2026) and avoided costs using the relevant avoided cost percentage thereafter (from July 27, 2026 through 2051).[50]

5. Step 5: Allocate System-Wide Indirect Avoided Costs to Electric Distribution and Transmission

PG&E collects revenues from customers through numerous discrete electric rate components. To align the avoided costs to the rate components, I allocated system-wide indirect avoided costs between electric distribution and electric transmission.[51] I relied on the methodology used in the 2023 GRC to allocate the system-wide avoided costs between functional

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48 Schedule 4.17.

49 Discussion with PG&E legal department subject matter expert.

50 Schedule 4.13A.1.

51 The calculated avoided costs only relate to PG&E's electric business and therefore only need to be split between electric distribution and transmission.

categories.[52] The 2023 GRC includes allocation percentages by MWC or GRC chapter for each functional category (*i.e.*, electric distribution, electric transmission, generation, gas distribution, and gas transmission and storage).[53] I used these allocations to calculate the split of electric costs between distribution and transmission. I then applied the electric distribution and electric transmission percentages to the avoided costs to calculate the electric distribution and electric transmission avoided costs, respectively.

As an example, the 2023 GRC shows the Common Allocation per O&M Labor Factor for 2026 is 9% Power Generation, 35% Gas, and 56% Electric. 20% of the Electric portion is for Electric Transmission and 80% is for Electric Distribution. Table 8.2-4 below shows the percentages PG&E uses to allocate system-wide costs to each functional category in 2026.

TABLE 8.2-4
2026 COMMON ALLOCATION PER O&M LABOR FACTOR[54]

Line No.	Category	2026 Total	2026 % Electric
1	EG - Power Generation	9%	
2	GT - Gas Transmission & Storage	11%	
3	GD - Gas Distribution	24%	
4	Subtotal Gas	35%	
5	ED - Electric Distribution	45%	80%
6	ET - Network & Other Transmission	11%	20%
7	Subtotal Electric	56%	100%
8	Total	100%	

52 I understand that while the GRC ultimately does not include electric transmission costs in its revenue requirement (and electric transmission costs are recovered through the TO Rate Case), the system-wide forecasts in the GRC include the total forecasted costs for all functional categories and then only the costs allocated to the functional categories recovered through the GRC are included in the revenue requirement. *See* PG&E 2023 GRC Exhibit 10, Chapter 17 at 17-3 ("PG&E removed all FERC-jurisdictional electric-transmission-related revenues and costs from the GRC revenue requirement request.")

53 *See* PG&E 2023 GRC Exhibit 10, Workpaper Supporting Exhibit (PG&E-10), Chapter 1A at WP 1A-1 to WP 1a-13.

54 Schedule 4.16A.

E. Determination of the Avoided Cost Percentage

The avoided cost percentage represents the portion of total system-wide costs that would be avoided if PG&E no longer provided electric service in San Francisco.[55] I determined the avoided cost percentage using different methodologies, depending on the type of cost and the location-specific information available (*i.e.*, information that is identifiable to a specific location, including San Francisco). The cost categories can be broken into four different groups that align to the methodology used to determine the avoided cost percentage, as described further in the following sections:

1) Location-specific historical costs;
2) Location-specific operational data;
3) No avoided costs; and
4) General support costs.

1. Location-Specific Historical Costs

I analyzed approximately five years of historical costs prior to the Petition date (*i.e.*, 2017 through July 2021) for electric distribution and electric transmission O&M to determine which cost categories include costs that are directly attributable to a specific location and that are identifiable to that location based on attributes in the cost data.

I obtained historical cost data from PG&E's cost accounting system at the planning order level. The planning order provides a more detailed description of the work performed and is at a more granular level in PG&E's accounting system than the Major Work Category (MWC) or Maintenance Activity Type (MAT). In certain cases, the planning order description indicates where the work is performed. The accounting data includes other fields that indicate where the work is performed, such as county code, which aligns to the California counties that PG&E serves, and division, which aligns to the operational boundaries PG&E uses for the 19 divisions it serves. San Francisco is both a California county and a PG&E division.[56]

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[55] Selected avoided cost percentages represent the portion of total electric costs that would be avoided.

[56] Discussion with PG&E business finance personnel and 2017-2021 historical cost data.

I worked with PG&E Business Finance personnel to analyze multiple attributes in the cost data, such as planning order, county code, and division, to categorize the costs as either associated with electric work in San Francisco, outside of San Francisco, or general costs that are not location specific or where the location is unknown. For example, work performed to repair an overhead line is traceable to the location where the repair was performed, and therefore the cost data indicated the location of the work and the costs could be categorized as San Francisco or non-San Franciso. However, other costs, such as labor costs of distribution operators, are not traceable to a specific location as I understand distribution operators work from a central location and support multiple divisions at PG&E.

For the cost categories that had sufficient location-specific costs, I divided the San Francisco costs by PG&E's total system-wide location-specific costs (*i.e.*, San Francisco costs plus non-San Francisco costs) to calculate the percentage of costs related to electric work in San Francisco. Based on discussion with PG&E SMEs, I determined that all the costs identified in San Francisco would be avoided if PG&E no longer provided electric service in San Francisco. In other words, the percentage of costs related to San Francisco represents the avoided cost percentage.

a. Examples of Cost Categories with Location-Specific Historical Costs

Example: Electric Distribution Overhead Line Maintenance – this cost category is a direct electric distribution O&M cost and includes the costs to repair or replace overhead lines to address overhead maintenance conditions identified by PG&E's patrol and inspection process.[57] The historical cost data for this category reflected the location of where the work was performed. I divided 2017-2021 San Francisco electric distribution overhead maintenance costs by total 2017-2021 PG&E electric distribution overhead maintenance costs to determine the avoided cost percentage. Table 8.2-5 below shows the

[57] PG&E 2023 GRC Exhibit 4, Chapter 11.

avoided cost percentage for Electric Distribution Overhead Maintenance.

TABLE 8.2-5
ELECTRIC DISTRIBUTION OVERHEAD MAINTENANCE AVOIDED COST PERCENTAGE[58]
(MILLIONS OF DOLLARS)

Line No.	Description	2017-2021 Costs
1	San Francisco ED Overhead Maintenance	[redacted]
2	Total PG&E ED Overhead Maintenance (SF and Non-SF)	
3	Avoided Cost Percentage	1.59%

I confirmed the resulting avoided cost percentage of 1.59% is reasonable by comparing it to the percentage of electric distribution primary overhead miles in San Francisco, which is approximately 0.59%.[59] I confirmed with the PG&E SME that the higher avoided cost percentage accounts for the higher cost to perform work in San Francisco, such as the additional complexity of performing work in a concentrated urban area.

Example: Electric Distribution Routine Vegetation Management – this cost category is a direct electric distribution O&M cost. Routine vegetation management includes the costs of patrolling, inspecting and maintaining clearances of vegetation along PG&E's overhead high voltage electric distribution lines, such as routine tree trimming and removal. The routine vegetation management program relates to safety and reliability by managing the vegetation adjacent to powerlines to reduce the risk of vegetation contact with the electric distribution equipment.[60]

The historical cost data identified where the routine tree work (*i.e.*, trimming and removal) was performed. PG&E provided both total system-wide PG&E routine tree work costs and San Francisco routine

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58 Schedule 2.6B.4.

59 480 miles in San Francisco divided by 80,715 total miles = 0.59%. San Francisco mileage per the asset stipulation documents; PG&E 2023 GRC Exhibit 4, Chapter 3.

60 PG&E 2023 GRC Exhibit 4, Chapter 9.

tree work costs in 2020. I relied on 2020 historical costs as it is the most recent full year of costs prior to the Petition date. As PG&E's wildfire prevention efforts have expanded significantly (as described in Section C.4), 2020 is more representative of the portion of wildfire prevention efforts in San Francisco in 2021 and onwards than earlier years. I divided 2020 electric distribution routine tree work O&M costs in San Francisco by 2020 total PG&E system-wide electric distribution routine tree work O&M costs to calculate the avoided cost percentage. Table 8.2-6 below shows the avoided cost percentage for Electric Distribution Routine Tree Work.

TABLE 8.2-6
ELECTRIC DISTRIBUTION ROUTINE TREE WORK AVOIDED COST PERCENTAGE[61]
(MILLIONS OF DOLLARS)

Line No.	Description	2020 Costs
1	San Francisco ED Routine Tree Work	[redacted]
2	Total PG&E ED Routine Tree Work	
3	Avoided Cost Percentage	0.43%

The avoided cost percentage of 0.43% is in line with 0.59% electric distribution primary overhead line miles in San Francisco and is slightly lower due to San Francisco's harder landscape (*i.e.,* less trees than in rural areas).

2. Location-Specific Operational Data

Certain cost categories include costs that are directly attributable to San Francisco; however, the historical cost data does not include sufficient level of detail to determine costs specifically in San Francisco. For example, I understand that PG&E does not maintain the same location-specific information (*e.g.*, county code and division code) for electric transmission O&M costs as compared to electric distribution O&M costs. Therefore, most of the historical electric transmission O&M costs analyzed did not identify a specific location.

61 Schedule 2.4A.4.

I worked with PG&E SMEs to identify other operational metrics (*i.e.*, non-cost data) that would reasonably estimate the portion of costs attributable to San Francisco and avoidable if PG&E no longer provided electric service to San Francisco. For example, I considered miles of underground lines in and outside of San Francisco for underground-related work.

After an operational metric was identified, I considered whether the costs for the category are higher in San Francisco than other areas. For example, the average cost of a pole replacement is over 2x higher in San Francisco than rural areas of PG&E's territory given that poles are more difficult to access in urban areas and require additional equipment, such as a crane.[62] If I determined the costs for a specific category are higher in San Francisco, I adjusted the avoided cost percentage, which is based on non-cost data, to account for the higher costs.

For system-wide indirect cost categories, which support gas and energy supply in addition to PG&E's electric service, I considered whether the operational metrics were specific to PG&E's electric business or PG&E's entire business. If an avoided cost percentage was based on electric-only data and therefore only applies to PG&E's electric business, I first needed to identify the portion of PG&E's system-wide forecast related to PG&E's electric business. I relied on the methodology used in the 2023 GRC to allocate system-wide forecasts between functional categories.[63]

a. Examples of Cost Categories with Location-Specific Operational Data

<u>Example: Electric Transmission Underground Line Maintenance</u> – this is a direct transmission O&M cost category that includes the costs to repair or replace underground lines to address underground maintenance conditions identified by PG&E's patrol and inspection process.[64]

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62 The avoided cost percentage for pole asset management increased from 1.40% to 3.68%. *See* Schedule 2.9B.4.

63 Schedule 4.16, Schedule 5.8, and PG&E 2023 GRC Exhibit 10, Workpaper Supporting Exhibit (PG&E-10), Chapter 1A at WP 1A-1 to WP 1a-13.

64 Discussion with PG&E transmission line maintenance subject matter expert.

Given the historical cost data did not include information to identify costs incurred in specific locations, I determined that 2021 transmission underground line miles reasonably estimate the maintenance work performed in San Francisco based on discussions with PG&E SMEs. I divided transmission underground line miles in San Francisco by total PG&E transmission underground line miles to determine the avoided cost percentage of 38.46%. Table 8.2-7 below shows the avoided cost percentage for Electric Transmission Underground Line Maintenance.

TABLE 8.2-7
ELECTRIC TRANSMISSION UNDERGROUND LINE MAINTENANCE AVOIDED COST PERCENTAGE[65]

Line No.	Description	2021 Data
1	San Francisco ET Underground Line Miles	67.3
2	Total PG&E ET Underground Line Miles	175.0
3	Avoided Cost Percentage	38.46%

Example: New Electric Meter Purchases – this is an indirect system-wide capital expenditure and includes the costs of electric meters for new customer growth, replacement of failed units, and retirements.[66] I relied on five years of historical data (2017 – 2021) for the number of electric meter changes specifically in San Francisco. Because meters are not changed on a regular schedule, I used five years of data to smooth annual fluctuations. I confirmed with PG&E's SME that this data is representative of the costs in San Francisco. I divided the number of electric meter changes in San Francisco by total electric meter changes to determine the avoided cost percentage.[67] Table 8.2-8 below shows the avoided cost percentage for New Electric Meter Purchases.

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65 Schedule 3.1A.3.

66 PG&E 2023 GRC, Exhibit 6, Chapter 7 at 7-11.

67 The cost of the electric meter inventory is the same across PG&E's territory, so no adjustment is required to account for a difference in costs in San Francisco.

TABLE 8.2-8
NEW ELECTRIC METER PURCHASES AVOIDED COST PERCENTAGE[68]

Line No.	Description	2017-2021 Data
1	San Francisco Electric Meter Changes	[redacted]
2	Total PG&E Electric Meter Changes	
3	Avoided Cost Percentage	3.79%

I relied on the 2023 GRC forecast for electric meter purchases, and the forecast separates the capital expenditures for electric meters and gas meters, so I applied the avoided cost percentage to the forecast for electric meters only.

Example - Manage and Maintain Facilities - PG&E's Real Estate forecast in the 2023 GRC includes indirect O&M and CapEx to manage and maintain facilities by PG&E's Corporate Real Estate Strategy and Services ("CRESS") group. The facilities include service centers, data centers, office buildings, shops, warehouses, construction and equipment yards, and vehicle maintenance garages, among others.[69] Based on input from PG&E's SME, I determined that the square footage of CRESS managed buildings reasonably estimate the facilities maintenance work performed in San Francisco.

I divided the square footage of facilities in San Francisco supporting PG&E's electric business by the total square footage of PG&E's facilities.[70] I relied on data as of July 2021 as it is most representative of PG&E's facilities because earlier historical data includes facilities that are no longer used by PG&E. The facilities data included both gas and electric facilities, consistent with the 2023 GRC Real Estate cost

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68 Schedule 5.2A.4.

69 PG&E 2023 GRC, Exhibit 7, Chapter 5 at 5-1.

70 I understand that PG&E will retain the Harrison Service Center and the Customer Service Offices in San Francisco to continue to support PG&E's gas operations in San Francisco. The continued costs of operating and maintaining these shared assets include stranded costs for the portion that previously supported PG&E's electric business. I also understand that a new Service Center will be constructed to replace the existing Martin Service Center for PG&E. Only the square footage of facilities in San Francisco that PG&E will no longer retain are included in the numerator of the avoided cost percentage calculation.

forecast, which is a system-wide forecast for both gas and electric facilities, so I did not need to identify the electric portion of the forecast.

The cost to maintain and operate facilities in San Francisco is higher than other areas in PG&E's territory, so I adjusted the avoided cost percentage based on a cost factor for San Francisco as compared to other areas in PG&E's cost estimating models.[71] Table 8.2-9 below shows the avoided cost percentage for Manage and Maintain Facilities.

TABLE 8.2-9
MANAGE AND MAINTAIN FACILITIES AVOIDED COST PERCENTAGE[72]

Line No.	Description	2021 Data
1	Square Footage in San Francisco - Electric Facilities	[redacted]
2	Total PG&E Square Footage - All Facilities	8,256,000
3	% Electric Facilities in San Francisco	[redacted]
4	San Francisco Higher Cost Factor	
5	Avoided Cost Percentage	0.09%

3. No Avoided Costs

For certain cost categories, PG&E will continue to incur the same level of costs with or without San Francisco electric customers. Based on discussions with PG&E SMEs and review of relevant documentation, including the 2023 GRC, I identified cost categories that would be unimpacted if PG&E no longer provided electric service in San Francisco.

The significant cost categories with no avoided costs are wildfire-related. As discussed in Section C.4, PG&E incurs significant costs for wildfire prevention in HFTDs, and San Fransico is not a high-risk area for wildfires. Therefore, I understand PG&E would maintain its existing wildfire mitigation

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71 The San Francisco Higher Cost Factor is based on a CRESS-specific estimating tool used to develop early-stage project costs. The model is informed by historical cost data from previously completed CRESS projects. Based on discussion with PG&E CRESS subject matter expert.

72 Schedule 4.6A.4. Note that the avoided cost percentage of 0.09% described here is applied to the Real Estate cost subcategory manage and maintain facilities. There are other subcategories of Real Estate that would have no avoided costs; for example, subcategories related to Real Estate projects that will occur regardless of whether PG&E provides electric service in San Francisco, such as moving PG&E's General Office from San Francisco to Oakland.

programs and would not avoid any costs with the loss of San Francisco electric customers.

a. Examples of Cost Categories with No Avoided Costs

Example: PSPS - PG&E's PSPS program includes "activities supporting information-gathering, decision-making, and customer-outreach processes when PG&E considers proactively de-energizing portions of the PG&E electric system in the interest of public safety. Line de-energization may be necessary when a combination of winds and location-specific factors are forecast to present a statistically high likelihood of damage or disruption to PG&E's above-ground power lines, suggesting a heightened risk of a catastrophic wildfire."[73] PG&E's PSPS program encompasses electric lines in HFTD areas, and the most common electric lines considered for de-energization are in Tier 2 or Tier 3 HFTD areas.[74] Per the 2023 GRC forecast, PG&E estimates approximately $120 million per year in O&M costs related to its PSPS program.[75] Based on discussions with PG&E SMEs, PG&E would maintain its existing PSPS program and would not avoid any costs if PG&E no longer provided electric service in San Francisco, which is reasonable given San Francisco is not a HFTD.[76]

Example: Wildfire Liability Insurance – this is a system-wide indirect O&M cost for wildfire liability insurance, which covers a broad range of claims with respect to wildfires involving PG&E's facilities.[77] Based on PG&E's renewal of wildfire liability insurance in April 2021, PG&E paid approximately $700 million per year in premiums.[78] Per PG&E SMEs, PG&E will maintain the same level of wildfire liability insurance coverage and therefore pay the same insurance premiums if PG&E no longer

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[73] PG&E 2023 GRC Exhibit 4, Chapter 4.2 at 4.2-1.

[74] PG&E 2023 GRC Exhibit 4, Chapter 4.2 at 4.2-7.

[75] PG&E 2023 GRC Exhibit 4, Chapter 4.2 at Table 4.2-4.

[76] Discussion with PG&E wildfire mitigation personnel.

[77] PG&E 2023 GRC Exhibit 9, Chapter 3 at 3-23.

[78] PG&E 2023 GRC Exhibit 9, Chapter 3 at 3-22. I understand PG&E changed to self-insurance for wildfire liability insurance in 2023. However, my analysis is based on information as of 2021.

provided electric service in San Francisco, which is reasonable as San Francisco is not a high risk area for wildfires.

4. General Support Costs

General support costs support the entire PG&E business, including electric, gas and energy supply, and are not associated with specific locations. For example, PG&E's Finance team provides finance support to the entire PG&E business, and the finance team's work is not assigned based on location.

Based on discussions with PG&E SMEs, I understand that many of the general support cost categories may not have any avoided costs, particularly in the years immediately following CCSF's acquisition of PG&E's electric assets in San Francisco. For example, PG&E would not reduce its headcount for corporate departments, such as finance, legal, and IT. However, I conservatively assumed that some costs would be avoided, representing a decreased level of effort, if PG&E no longer provided electric service in San Francisco. I estimated the avoided costs would be proportional to the overall avoided O&M costs for electric distribution and transmission.

a. Examples of Cost Categories with General Support Costs

Example: Finance Department – this cost category is a system-wide indirect O&M cost and includes the cost of personnel responsible for investor relations, financial forecasting and budgeting, financial statement reporting, taxes, and payment management, among other services.[79] As described above, the Finance Department is a general support cost, and I conservatively estimated the avoided costs would be proportional to the overall avoided O&M costs for electric distribution and transmission. Since the avoided cost percentage is based on electric transmission and electric distribution costs only, it is specific to PG&E's electric business, so I first identified the portion of PG&E's system-wide forecast for the finance department related to PG&E's electric business. Using the allocations in the 2023 GRC, I determined that 56% of the forecast supports PG&E's electric business. Table 8.2-

[79] PG&E 2023 GRC, Exhibit 9, Chapter 2 at 2-1.

10 below shows the avoided cost percentage for the Finance Department in 2026.

TABLE 8.2-10
2026 FINANCE DEPARTMENT AVOIDED COST PERCENTAGE[80]
(MILLIONS OF DOLLARS)

Line No.	Description	Direct O&M
1	Total Avoided ED & ET O&M Costs (30 Years)	$1,711.8
2	Total PG&E ED & ET O&M Costs (30 Years)	$122,084.8
3	Overall Direct ED & ET O&M Avoided Cost Percentage	1.40%
4	2026 ED & ET % System Forecast	56.19%
5	Avoided Cost Percentage	0.79%

Example: Employee Benefits – this cost category is a system-wide indirect O&M cost that includes health, retirement, and insurance benefits programs.[81] The Employee Benefits programs support all PG&E employees in all locations and across functional categories. I assumed the avoided costs for Employee Benefits are proportional to the overall avoided O&M labor costs for electric transmission and distribution. As employee benefits costs only relate to PG&E employees, I isolated the labor portion of the avoided costs (*i.e.*, the avoided costs for PG&E employees). Since the avoided cost percentage is based on electric transmission and electric distribution costs only, it is specific to PG&E's electric business, so I first identified the portion of PG&E's system-wide Employee Benefits forecast related to PG&E's electric business. Table 8.2-11 shows the avoided cost percentage for Employee Benefits in 2026.

80 Schedules 4.11, 4.16 and 4.17. Consistent with the 2023 GRC, the electric distribution and transmission portion of the Finance forecast varies between 2021 and 2026. For illustrative purposes, the table shows the 2026 percentage.

81 PG&E 2023 GRC, Exhibit 8, Chapter 5 at 5-1.

TABLE 8.2-11
2026 EMPLOYEE BENEFITS AVOIDED COST PERCENTAGE[82]
(MILLIONS OF DOLLARS)

Line No.	Description	Direct O&M
1	Total Avoided ED & ET O&M Costs (30 Years)	$1,711.8
2	Total PG&E ED & ET O&M Costs (30 Years)	$122,084.8
3	Overall Direct ED & ET O&M Avoided Cost Percentage	1.40%
4	ED & ET O&M % Labor	23.71%
5	Overall Direct ED & ET Labor O&M Avoided Cost Percentage	0.33%
6	2026 ED & ET % System Forecast	56.19%
7	Avoided Cost Percentage	0.19%

Example: Electric Distribution Support Activities – this category is a direct electric distribution O&M cost and includes Operations Management and Support organizations, which supervise and support the enablement and execution of field work.[83] The Operations Management and Support organizations support electric distribution field work throughout PG&E's territory and reflect a general support cost. The costs are specific to electric distribution, so I relied on the overall avoided cost percentage for electric distribution O&M.[84] Table 8.2-12 below shows the overall avoided cost percentage for electric distribution O&M applied to Electric Distribution Support Activities.

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82 Schedules 4.10, 4.16, 4.17, and 4.18. Consistent with the 2023 GRC, the electric distribution and transmission portion of the Employee Benefits forecast varies between 2021 and 2026. For illustrative purposes, the table shows the 2026 percentage.

83 PG&E 2023 GRC Exhibit 4, Chapter 22 at 22-5.

84 As described in the following section, I performed a detailed review of above-threshold cost categories, which represent the top 85% of costs. The overall avoided electric distribution O&M percentage applied is based on the above-threshold non-wildfire categories that are not general support costs.

TABLE 8.2-12
ELECTRIC DISTRIBUTION OPERATIONS MANAGEMENT & SUPPORT
AVOIDED COST PERCENTAGE[85]
(MILLIONS OF DOLLARS)

Line No.	Description	Electric Distribution O&M
1	ED O&M Avoided Costs (Above Threshold & Non-General Support & Non-Wildfire)	$660.8
2	Total ED O&M Costs (Above Threshold & Non-General Support & Non-Wildfire)	$19,001.9
3	Avoided Cost Percentage	3.48%

5. Other Costs "Below Threshold"

I analyzed the 2023 forecasts in the 2023 GRC and Electric Transmission Forecast and determined which cost categories within a functional category (*i.e.*, electric distribution O&M, electric transmission O&M, indirect O&M, and indirect CapEx) represented the top 85% of the costs. I performed a detailed analysis of all cost categories making up 85% of each functional category ("above threshold"). The remaining cost categories represented smaller cost categories and were considered "below threshold." I reviewed the list of below threshold categories with PG&E, and based on our understanding of the nature of the costs, identified any categories that were unique and would have a distinctly higher or lower avoided cost percentage than the overall avoided cost percentage of the above-threshold cost categories and therefore warranted a detailed review.

For example, there are wildfire-related below-threshold cost categories that would have no avoided costs, consistent with the above-threshold wildfire-related costs. As another example, Network Asset Management, which relates to the maintenance of PG&E's Electric Distribution Network assets, warranted additional review because the network only supports San Francisco and Oakland,[86] and therefore there would be a higher percentage of avoided costs than other categories.

For the remaining below-threshold categories that did not warrant additional review, I assumed the avoided costs would be proportional to the

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85 Schedule 2.13.

86 PG&E 2023 GRC Exhibit 4, Chapter 14 at 14-5.

overall avoided O&M costs. Specifically, for electric distribution and electric transmission O&M below-threshold items, I relied on the overall avoided O&M costs for the respective electric distribution or electric transmission non-wildfire-related above-threshold cost categories. I excluded wildfire-related cost categories (Vegetation Management and PSPS) as the below-threshold wildfire-related cost categories were analyzed separately, and the inclusion of the wildfire-related costs would skew the overall avoided cost percentage lower. Table 8.2-13 below shows the overall avoided cost percentage for electric distribution O&M (limited to non-wildfire-related above-threshold cost categories) applied to Electric Distribution O&M Below-Threshold cost categories.

TABLE 8.2-13
ELECTRIC DISTRIBUTION O&M BELOW-THRESHOLD AVOIDED COST PERCENTAGE[87]
(MILLIONS OF DOLLARS)

Line No.	Description	Electric Distribution O&M
1	Non-Wildfire-Related Above-Threshold ED O&M Avoided Costs	$873.5
2	Total PG&E Non-Wildfire-Related Above-Threshold ED O&M Costs	$25,116.4
3	Avoided Cost Percentage	3.48%

Table 8.2-14 below shows the overall avoided cost percentage for electric transmission O&M (limited to non-wildfire-related above-threshold cost categories) applied to Electric Transmission O&M Below-Threshold cost categories.

87 Schedule 2.12.

TABLE 8.2-14
ELECTRIC TRANSMISSION O&M BELOW-THRESHOLD AVOIDED COST PERCENTAGE[88]
(MILLIONS OF DOLLARS)

Line No.	Description	Electric Transmission O&M
1	Non-Wildfire-Related Above-Threshold ET O&M Avoided Costs	$83.9
2	Total PG&E Non-Wildfire-Related Above-Threshold ET O&M Costs	$18,657.5
3	Avoided Cost Percentage	0.45%

For system-wide indirect below threshold categories (both O&M and CapEx), I assumed the avoided costs would be proportional to the overall avoided O&M costs for electric distribution and transmission of 1.40%, consistent with the indirect general support cost categories.

6. Martin Substation Avoided Costs

CCSF's separation plan assumes that CCSF will acquire PG&E's Martin Substation and that PG&E will construct a new, smaller PG&E substation directly adjacent to the existing site.[89] I understand that the Martin Substation serves both customers in San Francisco and San Mateo County, so if CCSF acquires the Martin Substation, a new substation is required for PG&E to continue to serve its remaining customers in San Mateo County.

While PG&E will avoid costs associated with the Martin Substation that CCSF will acquire, PG&E will also incur additional costs associated with the new substation. I adjusted the avoided cost percentage to account for the net avoided costs of the Martin and new substation.

For electric distribution and electric transmission substation O&M, which include costs directly related to the Martin Substation, I assumed a percentage of costs associated with the Martin Substation would be avoided based on the proportion of the number of assets required for the new substation as compared to Martin. I confirmed with PG&E's SME that this data is representative of the proportion of costs of the new substation. For example, the new substation will include approximately [redacted] of the number

88 Schedule 3.10.

89 Exhibit CCSF-007C – Prepared Joint Direct Testimony of Manho Yeung and Ryan Wu (Apr. 20, 2026) (Errata May 21, 2026), Appendix II City and County of San Francisco Separation Plan at 4.

of electric distribution assets at Martin, so I assumed PG&E would continue to incur [redacted] of the current electric distribution substation O&M costs for Martin to maintain the new substation and the remaining [redacted] of Martin electric distribution substation O&M costs would be avoided.[90]

90 Schedule 2.7E.2.

CURRICULUM VITAE

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QUALIFICATIONS

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Member, American Bar Association, Section of Litigation

PROFILE

Whitney Alary has 19 years of experience in business and litigation consulting. Whitney provides consulting services related to economic damages, forensic accounting, and business valuation issues for matters involving commercial litigation, aerospace, government contracts, class actions, bankruptcy, intellectual property, and others.

Whitney has assisted Fortune 100 companies and other clients in a variety of industries, including aerospace, government contracts, energy, mortgage banking, software, construction, investment management, financial services, professional services, and telecommunications.

Whitney specializes in complex data analysis, including building intricate and dynamic financial models and constructing, managing, and analyzing large databases.

EXPERT TESTIMONY

In re: Ligado Networks LLC, et al., Debtors – Boeing Cure Dispute, United States Bankruptcy Court, District of Delaware – Deposition, 2026

Duke Park v. Lee Soo Ahn and Bok Hyun Eum, Eighth Judicial District Court, Clark County, Nevada – Bench Trial, 2026

Confidential Arbitration, American Arbitration Association – Arbitration Hearing, 2025

EXPERT DESIGNATIONS AND REPORTS

JPMorgan Chase Bank, NA v. ESC-Toy Ltd. and Erick Chatel, Eighth Judicial District Court, Clark County, Nevada – Rebuttal Expert Report, 2026

In re: Ligado Networks LLC, et al., Debtors – Boeing Cure Dispute, United States Bankruptcy Court, District of Delaware – Expert Report, 2026

Confidential Arbitration, American Arbitration Association – Expert Report, 2025

Duke Park v. Lee Soo Ahn and Bok Hyun Eum, Eighth Judicial District Court, Clark County, Nevada – Expert Report, 2025

Invictus Global Services, Inc. v. Insitu, Inc., United States District Court, Eastern District of Washington – Rebuttal Expert Report, 2023

EXPERIENCE

COMMERCIAL LITIGATION

Determined economic damages on a variety of commercial litigation matters, including calculation of lost profits and increased costs, investigation and analysis of fraud allegations, business and asset valuation, and other economic damages issues resulting from breach of contract, copyright infringement, wrongful termination, and other claims.

Calculated damages for a couple whose businesses and properties were fraudulently taken while they were out of the country. Performed forensic analysis of unauthorized property sales, mortgages, and cash payments executed without their knowledge or consent to determine total losses.

Performed forensic accounting analysis of investor losses from participation in a fraudulent scheme to issue short-term, high-interest liquor license loans. Traced investor transactions in and out of escrow accounts. Evaluated one investor's bank loan application to identify potential investment risk and other red flags, including reconciling loan assets and liabilities of the loan applicant and related entities.

Performed forensic analysis of the acquisition price of a software company, including evaluating the likelihood and legitimacy of revenues considered as a basis for calculating an additional contingency payment. Performed funds tracing analysis to identify alleged fraudulent transfers between executives as incentive for generating revenues.

Evaluated a $1.7 billion damages claim by institutional investors of a residential mortgage-backed investment facility used as a vehicle to perpetrate a decade-long fraudulent scheme. Determined would-have-been investor losses had the fraud been discovered at earlier points in time by any parties involved. Performed fraud analyses, including tracing more than $30 billion of wire transactions and analyzing the use of funds to explain how the fraud was perpetrated. Developed complex database models to analyze ownership of more than 330,000 residential mortgages alleged to have served as collateral for the investment facility. Assisted counsel with structured data collection from various sources and with analyzing and documenting relevant investor and third-party knowledge.

Analyzed causation and damages claims brought by a real estate investment trust for failure of its auditor to apply the correct accounting principles. Researched business, economic, and market influences on trading activity, including analysis of company and competitor financials.

Calculated lost profits resulting from a breach of contract between television stations related to programming ownership rights and calculation of royalties. Analyzed historical and projected advertising revenue as well as programming, distribution, and other costs.

Analyzed damages resulting from construction schedule delays. Evaluated ongoing construction costs and excess costs, calculated a delay cost rate, and identified the applicable delay period.

Analyzed lost business value claims in connection with employment disputes. Studied issues involving compensation plans, attrition, and market changes.

Evaluated causation and damages issues in professional negligence matters involving public accounting firms and law firms. Studied various complex tax strategies and analyzed alternative payment solutions with the government. Assessed damage claims resulting from alleged error in will execution, including review of trust accounting and estate planning.

AEROSPACE

Analyzed the financial performance and operations of many commercial and military aerospace programs, including commercial passenger, cargo, and business jets and military attack and tanker

aircraft (both new build and maintenance and modification work). Also analyzed satellite, launch vehicle, and scientific research programs.

Calculated lost profits in a breach of contract matter for a subcontractor providing drone operators for deployment by the U.S. military. Analyzed the revenue the subcontractor would have earned for the contractual minimum guaranteed days, less the incremental costs the contractor would have incurred to perform the work. Analysis led to a favorable settlement for the client.

Prepared increased cost claims related to the production of commercial and military aircraft due to nonconforming parts received from suppliers and subcontractors on various aircraft model programs. Analyzed and prepared claims for rework and engineering hours to correct the nonconforming parts, factory disruption, pauses in production, concessions paid to customers, opportunity cost of delayed customer payments, support to contract workers, and additional equipment.

Evaluated the value of engineering and design services performed towards developing an innovative specialty aircraft, including the parties' performance under the contract, in a breach of contract dispute. Assessed adherence to contractual billing terms by analyzing costs incurred and amounts invoiced, and calculated invoice amounts outstanding.

Measured disruption damages from late delivery of major commercial airplane parts, including increased labor hours above projected learning curves and increased overtime pay. Studied the impact of disruption in various stages of production for three airplane model derivatives.

Performed forensic analysis of the increased costs associated with defective parts produced by a major parts supplier of a military helicopter program, including review and rework to correct nonconforming parts and associated disruption. Analyzed and prepared claims related to the supplier's delay in delivering parts and delivery of incomplete parts.

Evaluated breach of contract claims for the termination of an agreement to jointly provide maintenance and modification work that allegedly resulted in the destruction of the plaintiff's business. Analyzed damages claims for the value of the business, lost profits under an assumed joint or solo contract award, and disgorgement of defendant's profits.

Analyzed claims of financial losses related to the allegedly defective design and qualification of solar array panels for communications and broadcast satellites. Evaluated damage models forecasting lost profits over a 40-year period and spanning two continents. Performed company and industry analyses to address causation issues.

Calculated increased costs, unpaid lease amounts, and disgorgement of profits for a business jet manufacturer performing winglets retrofit.

Analyzed damages related to claims of unfair and unreasonable pricing brought forth against a space and communications satellite manufacturer.

GOVERNMENT CONTRACTS AND COMPLIANCE

Consulted on government contract matters involving aircraft and aerospace, communication systems, computer software, and construction, including review and evaluation of cost estimates, bids and proposals, change orders, contract prices, and incurred costs on government contracts. Performed investigation and forensic analysis of fraud allegations, including under the False Claims Act.

Prepared claims for increased costs resulting from a supplier's delays and delivery of nonconforming parts for a high-frequency radio system. Analyzed incremental labor hours, scrapped parts, and the replacement of parts returned under warranty, among other claims.

Assisted a tobacco product manufacturer in responding to inquiries from an attorney general regarding the alleged sale of flavored tobacco products in jurisdictions where they are banned. Analyzed multiple levels of sales through a distribution network using several sales databases. Evaluated the company's exposure for penalties and for the same issues in other locations.

Investigated allegations of overbilling related to the construction and maintenance of a nuclear waste treatment plant. Analyzed time charging records and operations data for craft employees and subcontractors and non-manual employees (i.e., managers and engineers) to explain hours billed to the government, isolate instances of idle time, and identify potentially avoidable overtime. Also evaluated the preparation of a baseline change proposal and contract modification in support of a government audit, including assessing the reasonableness of cost estimates for direct and subcontract labor.

Investigated anonymous reports of time charging infidelity and potential overbilling for Over and Above tasks on the modification of military tilt-rotor aircraft. Analyzed the estimating process and time charging records, including interviewing program personnel, to evaluate potential mischarging and other inefficiencies on the program.

Evaluated damages in a false claims case for alleged overpayment by the government for the procurement of more than 60 contracts for software licenses and support services, including evaluation of industry profit margins. Performed funds tracing of the development costs and funding of the software to define government rights.

Assessed the value of lost or damaged research material from a National Aeronautics and Space Administration (NASA) mission and potential damages resulting from a delay in scientific research. Studied the applicability of economic and accounting concepts to pure science.

CLASS ACTIONS

Supported plaintiffs in a class action alleging discrimination in mortgage lending against a major bank. Determined a formula to uniformly quantify the economic impact to each class member of being denied a loan during a time of historically low interest rates. Calculated damages for 119,000 potential class members who applied for, but were denied, refinance loans, home purchase loans, and home equity lines of credit using the damages formulas developed and data for each class member produced by the bank.

Analyzed the economic impact of an oil pipeline spill on various groups of claimants, including fishers and fish processors, oil workers, property owners, and others. Examined more than 10 years of regional commercial fishing data to identify members of the fisher and fish processor subclass and quantify the reduction in catch and revenue after the spill for each class member. Studied market changes in the oil and commercial fishing industries to evaluate the causal linkage between fisher losses and the oil spill.

Evaluated causation and damages issues related to an oil pipeline spill's impact on the population of a particular species of fish and the economic impact to local commercial fishing.

Evaluated allegations of an energy company's promotion of an illegal pyramid scheme. Analyzed 12 years of participant and customer sales data to demonstrate how participants made money. Calculated gains and losses for more than 400,000 program participants.

OTHER MATTERS

Assisted an investment management firm in executing two shareholder distributions to remedy mispriced mutual funds and improperly charged fees. In the first matter, corrected the price of seven bonds held in nine mutual funds and repriced the funds' daily net asset value to reprocess millions of shareholder transactions over a 3-year period. In the second matter, calculated fees overpaid by individual shareholders of 92 funds over 7 years.

Prepared lost profits and reasonable royalty claims related to copyright infringement allegations for a global provider of enterprise software and support services. Developed a database model to analyze the purchase history of more than 1,000 customers, including products used, timing of cancellation, customer attrition, and historical pricing trends.

PRESENTATIONS & SPEAKING ENGAGEMENTS

"**Big Data: The Untapped Opportunity in Litigation**," Co-Presenter, American Institute of Certified Public Accountants (AICPA) Forensics & Valuation Services Conference, *November 2018*

"**It's in the Details: Winning Big Cases with Big Data**," Co-Presenter, California Institute of Certified Public Accountants (CalCPA) Economic Damages Meeting, *August 2016*

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Electric Distribution	2.1	PSPS Operations	Ex 4, Ch 4.2	PSPS Program Cost	$ -	0.00%	No Avoided Costs	Wildfire-related	$ 42,268	Planning, readiness, field exercises, coordination, and program support for Public Safety Power Shutoff events. These activities prepare personnel, systems, customers, and operational processes for potential de-energization and restoration.
				PSPS Events	$ -	0.00%	No Avoided Costs	Wildfire-related	$ 72,998	Emergency Operations Center activation, customer and agency notification, de-energization, field inspection, and re-energization during a Public Safety Power Shutoff event. This work coordinates operational decisions and field activities from event initiation through safe restoration.
Electric Distribution	2.2	Electric Emergency Recovery	Ex 4, Ch 6	Routine Emergency	$ 154,102	4.54%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 73,678	Routine electric distribution outage response and service restoration. This activity includes identifying abnormal conditions, dispatching field personnel, isolating problems, completing repairs, and returning affected customers to service.
				Major Emergency	$ 44,729	1.54%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 62,788	Response and restoration for electric events classified as major emergencies. This work coordinates crews, equipment, materials, logistics, damage assessment, repairs, and system restoration during large or severe events.
Electric Distribution	2.3	Distribution System Operations	Ex 4, Ch 7	Customer Field Service Work	$ 16,115	1.39%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 23,776	Customer field service activities covering equipment trouble, swing-service work, disconnections, reconnections, scheduling, and dispatch. These services address customer requests, outages, emergencies, and other assignments requiring field response.
				Electric Distribution Operation Activities	$ 59,892	4.17%	Location-Specific Operational Data	(SF Division / Divisions in Central DCC) x (Central DCC / Total DCCs)	$ 29,478	Continuous monitoring and operation of the electric distribution grid. Includes outage identification, switching coordination, system control, field communication, and direction of response activities needed for safe and reliable service.
				Distribution Operational Technology	$ 9,265	3.48%	General Support Costs	ED O&M Above Threshold Avoided Costs (excluding wildfire-related and general support costs) / ED O&M Above Threshold Costs (excluding wildfire-related and general support costs)	$ 5,392	Operational technology applications and tools used for distribution grid control, outage management, and dispatch. Includes SCADA-related systems, the OBI workstream, technology development, licensing, enhancements, operation, and maintenance.

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Electric Distribution	2.4	Vegetation Management	Ex 4, Ch 9	Routine Vegetation Management	$ 100,437	0.43%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 575,225	Routine inspection and clearance of trees and vegetation near electric distribution facilities. This work maintains required clearances, addresses hazardous vegetation, reduces contact and wildfire risk, and supports reliable electric service.
				Tree Mortality	$ 4,256	0.15%	Location-Specific Historical Costs	SF Imputed Historical Costs (based on # trees worked and SF cost ratio) / Total PG&E Historical Costs	$ 70,771	Identification and mitigation of dead, dying, diseased, or hazardous trees near electric distribution facilities. Includes tree assessment, pruning, removal, and related measures that reduce contact, outage, and wildfire risks.
				Enhanced Vegetation Management	$ -	0.00%	No Avoided Costs	Wildfire-related	$ 550,686	Enhanced pruning and tree removal along the highest-risk circuit protection zones in High Fire Threat Districts. The program prioritizes wildfire risk reduction, safety oversight, quality verification, and completion of vegetation work in vulnerable areas.
Electric Distribution	2.5	Overhead and Underground Electric Asset Inspections	Ex 4, Ch 10	Underground Inspections & Patrols	$ 51,953	7.60%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 16,238	Routine patrols, detailed inspections, and infrared assessment of underground electric distribution assets. The activities examine facilities on recurring schedules to identify deterioration, hazards, and conditions requiring maintenance or repair.
				Overhead Inspections & Patrols	$ 10,240	0.37%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 65,867	Inspection, assessment, prioritization, and documentation of abnormal conditions on overhead electric distribution assets. The program includes more frequent work in High Fire Threat Districts, quality control, and follow-up on identified safety and reliability issues.
				Inspection Support Costs & Other	$ 2,498	0.81%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 7,359	Materials and program support for overhead and underground distribution inspections. The activity includes streetlight inspections and other resources used to identify asset conditions and maintain a safe and reliable distribution system.

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Electric Distribution	2.6	Overhead and Underground Electric Distribution Maintenance	Ex 4, Ch 11	Underground Maintenance	$ 97,873	12.17%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 18,938	Repair and replacement of abnormal conditions on underground electric distribution facilities. This work addresses inspection findings, field observations, equipment deterioration, and maintenance notifications.
				Overhead Maintenance	$ 50,121	1.59%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 74,135	Repair and replacement of abnormal conditions on overhead electric distribution facilities. Includes resolving maintenance tags, replacing surge arresters, removing idle facilities, and correcting other conditions identified through patrols and inspections.
				Distribution Equipment Overhauls	$ 2,828	3.48%	General Support Costs	ED O&M Above Threshold Avoided Costs (excluding wildfire-related and general support costs) / ED O&M Above Threshold Costs (excluding wildfire-related and general support costs)	$ 1,912	Repair and overhaul of transformers, capacitor banks, line switches, and other overhead and underground distribution equipment. This work restores equipment condition, extends asset life, and returns serviceable units to field use.
Electric Distribution	2.7	Substation Asset Management	Ex 4, Ch 15	Substation Support Activities	$ 78,775	5.79%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs (adjusted for Martin substation)	$ 30,403	Engineering and maintenance support for distribution substations. The services include emergency corrective maintenance, wildfire safety inspections, vegetation management, building maintenance, site support, and other activities needed for safe and reliable facilities.
				Corrective Maintenance	$ 27,650	6.42%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs (adjusted for Martin substation)	$ 9,530	Restoration and repair of failed, damaged, or deficient distribution substation equipment. This work addresses conditions identified through operations and inspections according to their severity, urgency, and effect on system performance.
				Preventative Maintenance	$ 60,286	12.13%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs (adjusted for Martin substation)	$ 11,009	Scheduled maintenance of distribution substation equipment to preserve condition and reduce failures. This work follows recurring inspection and service intervals for transformers, breakers, relays, batteries, switches, and other substation assets.

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				Miscellaneous Expense	$ 75,517	3.48%	General Support Costs	ED O&M Above Threshold Avoided Costs (excluding wildfire-related and general support costs) / ED O&M Above Threshold Costs (excluding wildfire-related and general support costs)	$ 49,510	General electric distribution support through the Electric Asset Excellence program, consulting, industry association participation, easement activities, and other smaller programs. The services provide technical guidance, external expertise, property rights support, and organizational resources used across distribution operations.
Electric Distribution	2.8	Electric Distribution Support Activities	Ex 4, Ch 22	Operational Management and Support	$ 125,036	3.48%	General Support Costs	ED O&M Above Threshold Avoided Costs (excluding wildfire-related and general support costs) / ED O&M Above Threshold Costs (excluding wildfire-related and general support costs)	$ 80,444	Supervision, coordination, planning, and enabling support for electric distribution work. The activity supports field execution, outage restoration, infrastructure improvements, wildfire mitigation, and other programs requiring operational management and oversight.
				Streetlights	$ 6,598	9.06%	Location-Specific Operational Data	Streetlights in SF / Total PG&E Streetlights	$ 1,641	Program support for PG&E streetlight activities and related public safety services. Includes operational coordination, planning, and organizational support for streetlight service and maintenance.

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Electric Distribution	2.9	Below Threshold	Ex 4, Ch 14; Ex 4 Ch 12; Ex 4, Ch 21; Ex 4, Ch 5; Ex 4, Ch 20; Ex 4, Ch 18; Ex 4, Ch 8; Ex 4, Ch 17; Ex 4, Ch 16; Ex 4, Ch 4.1; Ex 4, Ch 4.3; Ex 4, Ch 4.4; Ex 4, Ch 4.5; Ex 4, Ch 23; Ex 3, Ch 8	Network Asset Management	$ 199,842	88.99%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 5,021	PG&E's Electric Distribution Network serves customers in the downtown areas of SF and Oakland. Includes condition monitoring and testing of network cable and components, SCADA maintenance, corrective work in network vaults, and replacement of network assets. The activities identify emerging problems, maintain network reliability, and address equipment requiring repair or renewal.
				Pole Asset Management	$ 65,198	3.68%	Location-Specific Operational Data	SF Poles / Total PG&E Poles * SF Unit Cost Markup	$ 39,340	Inspection, treatment, restoration, and structural assessment of wood poles. Includes intrusive inspections, loading analysis, replacement planning, and coordination with joint utilities to maintain safe and serviceable pole assets.
				System-Wide	$ 238,140	3.48%	General Support Costs	ED O&M Above Threshold Avoided Costs (excluding wildfire-related) / ED O&M Above Threshold Costs (excluding wildfire-related)	$ 154,210	Electric distribution activities involving safety, reliability, inspections, maintenance, asset management, operations, planning, and supporting technology. Includes distinct functions that fall below individual modeling thresholds but collectively support distribution system performance.
				Wildfire or Gas-Related	$ -	0.00%	No Avoided Costs	Wildfire or gas-related	$ 118,636	Wildfire mitigation and gas-related activities involving risk assessment, vegetation management, inspections, maintenance, system hardening, and Public Safety Power Shutoff support. This work supports hazard identification, asset protection, emergency preparedness, risk reduction, and reliable utility operations. Includes distinct functions that fall below individual modeling thresholds but collectively support distribution system performance.
				Distribution Locate and Mark	$ 67,677	5.88%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 77,436	Locate and Mark activities are required to identify PG&E's gas and electric distribution assets for third-parties who plan to dig near those assets.
				Read and Investigate Meters	$ 49,011	10.45%	Location-Specific Historical Costs	SF Historical Costs / Total PG&E Historical Costs	$ 10,425	Field resources to provide manual gas and electric meter reading services, and the systems, administration, and clerical support necessary to effectively perform those activities.
				Service Inquiry (MAT EVA)	$ 7,922	3.56%	Location-Specific Operational Data	SF Electric Service Applications / Total PG&E Applications	$ 4,990	PG&E provides customer assistance to every gas and electric service applicant who requests a new connection. Includes all expenditures related to PG&E's Contact Center operations, which receives and processes new business applications.

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Electric Transmission	3.1	Electric Transmission Line Maintenance	"ET Expense 2022 Investment Plan_12-15-21", tab "Data."	Underground Line Maintenance	$ 14,369	38.46%	Location-Specific Operational Data	Transmission UG Miles in SF / Total PG&E Transmission UG Miles	[redacted]	Preventive and corrective maintenance of underground electric-transmission lines and associated facilities. This work addresses equipment condition, access needs, identified defects, and routine servicing required for safe and reliable operation.
				Overhead Line Maintenance	$ 459	0.01%	Location-Specific Operational Data	SF T-Line OH Structures / Total PG&E T-Line OH Structures	[redacted]	Maintenance of overhead transmission lines, towers, insulators, and related equipment. Activities include correcting inspection findings, washing insulators, coating structures, controlling corrosion, and extending the service life of transmission assets.
				Maintain Boardwalks	$ -	0.00%	No Avoided Costs	Not applicable to SF transmission lines	[redacted]	Maintenance of boardwalks used to access transmission structures located in water or difficult terrain. This work preserves safe and reliable routes for personnel performing inspections, maintenance, and repairs.
Electric Transmission	3.2	Vegetation Management	ET Expense 2022 Investment Plan_12-15-21, tab "Data."	Electric Transmission Tree Trim	$ 9,115	0.17%	Location-Specific Operational Data	(Trees Worked in SF / Total PG&E Trees Worked) * Higher Cost Factor for SF	[redacted]	Routine and integrated vegetation management along electric transmission corridors. Includes tree pruning and removal, orchard management, right-of-way expansion, quality assurance, safety oversight, work verification, event support, and response to changing vegetation conditions.
Electric Transmission	3.3	Electric Transmission Patrols/Inspections	"ET Expense 2022 Investment Plan_12-15-21", tab "Data."	Underground Patrols/Inspections	$ 5,352	38.46%	Location-Specific Operational Data	Transmission UG Miles in SF / Total PG&E Transmission UG Miles	[redacted]	Monthly patrols, detailed annual inspections, and alarm inspections of underground transmission facilities. These activities identify deterioration, hazards, equipment problems, and other conditions requiring maintenance or further assessment.
				Overhead Patrols/Inspections	$ 298	0.01%	Location-Specific Operational Data	SF T-Line OH Structures / Total PG&E T-Line OH Structures	[redacted]	Ground, aerial, infrared, helicopter, and drone inspections of overhead transmission facilities. The program uses recurring and risk-based inspection schedules to identify asset conditions, wildfire hazards, and reliability concerns.
				Bay Water & Climbing Inspections	$ -	0.00%	No Avoided Costs	Not applicable to SF transmission lines	[redacted]	Water-pile and foundation inspections in the Bay and Delta together with climbing inspections of transmission structures. These activities assess structural condition at locations requiring specialized access, equipment, and inspection methods.

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Electric Transmission	3.4	Miscellaneous Expense	"ET Expense 2022 Investment Plan_12-15-21", tab "Data."	Miscellaneous Expense	$ 11,265	0.45%	General Support Costs	ET O&M Above Threshold Avoided Costs (excluding wildfire-related and general support costs) / ET O&M Above Threshold Costs (excluding wildfire-related and general support costs)	[redacted]	Regulatory, technical, engineering, and operational support for the electric transmission system. Includes compliance activities, consulting, rentals, industry participation, line-hardening support, asset strategy, operability studies, benchmarking, and specialized analysis.
				PSPS	$ -	0.00%	No Avoided Costs	Wildfire-related	[redacted]	Public Safety Power Shutoff event support and transmission power-flow analysis. These activities assist with event readiness, de-energization planning, system-operability decisions, and evaluation of potential mitigation measures.
Electric Transmission	3.5	Transmission Substation O&M	"ET Expense 2022 Investment Plan_12-15-21", tab "Data."	Substation O&M	$ 45,377	2.15%	Location-Specific Operational Data	Transmission Substation Assets in SF / Total PG&E Transmission Substation Assets (adjusted for Martin Substation)	[redacted]	Operation and maintenance of transmission substations and associated equipment. Includes preventive and corrective maintenance, emergency repairs, relay testing, transformer and breaker work, station readings, battery and switch service, vegetation management, building upkeep, and engineering support.
				Substation Enhanced Inspections	$ -	0.00%	No Avoided Costs	Wildfire-related	[redacted]	Enhanced inspections of transmission substations in Tier 2 and Tier 3 high-fire-threat areas. This work identifies equipment and facility conditions that could affect safety, reliability, compliance, or wildfire ignition risk.
Electric Transmission	3.6	Electric Transmission Mapping	"ET Expense 2022 Investment Plan_12-15-21", tab "Data."	Mapping & Records Management	$ 16	0.01%	Location-Specific Operational Data	SF T-Line OH Structures / Total PG&E T-Line OH Structures	[redacted]	Transmission asset inventory, Geographic Information System maintenance, grid model data management, and records administration. These activities collect, validate, update, and organize information used for mapping, risk assessment, planning, engineering, and field operations.
				Probation Order Compliance	$ -	0.00%	No Avoided Costs	Compliance required regardless of CCSF petition	[redacted]	Transmission-asset record collection and review required under a federal probation order. These effort establish asset age, improve record completeness, and provide information used for risk management across transmission circuits.
Electric Transmission	3.7	Electric Transmission Operations General	"ET Expense 2022 Investment Plan_12-15-21", tab "Data."	Electric Transmission Operations General	$ 6,794	0.45%	General Support Costs	ET O&M Above Threshold Avoided Costs (excluding wildfire-related and general support costs) / ET O&M Above Threshold Costs (excluding wildfire-related and general support costs)	[redacted]	Transmission control center operations, grid operations engineering, operator training, performance improvement, compliance, and outage coordination. These activities support real-time system operation and coordinate maintenance, projects, and outages across transmission facilities.

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Electric Transmission	3.8	Below Threshold	"ET Expense 2022 Investment Plan_12-15-21", tab "Data."	Other Costs	$ 12,789	0.45%	General Support Costs	ET O&M Above Threshold Avoided Costs (excluding wildfire-related) / ET O&M Above Threshold Costs (excluding wildfire-related)	[redacted]	Land and right-of-way services, interconnection support, damage prevention, pole management, grid applications, Supervisory Control and Data Acquisition (SCADA), cybersecurity, automation, protection engineering, emergency response, and operational support. These below-threshold activities enable property access, system connections, reliable operation, technology management, wildfire-risk reduction, and coordination across the transmission system.
				Electric Transmission Planning	$ -	0.00%	No Avoided Costs	System-wide planning	[redacted]	Transmission asset development, system planning, engineering standards, and technical support for lines and facilities. Includes system studies, risk identification, compliance planning, design guidance, and engineering support for reliable transmission operation.
Indirect	4.1	Customer Engagement	Ex 6, Ch 2	PSPS Planning and Readiness	$ 6	0.00%	Location-Specific Operational Data	HFRA SF Customers / Total PG&E HFRA Customers	$ 24,387	Customer outreach, education, resiliency support, research, and readiness activities for Public Safety Power Shutoff events. The programs help customers and communities understand potential outages, prepare for disruptions, access available support, and remain informed during events.
				Customer Service Support	$ 22,158	2.81%	Location-Specific Operational Data	SF Business Customers / Total PG&E Business Customers weighted based on PG&E's employees dedicated to small vs. large businesses	$ 17,628	Customer assistance for large customers, small businesses, local governments, and other stakeholders. The services include relationship management, issue resolution, coordination with third-party energy providers, and support for community and business needs.
				Other Customer Engagement	$ 29,715	6.66%	Location-Specific Operational Data	SF Electric Customer Accounts / Total PG&E Electric Customer Accounts	$ 9,964	Customer and community programs not separately classified, including distributed generation tools, customer data services, clean energy transportation support, and escalated complaint handling. The activities improve access to PG&E programs, resolve customer issues, and support adoption of customer-facing energy solutions.
				Non-Tariffed Products and Services	$ 571,971	19.17%	Location-Specific Historical Costs	SF Imputed Historical Costs (based on historical SF portion of revenue) / Total PG&E Historical Costs	$ 49,851	Customer-requested utility products and services delivered through available portions of PG&E assets, operational capacity, and technical expertise. Offerings include specialized utility-related capabilities that make productive use of existing assets and resources.

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Indirect	4.2	Contact Centers, Customer Tech, and Digital Strategy	Ex 6, Ch 4	Customer Care Technology	$ 2,785	0.77%	General Support Costs	ET&D O&M Avoided Costs / ET&D O&M Total Costs	$ 7,362	Long-term technology strategy, implementation support, and project leadership for Customer Care. This work supports customer notifications, digital channels, service tools, and other technology used to improve customer interactions.
				Contact Center Operations	$ 62,626	2.10%	Location-Specific Operational Data	SF Electric Customer Calls / Total PG&E Customer Calls	$ 60,166	Contact Center service for customer emergencies, payment questions, technical issues, and requests for energy service or program assistance. The operation also manages call routing, staffing, workflow, quality, and service levels across millions of customer inquiries each year.
Indirect	4.3	Billing, Revenue, and Credit	Ex 6, Ch 6	Billing	$ 96,405	4.15%	Location-Specific Operational Data	SF Electric Customer Accounts / Total PG&E Electric Customer Accounts	$ 50,128	Customer billing and notice production, including bill calculation, exception resolution, printing, and electronic presentment. Activity also includes interval meter data processing and specialized handling for complex customer accounts.
				Manage Credit & Collect Revenue	$ 12,192	1.13%	Location-Specific Operational Data	SF Electric Only Customer Accounts / Total PG&E Electric Customer Accounts	$ 23,388	Payment processing, credit evaluation, deposit administration, receivables management, and delinquency notification. The activity also includes collection services and field coordination for nonpayment disconnections and reconnections.
Indirect	4.4	EHS/Occupational Health	Ex 7, Ch 1; Ex 7, Ch 1A	OnSite Clinics and Fixed Fees	$ -	0.00%	No Avoided Costs	Clinics and users of programs outside of SF or programs/fees based on overall size of company	$ 8,802	On-site clinics providing initial consultations and follow-up appointments for employees. Costs include contracted vendor fees for operating the clinics. Also includes occupational health programs supporting workplace ergonomics and fees for self-insurance.
				Occupational Health	$ 11,447	0.18%	General Support Costs	ET&D O&M Avoided Labor Costs / ET&D O&M Total Costs	$ 145,707	Occupational health programs supporting workers' compensation administration, employee fitness for duty, injury-prevention initiatives, and disability management services. Activities include claims and benefit administration, Fit for Duty evaluations, programs designed to reduce the frequency and severity of workplace injuries, and return-to-work planning.
				Enterprise Health & Safety	$ 3,003	0.18%	General Support Costs	ET&D O&M Avoided Labor Costs / ET&D O&M Total Costs	$ 38,253	Enterprise-wide safety governance, field support, incident investigation, safety assurance, occupational health coordination, transportation safety, and corrective action oversight. The activities identify workplace hazards, support compliance, strengthen safety practices, and reduce operational risk.

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				Depreciation, Fuel, Rentals	$ 121,830	3.03%	Location-Specific Operational Data	SF Fleet Assets / Total PG&E Fleet Assets	$ 93,589	Fleet support activities involving vehicle use, fueling, rentals, registration, parts, freight, and transportation coordination. The services help operating teams obtain and use appropriate vehicles and equipment for field and business activities.
				Vehicles	$ 69,082	3.03%	Location-Specific Operational Data	SF Fleet Assets / Total PG&E Fleet Assets	$ 53,114	Maintenance and operation of PG&E's cars, trucks, specialty vehicles, and related fleet equipment. The services include inspections, repairs, parts management, registration, assignments, and support for vehicle availability and safe operation.
Indirect	4.5	Transportation and Aviation Services	Ex 7, Ch 2	Heavy Lift Helicopters	$ -	0.00%	No Avoided Costs	Wildfire-related	$ 2,523	Heavy-lift helicopter operations supporting PG&E construction, restoration, transportation, patrol, and wildfire-response activities. The aircraft provide heavy-lift resources for maintenance and construction work, service restoration, fire suppression, and emergency response.
				Manage DCPP Business	$ -	0.00%	No Avoided Costs	Diablo Canyon Power Plant (Generation) Related	$ 910	Aviation support for activities associated with Diablo Canyon Power Plant. The services provide specialized transportation, site access, observation, and field support when aircraft are required.
				Maintain IT Apps & Infra	$ 112	0.78%	General Support Costs	ET&D O&M Avoided Costs / ET&D O&M Total Costs	$ 338	Fleet applications, infrastructure, and databases for work orders, engineering, preventive maintenance, inspections, acquisitions, dispositions, and vehicle assignments. These systems support asset tracking, maintenance planning, operational reporting, and day-to-day fleet management.
				Manage and Maintain Facilities	$ 2,730	0.09%	Location-Specific Operational Data	SF Square Footage of Facilities Taken By CCSF / Total PG&E Facilities Square Footage * SF Higher Cost Factor	$ 71,550	Operation and upkeep of PG&E-owned and leased offices, service centers, and other facilities. The services include repairs, utilities, janitorial work, grounds maintenance, and property management.
Indirect	4.6	Real Estate	Ex 7, Ch 5	SFGO/Oakland Lakeside Project	$ -	0.00%	No Avoided Costs	One-time cost required regardless of CCSF petition	$ 5,917	Headquarters relocation from the San Francisco General Office to Oakland Lakeside. The activity includes establishing the new workplace, moving business functions, and supporting ongoing operations at the Lakeside location.
				Fire Risk Mitigation Memorandum Account	$ -	0.00%	No Avoided Costs	Wildfire-related	$ 592	Facility-related wildfire mitigation and emergency response activities. This work prepares and protects operating locations, supports response during fire-related events, and restores facilities affected by wildfire conditions.

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Cost Type	Schedule Number	Cost Category	Forecast Source	Cost Subcategory	Total Avoided Costs - 30 Years (Nominal $000s)	Total Avoided Costs (%)	Method of Avoided Cost % Assumption	Basis of Avoided Cost % Assumption	2023 Annual PG&E Forecast ($000s)	Cost Description
Indirect	4.7	Information Technology	Ex 7, Ch 8	Information Technology	$ 130,937	0.78%	General Support Costs	ET&D O&M Avoided Costs / ET&D O&M Total Costs	$ 385,095	Operation of enterprise applications, infrastructure, hardware, software, telecommunications, and end-user technology services. Includes licensing, cloud services, third-party support, managed services, equipment maintenance, and technical assistance for employees and business operations.
Indirect	4.8	Cyber and Corporate Security	Ex 7, Ch 9	Physical Security	$ 23,161	2.70%	Location-Specific Operational Data	SF Security Weekly Bill Rate / Total PG&E Security Weekly Bill Rate	$ 19,159	Physical protection of PG&E employees, facilities, and assets. The services include guards, investigations, executive protection, access control, security testing, video monitoring, incident response, and repair of security equipment.
				Cyber Security & Enterprise-Wide Corporate Security	$ 12,844	0.78%	General Support Costs	ET&D O&M Avoided Costs / ET&D O&M Total Costs	$ 36,994	Cybersecurity and corporate security activities that protect PG&E systems, information, facilities, and operations. Includes security applications, infrastructure, monitoring, access control, investigations, protective services, and security-equipment support.
Indirect	4.9	Compensation	Ex 8, Ch 4	Compensation	$ 20,771	0.18%	General Support Costs	ET&D O&M Avoided Labor Costs / ET&D O&M Total Costs	$ 236,168	Employee compensation programs covering base pay, short-term incentives, non-qualified retirement arrangements, and recognition awards. The programs support competitive pay, employee attraction and retention, and performance objectives.
Indirect	4.10	Employee Benefits	Ex 8, Ch 5	Employee Benefits	$ 55,096	0.18%	General Support Costs	ET&D O&M Avoided Labor Costs / ET&D O&M Total Costs	$ 701,346	Employee benefit programs covering medical, dental, vision, life insurance, retirement savings, post-retirement medical, and related trust arrangements. The programs provide health, financial, and retirement protection for eligible employees and beneficiaries.
Indirect	4.11	Finance Organization Costs	Ex 9, Ch 2	Bank Fees	$ -	0.00%	No Avoided Costs	Account/ Banking service requirements unimpacted by CCSF petition	$ 10,749	Corporate banking services for deposits, disbursements, custody, trustee functions, letters of credit, and working capital arrangements. These services support cash management, financing, asset custody, payment processing, and treasury operations.
				Department Costs	$ 19,958	0.78%	General Support Costs	ET&D O&M Avoided Costs / ET&D O&M Total Costs	$ 54,925	Company-wide finance activities covering capital raising, investor communications, financial reporting, budgeting, process improvement, and financial systems planning. The function provides financial analysis, governance, planning, and information used to manage the business.

Pacific Gas and Electric Company
Chapter 8.2 Avoided Cost Study
Matrix of Avoided Costs By Category

Cost Type	Schedule Number	Cost Category	Forecast Source	Cost Subcategory	Total Avoided Costs - 30 Years (Nominal $000s)	Total Avoided Costs (%)	Method of Avoided Cost % Assumption	Basis of Avoided Cost % Assumption	2023 Annual PG&E Forecast ($000s)	Cost Description
Indirect	4.12	Risk, Audit, and Insurance Departments	Ex 9, Ch 3	Department Costs	$ 4,304	0.78%	General Support Costs	ET&D O&M Avoided Costs / ET&D O&M Total Costs	$ 13,324	Enterprise risk management, internal audit, and insurance administration. These functions evaluate business risks and controls, conduct independent reviews, coordinate corrective actions, and manage insurance protection.
				Non-Nuclear Property and Non-Wildfire Liability Insurance	$ 155,807	1.97%	Location-Specific Operational Data	Substations in SF / Total PG&E Substations	$ 190,282	Insurance protection for non-nuclear property and liabilities unrelated to wildfire. The coverage protects buildings, equipment, and operations against specified physical damage and third-party claims.
				Wildfire Liability, Officers Liability, and Nuclear Property Insurance	$ -	0.00%	No Avoided Costs	Wildfire-related; Nuclear (Generation) related; Officers at PG&E unimpacted by CCSF petition	$ 716,794	Insurance protection for wildfire liability, directors and officers liability, and nuclear property. The policies address distinct exposures involving wildfire claims, corporate leadership decisions, and nuclear-facility assets.
Indirect	4.13	Law Organization Costs	Ex 9, Ch 6	Law Organization	$ 26,714	0.71%	General Support Costs	ET&D O&M Avoided Costs / ET&D O&M Total Costs	$ 86,337	Legal representation and advice for regulatory matters, litigation, claims, settlements, compliance, and business operations. The function supports safe and reliable operations, protects PG&E's legal interests, and guides decisions involving legal or regulatory requirements.
Indirect	4.14	Indirect Below Threshold	Ex 6, Ch 1A; Ex 6, Ch 3; Ex 6, Ch 7; Ex 6, Ch 9; Ex 8, Ch 6; Ex 9, Ch 4; Ex 9, Ch 7; Ex 6, Ch 5; Ex 6, Ch 8; Ex 6, Ch 10; Ex 6, Ch 11; Ex 7, Ch 3; Ex 7, Ch 4; Ex 7, Ch 6; Ex 7, Ch 7; Ex 7, Ch 11; Ex 8, Ch 2; Ex 8, Ch 3; Ex 9, Ch 5; Ex 9, Ch 8	Fixed Costs	$ -	0.00%	No Avoided Costs	Gas-related; Officers/ Organizations unimpacted by CCSF separation	$ 89,059	Fixed or otherwise non-avoidable activities across customer service, metering, safety, human resources, compliance, and corporate governance. The activities represent separate program obligations grouped together because each falls below the applicable modeling threshold.
				System-Wide	$ 96,422	0.78%	General Support Costs	ET&D O&M Avoided Costs / ET&D O&M Total Costs	$ 269,832	Company-wide customer service, metering, communications, supply-chain, security, human-resources, training, compliance, corporate-affairs, data-management, and related support activities. The activities represent separate program obligations grouped together because each falls below the applicable modeling threshold.

Pacific Gas and Electric Company
Chapter 8.2 Avoided Cost Study
Matrix of Avoided Costs By Category

Cost Type	Schedule Number	Cost Category	Forecast Source	Cost Subcategory	Total Avoided Costs - 30 Years (Nominal $000s)	Total Avoided Costs (%)	Method of Avoided Cost % Assumption	Basis of Avoided Cost % Assumption	2023 Annual PG&E Forecast ($000s)	Cost Description
CapEx	5.1	Customer Care Technology Projects	Ex 6, Ch 10	Customer Care Technology Projects	$ 10,796	0.77%	General Support Costs	ET&D O&M Avoided Costs / ET&D O&M Costs	$ 75,600	Development and enhancement of customer-care applications, systems, and infrastructure that improve PG&E's customer experience and support billing, customer service, and customer data management. Projects include digital self-service and communication channels, billing and payment capabilities, customer relationship management, data security, regulatory compliance, reporting, and analytics.
CapEx	5.2	Metering Services and Engineering	Ex 6, Ch 7	Install New Gas Meters & Butte Wildfire Rebuild	$ -	0.00%	No Avoided Costs	Gas-related and one-time wildfire-related costs	$ 79,172	Purchase and installation of new gas meters for new customer service and the Butte wildfire rebuild. Activities include meter installation, exchange, removal, and retirement associated with customer growth, failed equipment, and wildfire-rebuild work.
				Other Metering Services and Engineering	$ 82	0.96%	Location-Specific Operational Data	Avoided Gas & Electric Meter Capex / Total PG&E Gas & Electric Meter Capex (based on the other two subcategories in this chapter)	$ 100	Development and improvement of metering tools, equipment, systems, and other long-lived capabilities used to support metering services. Projects support meter engineering, testing, quality assurance, network operations, SmartMeter Opt-Out administration, technology planning, standards development, and meter-data management.
				Install New Electric Meters	$ 53,036	3.79%	Location-Specific Operational Data	SF Electric Meter Changes / Total PG&E Electric Meter Changes	$ 28,056	Purchase and installation of new electric meters for new customer service and replacement or retirement needs. Investment is driven by customer growth and the expected volume of meters that fail or must be replaced or retired.
CapEx	5.3	Gas AMI Module Replacement	Ex 6, Ch 9	Gas AMI Module Replacement	$ -	0.00%	No Avoided Costs	Gas-related costs	$ 94,988	Proactive replacement of legacy gas Advanced Metering Infrastructure modules used to transmit meter information for customer billing. The program installs replacement assets to reduce module failures, estimated bills, delayed bills, and repeat field visits.
CapEx	5.4	Transportation and Aviation Services	Ex 7, Ch 2	Transportation and Aviation Services	$ 331,099	3.03%	Location-Specific Operational Data	SF Fleet Assets / Total PG&E Fleet Assets	$ 107,568	Acquisition and replacement of vehicles, aviation equipment, fleet tools, and related technology used across PG&E. Investment is driven primarily by asset-replacement cycles, electric-vehicle additions, accident replacements, and other fleet-capital needs.

Pacific Gas and Electric Company
Chapter 8.2 Avoided Cost Study
Matrix of Avoided Costs By Category

Cost Type	Schedule Number	Cost Category	Forecast Source	Cost Subcategory	Total Avoided Costs - 30 Years (Nominal $000s)	Total Avoided Costs (%)	Method of Avoided Cost % Assumption	Basis of Avoided Cost % Assumption	2023 Annual PG&E Forecast ($000s)	Cost Description
CapEx	5.5	Real Estate	Ex 7, Ch 5	SFGO/ Oakland Lakeside Project	$ -	0.00%	No Avoided Costs	One-time cost required regardless of CCSF petition	$ 892,000	Acquisition, preparation, and placement into service of the Oakland Lakeside headquarters as part of the transition from the San Francisco General Office. Project costs include the new facility and long-lived improvements required to establish and support the headquarters location.
				Maintain Buildings and Real Estate Projects	$ 6,789	0.09%	Location-Specific Operational Data	SF Square Footage of Facilities Taken By CCSF / Total PG&E Facilities Square Footage * SF Higher Cost Factor	$ 152,721	Repair, replacement, and improvement of buildings and real-estate assets at PG&E offices, service centers, and other operating locations. Projects extend useful life, address safety and regulatory requirements, improve accessibility, and preserve long-term facility functionality.
CapEx	5.6	Information Technology	Ex 7, Ch 8	Information Technology	$ 105,968	0.78%	General Support Costs	ET&D O&M Avoided Costs / ET&D O&M Total Costs	$ 265,900	Development, enhancement, and replacement of enterprise applications, infrastructure, hardware, software, telecommunications, and end-user technology assets. Projects create or improve long-lived technology capabilities used by employees and business operations.
CapEx	5.7	Below Threshold	Ex 6 Ch 2; Ex 6 Ch 5; Ex 6 Ch 6; Ex 7 Ch 1; Ex 7 Ch 3; Ex 7 Ch 4; Ex 7 Ch 6; Ex 7 Ch 7; Ex 7 Ch 9; Ex 8 Ch 2; Ex 8 Ch 6; Ex 9 Ch 3; Ex 9 Ch 4; Ex 9 Ch 5	System-Wide	$ 26,481	0.83%	General Support Costs	ET&D O&M Avoided Costs / ET&D O&M Total Costs	$ 66,478	Investment in smaller capital projects that create, replace, or improve long-lived assets across customer, safety, supply-chain, real-estate, security, communications, training, corporate-affairs, and other support functions. Projects include facilities, equipment, systems, and other enduring capabilities that address specific operational and regulatory needs.
				Fixed Costs	$ -	0.00%	No Avoided Costs	Gas-related; Organizations unimpacted by CCSF separation	$ 600	Investment in smaller capital projects that create, replace, or improve long-lived assets related to customer service offices and PG&E's compliance and ethics program.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8.2

SCHEDULES 1-5

AVOIDED COSTS STUDY

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CHAPTER 8.3

NON-TARIFFED PRODUCTS AND SERVICES

WITNESS: MICHAEL DELANEY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8.3
NON-TARIFFED PRODUCTS AND SERVICES
WITNESS: MICHAEL DELANEY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8.3
NON-TARIFFED PRODUCTS AND SERVICES

A. Introduction

In my testimony, I provide information on PG&E's offerings of non-tariffed products and services (NTP&S) in San Francisco and information on the amount of net income from those NTP&S offerings that would be lost to PG&E customers and shareholders if the Subject Assets are taken.

In Part B, I provide background on PG&E's NTP&S program and explain how PG&E shares the net income it generates from NTP&S offerings with customers.

In Part C, I outline the main NTP&S offerings in San Francisco, and provide historical net income figures for those offerings for the period from 2018 through 2021, prior to and including the petition date in this proceeding.

In Part D, I recommend a growth rate for the net income from PG&E's NTP&S offerings in San Francisco, and provide information relevant to that recommendation. This net income growth rate is used in the business severance testimony of David Rubin to calculate lost profits from NTP&S offerings in San Francisco.

B. NTP&S / NRD Background

1. Background on NTP&S Programs and Services

NTP&S are products and services offered by utilities outside of their traditional tariffed utility offerings that use an available portion of a PG&E asset (such as electric transmission towers and distribution poles, streetlights, underground electrical conduit, overhead fiber, land, testing facilities, and intellectual property) or utility personnel time to generate incremental revenue, without adversely affecting the cost, quality, or reliability of the utilities' tariffed offerings or encumbering utility operations. NTP&S offerings encourage utility management to "find and exploit economies of scope available in any underutilized capital or capacity already

acquired by ratepayers and used for the provision of the utility service."[1] The Commission has found that leveraging such excess and unused utility capacity inures to the benefit of "ratepayers, shareholders, and the California economy," thereby serving the public interest.[2]

PG&E provides the majority of its CPUC-jurisdictional NTP&S offerings, which the CPUC approves and regulates, through its New Revenue Development (NRD) department. PG&E's NRD department generates NTP&S net income by leasing and licensing the use of infrastructure to third parties—such as to telecommunications companies, which pay to co-locate cellular equipment on unused portions of PG&E's transmission and distribution towers and poles—and by providing various non-tariffed services to enterprise customers, including other utilities and government entities. PG&E's NRD employees coordinate the development, administration, and delivery of NTP&S offerings to customers, and also manage customer education and outreach to generate new business.

A significant portion of PG&E's NTP&S net income is derived from its wireless, pole-top and fiber programs, which involve entering into leases and licenses with telecommunications companies for use of the excess capacity of PG&E infrastructure to improve connectivity and coverage. The available capacity that PG&E leases and licenses is space that it otherwise would not use, and there is substantial benefit in leveraging this excess space to support wireless and fiber technologies. Providing this access to existing structures allows for and/or improves cellular and Wi-Fi coverage without the disruption or cost of new construction. Indeed, many densely populated Bay Area communities strongly prioritize the use of existing infrastructure (including PG&E-owned infrastructure) for telecom network expansion, rather than the construction of new facilities. By leveraging the excess capacity of existing PG&E structures and rights-of-way, stakeholders can

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1 D.11-05-018at 22–23

2 Resolution G-3417 at 3; *see also* Resolution G-3456 at 3 ("It is Commission policy to encourage the use of excess utility capacity and underutilized utility assets through non-tariffed products and services (NTP&S)."); D.08-01-036 at 6; D.11-12-050 at 9.

minimize land use conflicts, permitting issues, and environmental impacts, all while enhancing infrastructure efficiency to the benefit of customers.

PG&E's existing infrastructure, such as poles, towers, streetlights, and underground electrical conduits, has been used as a mutually beneficial real estate option for telecommunications companies for more than 25 years. PG&E's wireless attachment and fiber co-location programs represent a significant NTP&S business that could not have been fully anticipated in the 1990s. As discussed further below (see Part D.2), the ability to continue leveraging the excess capacity of utility assets in the future creates additional opportunity to support affordable rates for customers by lowering utility bills, underscoring the importance of PG&E's ongoing work in developing and growing existing NTP&S programs and identifying new such offerings.

2. NTP&S Ratemaking for CPUC and FERC Jurisdictional Net Income

NTP&S net income is either CPUC- or FERC-jurisdictional, depending on whether the underlying asset or utility personnel providing the product or service relates to the CPUC-jurisdictional electric distribution and generation functions or the FERC-jurisdictional electric transmission function.

As of the valuation date in this proceeding, July 27, 2021, CPUC-jurisdictional NTP&S net income generated by PG&E's NRD department was distributed to ratepayers on a forecast basis through PG&E's General Rate Case (GRC) proceedings. Under forecast ratemaking, all forecasted profits from CPUC-jurisdictional NTP&S offerings flow to customers through the GRC. PG&E forecasts the revenues for all of its CPUC-jurisdictional NTP&S offerings in the GRC (classified as Other Operating Revenue), as well as all associated expenses, for both the Test Year and all subsequent attrition years covered by the GRC. The difference between those forecasted revenues and expenses is then credited back to customers in the form of a reduction to PG&E's total GRC revenue requirement. Stated another way, while the expenses of NTP&S offerings are technically funded by customers through forecast GRC ratemaking, customers also are credited with the expected program revenues. Thus, the result of forecasting both revenues and expenses is a forecasted net profit from

NTP&S offerings that reduces the overall revenue requirement that customers are obligated to fund. In short, customers receive the forecasted profits from PG&E's NTP&S Program.

PG&E shares FERC-jurisdictional NTP&S net income with customers on a 50/50 basis through the FERC formula rate set in PG&E's transmission owner tariff rate case.

As of the petition date, the only NRD NTP&S offering in San Francisco with a FERC-jurisdictional component was Wireless Services, apportioned 41 percent to FERC-jurisdictional transmission and 59 percent to CPUC-jurisdictional distribution. In February 2021, PG&E entered into a transaction with SBA to lease the wireless communication rights for the vast majority of its transmission, telecommunication, and other towers for a significant upfront fee. This transaction gave SBA the exclusive right to market and sublicense space on those transmission towers, which consequently reduced PG&E's net income from Wireless Services within San Francisco to an immaterial amount—approximately $5,000 for the 2021 calendar year. To avoid unnecessarily complex accounting for this de minimis amount, the FERC-jurisdictional net income from Wireless Services is treated as CPUC-jurisdictional net income in calculating lost profits from PG&E's NTP&S program in the business severance testimony of David Rubin.

C. NTP&S Programs and Net Income within SF

PG&E's NTP&S offerings generate significant net income from secondary use of the Subject Assets.[3] The most significant of these programs in existence in San Francisco as of the petition date (July 27, 2021) were:

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[3] PG&E's testimony calculates its just compensation as of the July 27, 2021 petition date and all of my calculations are "as of July 2021" unless stated otherwise. As a result, some of the facts underlying my analysis will change. Indeed, some facts already have changed, including that PG&E began sunsetting its UESC, FM, and SST programs in 2025. Of course, over the past 5 years PG&E has continued to develop other NTP&S programs, and likely will identify others. If CCSF elects to move forward with condemnation, the parties will have to update these facts and valuations through a separate proceeding at the CPUC.

- **Facilities Maintenance (FM) –** Maintenance, repair, construction, and inspection of customer-owned gas and electric facilities, including high-voltage substations.
- **Sustainable Solutions Turnkey (SST) –** Audit, design, and construction of energy efficiency measures for municipalities, universities, school districts, and hospitals, including financing coordination.
- **Utility Energy Services Contracts (UESC) –** Audit, design, and construction of energy efficiency measures for federal facilities, including financing. Through a UESC, PG&E acts as utility project management entity for identified federal facilities, helping to scope, finance, and deliver energy conservation, energy efficiency, and energy resiliency projects. These "behind-the-meter" contracts serve as energy conservation and cost saving levers for customers, and typically drive revenues to PG&E over time based on savings or through structured payments.
- **Wireless Services –** Leasing/licensing of PG&E's electric transmission assets, lattice towers, and monopoles to wireless telecom carriers to support their placement of antennas and base stations.
- **Fiber Services –** Dark fiber licensing and leasing.
- **Pole Top-Streetlight Attachments (PT-SLA) –** Design review, field inspection, approval, and licensing for third-party-owned telecom antennas on PG&E distribution poles and streetlights. Similar to Wireless Services, but the program focuses on providing sites for small cell antennas.
- **Intellectual Property (IP) –** Identification, protection, and licensing of IP that PG&E develops or co-develops.

PG&E does not have annual forecasts for NTP&S revenues and expenses specifically related to the Subject Assets as of the 2021 valuation date. Therefore, to forecast NTP&S net income growth associated with the Subject Assets with greater confidence, I analyzed the estimated revenues and expenses associated with the subject assets for the four years from 2018 to 2021. While PG&E primarily tracks its NTP&S revenues and expenses in the aggregate across its entire service territory, rather than broken out by specific areas within that territory, NRD was able to leverage data on assets within San

Francisco and project names to estimate the net income (revenue minus expenses) from NTP&S offerings that utilized the Subject Assets in each year from 2018 to 2021. Table 1 shows the results of this analysis:

TABLE 8.3 1
NRD DEPARTMENT NTP&S 2018–2021 ESTIMATED NET INCOME FOR SUBJECT ASSETS WITHIN SAN FRANCISCO

Line No.		2018	2019	2020	2021
1	Net Income	$6,882,458	$6,563,940	$7,083,608	$7,773,446

As shown in Table 1, the net income for the NTP&S offerings associated with the Subject Assets was $6.9 million for 2018, $6.6 million for 2019, $7 million for 2020, and $7.8 million for 2021, which represents a compound annual growth rate for net income across that period of 4.1 percent.

D. Growth Rate for NTP&S Associated with Subject Assets

To estimate future growth in the net income from PG&E's NTP&S offerings associated with the Subject Assets for the purpose of calculating lost NTP&S profits from the taking of those assets, I recommend the use of a 3.121 percent growth rate in the business severance testimony of David Rubin. This figure is derived from compounding an inflation rate of approximately two percent (equal to the Federal Reserve's long-run target) and one percent real growth, and is the same long term growth rate used by EPS in its income approach analysis.[4]

The 3.121 percent growth rate is conservative in both the short and long term. From a short-term perspective, it is below the compound annual growth rate in net income associated with the Subject Assets for the 2018 to 2021 period, as represented in Table 8.3-1, above. It is also well below the compound annual revenue growth rate for fiber and PT-SLA offerings—two of the most significant long-term sources of NTP&S revenue for PG&E's NTP&S offerings associated with the Subject Assets—from the 2018–2021 period, as shown in Tables 8.3-2 and 8.3-3, below. The 3.121 percent growth rate is also conservative in the long term in light of reasonable expectations for significant

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4 *See* Appraisal Report of Dr. John A. Williams, Section 12.

future growth opportunities in new and innovative NTP&S associated with the Subject Assets, as further described below. The 3.121 percent growth rate applied in this analysis also accounts for uncertainty in the timing of NTP&S development and growth.

The following factors further support a 3.121 percent long-term growth rate:

1. Escalation of rental revenue from long-term fiber and PT-SLA contracts

PG&E's fiber and PT-SLA rental revenue is based on long-term rental agreements, typically with 20-year terms, that contain revenue escalation clauses. The rental revenue escalation rates in PG&E's fiber and PT-SLA contracts are typically set at 3-5 percent per year. A three percent growth rate therefore represents the low-end estimate of the growth in rental revenue that PG&E should expect through the progression of these long-term fiber and PT-SLA contracts and through execution of additional similar contracts.

The growth of fiber rental revenue by means of revenue escalation contract clauses is reflected in PG&E's 2018–2021 NTP&S revenue data associated with the Subject Assets. As shown below in Table 8.3-2, while fiber fee revenue declined between 2018–2021,[5] fiber rental revenue increased each year, growing 25 percent between 2018 and 2021, from $4.0 million in 2018 to $5.0 million in 2021. This represents a compound annual growth rate of 7.6 percent, well above the conservative 3.121 percent growth rate used to provide the overall value of PG&E's NTP&S offerings associated with the Subject Assets.

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[5] Fiber/PT-SLA fee revenue and expenses are primarily associated with PG&E inspecting fiber and PT-SLA installations, which occurs at the time of installation.

TABLE 8.3-2
NRD DEPARTMENT NTP&S 2018–2021 FIBER REVENUES
ASSOCIATED WITH THE SUBJECT ASSETS

Line No.		2018	2019	2020	2021
1	Rent	$4,019,093	$4,407,850	$4,732,054	$5,010,278
2	Fees	2,015,126	1,320,449	1,046,394	578,509
3	Total	$6,034,219	$5,728,299	$5,778,448	$5,588,787

The same pattern exists in the 2018–2021 NTP&S revenue data associated with the Subject Assets for PT-SLA. As shown below in Table 8.3-3, PT-SLA rental revenue grew by 18 percent from 2018 to 2021, from $1.125 million in 2018 to $1.33 million in 2021, a compound annual growth rate of 5.8 percent—again well above the 3.121 percent growth rate used to value PG&E's NTP&S offerings associated with the Subject Assets.

TABLE 8.3-3
NRD DEPARTMENT NTP&S 2018–2021 PT-SLA REVENUES
ASSOCIATED WITH THE SUBJECT ASSETS

Line No.		2018	2019	2020	2021
1	Rent	$1,125,509	$1,175,200	$1,241,404	$1,333,023
2	Fees	90,198	70,707	55,810	142,165
3	Total	$1,215,707	$1,245,907	$1,297,214	$1,475,188

In addition, it is reasonable to assume that the increasing trend of 5G "densification" needed to support enhanced wireless network coverage and performance will lead to more fiber and PT-SLA contracts and a corresponding growth in NTP&S revenue associated with the Subject

Assets.[6] 5G network densification requires deploying more small-cell antenna sites, which carriers frequently seek to install on utility poles and streetlights. It also requires transport infrastructure to connect 5G small cells to the broader network ("backhaul"), which may rely on PG&E-owned underground electrical conduit and fiber. As densification increases the number and density of urban and suburban small-cell sites, particularly in the major tech hub that is San Francisco, with its corresponding heightened demand for enhanced connectivity and network capacity, it is reasonable to assume that the number of PT-SLA attachment transactions and need for fiber co-location/backhaul arrangements will increase, leading to higher NTP&S revenues where PG&E has usable pole, streetlight, and conduit capacity.

2. Future blue sky growth opportunities

The 3.121 percent growth rate that I use to value future NTP&S net income derived from the Subject Assets is conservative because PG&E expects continued, long-term growth from its NTP&S offerings in San Francisco as it continues to develop innovative NTP&S offerings to support California's affordable, clean energy future.

Future blue sky growth expectation for NTP&S offerings using the Subject Assets is consistent with the potential for utilities to benefit from the transition to "smart cities," leading to increased demand for utility infrastructure to provide intelligent controls for a variety of systems, including management of traffic, parking, and public transportation, autonomous vehicles, security systems, and drones. San Francisco in particular is

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6 *See* R.17-06-028, Order Instituting Rulemaking into Access by Competitive Communications Providers to California Utility Poles and Conduit, at 4 ("advanced telecommunications technologies have driven demand for access to poles and conduit to unprecedented levels"); *id.* at n.10 (5G services claimed to "require the exponential 'densification' of the network, and a concomitant increase in (small cell) sties and writed backhaul"); In re Accelerating Wireless Broadband Deployment, WT Docket No. 17-79 (FCC 17-38) (Apr. 21, 2017) ¶ 32 ("Improving spectrum efficiency for future 4G and 5G services by providing end users with higher quality connections, more bandwidth and lower latency will require significant densification of DAS and small cell facilities. To achieve this anticipated level of service, wireless providers will need flexibility to strategically place thousands of DAS and small cell facilities throughout the country within the next few years"); D.16-12-025, slip op. at 111 ("5G will require perhaps ten times as many wireless antennas as currently deployed").

rapidly expanding smart city electrical and utility infrastructure that drives demand for third-party attachments, connectivity, and other monetizable secondary uses of utility assets.

As discussed above, PG&E also expects increased NTP&S revenue growth from telecommunications, data, and internet service providers to support their deployment of additional wireless attachments, fiber backhaul, and co-location needed to support the advancement of 5G and future generation networks. Such network densification requires adding numerous small-cell antenna sites to utility infrastructure (*e.g.*, poles and streetlights) to increase overall network capacity and coverage,[7] as well as increasing the number of high-bandwidth fiber optic connections, which often rely on utility-owned underground electrical conduit and fiber. As a major technology hub, San Francisco has a particular need for 5G infrastructure densification and deployment, and the presence of massive Bay Area data centers require constant, high-speed connectivity, especially as AI-related bandwidth needs rapidly accelerate.[8]

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[7] *See supra* note 6; *see also* https://www.ctia.org/news/what-is-a-small-cell.

[8] San Francisco Data Center Locations, DATACENTERS.COM (last accessed Sept. 10, 2026), https://www.datacenters.com/locations/united-states/california/san-francisco.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

PHYSICAL SEVERANCE DAMAGES

WITNESSES: STEPHEN TERAN, DEWEY DAY, MATTHEW THIBODEAU, MARCELO ROMANO, AND TIM WEDLAKE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
PHYSICAL SEVERANCE DAMAGES
WITNESSES: STEPHEN TERAN, DEWEY DAY, MATTHEW THIBODEAU, MARCELO ROMANO, AND TIM WEDLAKE

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
PHYSICAL SEVERANCE DAMAGES
WITNESSES: STEPHEN TERAN, DEWEY DAY, MATTHEW THIBODEAU, MARCELO ROMANO, AND TIM WEDLAKE

A. Introduction

My name is Stephen Teran. I am Senior Director of Integrated Systems Planning at Quanta Technology, LLC d/b/a Danovo Energy Solutions.[1] Unless otherwise stated, I sponsor the testimony in this chapter; other witnesses sponsor sections of this chapter where explicitly stated. We submit this testimony on behalf of Pacific Gas and Electric Company (PG&E) in response to the Petition of the City and County of San Francisco (CCSF) (CPUC Docket P.21-07-012). This testimony accompanies and must be read in conjunction with Danovo's longer, more detailed report (Report), which is incorporated into our testimony as if fully set forth herein.[2]

My testimony provides an overview of PG&E's physical severance damages, which are the costs PG&E would incur to physically separate the electric assets CCSF proposes to take from PG&E's grid and to restore and reintegrate PG&E's remaining system so that it can continue to provide safe and reliable electric service to PG&E's customers outside of San Francisco. Specifically, I (1) analyze CCSF's Separation Plan; (2) present PG&E's Restoration Plan, which identifies the steps PG&E would need to take to restore its grid and make its system whole following CCSF's separation; (3) summarize the costs PG&E would incur to do so; and (4) briefly discuss the timeline for physical severance and restoration. Other witnesses provide supporting testimony regarding: (1) the process and certain costs to restore PG&E's

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1 For purposes of this testimony and the accompanying Report, I served as the lead consultant for, and oversaw the work of, the Danovo team working on this matter. That work was also performed in close coordination with PG&E subject matter experts, including the other witnesses supporting this chapter, and involved site visits and visual inspections of PG&E's electric assets.

2 The Report, including its distribution appendix, is attached as **Attachment A** to this testimony and incorporated by reference. Note that the Report, like this testimony, contains subsections sponsored by and/or developed with the assistance of witnesses Dewey Day and Marcelo Romano.

fiberoptic and telecommunications assets (Dewey Day); (2) the costs associated with restoring PG&E's transmission, distribution, substation, and certain fiberoptic assets (Matthew Thibodeau); (3) the costs associated with relocating PG&E's Martin Service Center (Marcelo Romano); and (4) the amount PG&E would be owed to offset taxes applied to the severance damages paid by CCSF ("tax gross-up") (Tim Wedlake).

Based on our analysis, PG&E's physical severance damages as of July 2021 would be $1,003,172,000 comprised of $722,486,000 in separation and restoration costs and $280,686,000 in the tax gross-up. This figure assumes that PG&E severs the assets that CCSF proposes to take pursuant to CCSF's Separation Plan *and* fully remediates PG&E's remaining system pursuant to PG&E's Restoration Plan. Taken alone, CCSF's Separation Plan is an incomplete first step because it does not adequately address PG&E's post-separation operational requirements. Execution of PG&E's Restoration Plan is necessary to meet the criteria in the Interim Decision, namely, ensuring that PG&E's customers outside of CCSF will remain neutral to the taking and will receive the same level of service from PG&E that they received prior to any system separation.

The remainder of this testimony chapter is organized as follows. Section B provides an overview of the key features of CCSF's Separation Plan. Section C identifies the principal flaws and deficiencies in CCSF's proposals for restoring service to PG&E's remaining system—flaws that, as noted, would leave the system less safe and less reliable for remaining PG&E customers. Section D summarizes PG&E's Restoration Plan, which includes testimony from myself (for most aspects of the Restoration Plan) and Dewey Day (for telecommunications separation and restoration). Section E presents PG&E's physical severance costs, which includes testimony from myself, Matthew Thibodeau (for unit costs), Dewey Day (for certain fiber and telecommunications separation and restoration costs), Marcelo Romano (for real estate and construction costs for a replacement service center), and Tim Wedlake (for tax gross-up on physical severance). Section F discusses the timeline for separation and restoration.

B. Overview of CCSF's Separation Plan

CCSF's Separation Plan details what assets CCSF proposes to take from PG&E and how CCSF proposes to separate those assets from the assets that

PG&E will retain to serve non-San Francisco customers. CCSF's Separation Plan also proposes limited remedial actions that CCSF believes PG&E should take to reintegrate its remaining system after the taking. For purposes of this analysis, PG&E's counsel has instructed me that PG&E must accept CCSF's plan with respect to the scope of CCSF's taking, but PG&E can and should independently determine how to restore its own grid and its capacity to provide its remaining customers with service that is as reliable and safe as it was prior to separation.

1. Guiding Principles

CCSF's Separation Plan sets forth seven guiding principles: (1) maintain safety and reliability for customers of both utilities; (2) enable independent distribution operations; (3) enable coordinated but independent transmission operations; (4) minimize metering and Points of Interconnection between PG&E's and CCSF's systems; (5) minimize asset co-location; (6) establish clear operational and planning controls; and (7) effectuate severance through physical separation of assets where feasible.[3]

I agree that these principles are reasonable. However, as I discuss in Section C, CCSF's Separation Plan fails to adhere to them when it comes to restoration of PG&E's remaining system.

2. Scope of the Taking

Per CCSF's Separation Plan, CCSF plans to take all of PG&E's electric transmission and distribution assets located within San Francisco, including substations, transmission lines, and distribution circuits; the site of the future Egbert Switching Station in San Francisco; most of PG&E's telecommunications assets within San Francisco, including almost all of its fiberoptic network; all of PG&E's Martin Substation in San Mateo County; and the transmission and distribution lines feeding San Francisco from the Martin Substation.[4]

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[3] CCSF Separation Plan, Vol. 1 at 3.

[4] *Id.* at 4–8.

3. Transmission Separation Plan

The main focus of CCSF's transmission separation plan is PG&E's Martin Substation, which is a major transmission and distribution substation located in San Mateo County just south of San Francisco [redacted]. [5] Adjacent to the Martin Substation is PG&E's Martin Service Center, [redacted] (referred to by CCSF witnesses as the Daly City Yard). PG&E relies on the Martin Service Center to support gas and electric operations in San Francisco and on the peninsula.

Under CCSF's Separation Plan, CCSF would take the entire Martin Substation [redacted] [6]

To replace the function of the Martin Substation for PG&E, CCSF proposes that PG&E construct a [redacted] substation on PG&E's Martin Service Center main area, which CCSF does not plan to take. [redacted]

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[5] PG&E is in the process of constructing a new switching station, the Egbert Switching Station, which will be a third point through which electricity reaches San Francisco at the transmission level.

[6] CCSF Separation Plan, Vol. 1 at 7–11. I note, however, that by the time any taking and physical separation could actually occur, PG&E will likely have finished building its new Egbert Switching Station in San Francisco, so one of CCSF's proposed POIs would be expected to connect at Egbert rather than Martin. *See* CCSF Separation Plan, Vol.3 at 11.

[redacted]

4. Distribution Separation Plan

CCSF's distribution separation plan proposes, at a high level, how to reconfigure PG&E's grid to separate distribution circuits at the San Francisco-San Mateo County border. PG&E's current distribution system was not constructed with county borders in mind. Accordingly, some electric customers within San Francisco receive their electricity from substations in San Mateo County and vice versa, and many distribution circuits cross over the boundary between San Francisco and San Mateo Counties.

Under CCSF's Separation Plan, CCSF would reorganize the distribution circuits so that customers within San Francisco receive electric service exclusively from CCSF and customers in San Mateo County receive electric service exclusively from PG&E. CCSF's plan identifies [redacted] separation points across [redacted] distribution feeders. To serve additional load within San Francisco that currently receives electricity from PG&E's other substations in San Mateo County, CCSF plans to install [redacted] from the Martin Substation. CCSF proposes that PG&E serve its customers in San Mateo who currently receive service from Martin or from substations within San Francisco by rerouting their service to connect to distribution circuits from [redacted] or from the proposed new PG&E [redacted] substation. CCSF further proposes that PG&E co-locate [redacted] from PG&E's new substation in the same duct banks as CCSF's new express feeders.

C. Flaws in CCSF's Proposed Remediation Steps

PG&E takes no position on the portions of CCSF's Separation Plan that address CCSF's post-separation restoration or construction of its own electric system. I did not analyze the sufficiency or efficacy of CCSF's plans to serve its own customers post separation, as that is outside of my role in this case.

However, I did analyze the components of CCSF's Separation Plan that propose remediation steps for *PG&E* to take, and I found several major flaws in

those proposals. As an initial matter, CCSF's Separation Plan fails to adhere to its own guiding principles when proposing steps for PG&E to take to restore its system. As a result, CCSF's incomplete proposals would leave PG&E operationally dependent on CCSF during contingency events (and, with respect to one transmission line, under normal operations); unable to expand its future operations in a manner sufficient to meet anticipated future demand; and with commingled assets and potentially stranded [redacted] assets that PG&E is actively phasing out of use. I summarize below some of the most significant flaws in CCSF's Separation Plan with regard to its impact on PG&E's post-separation grid.

1. Unnecessary Operational Dependence at the Transmission Level

Under CCSF's plan, and in particular under CCSF's proposed approach to reconfiguring the transmission lines into and out of Martin Substation, PG&E would be operationally dependent on CCSF in a variety of N-1 contingency events (*i.e.*, situations in which a single component is offline). During these contingency events, PG&E's customers would be served through CCSF assets, introducing a need for ongoing operational coordination with CCSF during restoration of both planned and unplanned outages and violating the principle of independent operations.

Additionally, CCSF proposes that [redacted] remain connected to the Martin Substation after CCSF's taking. This line does not serve any CCSF customers or provide power to substations in San Francisco; rather, it energizes other PG&E substations in northern San Mateo County. Under CCSF's plan, then, PG&E would be dependent on CCSF to energize [redacted] under normal operating conditions.

2. Inadequate Replacement for Martin Substation

CCSF proposes that PG&E's replacement for the Martin Substation be a [redacted]. That is not a sufficient replacement for PG&E's Martin Substation and does not restore PG&E's grid to its current level of safety and reliability. To maintain PG&E's operational independence, fix the operational dependence issues described above, and serve PG&E's customers in San Mateo County who currently

receive power from Martin, the replacement substation will need to be [redacted], as described in PG&E's Restoration Plan. [redacted] While PG&E standards do allow [redacted], CCSF's proposal does not consider that PG&E has [redacted] at the Martin Substation. CCSF's plan [redacted] constrains PG&E's ability to serve future load growth on the peninsula.

3. Omissions in CCSF's Plan

CCSF identified [redacted] separation points at the distribution level. PG&E's more thorough analysis identified that there are [redacted] separation points in the primary distribution system (i.e., [redacted] systems) and [redacted] in the secondary distribution system (i.e., [redacted] systems), for a total of [redacted] points requiring separation and/or restoration work. CCSF's plan fails to address [redacted] points that will require PG&E service restoration after the separation.

CCSF also entirely failed to address fiberoptic cables and telecommunication assets in its Separation Plan. It does not specify how the fiberoptic cables it plans to take will be separated from the fiberoptic "routes" that PG&E will retain and continue to use post-taking. It also does not address any of the operational control systems that would be impacted by the separation (e.g., Supervisory Control and Data Acquisition (SCADA), Energy Management System (EMS), Advanced Distribution Management System (ADMS), etc.), which would be critical for operations throughout the separation process.

4. Unnecessary Commingling of Assets

As part of its Separation Plan, CCSF proposes [redacted] and [redacted] running alongside PG&E distribution circuits. This proposed approach contradicts the guiding principle of minimizing co-location and unnecessarily creates ongoing operational complexity and safety risks. This is particularly

problematic for service reliability of PG&E's post-separation system because the nature and design of the lengthy [redacted] that CCSF plans [redacted]

5. Short-Sighted [redacted] Investments

CCSF proposes that PG&E restore service for its stranded customers that are currently served by [redacted] distribution circuits by (1) installing new [redacted] infrastructure in PG&E's new distribution substation and (2) reconnecting the existing [redacted] distribution circuits to these assets at the new substation. This approach runs counter to PG&E's current objective to phase out its [redacted] systems, which are limited in their ability to connect larger loads and tend to be older infrastructure (often near the end of their useful life), and replace them with higher distribution voltages. CCSF's proposal would also result in a small island of [redacted] circuits surrounded by [redacted] circuits with limited switching capability. In these circumstances, and pursuant to PG&E's policies, PG&E would convert the [redacted] infrastructure to [redacted] infrastructure, which eliminates the need to install space-intensive [redacted] assets at the new substation and ensures that reliability is not compromised for PG&E's distribution customers in northern San Mateo County.

D. PG&E's Restoration Plan

In response to CCSF's Separation Plan, which primarily focused on identifying what CCSF wanted to take and how to create separate systems after the taking, PG&E developed a Restoration Plan, which identifies all of the steps PG&E would need to take to restore its post-separation grid to current levels of safety, reliability, and operational independence following CCSF's taking. To be clear, PG&E's Restoration Plan is not a competing separation plan, and it does not (and cannot, per counsel's instruction) propose any changes to the assets CCSF plans to take. The Restoration Plan concerns PG&E's remediation to its own, remaining grid after CCSF's taking and proposed separation approach.

I summarize below the planning and development process for PG&E's Restoration Plan and some of the key aspects of that plan.

1. Planning Principles and Development

PG&E's Restoration Plan is guided by four principles: (1) safety and reliability for PG&E's remaining customers; (2) minimal interconnections and commingled assets between the two utilities; (3) operational independence and control for PG&E; and (4) adherence to PG&E's engineering standards, applicable Commission rules, and other legal and regulatory rules and requirements.

As much as possible, I developed PG&E's Restoration Plan using a system planning study to reflect a hypothetical separation as of the date of valuation in July 2021.[7] That exercise, which I understand is required by law, is somewhat artificial, because PG&E's system has changed considerably in the more than five years since the valuation date and will continue to change before any actual separation could occur. I understand that the Public Utilities Code provides a procedure to adjust the Commission's determination of compensation when circumstances change between the valuation date and the actual taking. Such an update will be critical to allow PG&E to revise and refresh its Restoration Plan to reflect the then-current circumstances at the time of the taking and the associated costs.

As I developed this plan, I consulted with internal PG&E subject matter experts, who confirmed that the Restoration Plan would allow PG&E, after separation, to serve its remaining customers safely, reliably, and in accordance with PG&E's company standards. Among others, I relied on the expertise of Marcelo Romano and Dewey Day, who (together with their teams) helped develop PG&E's Restoration Plan for real estate and telecommunications, respectively.

2. New PG&E Substation

Under PG&E's Restoration Plan, PG&E would construct a new [redacted] substation at the current site of PG&E's Martin Service Center (the "New PG&E Substation), instead of the [redacted] substation that CCSF's Separation Plan proposes. The New PG&E

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[7] However, in order to be consistent with the CCSF Separation Plan, I utilized the same non-2021 models and forecasts as CCSF.

Substation would feature a [redacted]. This configuration provides similar expansion capacity as the current Martin Substation, as well as the required redundancy and flexibility necessary to ensure reliable service during normal operations and contingency events alike.

3. Transmission Line Reconfiguration

[redacted]

This re-routing results in [redacted] between PG&E's and CCSF's systems compared to the [redacted] that CCSF proposes. Fewer interconnections mean fewer potential points of failure, simpler coordination requirements, and greater operational independence for both utilities. This re-routing also resolves the operational dependency problems introduced by CCSF's Separation Plan, as described in Section C.1 above. Under PG&E's Restoration Plan, PG&E would no longer be dependent on CCSF [redacted] during an N-1 contingency or, [redacted], under normal operating conditions. In other words, PG&E's Restoration Plan enables PG&E to [redacted], without any reliance upon CCSF, under both normal operating conditions and contingency events.

4. Distribution Separation and Restoration

PG&E's Restoration Plan, including its distribution appendix, outlines a plan for complete separation and restoration at [redacted] separation points, including the many points omitted from CCSF's Separation Plan.

PG&E's Restoration Plan would also restore service to PG&E's stranded customers currently served by [redacted] circuits in the area, consistent with PG&E's current modernization policies. This approach eliminates the need to install new [redacted] at the New PG&E Substation and reduces disruption at the Martin Service Center. Combined with the use of [redacted], it also allows the New PG&E Substation to have a smaller footprint, meaning it can fit in the Martin Service Center main area without requiring demolition of the existing operations building.[8]

Finally, PG&E's Restoration Plan routes PG&E's distribution feeders emanating from the New PG&E Substation [redacted], consistent with both CCSF's and PG&E's guiding principles; allows PG&E to operate and maintain its assets without coordinating with CCSF to access those assets; and increases the safety and reliability of PG&E's remaining grid by separating PG&E's assets from CCSF's [redacted].

5. Martin Service Center Relocation

Because PG&E's existing Martin Service Center will be severely impaired by both CCSF's taking (which includes portions of the service center) and by the construction of the New PG&E Substation on the existing

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8 Retaining this building reduces demolition costs and allows certain PG&E facilities—[redacted]—to remain in place. However, PG&E will still need a [redacted] replacement service center because, to support efficient operations, the operations building needs to be co-located with the service center's operational facilities and functions, which could not feasibly continue operations from the existing Martin operations building once the New PG&E Substation is constructed.

operation yard, PG&E will need to acquire replacement property on the peninsula and relocate its displaced Martin Service Center facilities to that new property. PG&E's Restoration Plan contemplates purchasing a new parcel somewhere in the vicinity of the Martin property, as further described in the testimony of Marcelo Romano. This to-be-acquired property must be developed by PG&E to allow for the same gas, electric, and other operations currently served via the Martin Service Center, including [redacted], and other infrastructure required for day-to-day operations. The new service center will need to be operational before any construction of the New PG&E Substation can begin.

6. Fiber and Telecommunications (Sponsored by Dewey Day)

My name is Dewey Day, and I am PG&E's Infrastructure & Cloud Service Director. I have been a PG&E employee for 32 years holding roles in telecommunications engineering, telecommunications planning, and now directing our telecom strategic investments team. As part of our planning team over the last 20 years, I have prepared GRC requests and testimony for telecommunications investments across PG&E's system. I have also been actively involved in industry groups such as the Utility Technology Council and regulatory groups such as the Western Electric Coordinating Council.

CCSF's Separation Plan does not address separation and restoration of PG&E's fiber and telecommunications assets. Together with my team, I developed PG&E's fiber and telecommunications Restoration Plan to fill this gap. As for separation, PG&E will need to disconnect each of its San Francisco substations and the Martin Substation from its communications network so that PG&E will not receive alerts about substations that it no longer operates.[9]

PG&E will also need to restore its telecommunications system after the taking, including its fiberoptic system. CCSF plans to take almost all of

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[9] I developed the separation work scope and related cost estimate based on the technology that was in place in 2021. The telecommunications technology that PG&E uses in its substations has changed since then, and those changes would need to be addressed in an update proceeding.

PG&E's fiberoptic cables within San Francisco, including cables that PG&E uses to (1) support its gas operations (including operations within San Francisco and outside of it) and/or (2) support its electric operations outside of San Francisco. CCSF's taking will disrupt the "backbone" fiber routes PG&E uses to connect its substations in San Mateo with its substations in the North Bay and East Bay and to coordinate gas and electric operations throughout its larger grid. PG&E will therefore need to install new cables to rebuild the backbone fiber routes and support PG&E's continued operations post-taking. That work would require additional trenching and underground construction, which would be performed in accordance with PG&E's Fiber Optic Cable Underground Construction Standard.

PG&E will also need to perform telecommunications work at the Martin Substation and New PG&E Substation. In particular, PG&E will need to: (1) install new protective communications equipment on all new and rerouted transmission lines at the New PG&E Substation, (2) reroute fiber circuits currently terminating at the Martin Substation to the New PG&E Substation [redacted], (3) relocate its microwave link at the Martin Substation and replace it with a new tower and antenna at the New PG&E Substation; and (4) install additional telecommunications assets, [redacted].

I provide additional details about this work in Section 3.7 of the Danovo Report containing PG&E's Restoration Plan. The precise scope of that work will vary based on the conditions at the time of any actual taking.

E. Cost Summary

After preparing PG&E's Restoration Plan, Sargent & Lundy and internal PG&E subject matter experts developed the estimated costs to implement the plan. I have summarized the separation costs (that is, physical severance damages) that PG&E would incur as of July 2021 below. Our cost conclusions assume that PG&E severs the systems pursuant to CCSF's Separation Plan, takes as many remedial steps as it can in compliance with that plan, and then also takes the steps outlined in the Restoration Plan to ensure that service and

reliability are restored to PG&E's customers. All costs are presented in 2021 dollars, consistent with the July 2021 valuation date.

TABLE 9-1
SUMMARY OF PHYSICAL SEVERANCE COSTS (2021, ROUNDED TO NEAREST $1,000)

Line No.	Cost Category	Costs
1	Transmission	$14,677,000
2	Substation	290,141,000
3	Distribution	44,409,000
4	Telecommunications / Fiber	38,395,000
5	Real Estate / Service Center (including contingency)	334,864,000
6	Total Before Gross-Up	722,486,000
7	Tax Gross-Up on Physical Severance Cost	280,686,000
8	Total After Gross-Up	$1,003,172,000

These costs are the appropriate measure of physical severance damages because they reflect all separation and remediation work necessary to make PG&E's remaining system whole after CCSF's taking. CCSF's Separation Plan primarily addresses the separation process and CCSF's post-taking system; it does not focus on PG&E's remaining system, and the remedial measures it proposes PG&E take are insufficient. CCSF's Separation Plan leaves PG&E operationally dependent on CCSF, fails to adequately replace the Martin Substation, does not consider all of the restoration steps that are necessary after separation, and implements technology that PG&E is phasing out throughout its grid. PG&E's Restoration Plan builds upon CCSF's Separation Plan to address these shortcomings and complete the restoration of PG&E's system to its current levels of safety, reliability, and independence. The remediation steps that PG&E's Restoration Plan proposes, and the associated costs, are necessary to accomplish the Commission's goal of leaving PG&E and its remaining customers unharmed by CCSF's proposed taking.

1. Transmission, Distribution, and Substation Costs (Sponsored by Matthew Thibodeau)

My name is Matthew Thibodeau, and I am a Senior Vice President and Senior Project Director with Sargent & Lundy (S&L). Together with my team at S&L, I developed the physical cost estimates for physical separation and restoration of PG&E's transmission, distribution, and substation systems. I

also sponsor Chapter 3.1 of PG&E's testimony in this proceeding, which presents the Replacement Cost New (RCN) analysis for PG&E's electric assets serving San Francisco. My qualifications and experience are described more fully in that testimony.

S&L was engaged to estimate the costs PG&E would incur to physically separate its electric transmission, distribution, and substation systems from the assets CCSF proposes to take. The separation scope—that is, what work would need to be performed—was determined by other witnesses, namely, Mr. Teran and Mr. Day, as described elsewhere in this testimony chapter. S&L then applied the same general methodology and cost estimation framework that we used in the RCN analysis in Chapter 3.1. For each element of work required, S&L first identified the specific assets that would need to be installed, modified, removed, or reconfigured, and then applied appropriate unit costs to each element of work.

a. Sources of Cost Data

To estimate the costs of the physical separation work, S&L relied on the same data sources we used in the RCN analysis, namely:

- RSMeans, a widely recognized construction cost data resource, for material and labor costs applicable to standard construction activities; and
- S&L's internal project and cost information.

We developed craft labor rates in part from the 2022 edition of "RSMeans Labor Rates for the Construction Industry," supplemented by information from S&L's internal project and cost information. Consistent with the RCN analysis, the cost estimates assume that an independent contractor would be hired to perform the work and include appropriate allowances for social security, workers' compensation, and unemployment insurance, as well as general conditions costs (including construction management, labor supervision, overtime, and contractor profit).

b. Engineering Models

For asset categories involving complex construction requirements—particularly those requiring underground work in the dense urban

environment within and surrounding San Francisco—S&L applied the same conceptual engineering models developed for the RCN analysis in Chapter 3.1. For example, where the physical separation requires the installation of new underground conduit, we applied the same conduit and trench models that we developed for the RCN analysis, with specific assumptions tailored to the conditions of the greater San Francisco area. Similarly, where the physical separation requires the installation of new subsurface structures, we applied the engineering models we developed corresponding to the various structure types.

S&L also developed an additional model for trenching and construction costs of standalone fiberoptic cable that is not co-located with electric assets. S&L relied on the expertise of Mr. Day and the requirements specified in PG&E's Fiber Optic Cable Underground Construction Standard to determine the requirements for this model. Otherwise, S&L developed this model using the same approach to develop the undergrounding models used in Chapter 3.1.

c. Cost Adjustment Factors

The separation cost estimates include the following adjustment factors where applicable:

- Sales tax on materials and equipment at the San Francisco rate of 8.625%;[10]
- An engineering allowance of [redacted];
- Owner's costs of [redacted] for most assets and [redacted] for transmission assets and transmission substations, to account for project management, permitting, regulatory compliance, environmental compliance, commissioning, and related costs that any owner would incur; and
- Contingency of [redacted] for most assets and [redacted] for assets where large amounts of ground excavation are required, to account for unforeseen conditions, design modifications during construction, material price escalation, labor availability constraints, and other

[10] For purposes of this valuation, we uniformly apply San Francisco tax rates regardless of whether the materials would be installed in San Francisco or San Mateo counties.

similar risks that are common to large-scale utility construction projects in and around San Francisco.

d. Valuation Date

Consistent with the approach taken in the RCN analysis, S&L developed initial estimates considering equipment and labor costs as of the fourth quarter of 2022. We then adjusted those costs back to the date of valuation, July 27, 2021. We used the same de-escalation factors as Ned Allis, who performed similar de-escalation as part of PG&E's Replacement Cost New Less Depreciation (RCNLD) valuation in Chapter 3.2.

e. Cost Estimate Results

Based on the methodology described above, I provide the following cost estimates for the physical separation and restoration supported by Danovo's analysis. The table below summarizes the total estimated costs by major category:

TABLE 9-2
COSTS FOR DISTRIBUTION AND TRANSMISSION SEVERANCE, FIBER RESTORATION, AND NEW PG&E SUBSTATION (2021, ROUNDED TO NEAREST $1,000)

Line No.	Cost Category	Costs
1	Distribution	$44,409,000
2	Transmission	14,677,000
3	Substation	290,141,000
4	Fiber[11]	32,295,000
5	Total	$381,522,000

The transmission portion of the physical separation and restoration costs includes the costs associated with installing interconnection points between PG&E's and CCSF's systems, reconfiguring existing transmission lines, constructing new transmission lines, and installing metering and disconnect equipment at points of interconnection. The estimated transmission cost is $14,677,000.

[11] Additional separation and restoration costs associated with fiber and telecommunications are described below in Section E.3.

The substation costs reflect the construction of a [redacted] substation [redacted] to replace the capacity lost when CCSF acquires the Martin Substation. The estimated substation cost is $290,141,000.

The distribution portion of the physical separation and restoration includes the costs to separate PG&E's and CCSF's distribution systems at all required primary and secondary separation points, to reconnect stranded PG&E customers, and to perform reliability upgrades where necessary. The estimated distribution cost is $44,409,000.

The fiber costs include the costs to restore PG&E's backbone fiberoptic cable routes and to reroute fiberoptic cables in and around the Martin site. Our fiber cost estimates cover only a portion of the total fiberoptic and telecommunications separation and restoration costs; Mr. Day sponsors the remainder of those cost estimates in Section E.3.

2. Replacement Service Center Costs (Sponsored by Marcelo Romano)

My name is Marcelo Romano, and I am the Director of CRESS (Corporate Real Estate Strategy & Services) Workplace Portfolio Strategy. I have approximately 20 years of corporate real estate industry experience, working for and consulting Fortune 500 companies on their corporate real estate portfolios. My background and experience spans several industries, including the utility, industrial, and high-tech industries.

Together with my team, I estimated the costs to acquire a replacement property for the Martin Service Center, build necessary facilities on that new property, transfer any materials from the Martin Service Center to the new replacement property, and complete any necessary demolition on the existing Martin Service Center property. I used a like-for-like replacement methodology intended to maintain the existing operational capabilities of the Martin Service Center.[12] Accordingly, I assumed that PG&E would need to

[12] However, all replacement facilities would need to comply with all applicable codes, permitting requirements, and regulatory and PG&E standards in effect at the time of construction, which may require modifications rather than direct one-for-one replacement. For example, replacement of the existing spoils storage area may require covered storage or other design enhancements to meet current regulatory requirements.

acquire an approximately 22.5-acre contiguous parcel for a replacement service center, which would need to be located in the vicinity of the existing Martin property and industrial zoned and entitled as-of-right for service center operations.[13]

To develop cost estimates, I relied on market information obtained for a potential replacement site and construction and demolition costs for recent PG&E projects, all de-escalated to 2021 dollars. Based on this information and the assumptions described above, I conclude that the estimated cost to relocate and replace the Martin Service Center is approximately $223 million. That includes the cost of real estate acquisition, building construction, supporting infrastructure, PG&E-specific direct costs, and representative soft costs associated with project delivery. The demolition estimate also includes allowances for building abatement and disposal activities associated with hazardous materials, such as asbestos and lead-containing materials, based on the age and condition of the existing facilities at the Martin Service Center.[14]

The table below summarizes the major categories of costs:

TABLE 9-3
COSTS FOR MARTIN SERVICE CENTER REPLACEMENT
(2021, ROUNDED TO NEAREST $1,000)

Line No.	Cost Category	Costs
1	Acquisition of New Parcel(s)	$130,680,000
2	New Service Center Construction	87,179,000
3	Demolition and Site Preparation at Existing Martin Service Center	5,384,000
4	Total	$223,243,000

[13] For purposes of this estimate, I also assumed that the replacement property would not require environmental remediation or state or federal resource agency permitting *(e.g.*, California Department of Fish and Wildlife, State or Regional Water Quality Control Boards, U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, Department of Toxic Substances Control, etc.) or mitigation.

[14] However, I assume that the existing gas pipeline transfer station will continue to function on its existing site and therefore do not include relocation or decommissioning costs associated with this transfer station.

The above estimate is a planning-level estimate consistent with an AACE Class 4 estimate and therefore carries a relatively high degree of uncertainty. To account for potential variability in scope, site conditions, inflation, regulatory requirements, and other unforeseen factors, I also evaluated a 50% contingency, resulting in an upper-range cost estimate of $269,524,000 (if the contingency is applied to construction costs alone) to $334,864,000 (if the contingency is applied to both construction and land acquisition costs). These cost estimates will, of course, have to be revised at a future date because they are based upon a 2021 scenario.

3. Telecommunication Costs (Sponsored by Dewey Day)

Based on the telecommunications Restoration Plan I described above, I estimate that the 2021 costs for the separation and restoration of PG&E's telecommunications system (not including the cost categories estimated by S&L that are reflected in Table 9.2) would be $6.10 million. The table below summarizes the total estimated costs by major category:

TABLE 9-4
TELECOMMUNICATION COSTS (2021, ROUNDED TO NEAREST $1,000)

Line No.	Cost Category	Costs
1	Separation at Substations	$2,100,000
2	New Equipment Costs	4,000,000
3	Total	$6,100,000

The first category includes the cost estimates to separate PG&E's telecommunications network from each of the substations with fiberoptic connectivity that CCSF plans to take, as well as establishing emergency communications circuits between CCSF's substations to PG&E control centers for functions such as Remedial Action Schemes.

The second category is a high-level approximation of the costs PG&E would need to incur for additional telecommunications and protection equipment at the New PG&E Substation/Martin Service Center site, including the costs to relocate the microwave link and replace the microwave tower currently located on the Martin Service Center, install new protective assets on transmission lines, and install additional equipment in

the Martin Service Center telecom center. Based on my knowledge of what this equipment costs in 2026, I very conservatively estimate that the total costs in 2021 would have been at least $4 million.

4. Tax Gross Up (Sponsored by Tim Wedlake)

My name is Tim Wedlake, and I am a Principal Tax Analyst on the Research, Audits and Planning Team in PG&E's Tax Department. I primarily manage PG&E's fixed asset tax depreciation and deferred tax system and its related work products. I hold a Bachelor of Arts degree and a Master's degree in Finance from California State University, Hayward, and a Juris Doctor from the University of California, College of the Law, San Francisco.

Generally, a contribution *to the capital* of a utility is excluded from the definition of "gross income" and thus not subject to federal income tax. 26 U.S.C. § 118(a). However, under applicable tax law a "contribution *in aid of construction* . . . by any governmental entity" is an exception to the general rule. 26 U.S.C. § 118(b) (emphasis added). Because the physical severance obligation described above will be paid by CCSF, it qualifies as a contribution by a governmental entity and is therefore subject to federal income tax. A gross up is needed to ensure that the full amount of the physical separation damages (after paying tax on the payment from CCSF) will be available to PG&E to carry out the separation and restoration plans described in this chapter.[15]

As I explain in more detail in Chapter 8.1, PG&E's combined tax rate on taxable revenues is 27.98%.[16] Given that tax rate, the amount of the tax gross-up associated with the physical separation and restoration costs of $722,486,000 is $280,686,000.

---

15 This amount will change due to updates to the physical severance damages that will be necessary if CCSF continues with this proceeding and the taking of the Subject Assets. PG&E has estimated the tax gross-up in this testimony and asks the Commission to rule that a tax gross-up will be necessary as part of the just compensation award for severance damages, but that the Commission update the final calculation of the tax gross-up (and the treatment of any potential future tax deductions) during the update phase when more precise information will be known.

16 *See* PG&E Testimony, Ch. 8.1 (Rubin et al.), § G (Wedlake)

F. Timing of Physical Separation

The seven-year construction timeframe for the electrical facilities described in CCSF's Separation Plan is likely a best-case scenario once PG&E can break ground for construction of the New PG&E Substation. However, the CCSF timeframe likely underestimates the duration of all separation- and restoration-related construction activities since it does not consider the time required for PG&E's acquisition of land, permitting, environmental reviews, and construction of PG&E's replacement service center, which will need to be completed first. Once PG&E has completed construction of a new service center, business operations at the current Martin Service Center could be relocated there. Only after the relocation of the Martin Service Center is complete could construction of the New PG&E Substation begin.

G. Conclusion

This concludes our testimony on the physical severance damages PG&E would be owed as a result of CCSF's taking.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

ATTACHMENT A

DANOVO ENERGY SOLUTIONS REPORT &

PG&E DISTRIBUTION RESTORATION PLAN DETAILS

DANOVO
ENERGY SOLUTIONS
A QUANTA SERVICES COMPANY

Report

PG&E'S RESTORATION PLAN IN RESPONSE TO CCSF'S SEPARATION PLAN

Prepared for:

Pacific Gas & Electric (PG&E)

Date:

October 20, 2026

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VERSION HISTORY

Version	Date	Description
1.0	10/20/2026	Initial report.

REPORT CONTRIBUTORS

- Dewey Day, PG&E's Director of Infrastructure and Cloud Services
- Marcelo Romano, PG&E's Director of Corporate Real Estate Strategy and Services

ACRONYMS AND ABBREVIATIONS

The following acronyms and abbreviations are used in this report:

ADMS	Advanced Distribution Management System
AIS	Air-Insulated Switchgear
BA	Business Area
BAAH	Breaker-and-a-half
BART	Bay Area Rapid Transit
CAISO	California Independent System Operator
CBA	Cost-benefit Analysis
CCSF	City and County of San Francisco
CPUC	California Public Utilities Commission
CRESS	Corporate Real Estate Strategy and Services
CSRP	Customer Service Re-platform
DANOVO	Danovo Energy Solutions
D/B/A	Doing Business As
DBDB	Double Bus Double Breaker
DCC	Distribution Control Center
DER	Distributed Energy Resources
DWDM	Dense Wavelength Division Multiplexing
EMS	Energy Management System
FLISR	Fault Location, Isolation, and Service Restoration
GCC	Grid Control Center
GIS	Gas-insulated Switchgear
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor-owned Utility
ISO	International Organization for Standardization
kV	Kilovolt
LCD	Line Current Differential
MPAC	Modular Protection and Automation Control
N-1	Normal Minus One
N-2	Normal Minus Two
NC	Normally Closed
NO	Normally Open
ODN	Operational Data Network
OU	Operating Unit
PCO	Point of Change of Ownership
PG&E	Pacific Gas & Electric
PTO	Participating Transmission Owner
POI	Point of Interconnection
POTT	Permissive Overreaching Transfer Trip
P&L	Profit and Loss
RTU	Remote Terminal Unit
SAMP	Strategic Asset Management Plan
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SFO	San Francisco International Airport
SME	Subject Matter Expert
SMUD	Sacramento Municipal Utility District
SONET	Synchronous Optical Network
T&D	Transmission and Distribution

EXECUTIVE SUMMARY

My name is Stephen Teran, and I am the Senior Director of Integrated Systems Planning at Quanta Technology, LLC, doing business as ("d/b/a") Danovo Energy Solutions ("Danovo").[1] I am the primary author and sponsor of this report ("Report"); Dewey Day, PG&E's Infrastructure and Cloud Service Director, is the author and sponsor of Section 3.7 of this Report, which concerns the restoration of PG&E's fiber optic and telecommunications system.[2] PG&E subject matter experts ("SME") also provided input on other sections throughout this Report.[3]

I submit this Report on behalf of Pacific Gas & Electric Company ("PG&E") in response to the City and County of San Francisco's ("CCSF") valuation petition, focusing on the separation plan put forth by CCSF's witnesses Manho Yeung and Ryan Wu ("Separation Plan").[4] This Report and its accompanying Appendix are incorporated into Chapter 9 of PG&E's testimony submission in Proceeding 21-07.12 as though fully set forth therein.

The objectives of my Report are to (1) analyze the Separation Plan that CCSF provided in its opening testimony, (2) independently determine the steps that PG&E would need to undertake to physically separate its electric transmission and distribution ("T&D") system from the assets that CCSF plans to take and restore PG&E's remaining system to its current levels of safety and reliability, and (3) provide an estimate of the costs PG&E would incur to perform that separation and remediation work.

My Report proceeds as follows. In Section 1, I provide an overview of PG&E's electric grid within and surrounding San Francisco to provide context for the Separation Plan discussion. In particular, I discuss the Martin Substation, a critical transmission and distribution substation located just south of San Francisco in Brisbane, San Mateo County, as well as the transmission lines coming into and out of that substation. I also discuss the distribution circuits along the boundary of San Mateo and San Francisco Counties and the fiber optic system supporting PG&E's electric and gas grid.

In Section 2, I discuss and analyze the Separation Plan from CCSF's testimony. That Separation Plan both delineates which assets CCSF plans to take and how it plans to separate those assets from PG&E's grid, and, to a lesser extent, how CCSF proposes PG&E should restore its grid in response to CCSF's taking. I am instructed by counsel that, for the purposes of this proceeding, PG&E must accept CCSF's Separation Plan insofar as it delineates which assets CCSF will take, but PG&E is not bound by CCSF's suggestions or proposal for restoring and reintegrating PG&E's remaining grid. As such, my critical and independent analysis of CCSF's Separation Plan focuses on the flaws in CCSF's proposals and its failure to consider and identify all steps necessary for restoring PG&E's remaining grid.

Finally, in Section 3, I put forth a **Restoration Plan** addressing how PG&E should reintegrate its grid following CCSF's taking over to restore service to PG&E customers. (As noted above, I am the primary author and sponsor of PG&E's Restoration Plan, and Mr. Day is the author and sponsor of the fiber optic and telecommunications component of PG&E's Restoration Plan.) The most important differences between the remediation steps proposed in CCSF's Separation Plan and those in PG&E's Restoration Plan are shown in Table ES-1.

Table ES-1. Key Differences Between CCSF's Separation Plan and PG&E's Restoration Plan

Key Feature of Plan	CCSF's Separation Plan	PG&E's Restoration Plan
Replacement for Martin Substation	PG&E builds a new [redacted] substation at the site of the "Daly City Yard."	PG&E builds a new [redacted] at the site of the operations yard within the existing Martin Service Center (which CCSF calls the Daly City Yard).

[1] For purposes of this report, I served as the lead consultant for, and oversaw the work of, the Danovo team working on this matter. That work was also performed in close coordination with PG&E subject matter experts and involved site visits and visual inspections of PG&E's electric assets.
[2] Mr. Day, along with PG&E witnesses Marcelo Romano and Tim Wedlake, Sargent and Lundy expert Matthew Thibodeau, and myself, each sponsored portions of PG&E's Testimony Chapter 9 concerning physical severance damages. Testimony Chapter 9 provides precise delineations of each witness's respective scope.
[3] In addition to authoring Section 3.7, Mr. Day and his team provided input on the background section concerning PG&E's telecommunications system (Section 1.3). Marcelo Romano, PG&E's Director of CRESS (Corporate Real Estate Strategy and Services) Workplace Portfolio Strategy, and his team provided background on the real property components of the Martin Substation and Martin Service Center sites (Section 1.1.1) and on the real property requirements (e.g., zoning and entitlement requirements, parcel size, etc.) for a like-for-like replacement of the Martin Service Center. Other PG&E experts provided background on the operations at the Martin Service Center site and the need to continue such operations after CCSF's proposed taking.
[4] See Ex. CCSF-007C – Joint Prepared Direct Testimony of Manho Yeung and Ryan Wu on Behalf of City and County of San Francisco (April 20, 2026) (Errata May 21, 2026) App'x II ("Separation Plan").

Key Feature of Plan	CCSF's Separation Plan	PG&E's Restoration Plan
Powering PG&E's Replacement Substation	New PG&E substation connects to [redacted]	New PG&E substation connects [redacted]
Interconnections Between PG&E's and CCSF's Transmission System	9 points of interconnection ("POI"): [redacted]	5 POIs: [redacted]
PG&E's [redacted] Substation	[redacted]	[redacted]
Feeders into Border Circuits	CCSF's new express feeders added to existing conduit and co-located with PG&E's existing distribution feeders.	PG&E's new distribution feeders will be routed through a new, PG&E-owned duct bank system.
Relocation of Martin Service Center	CCSF's plan does not acknowledge that construction of a new PG&E substation will require relocation of PG&E's existing Martin Service Center.	PG&E purchases new land and constructs new facilities to allow for relocation of its Martin Service Center.
Fiber Optic System	CCSF's plan does not address separation of PG&E's fiber or telecommunications assets.	PG&E reroutes certain fiber, replaces its critical backbone fiber routes, and relocates other telecommunications assets.

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[redacted]

1 PG&E'S ELECTRIC SYSTEM SERVING SAN FRANCISCO

For the reader's convenience, I begin with a brief overview of the Pacific Gas & Electric Company's ("PG&E") electric transmission and distribution ("T&D") system in and around San Francisco as of the date the City and County of San Francisco ("CCSF") filed its petition, July 27, 2021.[5] I focus on those aspects of the transmission and distribution system that are most relevant for physical separation. For more information on PG&E's system, see Chapter 2 of PG&E's opening testimony in this proceeding, sponsored by Shay Bahramirad, PG&E's Vice President, Electrical Engineering, Asset Management and Risk and Compliance.

1.1 PG&E's Transmission System Serving San Francisco

Electric transmission refers to the movement of high-voltage electrical energy from generation facilities to electric substations. PG&E's electric transmission assets within and around San Francisco generally operate at 230 kV, 115 kV, or 60 kV.

[redacted]

PG&E is also in the process of constructing the Egbert Switching Station in San Francisco. This project, developed and recommended by the California Independent System Operator ("[redacted] PG&E's construction of Egbert is expected to conclude in 2028. Accordingly, Egbert will be in service long before any potential physical separation occurs.

1.1.1 PG&E's Martin Substation and Associated Transmission Lines

PG&E's **Martin Substation** is a major T&D substation located in Brisbane, in San Mateo County. It serves retail electric customers in both San Francisco and San Mateo Counties. PG&E's **Martin Service Center** is adjacent to the Martin Substation and comprises approximately 22.5 acres in both Brisbane and Daly City, San Mateo County.

The Martin Site includes:

[redacted]

Confidential Confidential Figure 1-1 is an aerial map of the Martin Substation and Martin Service Center.

[5] I am instructed by counsel that, under the Public Utilities Code, all valuation figures must be as of the date of CCSF's valuation petition. This analysis presents some inherent difficulties, as I further describe in Section 3.1.2 of this report.

[redacted]

Confidential Figure 1-1. Aerial View of the Martin Site

[redacted]

- [redacted]
  - [redacted]
  - [redacted]
- [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]

[redacted]

[redacted]

Confidential Figure 1-2. [redacted] System Configuration between Martin [redacted] as of 2021

As noted above, electricity usually flows through [redacted] discussed above from Jefferson or San Mateo Substations northward into the Martin Substation. However, electrical energy can also flow south from the Martin Substation through these lines, including during an N-1 contingency event (i.e., an event involving one point of failure). [redacted]

[redacted]

[redacted]

1.1.2 PG&E's Transmission Assets within San Francisco's City Limits

In addition to the transmission assets at and connected to Martin, several categories of transmission assets exist wholly within the San Francisco city limits. Those include:

[redacted]

As noted above, PG&E is also in the process of constructing the Egbert Switching Station in San Francisco. [redacted]

1.2 PG&E's Distribution System Serving San Francisco

Within San Francisco, PG&E's electric distribution system consists of distribution assets inside [redacted] substations listed in the previous section [redacted]. Inside [redacted] substations, PG&E transforms power from transmission voltages to distribution voltages with distribution substation transformers. PG&E then provides power to San Francisco neighborhoods via distribution circuits that run overhead and underground. Each distribution circuit is protected by its own circuit breaker inside the substation. [redacted]

Table 1-1. [redacted]

Because there are many areas of San Francisco without transmission service [redacted], PG&E uses 12 kV distribution Tie Cables and 12 kV distribution circuits to provide power to areas [redacted]

Table 1-2. [redacted]

PG&E's distribution system includes main or "primary" [redacted] lines and lower voltage "secondary" [redacted] lines (both overhead and underground); distribution transformers, which lower voltage to levels used at customer premises; switching equipment to connect lines together in various combinations and patterns; and other assets, including capacitor banks and protective devices. Approximately 65% of PG&E's distribution system in San Francisco is underground based on conductor length.

PG&E's downtown distribution network system is particularly complex. That system serves [redacted] customers in downtown San Francisco and adjacent areas. The system is built in a network configuration beneath downtown San Francisco's sidewalks and streets and in its high-rise buildings. It is designed for redundancy to meet the higher reliability needs of a dense urban area. In a network system, customers are served by multiple transformers, and the loss of a single line or transformer does not cause an interruption of power. The result is highly reliable service for PG&E customers, which comes at a significant level of operational complexity and cost to PG&E.

PG&E's interconnected distribution system—and the assets that it relies on to provide power to San Francisco customers—is not confined to San Francisco's borders. Some of the primary distribution circuits that originate from substations within San Francisco also feed PG&E customers in San Mateo County. The same is true in the other direction. Some customers in San Francisco currently rely on substations outside of San Francisco for their power (such as the Daly City and Martin substations located in San Mateo County). For more details, refer to Chapter 2 testimony.

1.3 PG&E's Telecommunication Assets

PG&E's electric (and gas) grid is also supported by several classes of telecommunication assets including, as particularly relevant here, its fiber optic system.

PG&E's fiber optic system functions as a rapid communications network that transmits critical operational information between PG&E's various facilities. Each substation continually sends measurements and equipment status information over this fiber optic network to PG&E's control centers, allowing operators to monitor the grid and operate certain equipment (e.g., circuit breakers) remotely. PG&E's fiber optic system also allows protective relays at different substations to exchange information so that PG&E can detect a fault and disconnect an affected asset (e.g., a transmission line) very quickly, often within a fraction of a second.

The primary components of PG&E's fiber optic system are:

[redacted]

The cables that PG&E uses to support its electric and gas operations are grouped into routes, which connect specific endpoints (e.g., substations, service centers, etc.) to one another. These routes include both cables that PG&E owns outright and cables owned by third parties that PG&E uses pursuant to contracts. Those contracts include "fiber swap" agreements, in which PG&E gains the right to use a counterparty's fiber in exchange for allowing the counterparty to use some of PG&E's fiber in another location.

[redacted]

[redacted]

[redacted]

[redacted]

Confidential Figure 1-3. Fiber Routes in the Vicinity of Martin Substation

2 CCSF'S SEPARATION PLAN

CCSF's proposed taking is described in its testimony from Nelson Bacalao[6] and in the Separation Plan proposed by CCSF witnesses Wu and Yeung. CCSF plans to take all of PG&E's electric T&D assets within San Francisco, the property associated with the future PG&E Egbert Substation, almost all of PG&E's fiber optic network in San Francisco, the entirety of PG&E's Martin Substation in San Mateo, and the T&D lines emanating from Martin that feed CCSF load.

CCSF intends to effectuate the establishment of its new electric utility through its Separation Plan, which proceeds in three parts:

1. Volume 1, CCSF's Separation Plan summary containing CCSF's principles for separation.
2. Volume 2, CCSF's Distribution Separation Plan.
3. Volume 3, CCSF's Transmission Separation Plan.

As noted in the Executive Summary of my Report, these plans describe both CCSF's plans for separating the assets it intends to take from PG&E's remaining assets, and the remediation actions CCSF proposes that PG&E undertake to restore its own grid. I am instructed by counsel that CCSF has authority to dictate the former, but PG&E has control of the latter to ensure that PG&E's system and customers are made whole and that service and reliability are restored after separation.

As such, below I provide an objective overview of each component of CCSF's Separation Plan and analyze the technical viability and sufficiency of CCSF's proposed remediation steps for PG&E and its customers. My Report neither analyzes nor endorses the portions of the CCSF plan focused on service to the post-separation CCSF system, nor does it address the sufficiency or efficacy of CCSF's Separation Plan with respect to CCSF's proposed electric service to its own customers.

2.1 CCSF's Separation Principles

CCSF's Separation Plan, Volume 1, outlines the aims and principles Messrs. Wu and Yeung purportedly used to develop CCSF's Transmission Separation Plan and its Distribution Separation Plan.[7] Those principles are:

- Maintain safety and reliability.
- Establish independent distribution operations.
- Create coordinated (but independent) transmission operations.
- Minimize metering points.
- Minimize co-location of utilities.
- Establish clear operational and planning controls.
- Preference for physical separation of systems.

PG&E agrees that these principles form a reasonable basis for the development of a separation plan. Having said that, in many circumstances, CCSF's Separation Plan fails to adhere to the principles it has outlined—particularly when it comes to PG&E's remaining assets after the separation. Table 2-1 describes each of CCSF's planning principles and explains whether and to what extent CCSF implemented that principle in its Separation Plan and proposed remedial actions for PG&E.

Table 2-1. Assessment of CCSF Planning Principles Relative to Its Proposed Separation Plan

CCSF Planning Principle	Does CCSF's Separation Plan Adhere to its Principle?
Maintain Safety and Reliability. Preserve system safety and reliability during and after separation, including system protection, normal and contingency capability, voltage performance, and maintenance and operation flexibility.	**Uncertain.** CCSF's testimony shows that it performed analyses to determine impacts of separation on both the distribution and transmission systems. However, CCSF's transmission system analysis focuses exclusively on the portion of the system that CCSF would own after the separation. CCSF's Plan does not address PG&E's system post-separation.

[6] Ex. CCSF-002C – Prepared Direct Testimony of Nelson Bacalao on Behalf of the City and County of San Francisco (Apr. 20, 2026) (Errata May 21, 2026) ("Bacalao Testimony").
[7] CCSF Separation Plan, Vol. 1 at 3.

CCSF Planning Principle	Does CCSF's Separation Plan Adhere to its Principle?
Establish Independent Distribution Operations. Ensure each utility would be able to serve its retail customers independently, with no distribution-level interdependencies after full separation.	**Yes, but CCSF's Plan is incomplete.** The CCSF Distribution Separation Plan will result in fully separate utility systems at the distribution level. Still, it lacks sufficient detail to perform the separation at each point and restore service to PG&E customers. Below, PG&E provides the analysis for each separation point.
Create Coordinated (but Independent) Transmission Operations. Separate into transmission systems that operate independently but in coordination, consistent with common utility practices and clearly defined roles and responsibilities.	**Not for PG&E.** CCSF's Transmission Separation Plan does not support PG&E's ability to serve its retail customers independently. CCSF's Plan creates operational dependence during N-1 conditions (and, in one instance, during normal operations) in which CCSF will be an intermediary receiving high-voltage service from PG&E, transforming it to a lower voltage, and then providing it back to PG&E.
Minimize Metering Points. Minimize the number of revenue metering points, points of interconnection (POI), and points of change of ownership (PCO) to reduce complexity and operational risk.	**No.** Under CCSF's Separation Plan, there will be [redacted] metered POIs between the post-separation systems at Martin Substation. A simpler interconnection scenario, as identified below, would require [redacted] POIs.
Minimize Co-location of Utilities. Minimize physical co-location of the City's and PG&E's facilities where feasible to support operational clarity, safety, and independence.	**No.** Complete physical separation with zero co-located facilities would be ideal, but it is not feasible to fully separate the highly integrated existing electric system. That said, CCSF proposes to co-locate more assets than strictly necessary.
Create Clear Operational and Planning Controls. Establish clear ownership, operational authority, maintenance responsibility, and planning control for all facilities post-acquisition.	**Not for PG&E.** While CCSF's Separation Plan draws lines of ownership, there are assets within Martin Substation that exist to support operations of transmission line facilities that PG&E will continue to own and operate after the separation. The ongoing operations, maintenance, and planning for those assets will require ongoing coordination.
Preference for Physical Separation. Physically separate the utilities' systems at boundary crossing, and utilize focused administrative arrangements, where physical separation is infeasible.	**No.** While CCSF's Separation does result in physically separate distribution systems, the wholesale taking of Martin Substation will result in the need for CCSF to grant easements and for ongoing operational coordination for assets that support PG&E's post-separation facilities.

2.2 CCSF's Transmission Separation Plan

2.2.1 Overview of CCSF's Transmission Separation Plan

Under CCSF's Transmission Separation Plan, CCSF would take [redacted] PG&E's transmission substations within San Francisco, the future Egbert Switching Station, [redacted] PG&E's transmission lines located within San Francisco, [redacted] PG&E's transmission lines that enter San Francisco from Martin Substation, and the entire Martin Substation.[8]

CCSF's Transmission Separation Plan creates some unavoidable operational interdependencies between PG&E's grid and CCSF's planned grid. [redacted]

CCSF's Separation Plan proposes [redacted] between the transmission lines that PG&E will continue to own and the transmission assets that CCSF plans to acquire, with a transmission revenue quality meter and disconnect switch installed at each POI.[9] The switches would be the PCO between PG&E's system and CCSF's system.[10] The POIs and PCOs would be on the following lines:

[8] Separation Plan, Vol. 3 at 8–9.
[9] Id. at 14.
[10] Id. at 8.

[redacted][12]

To replace the capacity that PG&E would lose if CCSF takes Martin Substation, CCSF proposes that PG&E construct a new [redacted] substation in the Martin Service Center Yard immediately adjacent to Martin Substation. CCSF proposes that this new substation contains [redacted]. Under CCSF's plan (and as shown in Confidential Confidential Figure 2-1), the proposed new PG&E substation would be fed by reconfiguring [redacted] transmission lines to land at the new [redacted] substation instead of at Martin (where they are currently interconnected):

[redacted]

[redacted]

Confidential Figure 2-1. CCSF's Proposed [redacted] Connections to the New PG&E [redacted] Substation[13]

[11] CCSF's Separation Plan states that this interconnection will initially occur at the Martin substation, but after the completion of the Egbert Switching Station, the POI and associated PCO would occur at the Egbert Switching Station. (Refer to Separation Plan, Vol. 3 at 11.) However, as a practical matter, any taking by CCSF would occur after the Egbert Switching Station is completed and online.
[12] Separation Plan, Vol. 3 at 13.
[13] Id.

Confidential Confidential Figure 2-2 shows the [redacted] system reconfigured to reflect CCSF's proposal for transmission separation and interconnection of a New PG&E [redacted] Substation, with PG&E ownership demarcated in blue and CCSF ownership in tan.

[redacted]

Confidential Figure 2-2. CCSF's Proposed [redacted] Configuration

CCSF's Transmission Separation Plan also contains load flow and contingency analyses showing the impacts to the lines that CCSF will own and operate after the separation but does not show the impacts to PG&E's remaining lines.[14]

2.2.2 Flaws with CCSF's Proposed New Substation and Transmission Reconfiguration

The remediation steps that CCSF would have PG&E undertake—namely, replacing the Martin Substation with a new [redacted] would undermine the reliability and operational independence of PG&E's grid.

2.2.2.1 Unnecessary Operational Dependence Due to Retained PG&E Transmission Connections into Martin

Contrary to the principle of operational *independence* CCSF identified in its testimony, CCSF's plan will make PG&E operationally *dependent* on CCSF in the event of an N-1 contingency (i.e., a situation in which one component of the transmission system is offline, whether for clearance for standard maintenance activities or due to an unplanned outage). The [redacted] lines feeding Martin Substation from the south provide an example of this unnecessary operational dependence that results from CCSF's proposal.

[redacted]

[14] CCSF's testimony also includes a section that evaluates the anticipated impact of the future Egbert Switching Station not being constructed from a load flow and contingency perspective. As noted above, the Egbert Switching Station is necessary to provide a diverse service path into San Francisco from the south, is already under construction, and will, as a practical matter, be complete before any taking would occur.

[redacted]

[redacted]

As described in Section 1, PG&E's current configuration allows power to flow along these lines from south to north under normal operations but also allows power to flow from north to south under contingency circumstances. [redacted] 2-3 [redacted]

[redacted]

Confidential Figure 2-3. N-1 Scenarios Where PG&E Would Be Dependent on CCSF Operations

2.2.2.2 Unnecessary Operational Dependence Due to Transmission Connections at the New PG&E Distribution Substation

Similarly, CCSF's Separation Plan creates unnecessary operational dependencies if a contingency event affects the New PG&E [redacted] Substation. [redacted] But CCSF's plan decreases this reliability and creates additional situations in which PG&E would be operationally dependent on CCSF.

[redacted]

[redacted] 2-4[redacted].

[redacted]

Confidential Figure 2-4. Operational Dependence Example: Normal Direction of Power Flow

[redacted] 2-5[redacted]

[redacted]

Confidential Figure 2-5. Operational Dependence Example: Outage of [redacted]

When coupled with the uncertainty about whether CCSF will become a Participating Transmission Owner ("PTO") with CAISO, CCSF's proposed approach to remediate PG&E's grid runs counter to CCSF's and PG&E's objective (and principle) of having two independent utilities that minimize operational interdependency.

With respect to undesirable operational interdependency, the situation would become even worse in an N-2 contingency event. [redacted] 2-6 [redacted]

[redacted]

Confidential Figure 2-6. [redacted] Configuration Impacts [redacted]

[redacted]

2.2.2.3 Unnecessary Operational Interdependence [redacted]

[redacted] 2-7 [redacted]

[15] CCSF Response to PG&E Data Request Set 21, No. 20.

[redacted]

Confidential Figure 2-7. [redacted] Assets at Martin Substation That [redacted]

[redacted]

[redacted]

2.2.2.4 CCSF's Separation Plan Limits Expansion Capabilities

Finally, CCSF's proposed configuration for PG&E's new [redacted] substation does not adequately account for PG&E's anticipated future [redacted] needs. [redacted]

[redacted]

2.3 CCSF's Distribution Separation Plan

2.3.1 Overview of CCSF's Distribution Separation Plan

Under CCSF's Distribution Separation Plan, CCSF plans to acquire all distribution assets within San Francisco [redacted]

CCSF proposes to separate and reconfigure the distribution circuits that cross the San Francisco–San Mateo boundary so that customers on the San Francisco side would receive service exclusively from CCSF. In contrast, customers on the San Mateo side would receive distribution service exclusively from PG&E. [redacted]

[redacted]

[redacted]

2.3.2 Flaws with CCSF's Distribution Separation Plan and Remedial Steps

I have several concerns with CCSF's Distribution Separation Plan that, when viewed in their totality, make CCSF's plan deficient in meeting its stated objectives. CCSF's plan does not address all separation points at the City's southern boundary required to implement a full distribution system separation, includes commingled assets that can feasibly be separated, and will have adverse impacts on the reliability of PG&E customers in San Mateo County.

2.3.2.1 CCSF's Incomplete Analysis of Boundary Crossings

Based on the analysis in CCSF's testimony and Separation Plan, CCSF determined the location of boundary crossings using the CYME[17] models PG&E provided via discovery. CCSF identified a total [redacted] where the existing circuitry will need to be physically severed and disconnected to isolate the post-separation CCSF and PG&E distribution systems. CCSF did not perform any analysis of the need for separation of the secondary voltage distribution system, presumably since the secondary voltage assets are not included in the CYME models.

PG&E performed a similar analysis using the geospatial asset data it provided to CCSF and determined that CCSF's analysis is incomplete and deficient. The boundary line mapped in EDRS intersects with PG&E distribution lines at [redacted] points. All [redacted] of these points are included in the separation points list (spreadsheet). Not all of these intersections will require separation and restoration work because of CCSF taking assets in the Martin Triangle area on the PG&E side of the boundary. There are [redacted] separation points for the feeders along the boundary that would require work to achieve the proposed separation, in addition to more service restoration work for stranded customers.

Any complete separation will have to address all [redacted] separation points. Because CCSF's plan does not address these interconnections, I have proposed separations in PG&E's Restoration Plan (refer to Section 3), so that I could develop a more accurate cost estimate for physical severance damages (refer to Section 4).

2.3.2.2 CCSF's Unnecessary and Unsafe Commingling of PG&E and CCSF Assets

CCSF's Distribution Separation Plan will result in the co-location of PG&E's and CCSF's assets. Although such commingling is sub-optimal, I acknowledge that it is not practical to separate every single asset physically. For example, CCSF's proposed taking of PG&E electric assets within the CCSF boundary will result in trenches

[16] CCSF Response to PG&E Data Request Set 21, Nos. 18 and 19 (Yeung/Wu).
[17] CYME is a widely used power engineering software tool owned by Eaton that is used for comprehensive analysis of distribution networks.

where CCSF will own and operate the electric assets, and PG&E will own and operate the gas assets. While there is a precedent for this arrangement,[18] it is not standard practice to commingle electric and gas assets from multiple utilities in this manner. However, if CCSF insists on taking the trenches, there is no feasible alternative to co-locating the assets.

Having said that, CCSF's Distribution Plan proposes unnecessary commingling of future utility assets that create operational risks for PG&E. For example, CCSF's plan proposes [redacted] Under CCSF's Separation Plan, both CCSF and PG&E would [redacted], which can lead to operational errors. Additionally, CCSF's plan to [redacted].

Both arrangements would result in a suboptimal state of increased coordination and operational complexity and increase safety risk for both entities during maintenance and operations activities.

2.3.2.3 CCSF's Short-sighted Investments in [redacted] Infrastructure

Under CCSF's Distribution Separation Plan, CCSF proposes to keep the PG&E customers in San Mateo County who are currently served [redacted] through step-down transformers at the New PG&E [redacted] Substation.

However, this proposal does not align with PG&E's ongoing efforts [redacted].[19] PG&E's [redacted] system is aging and capacity-constrained. Moreover, [redacted] are limited in their ability to connect larger loads and distributed energy resources ("DER"). Accordingly, PG&E's current policy limits the use of [redacted] interim solutions during voltage conversion. If PG&E were to construct new distribution assets as a result of CCSF's taking, it would [redacted].

[18] PG&E operates and owns some gas facilities in shared trenches with Sacramento Municipal Utility District's ("SMUD") electric facilities.
[19] See A.25-05-009, Ex. PG&E-4 (Electric Distribution), Ch. 9, Vol. 1 at 9-50 to 9-58 and supporting workpapers at WP 9-82 to 9-84 (Project Summary – Convert 4 kV Systems) for the details of PG&E's 4 kV conversion program.

3 PG&E'S RESTORATION PLAN

In this section of my Report, I propose an alternative approach for PG&E to restore and reintegrate its system (hereafter referred to as the "**Restoration Plan**"). Unlike the remedial steps in CCSF's Separation Plan, the Restoration Plan fully restores the functionality, safety, and reliability of PG&E's grid and provides PG&E with the maximum amount of operational control over its own assets. It also fully addresses and mitigates the technical concerns and deficiencies of CCSF's T&D Separation Plans that are identified in the prior sections of my Report.

To be clear, the Restoration Plan is not a competing separation plan. *It does not propose any changes to the assets CCSF proposes to take*. Nor does it analyze or otherwise evaluate CCSF's plans for providing electrical T&D services to its own residents. CCSF's Separation Plan controls the actions necessary to physically separate the assets CCSF intends to take from the assets PG&E would retain. The Restoration Plan does not change those actions. Instead, it describes PG&E's remediation to its own grid after CCSF's taking and separation. Insofar as CCSF's Separation Plan proposed remediation actions for PG&E to take that are insufficient or otherwise deficient, this Restoration Plan alters those proposals to meet PG&E's needs. Insofar as there were major omissions in CCSF's plan (for example, with respect to fiber optics), PG&E's Restoration Plan fills the necessary gaps. Otherwise, it does not affect or alter any other part of CCSF's Separation Plan.

3.1 Developing PG&E's Restoration Plan

3.1.1 Guiding Principles Underlying PG&E's Plan

Given the complexity associated with the anticipated physical severance of PG&E's existing, integrated electric grid both within and beyond CCSF, PG&E developed a set of core planning principles based on the criteria set forth in Decision 25-10-039[20] and CCSF's Separation Plan.[21] These principles guided my development of PG&E's Restoration Plan.

To develop these principles, I relied first and foremost on the goals set out in the Commission's Interim Decision:

> (a) [PG&E] investors are made whole, and remaining customers are left neutral to the potential acquisition; (b) [CCSF's] possible condemnation of PG&E's property in and around San Francisco constitutes a partial taking; and (c) PG&E may be entitled to business and physical severance damages.[22]

I also relied upon, and agree with, the seven principles set out in CCSF's Separation Plan and agree that those same principles—including operational independence and control—should apply to both CCSF's system *and PG&E's system* after CCSF's proposed taking.

Combining these sources, I developed the following set of planning principles, which I used to develop PG&E's Restoration Plan:

1. **Safety and Reliability.** Post-separation, PG&E will maintain sufficient operational capabilities, equivalent to its current capabilities, to serve its customers safely and reliably.
   a. Reliability is measured from a system design perspective and must cover both normal operations and contingencies.
2. **Minimal Interconnections and Commingled Assets.** To ensure safe and independent operations, the separation should be conducted in a manner that minimizes the number of interconnections and commingled assets.
   a. Post-separation, the PG&E and CCSF transmission systems will be as separate as possible with the minimum number of interconnections.
   b. Post-separation, the PG&E and CCSF distribution systems will be physically separated with no POIs at distribution voltages.
3. **Independence and Control.** PG&E and CCSF will each maintain similar levels of operational independence and control.

[20] Establishing Methods and Standards for Just Compensation and Valuation, D.25-10-039 (Oct. 30, 2025) ("Interim Decision").
[21] Separation Plan, Vol. I, § 3.1.
[22] Interim Decision at 2.

a. In other words, just as CCSF's Separation Plan provides it with maximal operational control and independence over its grid, PG&E's remediation steps must provide PG&E with similar levels of operational control and independence over its remaining grid.

4. **PG&E Standards.** Where PG&E facilities need to be modified or installed, all design decisions must be made in alignment with PG&E standards, safety and reliability requirements, and planning criteria—as well as in accordance with California Public Utilities Commission ("CPUC") rules and other legal and regulatory rules and requirements.

These principles provide additional definition and guidance in support of operational independence and reliability performance and help ensure that all modifications to the electric system are made in accordance with PG&E's existing standards.

3.1.2 System Planning Study and Timing Considerations

The preparation of PG&E's Restoration Plan was constrained by the legal rules under which this proceeding operates—and particularly the fact that the separation plan for PG&E's electric system is intended to reflect a hypothetical separation as of July 2021. The artificiality of that exercise is complicated by the fact that devising an optimal method to separate an electric system is a multilayered activity that includes many interdependent planning decisions, in addition to the constant changes occurring within any operative system.

The analysis I undertook to develop the Restoration Plan is a form of system planning study that involves the following inputs:

- **Models of the electric system.** I relied upon digital representations of the relevant electric system to simulate the behavior of the electric system under different conditions.
  - These models contain the configuration of physical assets (e.g., conductors, transformers, and switches), loads, and generation resources and represent the as-planned, or normal, operating configuration of the assets.
- **Load and generation forecasts.** I also analyzed the amount of demand or supply that is expected to be present at each node in the model.
  - Loads and generation are often aggregated at a transformer-level (for distribution analysis) or at a substation bus (for transmission analysis).
  - Forecasts are typically developed to represent critical system conditions that will help planners identify when and where system upgrades are needed. In most system planning studies, forecasts span 5- or 10-year periods and include peak and off-peak conditions.
- **Objectives and criteria.** In this case, I relied upon the principles articulated in the prior section of this Report, which I developed from the Interim Decision and CCSF's testimony.

Absent the timing constraints imposed here, the leading practice in the industry would be to establish a contemporaneous set of baseline models and forecasts (both transmission and distribution) using data available from the most recently completed annual planning cycle. These models would incorporate any in-progress or planned projects that would change the configuration and operational capability of the system. This would ensure the most recently available view and information relating to the expected electric system and its anticipated separation in 2028 were considered and embedded into a proposed physical separation plan.

In this valuation proceeding, however, the valuation date is set by the date of CCSF's Petition: July 27, 2021. As such, I conducted an engineering analysis on PG&E's 2021 system, even though there have been many changes to that system in the intervening five years. The requirement to develop costs that reflect the 2021 petition date forces the use of models and data that are not concurrent and sometimes lead to artificial or confusing results.

Complicating an already challenging task, CCSF's Separation Plan did not adhere to the statutory obligation to prepare a separation plan that reflected CCSF's July 2021 Petition date. Instead, CCSF's taking and Separation Plan are based on asset data and distribution models from **2022–2023**, distribution load forecasts from **2025**, and transmission models from **2025**. CCSF's Separation Plan relies upon modified **2023** distribution models that reflect **2028** forecasted load from the **2025** vintage forecasts, while CCSF's transmission models reflect **2030** and

2035.[23] In evaluating CCSF's Separation Plan, there does not appear to be any reliance upon a consistent set of models that accurately reflect the state of the system at the time of CCSF's Petition or anticipated separation, which results in a CCSF Separation Plan that fails to reflect the statutory mandate to prepare a separation plan contemporaneous with the petition date. However, for the sake of consistency with CCSF's Separation Plan, the same models were used to develop the PG&E Restoration Plan.

I understand that the Public Utilities Code provides for subsequent proceedings to adjust the amount of compensation due to PG&E to reflect changed circumstances, system modifications, and changes in value subsequent to the date of the Petition (here, after July 2021).[24] That proceeding will be essential because the underlying electric system at issue in this proceeding is extremely dynamic and has changed significantly since 2021 and is expected to change dramatically in the upcoming years before any potential separation would actually occur.

Given the complex analytic study process described above and the significant changes to the system and costs since the Petition date, I anticipate that updating the scope and costs of the physical separation plan to reflect a future separation date will be a major undertaking. For example, since July of 2021, substantial load growth and multiple interconnection requests near the CCSF–San Mateo County boundary have driven initiation and construction of multiple major projects [redacted] that are not included in the models CCSF used to prepare its Separation Plan. These projects will substantially alter the configuration of PG&E's system, so the separation and remediation plan will need to be refreshed to reflect actual (and anticipated) circumstances at the time of the expected separation.

3.1.3 Consultation with PG&E Subject Matter Experts

As I developed this plan, I also consulted with internal PG&E subject matter experts ("SME"), who confirmed that the Restoration Plan would allow PG&E, after separation, to serve its remaining customers safely, reliably, and in accordance with PG&E's company standards. PG&E made available SMEs covering transmission and distribution planning, protection, asset management, corporate real estate, information technology, and telecommunications. These experts provided input on critical system needs, mitigations necessary for the development of the Restoration Plan, and costs to execute portions of the Restoration Plan.

Two internal PG&E SMEs played particularly notable roles. Marcelo Romano, PG&E's Director of Corporate Real Estate Strategy and Services ("CRESS") Workplace Portfolio Strategy, and his team provided key costing input regarding the replacement for PG&E's Martin Service Center, some of which is incorporated into Section 3.5 of this report. Dewey Day, PG&E's Infrastructure and Cloud Service Director, together with other members of his team, developed PG&E's Fiber Optic and Telecommunications Restoration Plan presented in Section 3.7.

3.2 Overview of PG&E's Restoration Plan

PG&E's Restoration Plan proposes an alternative approach to restoring PG&E's grid to its current level of safety and reliability and to ensuring that both CCSF and PG&E have operational control and autonomy over their respective grids. The key aspects of PG&E's plan are as follows:

- **New PG&E Substation.** To restore its grid to its current level of reliability, PG&E proposes to construct a new [redacted] substation to replace the Martin Substation, rather than the [redacted] substation proposed by CCSF's Separation Plan.
- **Reconfigure [redacted] Lines.** PG&E's plan proposes to reconfigure [redacted] lines currently connected to the Martin Substation to connect instead to the New PG&E Substation [redacted]
  - This configuration removes PG&E's operational dependence on CCSF during N-1 situations that would result from the CCSF Separation Plan.
- **New [redacted] Interconnections.** PG&E proposes to connect the New PG&E Substation to CCSF's Martin Substation via [redacted] lines.

[23] Separation Plan, Vol. 1 at 9.
[24] Cal. Pub. Util. Code § 1417.

[redacted]

- **Complete Distribution Separation.** The physical separation of the distribution facilities in PG&E's plan reflects all required separation points (both primary and secondary voltage), including the points omitted from CCSF's Separation Plan.
- **Install [redacted] Assets.** PG&E will [redacted] to ensure a robust network of circuit ties to maintain reliable performance and to eliminate the need for [redacted] in the New PG&E Substation.
- **Relocate the Martin Service Center.** Since large portions of the Martin Service Center would be repurposed for the construction of the new substation, PG&E's plan includes the relocation (and construction) of new service center operations to a nearby property that PG&E would have to acquire in the future.
- **Restore Fiber Optic Network.** PG&E will reroute certain fibers to terminate at the New PG&E Substation, replace the critical backbone fiber routes CCSF intends to take, and separate its telecommunications systems from the San Francisco substations.

3.3 Transmission Restoration Plan

3.3.1 Transmission Line Reconfiguration Approach

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] 3-1 [redacted]

[redacted]

Confidential Figure 3-1. PG&E's Proposed [redacted] Configuration

[redacted] 3-2 [redacted]

[redacted]

Confidential Figure 3-2. Proposed Line Routes at New PG&E Substation

3.3.2 Advantages and Analysis of PG&E's Plan

PG&E's interconnection plan has several advantages over the interconnection approach articulated in CCSF's Separation Plan:

- PG&E's plan [redacted]. This furthers the goal of minimizing interconnection, which both parties rely upon as a guiding principle.
- [redacted] PG&E's plan eliminates its reliance on CCSF as an intermediary in PG&E's transmission operations.
  - [redacted] Under PG&E's plan, PG&E will not have to rely on CCSF as an intermediary [redacted]
  - [redacted]
  - [redacted]
- Similar to the CCSF Separation Plan, the PG&E Restoration Plan does not drive the need for any other related transmission upgrades.

3.3.3 Required Ongoing Operational Coordination

Finally, although PG&E's Restoration Plan aims to promote clear lines of ownership and operational control, there are some assets CCSF plans to take [redacted]

[redacted]

Importantly, PG&E's plan assumes that CCSF will be willing and able to coordinate real-time operations and maintenance activities of the [redacted] to allow for continued safe and reliable operations of [redacted] To the extent CCSF is unwilling or unable to do so, PG&E's Restoration Plan will require additional modifications to ensure reliability for remaining PG&E customers.

3.4 Plan for New PG&E Substation

PG&E's Restoration Plan includes the construction of a new substation to replace Martin (the "New PG&E Substation"). [redacted]

The New PG&E Substation will require [redacted] to connect the following lines and assets (Table 3-1).

Table 3-1. Circuit Breaker Positions Required at New PG&E Substation

[redacted]

Per PG&E standards, a [redacted] substation requiring that many positions should be designed [redacted] This provides operational flexibility [redacted] while reducing costs relative to [redacted]

The New PG&E Substation is designed with [redacted]

[redacted]

[redacted]

[25] The main Martin Service Center building would be used to house the telecommunications facilities required for the New PG&E Substation and those facilities that would need to be relocated from Martin Substation.

- [redacted]

3.5 Plan for Martin Service Center Relocation

Per CCSF's Separation Plan, CCSF intends to acquire Martin Substation and portions of PG&E's adjacent property that make up the Martin Service Center, [redacted], and portions of the main service center area (Confidential Confidential Figure 3-3). Further, as described in the last section, PG&E will need to construct a new substation adjacent to the existing Martin Substation on what is now the main area of the Martin Service Center.

[redacted]

Confidential Figure 3-3. Martin Substation and Martin Service Center

Accordingly, PG&E will need to purchase land and construct a like-for-like replacement of the taken and repurposed portions of the Martin Service Center at a new location to restore its existing operational capabilities. The replacement property that PG&E will need to acquire must align not only with the land requirements but also with the operational functions, facilities, and uses provided at the Martin Service Center.

PG&E proposes to relocate its Martin Service Center operations to a new parcel that is at least 22.5 acres.

The replacement site would require the acquisition and development of a contiguous 22.5-acre parcel to replace the operational functions currently provided at the Martin Service Center. To maintain operational efficiency, workforce accessibility, emergency response capabilities, and continuity of service, the replacement site would need to be in proximity to the existing Martin Service Center.

The replacement site would need to be zoned, or capable of being entitled, for service center operations, including vehicle and equipment storage, warehouse operations, material storage, maintenance activities, spoils management, fleet functions, and administrative uses. For purposes of PG&E's estimate, it is assumed that the replacement site would be zoned "as-of-right" for these uses.

To maintain uninterrupted operations and service, the replacement site must be fully functional and capable of supporting the full range of functions currently performed at the Martin Service Center before the existing service center is vacated.

3.6 Distribution Restoration Plan

3.6.1 Separation and Restoration of Distribution Circuits

As explained earlier in my Report, CCSF's Separation Plan does not address all separation points [redacted] Therefore, the first portion of PG&E's Distribution Restoration Plan focuses on accomplishing complete separation in addition to restoring service for all of PG&E's San Mateo customers. This Report provides an overview. **Confidential Appendix B** to this Report includes a comprehensive plan for distribution separation and restoration.

3.6.1.1 Development of Plan

I developed this portion of PG&E's Distribution Restoration Plan to meet the objective of a full physical separation of the distribution systems and restoration of service to PG&E customers while still following the planning principles established in Section 3.1. To do so, I performed the following steps.

1. Use geospatial asset data to identify all locations where PG&E distribution circuits cross the southern CCSF boundary into San Mateo County.
   a. This step includes a review of both the primary and secondary voltage distribution assets (i.e., all distribution assets).
2. Determine removal and/or construction activities required to create a physical separation between the CCSF and PG&E distribution systems.
   a. Remove any facilities that would be rendered idle after the separation.
3. Model the primary separation points in CYME.
4. Determine the construction activities required to restore service to PG&E customers that would be stranded after the separation.
   a. This includes [redacted]
5. Identify upgrades required, if necessary, to correct thermal overloads or Electric Rule 2[26] voltage violations.
6. Review the design of the post-separation distribution system to ensure that it meets PG&E Distribution Planning Criteria and has similar load transfer capability as the pre-separation system and restores full reliability to PG&E's system.

[26] Cal. P.U.C. Sheet No. 56716-E

I performed all analyses using the same asset data, CYME models, and load forecasts that PG&E provided to CCSF through discovery.

I relied upon the PG&E Electric Design Manual[27] for technical reference, and the following distribution system planning criteria were employed during my analysis:

- Limit each circuit to no more than 6,000 customers.
- Limit loading on each circuit such that emergency rating and normal ratings stay within industry norms.
- Install a manual switch before the first customer on the circuit.
- Limit protection zones to select customer counts and load limits.
- Install remote control consistent with industry-leading practice.

3.6.1.2 Separation Point Analysis

The scope of my analysis was largely governed and dictated by the physical boundary line separating San Mateo and San Francisco Counties. The boundary line is approximately eight miles long, running east to west (Figure 3-4) and is irregular in nature. The irregularity results in a zig-zag line traversing residential streets.

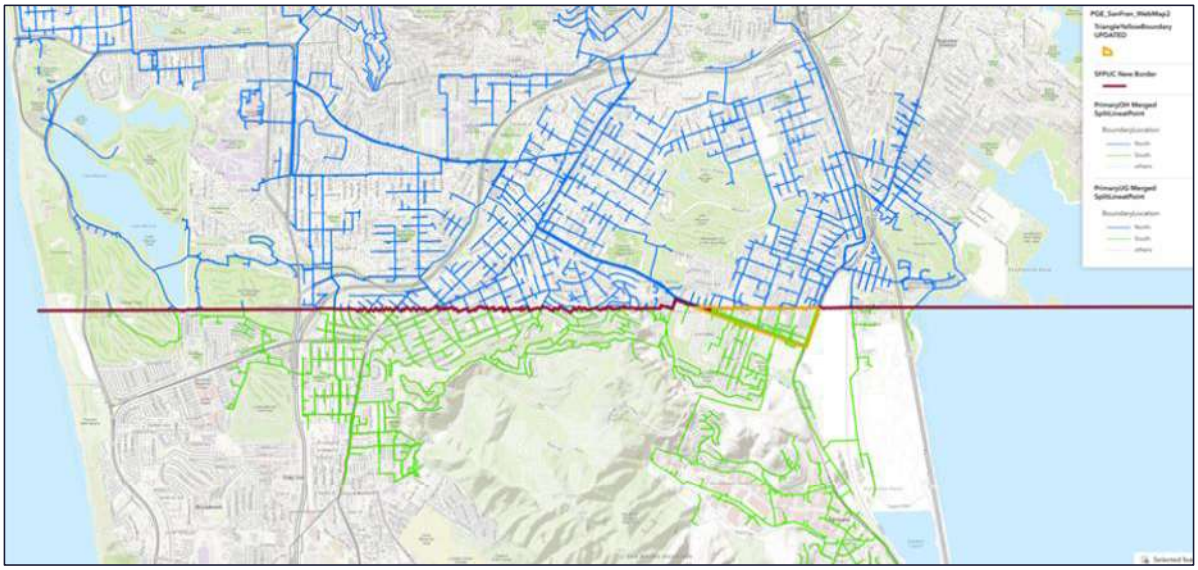

Figure 3-4. The Southern CCSF Boundary

To create two independent distribution systems, one operated by CCSF within San Francisco and the other operated by PG&E in San Mateo County (and beyond), each system will need to be properly isolated via physical separation points along the entire boundary line. The required work to perform the separation and restoration at each separation point includes removing existing overhead and underground infrastructure and assets, installing new assets, and making related modifications to the distribution circuits.

I relied upon geospatial asset data to identify all separation point locations where PG&E distribution feeders cross the southern CCSF boundary. My analysis included both the primary and secondary voltage distribution assets. As noted above, as a result of this analysis, I identified [redacted] separation points in the distribution primary and 1 in the distribution secondary.

I then evaluated each distinct point to determine the work required to complete the physical separation at that point. The construction required for each separation point is detailed by feeder in Appendix B of this report. Table 3-2 summarizes the construction required to effect the separation.

[27] PG&E, TD-9001M, Electric Design Manual.

Table 3-2. Separation Point Scope Summary

Description	Quantity
Terminate Primary Cables, Remove Abandoned Cables	[redacted]
Open and Remove Fuses, Remove Overhead Span	[redacted]
Replace Pole, Install Dead Ends, Remove Overhead Span	[redacted]
Open and Disable Switch, Remove Overhead Span	[redacted]
Secondary Removals Only, CCSF Stranded Load to Be Served	[redacted]
Total	[redacted]

3.6.1.3 Service Restoration

After I determined the locations of all separation points, I modeled the physical separation in CYME. That analysis revealed portions of PG&E's distribution circuits that became "islanded," or disconnected from PG&E's system, as a result of the separation work described in the prior section (and Appendix B).

I used the CYME models and the geospatial asset data to identify the scope of new construction and areas that will require installing overhead and underground distribution systems infrastructure and assets such as poles, conductors, cables, and transformers to create connections necessary to provide service to stranded PG&E customers post-separation.

In cases where [redacted], the service restoration scope included [redacted] the reliability for customers in the area by improving the tie network between circuits while also reducing electrical losses in the system. [redacted]

My proposals to restore service to each islanded customer, along with a fuller description of the work required for each such restoration, are detailed by feeder in Confidential Appendix B. As described above, the Restoration Plan only covers the construction required for PG&E's post-separation system. While there are some similarities to the restoration activities proposed in CCSF's Separation Plan, the PG&E Restoration Plan takes a longer-term approach that includes [redacted] utilizes newly created capacity on existing feeders to balance loading, and restores the FLISR tie network to maintain reliability performance.

Table 3-3. Service Restoration Scope Summary

Description	Quantity	Units
[redacted] Single-phase Transformers	135	count
[redacted] Three-phase Transformers	5	count
Convert Overhead Lines and Poles to Support [redacted] Voltage	35,239	feet/phase
Convert Underground Cables to Support [redacted] Voltage (Three-phase)	1,649	feet
Install New Overhead [redacted] Three-phase Lines	5,593	feet/phase
Install New Overhead [redacted] Two-phase Lines	1,020	feet/phase
Install New Overhead [redacted] Single-phase Lines	1,440	feet/phase
Install New Underground [redacted] Three-phase Cables NOT Connected to New PG&E Substation	7,660	feet
Install New Underground [redacted] Three-phase Cables Connected to New PG&E Substation	16,630	feet

After the separation and service restoration construction is completed, there will be overhead lines and underground cables that will be idle or abandoned in place. These lines and cables present a safety risk and need to be removed. Table 3-4 provides a summary of this removal scope.

Table 3-4. Abandoned Conductor and Cable Scope Summary

Description	Quantity	Units
Remove Overhead Lines	14,264	feet/phase
Remove Underground Cables	27,436	feet
Remove Abandoned Poles	14	poles

3.6.1.4 Reliability Analysis

The act of separating one distribution network into two separate distribution systems carries an inherent risk of reducing the reliability of each system. One major driver of reliability performance in distribution circuits is the availability of a robust network of ties between circuits. In the event of an outage, switches and reclosers are used to isolate the outage and restore service to as many customers as possible while repairs are performed. PG&E employs a FLISR system[28] to automatically operate SCADA-enabled devices to reconfigure the distribution system in the event of an outage to minimize outage disruption. Separating one distribution network into two physically separate systems will, by its very nature, reduce the number of available ties between circuits, therefore potentially impacting reliability.

To ensure that the separation would not adversely impact PG&E's reliability performance, I assessed the post-separation distribution network to ensure that the following criteria were met:

- Transferable load blocks contain at least 500 customers.
- The post-separation number of SCADA-enabled ties for FLISR per circuit is the same as the pre-separation amount.

The pre-separation load blocks and number of SCADA-enabled ties were also considered to limit the number of new devices in the Restoration Plan to avoid improving post-separation performance being better than pre-separation performance. This analysis confirmed that the separation and restoration steps proposed in PG&E's Distribution Restoration Plan would restore PG&E's distribution circuits to their current levels of reliability, thereby leaving PG&E's customers unharmed from a distribution reliability standpoint.

Table 3-5. Reliability Scope Summary

Description	Quantity
Overhead Line Reclosers	9
Overhead Sectionalizing Switches	1
S&C 6802 Controller for Underground Sectionalizer	1
12 kV Three-phase Fuse	1
Total	**12**

3.6.2 Separation of Co-located Assets

In addition to the complete separation of the distribution circuits that cross the San Francisco–San Mateo boundary and the restoration of PG&E's distribution circuits for its remaining customers, PG&E's Distribution Separation includes the relocation of certain distribution assets to minimize co-mingling—particularly where such co-mingling places PG&E's assets at risk.

The proposed substation exit routes for [redacted] served by the New PG&E Substation include a [redacted]. The feeders served by the New PG&E Substation will be routed through this [redacted]

[28] FLISR is an advanced smart grid automation technology used by electric power utilities to automatically detect where a power line break or fault happens, disconnect the broken section, and reroute electricity to restore power in seconds instead of hours.

3.7 Fiber Optic and Telecommunications Restoration Plan

As noted above, CCSF's Separation Plan did not address PG&E's fiber optic system or other telecommunications assets, even though CCSF plans to take most of PG&E's fiber optic cables within San Francisco's boundaries. As such, this portion of PG&E's Restoration Plan addresses both separation of PG&E's fiber optic system into two systems supporting two separate utilities, and restoration of PG&E's remaining fiber optic and telecommunications systems.

3.7.1 Separation of Telecommunications Assets

Currently, PG&E's fiber optic network connects all of its substations within San Francisco to PG&E's control and monitoring centers outside of the city, which monitor the equipment and operations at each substation and alert PG&E of any problems. If CCSF proceeds with its taking, it will assume responsibility for operating the substations within San Francisco. PG&E will therefore need to disconnect these substations from its broader asset monitoring systems, so that PG&E will not receive alerts about assets it no longer controls.

To effectuate this separation, PG&E will need to take the following actions at [redacted][29] within San Francisco that CCSF intends to take:

- Confirm that all ODN and fiber terminations correctly map to the as-built and as-operated network model for the Transmission Energy Management System ("EMS") and Advanced Distribution Management System ("ADMS").
- Perform network severance at each substation after obtaining required clearances from T&D control centers and transferring operations controls to CCSF control centers.
- Delete all network and monitoring points from ODN tools databases and clean up associated alarms/events.
- Perform system failover of the remaining part of ODN and critical routing points to make sure that system connectivity is preserved.

PG&E will also need to perform these same steps at the Martin Substation. Additionally, PG&E will need to reroute certain fiber optic cables that currently connect to the Martin Substation to instead connect to the telecom room currently located in the operations building at the Martin Service Center (which would be retained in its current location even after the New PG&E Substation is completed). Table 3-6 shows the cables that PG&E would have needed to separate and re-route had the taking occurred in 2021, and Confidential Confidential Figure 3-5 (also displayed in Section 1.3 of this report) provides a visual reminder of where the relevant cables were located as of 2021. However, specific rerouting will need to be updated at the time of taking, if any, and may include additional cables not listed in the table below.

Table 3-6. Fiber Optic Cables Requiring Rerouting

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[29] PG&E's fiber optic asset inventory indicates that no such communication assets are present at the two customer-dedicated substations. If CCSF proceeds with its taking, the presence or absence of such assets would be manually verified.

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Confidential Figure 3-5. Fiber Routes in the Vicinity of Martin Substation That Will Need to Be Rerouted

3.7.2 Restoring Backbone Fiber Routes

As described in Section 1.3, certain "backbone" routes of PG&E's fiber optic system transit through San Francisco but support PG&E's electric and gas operations within and outside of San Francisco. CCSF is planning to take some or all of the component cables within each of these backbone routes to support CCSF's electric operations. But PG&E will still need those routes to support its remaining electric operations outside of San Francisco and/or its gas operations. As such, PG&E will need to replace all of the cables within its backbone routes that CCSF intends to take.

Further, because CCSF plans to take not only PG&E's cables, but also its existing conduit and underground facilities, PG&E assumes that new trenching would be required to install replacement cables. This approach also ensures physical separation between PG&E's assets and CCSF's assets and minimizes co-mingling, which both parties use as guiding principles for separation and restoration. Trenching for standalone fiber optic assets is typically narrower and shallower than trenching for electric distribution or transmission assets. As of 2021, PG&E's standard approach involved 6- or 8-inch-wide trenches with cables buried in 4-inch conduit with subducts for each cable at a depth of approximately 36 inches. However, as with other types of undergrounding in San Francisco, trenching for fiber in San Francisco's dense, urban environment tends to be particularly complicated, time-consuming, and costly.[30]

Table 3-7 shows the component fibers of PG&E's backbone routes as of the date of valuation and whether each component fiber will need to be replaced with new cable in a new trench. That said, PG&E's fiber optic routes, like the rest of its grid, change over time. The component fibers in its backbone routes and the need for replacement will need to be re-evaluated at the time of any actual taking.

Table 3-7. Impacted Fiber Routes and Component Fibers

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]

[30] PG&E Testimony, Ch. 3.1 (Thibodeau), § F.2.a.

[31] [redacted] is listed on the asset stipulation as having a length of 8464.0 feet. This Report and the costing testimony in Chapter 9 conservatively assume that PG&E will have to replace only 7,497.6 feet of fiber, the amount of cable attributed to this section of W195 and the overlapping section of [redacted].

[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
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	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]

3.7.3 Fiber Swaps

CCSF is also planning to take certain fiber optic cables that PG&E uses as part of fiber swap agreements with third parties. Those agreements generally do not involve the exchange of monetary compensation. Instead, they involve "mile-for-mile" swaps in which each party may use a specified number of miles of the other parties' fiber optic network. Such agreements are generally not geographically confined to San Francisco but span PG&E's entire operational territory.

For example, a fiber swap between PG&E and a hypothetical Third Party could involve the exchange of 150 miles of fiber optic cables. PG&E would allow the Third Party to use specific PG&E-owned fiber optic cables adding up to 150 miles in locations where the Third Party needs additional fiber optic cables for its operations. In return, Third Party would allow PG&E to use 150 miles of the Third Party's fiber optic cables in areas across PG&E's service territory where PG&E needs additional fiber optic capacity for its electric and gas operations.

If CCSF takes PG&E's cables that are part of fiber swap agreements, PG&E may need to replace those cables to fulfill its agreements with the cable swap counterparties and maintain its reciprocal access to Third-party cables throughout its service area. However, whether PG&E would need to undertake such replacement will depend on the circumstances at the time of any actual taking, including the specific contractual provisions within the affected Third-party fiber swap agreement(s) and whether that Third Party might be willing to renegotiate the swapped

fibers. Accordingly, this report does not analyze which cables subject to fiber swap agreements will need to be replaced—but such replacements will need to be addressed in an update proceeding at the time of any actual taking.

3.7.4 Telecommunications Needs at New PG&E Substation

The New PG&E Substation, in addition to housing electric transmission and distribution equipment, will also need new telecommunications equipment. As noted above, PG&E will need to relocate existing fiber optic connections that currently terminate in the Modular Protection and Automation Control ("MPAC") buildings in Martin Substation and reroute them to connect instead to the New PG&E Substation. Additionally, PG&E will need to install or replace several other telecommunications assets.

First, PG&E will need to install new telecommunications protection circuits for each of the transmission lines that connect to the New PG&E Substation, including both the existing lines that will be rerouted to connect to the New PG&E Substation and [redacted] that would connect the New PG&E Substation to Martin Substation under CCSF's ownership (Table 3-8).

Table 3-8. New Telecommunication Protection Circuits

Circuit Name	Voltage	Equipment Needed
[redacted]	[redacted]	New Line Current Differential ("LCD") Protection Telecom Needed
[redacted]	[redacted]	New LCD Protection Telecom Needed
[redacted]	[redacted]	New LCD Protection Telecom Needed
[redacted]	[redacted]	New LCD Protection Telecom Needed
[redacted]	[redacted]	New LCD Protection Telecom Needed
[redacted]	[redacted]	New LCD Protection Telecom Needed
[redacted]	[redacted]	New LCD Protection Telecom Needed
[redacted]	[redacted]	New LCD Protection Telecom Needed
[redacted]	[redacted]	New Permissive Overreaching Transfer Trip ("POTT") Needed

Second, PG&E will need to restore its microwave link that connects San Bruno to the Martin Substation to instead connect to the New PG&E Substation. PG&E will need to construct a new path and new monopole structure within the New PG&E Substation site to mount a replacement microwave antenna.

Finally, PG&E will need to install new fiber optic equipment [redacted] to support the additional connections that will be rerouted from the Martin Substation [redacted]. That includes [redacted] hardware and new racks for telecom hardware.

APPENDIX A: CURRICULUM VITAE OF STEPHEN TERAN

STEPHEN TERAN, MBA

Executive Advisor

Stephen Teran, MBA, Executive Advisor, Senior Director of Integrated Systems Planning, joined Danovo Energy Solutions ("Danovo") in 2020. Stephen has over 20 years of utility experience spanning all distribution and system planning aspects. He has a demonstrated track record of driving organizations toward strategic objectives that require detailed, technical solutions. Stephen has led efforts to optimize capital portfolios for risk reduction, redesign engineering-related business processes, and implement technology solutions to meet critical business and regulatory requirements.

AREAS OF EXPERTISE

- Asset management
- Risk management
- Capital portfolio optimization
- Distribution planning and analysis
- Geospatial and network analysis
- General rate cases
- Software development and implementation
- Transmission and distribution ("T&D")

EXPERIENCE AND BACKGROUND

- Years of experience in the electric power industry 2003–Present
- Executive Advisor, Senior Director of Integrated Systems Planning, Danovo Energy Solutions .. 2026–Present
- Executive Advisor, Director of Advanced Planning, Danovo Energy Solutions 2025–2026
- Executive Advisor and Manager, Resilience, Danovo Energy Solutions 2022–2025
- Principal Advisor, Distribution and Asset Management, Danovo Energy Solutions 2020–2022
- Senior Manager, Asset Management, Southern California Edison 2006–2020

SELECT INDUSTRY ACCOMPLISHMENTS AND RECOGNITION

- Member, Institute of Electrical and Electronics Engineers ("IEEE")

EDUCATION

- MBA, California State University–Long Beach, 2012
- BS, Electrical Engineering, University of California–Irvine, 2008

EXPERIENCE DETAILS

Quanta Technology, LLC, doing business as ("d/b/a") Danovo Energy Solutions

Over a five-year period, progressed from an individual contributor to a lead position with increasing managerial, strategic, and technical consulting responsibilities.

Senior Director, Integrated Systems Planning, and Executive Advisor

2026–Present

- Responsible for a staff of 3 evaluating market opportunities and implementation approaches for Integrated Systems Planning.
- Profit and loss ("P&L") responsibilities for the Coordinated Studies and Optimization practice area.

Director, Planning Solutions, and Executive Advisor

2025–2026

- Responsible for a staff of 10+ engineers and advisors.
- P&L responsibilities for the Planning Solutions Practice Area.
- Lead for Distribution Planning Software Strategy and development of distribution planning area tools.
- Account Executive with business development responsibilities.
- Exceeding billability targets while functioning as technical lead on multiple projects.

Manager, Distribution Planning, and Executive Advisor

2023–2025

- Responsible for a staff of 6 engineers and advisors.
- Co-lead for the Climate Change and Resilience cross-Business Area ("BA") initiative.
- Supported business development activities and proposal development for resilience and distribution planning proposals.
- Account Executive with business development responsibilities.

Principal Advisor, Asset Management

2020–2023

- Supported business development activities and proposal development for the Asset Management BA.
- Led the Climate Change and Resilience and Coordinated Generation, Transmission, and Generation cross-BA initiatives while maintaining billability goals.
- Functioned as a project manager and technical lead for multiple client projects.

Southern California Edison ("SCE")

Senior Manager, T&D Asset Management

2019–2020

Responsible for the development of T&D's asset management framework in compliance with International Organization for Standardization ("ISO") 55000 standards and ensuring that key stakeholders across the Asset Management, Strategy, and Engineering organization are consulted and supportive of any proposed changes.

- **Strategic Asset Management Plan ("SAMP").** Responsible for evaluating the benefits of establishing a SAMP that would describe how T&D supports the achievement of SCE's strategic goals through the installation, inspection, maintenance, and replacement of its assets (the SAMP is a component of the ISO 55000 standards).
- **Asset Class and Integrated, Objective-focused Strategies.** Responsible for the creation of Asset Class Strategy documents that consolidate risk, financial, and life cycle management activities associated with key T&D assets.
- **Benchmarking.** Coordinated benchmarking activities with all California investor-owned utility ("IOU") asset management teams, as well as other peer utilities across the nation that are undertaking ISO 55000 certification.
- **Road Shows.** Provided strategic direction regarding road show presentations to ensure that each presentation meets change management objectives with a particular focus on increasing awareness of, and desire for, the benefits of implementing an Asset Management System.

Senior Manager, T&D Customer Service Re-Platform ("CSRP"), Front Office Lead

2018–2019

Provided primary strategic direction to the CSRP Business Integration team regarding front office processes that impact T&D operations. Led the business process documentation, analytics and reporting, and Transformer Load Management workstreams.

Senior Advisor, T&D Business Planning

2014–2018

Led the development, implementation, and regulatory support of a risk-based valuation and optimization framework for $800M of annual capital investment and drove organizational alignment across short-term operating plans, operating unit (OU) objectives, and strategic goals.

- **Business Planning.** Led a team through the development of SCE's first-ever business plan for the largest OU in the corporation ($15B capital over 5 years), developed multiple resource and capital scenarios with sensitivity analysis to support cross-OU decision-making, and presented results and recommendations to the OU executive leadership team.
- **Risk-informed Decision-making.** Led a team focused on the resolution of key methodology and application issues related to SCE's risk-based valuation framework and presented recommendations to OU technical leadership.
- **Regulatory Strategy.** Drove SCE's participation in a regulatory proceeding focused on the incorporation of risk into utility decision-making and developed materials and presented at workshops in front of regulatory officials, other utility representatives, and intervenor counsel.
- **General Rate Case.** Managed the development of 3 volumes of testimony in support of SCE's request for authorization of its 5-year capital and expense plan and coordinated cross-functional teams and helped align strategic direction across traditional grid infrastructure investments, internal research efforts, and support of California energy policies.

Engineer 3

2012–2014

Ensured the successful completion of the annual capacity planning process and supported the modernization of SCE's distribution system.

- **Advanced Technology.** Conducted cost-benefit analyses ("CBA") of proposed smart grid technologies in support of SCE's response to California State Assembly Bill 327 and consulted internally on advanced distribution modeling problems and research projects with academic and industry partners.
- **Expansion Plan Coordination.** Project-managed 8 teams of engineers through the successful completion, review, and approval of SCE's 10-year substation capacity plan; established capital project review guidelines to facilitate project approvals; and shepherded major projects through technical review committees and supported alternative project analysis.

Engineer 2

2008–2012

Developed SCE's distribution system modeling capability and functioned as a regional Field Engineer for multiple regions.

- **Field Engineering**. Performed 10-year capacity planning for multiple regions, supported major customer load expansion and reliability investigations, and developed a geographic information system visualization tool that layered capacity planning data over distribution circuits to facilitate project development and the identification of lowest-cost solutions.
- **Performance Management and Implementation.** Led the design and development of an import tool that leveraged existing geospatial data and other internal Oracle databases to build a model for distribution circuit analysis and coordinated the development of training material and delivered training sessions to 100 engineers across multiple departments.

Analyst

2003–2008 (N.B. Years 2003–2006 were as a contingent worker via multiple temp agencies)

Managed the Steel Pole Replacement Program and annual Streetlight Patrol.

- **Streetlight Patrol.** Created the Streetlight Patrol tracking database to support the reporting of metrics, ad-hoc data requests, and scheduling of patrols.
- **GIS Power User.** Subject matter expert ("SME") who performed daily administration tasks, supported the SmallWorld ERP upgrade, and performed complex spatial analyses.
- **Steel Pole Replacement Program.** Replaced the manual, paper-based work order creation process with an automated, AutoCAD-based mapping solution with a direct work order upload process into Design Manager.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

APPENDIX B

CONFIDENTIAL IN ITS ENTIRETY

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

ALLOCATION OF JUST COMPENSATION

WITNESS: SIENNA ROGERS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 10
ALLOCATION OF JUST COMPENSATION
WITNESS: SIENNA ROGERS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 10
ALLOCATION OF JUST COMPENSATION

A. Introduction

My name is Sienna Rogers, and I am the Senior Director of Financial Planning and Analysis with PG&E Corporation. I submit this testimony on behalf of Pacific Gas and Electric Company ("PG&E").

This chapter addresses the framework for allocation and distribution of the just compensation award. The award consists of: (1) the fair market value of the Subject Assets, (2) business severance damages, and (3) physical severance damages.[1] Pursuant to the Commission's Decision Establishing Methods and Standards for Just Compensation and Valuation (D.25-10-039) ("Interim Decision"), this framework includes PG&E's proposed regulatory accounting for the just compensation award, along with a rate impact analysis, demonstrating customer rate neutrality "based upon rates in place on the Petition Date."[2] This chapter also addresses how each business severance damage net revenue stream (revenues net of avoided costs) would flow through to each rate component by way of balancing accounts and other recovery mechanisms. In recognition that physical separation work must occur before the asset acquisition to ensure that the City and County of San Francisco ("CCSF") is capable of assuming its obligation to serve and that PG&E can continue to provide safe and reliable delivery to customers outside of San Francisco, my testimony also proposes a procedure for CCSF to fund the physical separation work via an up-front payment of estimated physical severance costs and ongoing update payments, which would replace the payment of physical severance damages in the ultimate just compensation award.

The remainder of this chapter is organized as follows:

- Section B provides a summary of key findings and conclusions.

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1 *See generally* PG&E Testimony, Ch. 1 (Peterman).

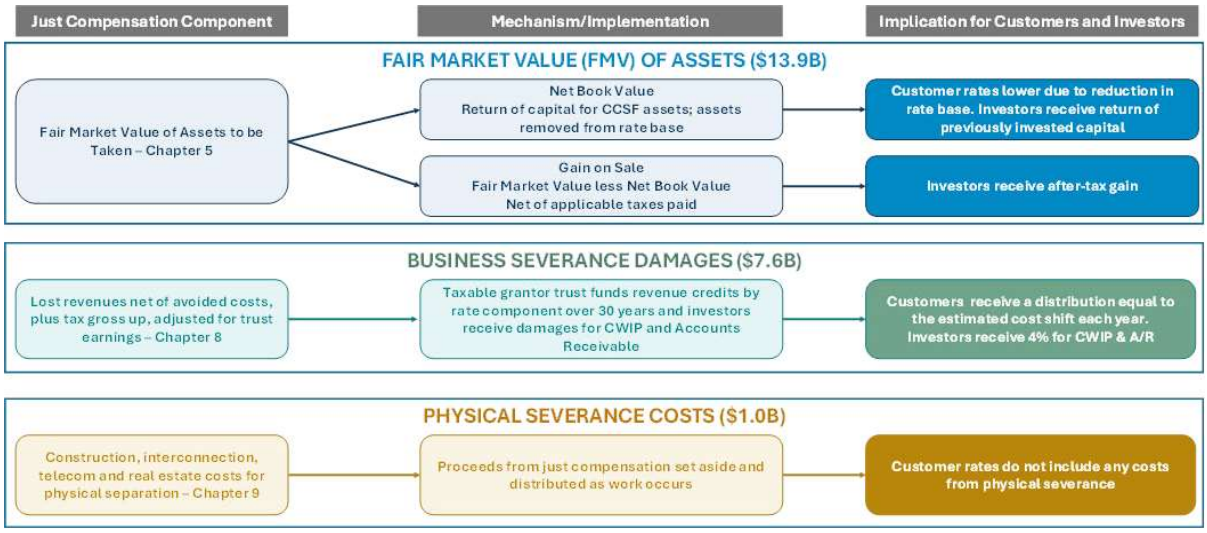
2 Interim Decision at 34, 36. As discussed in Chapters 1, 2, 8, and 9, an update will be necessary to ensure that other customers are truly left unharmed, given changes occurring during the intervening years between the valuation date and the condemnation date.

- Section C addresses the fair market value component and the proper allocation of the gain on sale to shareholders, based on the Commission's *Redding II* decision and the determination that remaining customers will be protected against any harm from the transfer.
- Section D addresses the business severance damages component, including allocation between PG&E and its customers, and PG&E's proposed approach for returning the customer portion of the award through a taxable grantor trust.
- Section E addresses the physical severance costs component, including PG&E's proposed procedure for CCSF to fund the separation work in advance of the asset acquisition, and the justification for that procedure.
- Section F provides a rate impact analysis demonstrating how the proposed ratemaking treatment of just compensation, including physical and business severance damages, maintains rate neutrality for PG&E's customers outside of San Francisco.
- Section G addresses the Interim Decision's testimony requirements under its Sections 7.2(d) (bullet 3), 7.2(e), and 7.2(i) as they relate to the calculation of business severance damages. Specifically, it demonstrates that PG&E's calculation of business severance damages using actual revenues and avoided costs under Section 7.2(i) is mathematically equivalent to the difference between the value of the remainder before and after the taking as required under Sections 7.2(d) and 7.2(e), and provides an income approach calculation of the whole property before the taking in compliance with Section 7.2(d).
- Section H concludes the chapter and notes that the testimony will need to be updated to account for changes between the valuation date and condemnation date.

B. Summary of Opinions

Consistent with the Commission's Interim Decision, the just compensation award should be allocated and implemented based on the purpose of each award component, ensuring that PG&E and its remaining customers are held harmless from CCSF's proposed taking. Figure 10-1 illustrates the allocation and how customers are left unharmed.

FIGURE 10-1
JUST COMPENSATION AWARD ALLOCATION FLOW CHART



The fair market value component compensates PG&E's investors for the property interest being taken. It also supports the goal of leaving customers unharmed because the ongoing transmission and distribution revenue requirements will be lower once the Subject Assets are removed from rate base.

As described in Chapter 8.1, business severance damages are calculated over a 30-year time frame and largely accrue to PG&E's remaining customers.[3] This portion of the award should be returned to PG&E's remaining customers over the same time frame and through the same ratemaking mechanisms and rate components through which the corresponding costs would otherwise have been recovered. In order to ensure that customers are protected from cost shifts, PG&E proposes that the business severance damages be held in a taxable grantor trust. Those trust assets would be invested (as described below) in Treasury bonds to ensure capital preservation, and credited each year to customers in an amount equal to the business severance damages calculated in Chapter 8.1 for that year to ensure customer neutrality. The business severance damages were calculated to ensure that (after taxes and costs) if invested in Treasury rates as of the Petition Date, there would be sufficient funds disbursed to customers, leaving them unharmed over the 30-year time frame. Actual

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3 *See* PG&E Testimony, Ch. 8.1 (Rubin *et al.*), § B. Specifically, over 95% of the business severance damages amount accrues to PG&E's remaining customers.

funding needs may vary depending on market rates at the time of any final decision or funding.

Physical severance damages should likewise be borne by CCSF as the party causing the need for the separation work. Because the separation work must be completed before CCSF can assume service obligations and close the transaction, CCSF should fund that work in advance through an upfront payment of estimated physical severance costs. This payment would be placed into a segregated interest-bearing account maintained by PG&E, subject to tracking, reporting, and replenishment if needed, with a final true-up.

Finally, because the Commission's required rate impact analysis is based on rates, balances, and assumptions in place as of the Petition Date, PG&E's allocation and implementation framework should be subject to an update as of the condemnation date. This would provide for an update of, among other things, the relevant rate base, regulatory balances, revenue requirements, customer consumption, trust funding requirements, trust earnings assumptions, and just compensation components to ensure that the final amounts paid by CCSF reflect current conditions in order to maintain rate neutrality for customers.

C. Just Compensation Component 1: Fair Market Value of Subject Assets

Chapter 5 has identified the award amount for fair market value ("FMV") of the Subject Assets as $13.88 billion.[4]

Although the FMV award is determined as a single amount, the award can also be viewed as comprising two distinct components for purposes of regulatory accounting and ratemaking. The first is the net book value associated with the Subject Assets; the second is the difference between the fair market value and net book value. Where, as here, fair market value exceeds net book value per PG&E's appraisal, the difference represents a gain on sale associated with the disposition of utility property. D.06-05-041 confirms a clear process for defining a gain on sale, recognizing the need for different treatment between the book

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[4] PG&E Testimony, Ch. 5 (Williams & Gerger), § A.

value of the assets and the monetary gain associated with the FMV of the assets.[5]

In his direct testimony, CCSF's witness Mark Fulmer testified as follows:

> Q. How should the Commission allocate the FMV of PG&E's assets and property being acquired by CCSF?
>
> A. As stated above, and without yet having seen PG&E's testimony on what is included in FMV and severance damages, my presumption is that the FMV should be allocated to shareholders because to the extent it represents the capital value of assets that shareholders own and on which they bear investment risk. Accordingly, the Commission should consider allocating the FMV to utility shareholders unless (a) the assets were contributed by PG&E's customers or ratepayers and/or (b) a portion of the FMV is necessary to ensure remaining ratepayers remain neutral to the City's acquisition.[6]

PG&E agrees with this approach.[7] The allocation of the gain on sale is governed by the Commission's shareholder allocation rule announced in *Redding II*.[8] Under that rule, as I understand it, gains from the sale of part or all of the utility operating system located within a geographically defined area to a governmental entity should be allocated to shareholders where the system has been included in rate base, and where the governmental entity assumes the public utility obligations to the customers within the area.[9] The allocation of the gain to shareholders applies so long as remaining ratepayers have not contributed capital to the system and are not adversely affected by the transfer.[10]

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5 As stated in the Commission's Opinion Regarding Allocation of Gains on Sale of Utility Assets, "A utility receives a gain on sale when it sells an asset such as land, buildings or other tangible or intangible assets at a price higher than the acquisition cost of the non-depreciable asset or the depreciated book value of the depreciable asset." D.06-05-041 at 8.

6 Ex. CCSF-006 – Prepared Direct Testimony of Mark Fulmer on Behalf of City and County of San Francisco at 6:15–23 (Apr. 20, 2026) ("Fulmer Testimony").

7 One qualification is that the net book value amount will be allocated to PG&E's investors (including both shareholders and debtholders), while the gain on sale will be allocated to PG&E's shareholders.

8 D.89-07-016, 32 CPUC 2d 233 (1989) ("*Redding II*").

9 D.06-05-041 at 18.

10 D.06-05-041 at 18.

If CCSF proceeds with a condemnation, I believe it would satisfy each element of *Redding II*: (1) PG&E's distribution system would be sold to CCSF, a governmental entity; (2) the distribution system consists of all of the utility operating system within San Francisco, a geographically defined area; (3) the components of the system have been included in PG&E's rate base; and (4) coincident with the sale, CCSF would assume the obligation to serve customers in San Francisco from PG&E.

Thus, the gains from the sale should be allocated to PG&E's shareholders, provided that remaining ratepayers (a) have not contributed capital to the distribution system, and (b) are not adversely affected by the transfer of the system. Both of these conditions are satisfied, as established by (i) PG&E's testimony in Chapter 6 regarding the lack of customer advances, (ii) PG&E's testimony in Chapters 8, 9, and this chapter regarding the business and physical severance damages that CCSF must pay (and their allocation) to ensure PG&E's remaining customers are left "neutral to the potential acquisition,"[11] and (iii) PG&E's testimony in Chapter 9 regarding the Restoration Plan that will ensure PG&E's remaining customers receive the same level of service from PG&E as prior to the potential system separation.

In sum, under *Redding II*, the Commission should allocate the entirety of the gain on sale from the distribution assets transferred in any eventual condemnation to PG&E's shareholders.[12] At the same time, the Subject Assets would be removed from PG&E's transmission and distribution rate base, thereby reducing the revenue requirement paid by remaining customers.

D. Just Compensation Component 2: Business Severance Damages

Chapter 8 identifies the "business severance damages" of CCSF's proposed taking as $7.61 billion.[13] The business severance damages presented in Chapter 8.1 are quantified primarily as the sum of revenues that would no longer be received from San Francisco customers over the period from the Petition

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[11] Interim Decision at 41 (Conclusions of Law ¶ 1).

[12] Pursuant to federal law, the gain on sale attributable to the transmission assets sold to CCSF via this transaction will be allocated via PG&E's FERC jurisdictional transmission cost recovery filing. *See* D.06-05-041 at 54–56.

[13] PG&E Testimony, Ch. 8 (Rubin), § A; *see also* PG&E Testimony, Ch. 8.1, § A.

Date through 2051 and deducts the costs that PG&E would avoid because of the taking. It also includes damages impacting investors (specifically Construction Work in Progress ("CWIP") and Accounts Receivable ("A/R")). A tax gross-up is applied to ensure the required neutrality. Finally, an amount is included to reflect the income taxes and operative reserve associated with the grantor trust proposed herein. These damages are intended to compensate for the financial burden that would otherwise occur if PG&E lost revenues from its San Francisco service territory and ensure that PG&E's remaining customers are left "neutral to the acquisition."[14]

The following sections discuss the allocation and ratemaking treatment necessary to ensure that the business severance damages award allocated to PG&E's customers outside of San Francisco actually provides the required neutrality.

1. Allocation Approach

The purpose of the business severance damages award differs from that of the fair market value award. While the FMV award is intended to compensate investors for their ownership interest in the Subject Assets and their investment risk, business severance damages are largely intended to ensure that costs arising from continuing utility obligations are not shifted to PG&E's remaining customers. With two exceptions, this portion of the award should therefore be allocated to PG&E's remaining customers, consistent with the Commission's neutrality requirement.

The two exceptions are CWIP and A/R, which should be allocated to investors. This is because these two items of damages would be borne by PG&E's investors were the taking to proceed. Accordingly, the portion of the award attributable to CWIP and A/R should not be placed within the trust mechanism described in Section D.2.c, but should be accorded the same treatment as the FMV component of the award.

2. Implementation Approach

In Chapter 8.1, PG&E identifies the revenue streams from charges and additional assets comprising the business severance damages. This

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[14] Interim Decision at 22.

section first presents PG&E's ratemaking proposal for returning the business severance damage award to customers. It then describes the appropriate amortization period over which to return the award. It finally describes the trust mechanism through which the award would be held and disbursed.

a. Ratemaking Components

Table 10-1 summarizes the charges and cost components constituting lost revenue streams or assets, the total business severance damages associated with those revenues or assets (net of avoided costs), the amortization period for returning the damages award to customers, and the ratemaking mechanisms and rate components PG&E proposes to use to return the business severance damages to customers for each revenue stream.[15, 16] Specifically, PG&E proposes to return to customers the business severance damage amounts through the same ratemaking mechanisms and rate components and over the same time period during which the costs would have been collected from San Francisco customers. This approach ensures the benefits to PG&E's remaining customers are distributed in a manner that offsets the increase in rates that would occur were the taking to proceed, thereby ensuring rate neutrality.

Tracking the return of these amounts to customers requires adding an accounting procedure to each of the ratemaking mechanisms specified in Table 10-1.[17] Specifically, PG&E proposes to add a

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15 Should a ratemaking mechanism change while amounts are still being refunded to customers, PG&E proposes to file a Tier 1 advice letter updating the ratemaking mechanism through which the amounts will continue to be refunded to customers.

16 Business severance damages detailed in Chapter 8.1 that are not associated with a ratemaking mechanism/balancing account are not included in the table. These include damages impacting shareholders (Construction Work in Progress and Accounts Receivable), damages PG&E proposes be the direct responsibility of CCSF (Wildfire Hardening Charge, Recovery Bond Charge/Credit) and items for which damage amounts have been deemed non-existent (Green Tariff Shared Renewables and Climate Credit).

17 The Wildfire Fund Charge is not tracked in a PG&E ratemaking mechanism/balancing account. In D.19-10-056, the CPUC established an annual process for the Department of Water Resources (DWR) to revise the Wildfire Fund Charge to ensure sufficient funding.

monthly credit entry equal to one-twelfth of the annual business severance damages for the applicable year. A credit entry allows funds received from CCSF to be returned to customers and reduces or offsets the costs billed to customers.

TABLE 10-1
RATEMAKING MECHANISMS AND RATE COMPONENTS FOR BUSINESS SEVERANCE DAMAGES IMPACTING CUSTOMERS[18]
(MILLIONS OF DOLLARS, AS OF JULY 27, 2021)

Line No.	Electric Revenue/Cost Component	Net Business Severance Damages	Amortization Period (Years)	Ratemaking Mechanisms and/or Rate Components to Return to Customers
1	Generation – Bundled	$121	30	Energy Resource Recovery Account (ERRA)
2	Distribution	$2,203	30	Distribution Revenue Adjustment Mechanism (DRAM)
3	Transmission	($548)	30	Transmission Access Charge Balancing Account and Transmission Revenue Balancing Account [(a)]
4	Public Purpose Program (PPP) – Non-CARE	$227	30	Public Purpose Program Revenue Adjustment Mechanism (PPPRAM)
5	PPP – CARE	$1,686	30	California Alternate Rates for Energy Account (CAREA)
6	Nuclear Decommissioning	$38	5	Nuclear Decommissioning Adjustment Mechanism (NDAM)
7	Competition Transition Charge	$0	5	Modified Transition Cost Balancing Account (MTCBA)
8	Energy Cost Recovery Amount	$5	4	Energy Recovery Bonds Balancing Account (ERBBA)
9	Wildfire Fund Charge	$273	14	Wildfire Fund Charge Rate Component
10	New System Generation Charge	$39	11	New System Generation Balancing Account (NSGBA)
11	Generation – PCIA	$1,061	30	Portfolio Allocation Balancing Account (PABA)
12	Non-Tariff Products and Services	$289	30	DRAM
13	Wildfire Mitigation and Catastrophic Event Accounts	$81	3	DRAM
14	Deferred Taxes	$166	17 (Dx), 35 (Tx)	DRAM [(a)]
15	Local Taxes and Fees	($942)	30	DRAM

(a) Any portion allocated to Electric Transmission costs will be addressed by the Federal Energy Regulatory Commission ("FERC"), which regulates these assets. PG&E will seek to return business severance damages to customers through its Transmission Owner rate filings with FERC.

18 *See also* PG&E Testimony, Ch. 8.1, Tbl. 8.1-4.

b. Amortization Approach

PG&E proposes to amortize the business severance damages award in a manner that aligns each component with the time period over which the corresponding revenue requirement or charge, net of avoided costs, would otherwise have been recovered from customers. For most charges, that period corresponds to the full 30-year forecast horizon used to quantify the business severance damages—July 27, 2021 through 2051—as those amounts represent lost revenues or costs that would otherwise continue over the forecast period. Returning those amounts to customers over the same period preserves the relationship between the damages calculation and the rate impact the award is intended to offset.

Certain charges, however, are subject to sunset provisions that expire before the forecast horizon ends. For those charges, the amortization period should reflect those shorter time frames. Because these sunset dates and remaining balances may change between the Petition Date and the condemnation date, any sunset-based amortization period will need to be revised through the update process to reflect the then-current period over which the charge would otherwise remain in effect.

c. Damage Award Disbursement

PG&E proposes to establish a trust (the "Business Severance Trust"), subject to approval of the Commission, to hold and distribute the business severance damage components of the just compensation award that are allocated to PG&E's remaining customers.[19] The Business Severance Trust would hold and invest the proceeds in US Treasury securities,[20] a low risk investment strategy designed to

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[19] As described in Chapter 8.1, § C.2.j–C.2.l, PG&E proposes that CCSF be directly responsible for their customers continuing responsibility for the Wildfire Hardening Charge, Recovery Bond Charge, and Recovery Bond Credit. If not approved, any amounts received by PG&E from CCSF go directly to the Special Purpose Entities and will not be included in the Business Severance Trust.

[20] The assumed US Treasury rates were as of or around the Petition Date (*e.g.* December 31, 2021).

preserve capital, protect the value of customer refunds and facilitate the appropriate return of benefits to customers. The funds would be disbursed over time consistent with the manner in which the business severance damages were determined.

The low-risk investment strategy would involve investing proceeds in US Treasury STRIPS, with each security selected to mature shortly before a corresponding year's projected damage payment becomes due. Because STRIPS make a single payment at maturity, the Business Severance Trust would not depend on reinvesting interim coupon payments or selling securities under future market conditions. This analysis assumes Treasury rates as of December 31, 2021 and produces an estimated rate of return of approximately 1.83% (pretax), representing a single annual earnings rate that equates the initial amount to fund the trust with the scheduled maturity proceeds. Since the creation of the Business Severance Trust would require the establishment of an operative reserve to fund trust expenses, and the interest associated with the aforementioned investment approach would be taxable, the July 27, 2021 value of these two elements of the trust operation—$0.47 billion—is included in the business severance damages amount to help ensure customer neutrality.

The trust agreement, governance provisions, investment policies, administrative requirements, and reporting obligations would be subject to approval in a later proceeding if CCSF proceeds with the taking. The trust assets, consisting of the after-tax lump sum payment from CCSF for business severance damages, would be invested in a manner intended to preserve principal and provide a high degree of certainty that the forecasted business severance damage amounts in each year can be returned to PG&E's remaining customers.

E. Just Compensation Component 3: Physical Severance Damages

Chapter 9 identifies the physical severance damages of CCSF's proposed taking of $1.003 billion.[21] As described in Chapter 9, the physical severance

[21] PG&E Testimony, Ch. 9 (Teran *et al.*), § A. This figure is comprised of approximately $722 million in separation and restoration costs and $281 million in the tax gross-up.

cost component reflects the scope and associated costs necessary to implement the physical separation of PG&E's and CCSF's systems, restore service to PG&E customers affected by the separation, and mitigate reliability and operational impacts so that the service quality to PG&E's remaining customers is not diminished. The required physical separation work includes the separation of the Subject Assets from PG&E's grid in San Francisco, pursuant to CCSF's Separation Plan as outlined in the testimony of Manho Yeung and Ryan Wu,[22] the remediation and restoration of PG&E's remaining system, pursuant to PG&E's Restoration Plan as outlined in the testimony of Stephen Teran, and the related construction of facilities necessary to operate two independent systems, pursuant to both plans[23] (collectively, the "Separation Work"). PG&E's costs to carry out the Separation Work—collectively, the "Physical Severance Costs"—are estimated in detail in Chapter 9. These Physical Severance Costs are PG&E's physical severance damages.[24]

Recovery of physical severance damages from CCSF is necessary to ensure that PG&E and its remaining customers are left neutral to this element of the taking. The award is to ensure that CCSF bears the costs of effectuating the taking and maintaining equivalent service, reliability, operational capability, and safety, rather than shifting the costs to PG&E customers or investors. The objective for physical severance costs is to ensure that the investments required to implement the taking do not create additional rate base or revenue requirement burdens for remaining customers. To fulfill this objective, my testimony addresses when and how CCSF should pay the Physical Severance Costs as part of its payment of just compensation.

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22 *See* Ex. CCSF-007C – Prepared Direct Testimony of Manho Yeung and Ryan Wu on Behalf of City and County of San Francisco, App'x II (Apr. 20, 2026) (Errata May 21, 2026) ("Yeung & Wu Testimony"). Appendix II of the Yeung & Wu Testimony is referred to herein as the "CCSF Separation Plan."

23 For example, both CCSF's Separation Plan and PG&E's Restoration Plan call for the construction of a new PG&E substation to serve PG&E customers in northern San Mateo County. *See* Yeung & Wu Testimony at 20; PG&E Testimony, Ch. 9, § D.2.

24 The Physical Severance Costs relate only to the costs that PG&E would incur in carrying out the physical separation of PG&E's and CCSF's systems and restoring PG&E's remaining system. CCSF will also incur costs to effectuate physical separation and ensure its readiness to operate as a public utility, which are not included here.

PG&E proposes a procedure for CCSF to pay for the Physical Severance Costs prior to CCSF's acquisition of the Subject Assets, because PG&E will need to complete the Separation Work prior to that date. That is, the Subject Assets and PG&E's remaining system will need to be prepared for physical separation as of the date that the Subject Assets are transferred to CCSF. This sequencing is necessary to ensure continuity of service to customers inside and outside of San Francisco, because the transfer of the Subject Assets to CCSF will result in the elimination of PG&E's obligation to serve San Francisco customers (subject to the Commission's approval).

This procedure will ensure that with respect to the Physical Severance Costs, PG&E is "in as good of a position pecuniarily as if the property had not been taken," as required by the Interim Decision.[25] This procedure will also ensure that the Physical Severance Costs paid by CCSF will be equal to the actual cost of the Separation Work, and that the net customer impact of the physical separation remains neutral. PG&E's proposal will also streamline and simplify the transition in utility system ownership by avoiding any need for PG&E and CCSF to enter into complex administrative agreements (for service, billing, and operations) to ensure the continuity of safe and reliable service during the period between asset acquisition and "Full Separation," as CCSF's Separation Plan would expressly require. Finally, it will also avoid the need for CCSF to post security or collateral for PG&E's ongoing Separation Work during the period prior to the asset acquisition, as would be required were PG&E ordered to commence Separation Work before CCSF pays the Physical Severance Costs in full.

1. Funding Procedure

PG&E's proposal for CCSF's funding of the Separation Work has three main components: (1) an up-front payment by CCSF to PG&E of the estimated Physical Severance Costs into a segregated interest-bearing bank account maintained by PG&E following a final determination of CCSF's

[25] Interim Decision at 40 (Findings of Fact ¶ 7).

right to take the Subject Assets (the "Taking"),[26] which PG&E would use to fund the Separation Work; (2) the tracking of Physical Severance Costs on an ongoing basis throughout the course of the Separation Work, including the tracking of incremental PG&E employee time spent on physical separation, with periodic reporting to CCSF; and (3) an ongoing update mechanism, whereby CCSF would be required to replenish the bank account in the event the Physical Severance Costs exceed the initial up-front payment, followed by the return of any account balance (including interest) to CCSF at the conclusion of the Separation Work, coincident with the asset acquisition and payment of just compensation, to ensure PG&E's actual Physical Severance Costs are reconciled with CCSF's up-front payment.

Up-front payment of Physical Severance Costs. In his testimony on physical severance costs, PG&E witness Matthew Thibodeau provides a detailed estimate of the Physical Severance Costs—i.e., the costs to separate the assets that CCSF plans to take from PG&E's grid, remediate and restore PG&E's grid following that separation, and construct the facilities necessary to operate two independent distribution systems—which are the costs PG&E will incur under both CCSF's Separation Plan and PG&E's Restoration Plan. These Physical Severance Costs total $722 million before tax gross-up ($1.003 billion including the tax gross-up).

Under PG&E's proposal, at the time of the Taking, CCSF would be obligated to pay this total estimate of Physical Severance Costs into a segregated interest-bearing bank account maintained by PG&E to fund the necessary Separation Work. Payment of the estimated Physical Severance Costs into PG&E's segregated bank account at the Taking would serve as the trigger for PG&E's obligation to begin the Separation Work. PG&E would then use the funds in the segregated bank account to pay Physical

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26 This determination would occur following the later of (1) a final determination in the state court eminent domain proceeding provided for in Pub. Util. Code § 1413 or (2) approval from the Commission under Pub. Util. Code § 851.

Severance Costs on an ongoing, as-incurred basis.[27] Requiring an up-front payment of the estimated Physical Severance Costs into a segregated interest-bearing bank account at the outset of the Separation Work is the most efficient funding procedure. It avoids the administrative burden of monthly invoicing and payment submission and also eliminates the need for CCSF to provide PG&E with security for the ongoing Separation Work.

Tracking of ongoing Physical Severance Costs. PG&E would record its ongoing Physical Severance Costs on an as-incurred basis in a tracking account dedicated to the Separation Work. PG&E would then report on these costs to CCSF on a periodic basis. PG&E would also track and record all incremental employee time spent on the Separation Work, and recover these costs from the Physical Severance Costs funds held in the segregated bank account.

Use of a tracking account will ensure that all Physical Severance Costs and incremental employee time devoted to the Separation Work are properly recorded, documented, and verified, and will facilitate any subsequent Commission reasonableness review. CCSF agrees that it is necessary to track ongoing Physical Severance Costs. In his testimony on the regulatory accounting treatment for the components of the just compensation award, CCSF witness Mark Fulmer states that "PG&E should be permitted to track actual [physical separation] costs in a memorandum account," in order to "ensure the Commission can confirm PG&E is neither over- nor under-

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27 CCSF's payment of the estimate of Physical Severance Costs into the segregated bank account at the Taking would also trigger its obligation to pay in full for all work needed to restore PG&E's San Francisco system in the event CCSF was to abandon its municipalization attempt after commencement of the Separation Work but before asset acquisition and payment of just compensation. A similar mechanism was used in the attempted municipalization in Boulder, Colorado, where the Cost Agreement entered by the parties to fund physical separation prior to the asset transfer provided that if Boulder decided not to continue with the municipalization after a "go" decision but before the asset transfer, it was required to pay "all costs to restore the Existing System to a single electric system that can provide service to customers both within and outside the Boulder city limits with the same safety, reliability and effectiveness (but not necessarily the same configuration) as it did prior to the ['go' decision]." Boulder–PSCo Agreement for Payment of Costs at 13 (Oct. 24, 2018), Ex. 4 to Joint Notice of Filing, Colo. PUC Proceeding No. 15A-0589E at 13 (filed Oct. 26, 2018).

compensated for the physical separation costs it incurs."[28] The parties therefore agree on ongoing tracking to facilitate full reimbursement of Physical Severance Costs.

True-up and return of any account balance. The final component of PG&E's funding proposal is a true-up mechanism, whereby CCSF would be required to replenish PG&E's segregated interest-bearing bank account maintained to pay Physical Severance Costs on a yearly basis in the event the Physical Severance Costs are projected to exceed the initial lump sum estimate paid into the account. The trigger for replenishment would be the submission by PG&E of an updated forecast of Physical Severance Costs (and related PG&E employee incremental time) establishing a shortfall between the account balance and the amount necessary to complete the Separation Work. At the time of the asset acquisition and payment of the just compensation award, any balance in the segregated account (inclusive of any interest) would be returned to CCSF. In this manner, the segregated Physical Severance Costs account would serve as the sole mechanism to account for the physical severance damages portion of the just compensation award at the time of the asset acquisition.

2. CCSF Pre-Funding Physical Separation Work is Appropriate

A procedure for CCSF to pre-fund PG&E's Physical Severance Costs is required by the fact that the Separation Work must occur *before* the asset acquisition. Under the Commission's decision in *Redding II*, as I understand it, the consequence of the sale of part or all of a utility operating system located within a geographically defined area to a municipality or other governmental entity is the utility being "relieved of, and the municipality or other governmental entity assum[ing], the service obligations to the

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28 Fulmer Testimony at 4. PG&E's proposal differs from CCSF's in that PG&E would use a basic tracking account to record Physical Severance Costs paid up-front by CCSF, while CCSF would use a memorandum account, which is a mechanism to record expenses not yet approved for rate recovery. PG&E would not be seeking recovery of the Physical Severance Costs in rates, as the entire purpose of the physical severance damages and the funding proposal put forth here is to maintain rate neutrality for PG&E customers—thus, a memorandum account is unnecessary.

customers served by the distribution system."[29] CCSF must therefore be ready and able to assume its service obligations to San Francisco customers when the assets are transferred—which it can only do once the Separation Work is completed and the systems are fully separated and capable of operating independently.

CCSF's Separation Plan contemplates transferring title to the Subject Assets *prior to* the initiation (or at least the completion) of the Separation Work: it references a "transition period between asset acquisition and Full Separation" of indefinite length while the Separation Work would be ongoing.[30] The result of this timeline would be an untenable jurisdictional circumstance where legal title to the assets would be vested in CCSF, but PG&E would retain operational responsibility for the utility system in San Francisco for some indefinite period due to the assets still being connected to PG&E's larger grid. Under *Redding II,* as I understand it, such a circumstance is fundamentally incompatible with the transfer of assets from PG&E to CCSF coinciding with the transfer of the legal obligation to serve the customers within the territory of the distribution system.

CCSF's Separation Plan attempts to skirt this problem by proposing that "the City and PG&E could enter into administrative service agreements" during the "transition period between asset acquisition and Full Separation," including "fringe area service agreements or alternative billing arrangements," as well as "coordinated operations agreements so that both the City and PG&E customers are reliably and safely served."[31] CCSF's Separation Plan provides no further details on these proposed service agreements. It is clear, however, that the complexity of any service

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29 *Redding II*, 1989 WL 1785731 (1989); *see, e.g.*, D.11-06-032 at 2 ("Upon final closing of the transfer and sale to Kirkwood Meadows Public Utility District pursuant to the Asset Purchase Agreement, Mountain Utilities is relieved of its obligation to provide public utility electric service to customers within its service territory.").

30 CCSF Separation Plan, Vol I at 10. The CCSF Separation Plan defines "Full Separation" as being achieved only after "each utility is able to serve its retail customers independently, with no distribution level interdependencies, and with the utilities' separated transmission systems operating independently but in coordination, consistent with common utility practices, and clearly defined roles and responsibilities." *Id.* at 2 n.7.

31 *Id.* at 10 & n.18.

agreements between PG&E and CCSF for post-acquisition operations would be significant, and that these agreements would raise a host of difficult issues about which entity is responsible for what—for example, maintenance, capital expenditures, outages, customer complaints, safety incidents, etc. I believe any such agreements would also raise complex jurisdictional questions as to the obligation to serve, and whether PG&E could be mandated to continue serving customers within San Francisco even after being stripped of its ownership of the utility assets by CCSF's condemnation action. Furthermore, without Commission action, a service agreement between parties cannot purport to assign the legal obligation to serve customers in a service territory—and CCSF has provided no authority for the Commission to depart from what I understand is the default rule under *Redding II* that the sale of a utility operating system within a defined region from an IOU to a municipality results in the municipality assuming, and the IOU being relieved of, the obligation to serve customers in that region.

Completing the Separation Work prior to the asset acquisition, as PG&E proposes, will avoid these operational and jurisdictional issues and ensure that CCSF is able to fully assume its obligation to serve at the time of the asset acquisition (which PG&E anticipates would occur in the event the Commission approves the transfer as being in the public interest under Public Utilities Code § 851), in keeping with *Redding II*. It will also avoid the considerable complications inherent in the service agreements that CCSF concedes would be necessary to ensure reliable and safe service during the interim period between "asset acquisition and Full Separation." The Commission should thus adopt a procedure whereby the Separation Work is completed prior to the asset acquisition, as being both legally sound and operationally efficient.

F. Rate Impact Analysis

This section explains how the proposed ratemaking treatment of just compensation, including physical and business severance damages, protects PG&E customers outside of San Francisco from adverse rate effects associated with the takeover of the Subject Assets and ensures rate neutrality.

Specifically, the business severance damages presented in Chapter 8.1 have been developed in order to mitigate the adverse financial impact on PG&E's customers resulting from the proposed taking.[32] The damages reflect the forecasted revenues that PG&E's customers in San Francisco would have contributed absent the taking ("lost revenues") plus San Francisco's share of certain recorded financial assets as of the Petition Date, minus any costs that PG&E would avoid were the taking to proceed. The lost revenues and avoided costs were developed for each of the revenue components ("charges") that customers pay in their bills. Included are generation, distribution, transmission, public purpose program charges and various other identified charges that comprise PG&E's total rates.

PG&E's business severance damages proposal described in Chapter 8.1 was determined with the express purpose of requiring CCSF to "fill the financial void" that would result from the loss of PG&E's assets and associated customer base in San Francisco. The damage award, along with the removal of the Subject Assets from PG&E's transmission and distribution rate base, will ensure that PG&E's customers outside of San Francisco would pay the same rates as if the taking did not occur. The proposal described in this chapter would place the damage award into a trust to ensure it is available for the express purpose of maintaining the required rate neutrality. To ensure rate neutrality, the damage award amounts from the trust will be returned to remaining customers to offset the higher rates customers would otherwise pay through the same rate components and over the same time frame that the damage amounts were determined.

The receipt of the proceeds associated with business severance damages does not, by itself, demonstrate rate neutrality. Although the damages are derived from forecast lost revenue requirements less avoided costs, the resulting lump sum proceeds can be translated into customer rate credits over an appropriate period and compared against the revenue requirement and sales effects resulting from the transaction.

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32 As described in Chapter 8.1, § A, approximately 95% of the business severance damage amount is allocated to PG&E's customers outside of San Francisco.

To illustrate the need for severance damages at the rate component level to ensure customers are made whole, PG&E's rate analysis compares the rate calculation for PG&E customers outside of San Francisco before a takeover with the corresponding changes after a takeover, with and without a severance payment. The "rate before" represents the amount of revenues non-San Francisco customers would provide relative to their consumption. After the takeover, while some costs are avoided from no longer needing to serve San Francisco, non-San Francisco customers will still have to pay for costs that shift to the remaining customer base, so the rate would only reflect the avoided costs deducted, not the entirety of costs San Francisco customers had been supporting. The severance payment, therefore, would offset this cost shift which would have otherwise been borne by the remaining customer base.

Similarly, regarding the costs necessary to separate the system and ensure that PG&E can continue to provide safe and reliable service to its customers outside of San Francisco, PG&E is proposing that CCSF fund the entirety of those costs such that its customers are not burdened with this requirement. Because CCSF's reimbursement offsets the corresponding expenditures, physical severance damages should also have a net zero effect on PG&E rate base, subject to the Commission-approved accounting treatment and confirmation that the reimbursement and associated plant costs are recorded consistently. Any temporary accounting balance created by differences in the timing of expenditures and reimbursement should be cleared when reimbursement is received and should not create a permanent rate base addition.

G. Difference between the Whole and the Remainder

1. Overview

This section addresses the Interim Decision testimony requirements under Sections 7.2(d) (bullet 3), 7.2(e), and 7.2(i) as they relate to calculating business severance damages. PG&E recommends that the Commission determine business severance damages by calculating the "present value of discounted cashflows for the part taken using actual

revenues and avoided costs,"[33] under Section 7.2(i). That calculation of business severance damages is set forth in Chapter 8 of PG&E's testimony. PG&E's approach is the same as that adopted by CCSF witness Mark Fulmer for business severance.[34] As shown below, in mathematical terms, that method of calculating business severance damages equals the difference between the remainder before and after the taking and fulfills the requirements of Sections 7.2(d) (bullet 3) and 7.2(e). Further, PG&E's approach treats as an avoided cost the capital-related revenue requirement for property to be taken, which is the same approach adopted by Mr. Fulmer,[35] and thereby avoids double counting between the part taken and business severance damages.

Section 7.2 of the Interim Decision sets forth requirements for PG&E's testimony:

> 7.2. PG&E Testimony
>
> PG&E is ordered to submit testimony subject to the following guidelines:
>
> a. Testimony must include an appraisal of the fair market value of the property to be condemned as of July 27, 2021 (the Petition Date).
>
> …
>
> d. The appraisal must be consistent with the calculation of severance damages to avoid double counting, and must utilize each of the following methods:
>
> …

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33 Interim Decision at 36 (Section 7.2(i)).

34 Fulmer Testimony at 3:13–18 ("I conclude that business severance damages and benefits, including ratepayer neutrality costs and benefits, should be calculated as the sum of the net present value (NPV) of any of PG&E's lost rate revenue resulting from the departure of the City's ratepayers *after* netting any costs PG&E's remaining ratepayers will avoid as a result of this departure.").

35 *Id.* at 12:9–14 ("These avoidable costs should be based on the assets being acquired by the City and the personnel and equipment who would have maintained those assets. With respect to the assets themselves, the non-San Francisco customers will no longer have to pay for: depreciation expenses on the acquired distribution assets, including meters; new capital expenses to upgrade or replace the acquired distribution assets; and the return on the existing rate base assets located in the City, including associated income taxes.").

> • Capitalized income approach, wherein projected future cash flows are discounted by the cost of capital to produce a discounted cash flow analysis; [second bullet]
>
> …
>
> • Income approach calculating the value of the whole property before the taking, the value of the remainder of the property before and after the taking, and the value of the part taken; [third bullet]
>
> …
>
> e. Appraisals as evidence supporting PG&E's claim for business severance damages. This includes an appraisal of the fair market value of PG&E's remaining system before the taking and after the taking.
>
> …
>
> i. A calculation of the present value of discounted cashflows for the part taken using actual revenues and avoided costs to show how the valuation accounts for the CCSF customer base's contribution to lowering PG&E system rates for remaining customers.[36]

In compliance with Sections 7.2(a) and 7.2(d) (bullet 2), PG&E has used a discounted cash flow analysis to value the property to be condemned under the income approach, which is set forth in Chapter 5, the testimony of Dr. John Williams of EPS. As discussed in more detail by EPS at § 12.2 of its report, the cashflows are based on the return on rate base of PG&E as authorized by the Commission and the Federal Energy Regulatory Commission ("FERC").[37] Under that methodology, also known as an investor owned utility ("IOU") methodology, the forecast of future cash flows (in the form of authorized return on rate base) is discounted to present value using the weighted average cost of capital of the hypothetical buyer.[38] Both EPS and CCSF witness Mr. Rabon incorporate this methodology to determine the revenue requirement for their income approach analyses of the part taken.[39]

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36 Interim Decision at 34–36.

37 PG&E Testimony, Ch. 5, Attach. A ("EPS Report"), § 12.2.0.9.

38 *Id*., § 12.3.

39 PG&E Testimony, Ch. 5, § E.3.

In compliance with Section 7.2(i), PG&E has calculated "the present value of discounted cash flows for the part taken using actual revenues and avoided costs,"[40] which is set forth in Chapter 8 of PG&E's testimony. As noted, this is the same approach adopted by Mr. Fulmer.[41] The avoided costs, as explained in Chapter 8, include the revenue requirement for the property to be taken (i.e. the authorized return, depreciation, and taxes for existing rate base as of the Petition Date) as well as the revenue requirement related to future capital expenditures avoided as a result of the taking. Mr. Fulmer also adopts this same approach, which treats capital-related revenue requirements as an avoided cost.[42] Chapter 8 uses the same revenue requirement for those avoided costs as used by EPS in Chapter 5 as part of the valuation of the part taken, as required under Section 7.2(d) of the Interim Decision.[43] In addition to the capital-related avoided costs, Chapter 8 also includes avoided operating and maintenance expenses, avoided taxes, and avoided costs related to public purpose or other charges.[44]

As shown below, the difference in the value of the remainder before the taking and after the taking (i.e. business severance damages as required under Sections 7.2(d) (bullet 3) and 7.2(e)), is the same as the present value of the actual cash flows from revenues lost from the customers served by the part taken less costs avoided by no longer serving the customers served by the part taken. In other words, in the case of a partial taking of property

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40 Interim Decision at 36 (Section 7.2(i)).

41 Fulmer Testimony at 3:13–18 ("I conclude that business severance damages and benefits, including ratepayer neutrality costs and benefits, should be calculated as the sum of the net present value (NPV) of any of PG&E's lost rate revenue resulting from the departure of the City's ratepayers *after* netting any costs PG&E's remaining ratepayers will avoid as a result of this departure.").

42 Fulmer Testimony at 12:9–14 ("These avoidable costs should be based on the assets being acquired by the City and the personnel and equipment who would have maintained those assets. With respect to the assets themselves, the non-San Francisco customers will no longer have to pay for: depreciation expenses on the acquired distribution assets, including meters; new capital expenses to upgrade or replace the acquired distribution assets; and the return on the existing rate base assets located in the City, including associated income taxes.").

43 PG&E Testimony, Ch. 8, § C.3.

44 *Id*.

from an IOU with cost of service ratemaking, the calculation that PG&E provides to fulfill Section 7.2(i) through the testimony in Chapter 8 also fulfills the purpose of the requirements for Sections 7.2(d) (bullet 3) and 7.2(e).

The only testimony required by Section 7.2(d) (bullet 3) that is not fulfilled by PG&E's other testimony is an income approach calculating the value of the whole property before the taking. That calculation is set forth below in Section G.2 of this testimony and is provided solely for that purpose and is not a comprehensive valuation of the whole PG&E system.

The remaining portions of this testimony show the calculation of the remainder before the taking and the remainder after the taking. Although not required under the Interim Decision, we also show the difference between the remainder before and after the taking, and the difference between the whole and the remainder after the taking to demonstrate that, mathematically, the difference between the remainder before and after the taking reduces to the same calculation of business severance that is calculated for Section 7.2(i) using actual revenue lost minus avoided costs. In addition, as shown below, the difference between the whole and the remainder after the taking reduces to the actual revenue lost minus avoided costs other than capital-related avoided costs for the property to be taken.[45]

2. Income Approach of the Whole

In response to the Interim Decision requirement, an income approach calculation of the whole of the PG&E system based on the IOU methodology, which is appropriate for this limited purpose of analyzing business severance, equals the systemwide rate base as of the Petition Date. This is because the rate of return that generates the free cash flows is

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[45] The calculation of the whole in this testimony is not intended as a comprehensive valuation of the whole but is provided to comply with the Interim Decision and in connection with business severance damages. As noted in PG&E's comments and recognized in the Interim Decision, California law requires that business severance damages be stated separately from the value of the part taken, which prevents use of a combined calculation of the part taken and business severance damages such as the difference between the whole and the remainder after the taking. Pub. Util. Code § 1411; Interim Decision at 42 (Conclusions of Law ¶ 8). As discussed below, using such a formula could artificially reduce either the part taken or business severance damages by offsetting one against the other.

assumed to be equal to the cost of capital by which those cash flows are discounted. The present value is the recovery of rate base over time.[46]

For example, the starting rate base of the part taken is $2.44 billion.[47] In the testimony of EPS in Chapter 5, that rate base generates a revenue requirement that is equal to the authorized rate of return, plus depreciation, plus taxes. Under perfect ratemaking, operating and maintenance expenses and taxes exactly offset (i.e. the revenue equals the expenses). The result is that revenue is recovered over time equal to rate base times the authorized rate of return adjusted for income taxes. If discounted at a rate equal to the authorized rate of return, the present value of the cash flows equals starting rate base.[48] The same principle applies to the cash flows generated by the rate base of the whole of PG&E. Under perfect ratemaking, the income approach value of the whole is equal to the rate base of the whole, which is [redacted].[49] We provide this value for the sole purpose of this testimony and solely in connection with analysis of business severance damages, and note that the value of the whole is much higher for fair market value purposes and using alternative methods of valuation.

3. Income Approach of the Remainder Before the Taking

The remainder of the PG&E property before the taking is equal to the income approach of the whole less the income approach of the part taken. As this approach for purposes of business severance analysis is focused on the income approach of the remaining property in the hands of PG&E as an

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46 As noted, this is not a comprehensive valuation of the whole as that would require other approaches such as cost or market, and the income approach may be based on a different methodology.

47 PG&E Testimony, Ch. 6 (Hegarty *et al.*), § C.4.e.

48 As shown in the testimony of EPS in Chapter 5, which uses an unregulated, tax-exempt buyer, the value of those revenues increases in the hands of a government owner because of a lower cost of capital (4.6%) than the authorized rate of return (7.34% Commission / 7.35% FERC) due to being less risky (which increases the value of the same cash flows) and the absence of taxes (which increases free cashflows). See PG&E Testimony, Ch. 5, § E; EPS Report, § 12.

49 *See* PG&E Workpapers (Rate Base & CapEx), Worksheet "Rate Base," Cell G67 (companywide PG&E rate base as of the Petition Date was [redacted]). Rate Base encompasses Electric Transmission and Distribution only.

IOU, it uses the IOU methodology, under which the remainder is equal to the rate base of the whole minus the rate base of the part taken.

Mathematically, under an IOU methodology:

Remainder Before = Whole – Part Taken.

This approach assumes that shared, common, or joint costs of the whole and the remainder are allocated pro rata based on rate base. Without this assumption, in order to determine the cashflows of the remainder, one would need to allocate shared costs between the part taken and the remaining property using some other basis, which requires arbitrary allocations.[50] This assumption is appropriate for business severance damages because under California law, the before and after rule is a measure of business severance damages, not the value of the part taken. The purpose of the before and after rule is to measure the change in the value of the remainder before and after the taking. Therefore, all that is needed is to measure the change—*i.e.*, the avoided costs, shared or otherwise, after the taking. Unlike allocating shared costs, which is inherently arbitrary, measuring the change in the amount of shared costs can be calculated.

4. Remainder After the Taking

The remainder after the taking equals the remainder before the taking minus the net present value of cash flows from the revenues from customers served by the part taken (SF Revenue) plus the net present value of costs avoided by no longer serving those customers (Avoided Costs).

Avoided Costs consist of the net costs that PG&E avoids if it does not own the assets being taken. As explained in the testimony in Chapter 8, these Avoided Costs consist of (a) the authorized rate of return on the part taken (*i.e.*, return on capital), (b) depreciation for the part taken (*i.e.*, return of capital) (together with (a), collectively, Avoided Costs Return on Rate Base), as well as (c) income taxes on the rate of return under (a), (d) the

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50 *See* PG&E Comments on Administrative Law Judge's Ruling Requesting Comments and Responses at 27–29 (Feb. 24, 2025).

avoided costs for future capital expenditures that will not be made because of the taking (consisting of the authorized rate of return, depreciation, and taxes), (e) operating and maintenance expenses avoided including property taxes, and (f) avoided costs (if any) for policy programs (*e.g.*, low-income subsidies) or other avoided costs (together with (c), (d), (e), and (f), collectively, Avoided Costs Other).[51] The cash flow for the Avoided Costs Return on Rate Base as well as for future capital expenditures under part (d) is the same cash flow as used in the income model prepared by EPS.[52]

Mathematically:

Remainder After = Remainder Before – (SF Revenue – Avoided Costs)

= [carrying the negative sign through the parenthesis]

Remainder After = Remainder Before – SF Revenue + Avoided Costs.

This demonstrates that calculating the difference in the value of the remainder before and after the taking is equal to modifying the cashflows and value of the remainder after the taking (as compared to before the taking) by the same cashflows used to calculate business severance damages, *i.e.*, the same cashflows used for the testimony required by Section 7.2(i).

The rationale for calculating the change in cashflows of the remainder after the taking by subtracting the SF Revenue and adding Avoided Costs is based on cost of service ratemaking principles, which apply to PG&E as an IOU in California that is regulated by the Commission (and FERC for transmission assets). Under those principles, PG&E is entitled to recover its costs plus an authorized rate of return (after taxes). As such, the loss of the part taken results in the loss of the SF Revenue. Under cost of service ratemaking principles, 100% of the lost revenue would be recovered from the remaining customers, *i.e.*, the cost of service would be shifted to the remaining customers and be included in the revenue requirement of the remaining customers. The only exception would be costs avoided as a result of the taking.[53] Thus, the cashflows of the remainder after the taking

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51 *See* PG&E Testimony, Ch. 8, § C.3; PG&E Testimony, Ch. 8.1, § E.

52 *See* PG&E Testimony, Ch. 8.1, § E.

53 As noted above, Mr. Fulmer agrees with this approach.

(*i.e.*, the revenue requirement for the remaining customers) will be impacted by the difference between the SF Revenue and the Avoided Costs. If SF Revenue is greater than Avoided Costs, then cashflows for the remainder after the taking will be lower (and would result in increased rates for remaining customers absent the award of business severance damages). Conversely, if SF Revenue is less than Avoided Costs, cashflows for the remainder will be higher (and remaining customers' rates would decrease).

By including as avoided costs both Avoided Costs Return on Rate Base (for the part to be taken) and Avoided Costs Other (including those associated with future capital expenditures for the part taken), the calculation of the remainder in the after condition avoids double counting the cashflows used by EPS in Chapter 5 to calculate the value of the part taken under the discounted cash flow analysis as required by Section 7.2(d) (bullet 2) of the Interim Decision.

5. Difference Between Remainder Before and After the Taking

Recall that the remainder after the taking equals the remainder before the taking minus SF Revenue plus Avoided Costs. When the remainder after the taking is subtracted from the remainder before the taking, the difference reduces to simply SF Revenue minus Avoided Costs. Mathematically:

Remainder Before – Remainder After
= [substituting for Remainder After]
Remainder Before – (Remainder Before – SF Revenue + Avoided Costs)
= [carrying the negative sign through the parenthesis]
Remainder Before – Remainder Before + SF Revenue – Avoided Costs
=
SF Revenue – Avoided Costs.

Thus, the testimony for Section 7.2(i) fulfills Sections 7.2(d) (bullet 3) and 7.2(e) related to the remainder before and after the taking.[54]

6. Difference Between Whole and Remainder After the Taking

The difference between the value of the whole and the value of the remainder after the taking is equal to the value of the part taken plus business severance damages (assuming that the same discount rate is applied to each component—the whole, the part taken, and the business severance damages). Thus, the result is the same as the difference between the remainder before and after the taking (SF Revenue minus Avoided Costs), plus the value of the part taken. Using an IOU approach for the part taken, as required for purposes of a before and after comparison involving the remainder, the part taken is equal to rate base and the separately stated business severance is simply SF Revenue minus Avoided Costs.

Mathematically:

Whole – Remainder After

=

Part Taken + Business Severance (assuming same discount rate for each component)

=

Part Taken + SF Revenue – Avoided Costs

Alternatively, the value of the part taken could be expressed in terms of cashflows, which for an IOU would be the same present value as the

[54] Note that because of cost of service ratemaking, if SF Revenue is greater than Avoided Costs, then the remainder after the taking is worth the same as the remainder before the taking, i.e. revenue is higher after the taking to cover increased costs of the remainder after the taking. This effect of cost of service ratemaking is one of the reasons why a before and after formula is not adequate to measure the cost shift to remaining customers for a partial taking of an IOU and the business severance calculated under Section 7.2(i) is more accurate and appropriate for this proceeding.

present value of the Avoided Costs Return on Rate Base.[55] Mathematically,

Whole – Remainder After

=

Part Taken + Business Severance (assuming same discount rate for each component)

= [substituting IOU cashflows for Part Taken] and [substituting SF Revenue – Avoided Costs for Business Severance]

Avoided Costs Return on Rate Base + SF Revenue – Avoided Costs

= [breaking Avoided Costs into two components]

Avoided Costs Return on Rate Base + SF Revenue – Avoided Costs Return on Rate Base – Avoided Costs Other

=

SF Revenue – Avoided Costs Other.

The above formula of SF Revenue – Avoided Costs Other also demonstrates a further reason that business severance should be calculated using the formula of SF Revenue minus Avoided Costs. In theory, the whole minus the remainder formula of SF Revenue – Avoided Costs Other could be further refined as SF Revenue related to the part taken + SF Revenue unrelated to the part taken – Avoided Costs Other. That would isolate the part taken from the other revenue and avoided costs. However, as part of a fully integrated electric transmission and distribution system, the revenue requirement paid by customers served by the Subject Assets is not correlated with the revenue or costs the Subject Assets produce as a standalone system. Rather, the revenue requirement paid by those customers is set systemwide. As the Interim Decision notes, those customers may be subsidizing the costs of other customers.[56] But

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55 When the capital-related revenue requirement for rate base (i.e. authorized rate of return plus depreciation) is discounted at the IOU cost of capital (which is equal to the authorized rate of return), those cashflows would equal rate base. If discounted at a GOU cost of capital (which is lower than the authorized rate of return), the present value of those cashflows would be greater than rate base.

56 Interim Decision at 23–26, 30–31.

determining what portion of SF Revenue is related to the return, depreciation, and taxes for the part taken, as opposed to other costs, is arbitrary. The better approach is simply to use SF Revenue – Avoided Costs Other to calculate Whole - Remainder After.

As noted already, the above equation only balances if consistent discount rates are applied to each component—the cashflows for the whole, for the part taken, and for business severance components. If consistent discount rates are applied, then the difference between SF Revenue and Avoided Costs Other would provide a single calculation of the part taken and business severance damages. However, if the discount rates vary, then the equation will not balance. For example, if the cash flows for the part taken are discounted at a GOU discount rate, then the part taken will be worth more and it would cause an artificial reduction in business severance damages. Conversely, if the business severance damages, *e.g.* costs shifted to remaining customers, are discounted based on the necessary return to provide a credit to customers over time to match the cost shifting over time, then those business severance damages would be larger and artificially reduce the value of the part taken.

Accordingly, the best approach is to calculate the value of the part taken separately from business severance damages where the business severance damages are measured as SF Revenue minus Avoided Costs.

H. Conclusion

In sum, PG&E's framework would ensure that each just compensation award component demonstrates neutrality for PG&E and its remaining customers. First, future revenue requirements associated with the rate base portion of the FMV of the Subject Assets would decrease after the taking. Second, business severance damages would be credited to customers through the applicable ratemaking mechanisms to offset future revenue requirement impacts identified in the business severance damages analysis. Third, physical severance damages would be used to fund the incremental investments needed to ensure continued safety and reliability of PG&E's system; as a result, those costs will not be borne by remaining customers. Each of the mechanisms described in this chapter will help ensure that remaining customers are held

harmless from the taking. Additionally, the testimony regarding the income approach value of the whole and the remainder in Section G demonstrates that PG&E's calculation of business severance damages using actual revenues and avoided costs is mathematically equivalent to the difference between the value of the remainder before and after the taking and avoids double counting between the value of the part taken and business severance damages.

Finally, for the reasons explained in Chapters 1, 2, 8.1, and 9,[57] the implementation approach presented in this chapter should be understood as demonstrating the regulatory accounting and ratemaking mechanics that would be used to ensure customers are held harmless as of the Petition Date. It will need to be updated as of the condemnation date, should the taking occur.

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57 PG&E Testimony, Ch. 1, § G; PG&E Testimony, Ch. 2, § A; PG&E Testimony, Ch. 8.1, § I; PG&E Testimony, Ch. 9, § D.1.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENT(S) OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF WHITNEY ALARY

Q 1 Please state your name and business address.

A 1 My name is Whitney Alary, and my business address is HKA, 333 South Grand Avenue, Suite 1400, Los Angeles, California.

Q 2 Briefly describe your responsibilities at HKA.

A 2 I am a Partner in HKA's Los Angeles office. HKA is a business, economic, financial, and damages consulting company that provides services to business entities, individuals, and counsel.

Q 3 Please summarize your educational and professional background.

A 3 I graduated summa cum laude from the University of California, Los Angeles, with a degree in Business Economics and a minor in Accounting. Previously, I was employed by TM Financial Forensics, LLC since its inception in January 2010 and held different positions, including Vice President. Prior to joining TM Financial Forensics, LLC, I worked for Navigant Consulting, Inc., an international consulting firm, in the Disputes and Investigations practice.

I have over 19 years of professional experience in the financial, economic, accounting, and damages concepts relevant to the scope of my work on this matter. Over the course of my professional career, I have consulted on numerous economic damages matters, including matters involving energy companies and other regulated industries and government contracts. I have studied economic damages in numerous business environments, including oil and gas, nuclear, finance and banking, insurance, telecommunications, transportation, tobacco, aerospace, defense, software, manufacturing and construction.

I have prepared and analyzed claims for lost revenue, avoided costs, lost profits, increased costs, loss of business value, and other financial and economic impacts. In that context, I have analyzed the financial performance and operations of many commercial entities and government contractors, including detailed studies of labor, material, equipment, overhead, general and administrative, and other types of costs, and profit and interest. I have also reviewed and evaluated cost estimates, bids and

proposals, change orders, contract pricing information, and incurred costs on government contracts.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 8.1, "Avoided Cost Study."

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF NED W. ALLIS

Q 1 Please state your name and business address.

A 1 My name is Ned W. Allis, and my business address is GTF Infrastructure, Inc. (GFT), 300 Sterling Parkway, Mechanicsburg, PA.

Q 2 Briefly describe your responsibilities.

A 2 I am Senior Vice President of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming), part of GFT. At GFT, my primary duties include conducting and overseeing a variety of services to clients in the electric, natural gas, water, and railroad industries. These services include depreciation studies, valuation studies, capital planning, and advising clients on industry trends and emerging issues in the utility industry. I have presented this work before state and federal regulatory agencies and have testified in more than twenty United States and Canadian regulatory jurisdictions. I am also responsible for developing and maintaining GFT's proprietary depreciation software, training depreciation staff, and developing solutions for technical issues related to depreciation. GFT has more than two decades of experience working with Pacific Gas and Electric Company (PG&E) on projects involving the estimation of depreciation, service lives, net salvage and the vintages of Company assets. As part of the depreciation studies filed with PG&E's General Rate Cases (GRC) and Transmission Owner rate cases, GFT has performed several service life studies of PG&E's transmission and distribution property, including analyses of asset vintages for particular portions of PG&E's service area and for particular time periods during its history. The first such study performed by GFT dates to PG&E's 2003 GRC, and the most recent was filed for PG&E's 2027 GRC. My involvement in these studies began with PG&E's 2011 GRC.

For purposes of this proceeding, I led the GFT team responsible for applying depreciation and percent good concepts to translate the replacement cost new number provided by Sargent & Lundy into a replacement cost new less depreciation figure for the Subject Assets at issue.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor of Science in Mathematics from Lafayette College in Easton, Pennsylvania and am a Certified Depreciation Professional.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 3, "Replacement Cost New Less Depreciation Valuation of Certain PG&E Electric Utility Assets in San Francisco";
- Chapter 3.2, "Physical Depreciation of RCN for Electric System in San Francisco";
- Chapter 3.2, Attachment A, "RCNLD, Asset Vintage and Service Life Study"; and
- Chapter 6, "Subject Asset's Net Book Value, Rate Base, and Forecast Of Capital Expenditures":
  - Sections A, B, C.1, C.2, C.3, D.2, and E.

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SHAY BAHRAMIRAD

Q 1 Please state your name and business address.

A 1 My name is Shay Bahramirad, and my business address is Pacific Gas and Electric Company (PG&E),300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Vice President (VP), Electric Engineering, Asset Management, and Risk and Compliance at PG&E. I oversee engineering, planning, and asset management to support the safe and reliable operation of PG&E's transmission and distribution systems.

The teams reporting to me develop engineering standards and design criteria and perform capacity planning. They manage asset health through risk-informed investment prioritization. They also oversee protection, automation, and grid modernization. I am also responsible for PG&E's electric risk management function. My teams also perform governance and compliance work. I lead work on grid technology to improve system performance, strengthen resilience, and reduce wildfire risk.

I oversee substation testing and commissioning and am responsible for substation and other compliance with North American Electric Reliability Corporation requirements. I also oversee real-time engineering support for transmission operations. My organization includes technical services and laboratories that support equipment testing, failure investigations, and investment decisions.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Ph.D. in Electrical Engineering from the Illinois Institute of Technology. I hold a Bachelor of Science in Electrical Engineering from Azad University. I have also pursued continuing education, including programs in finance and leadership at Northwestern University's Kellogg School of Management.

My work in the energy sector dates to 1999. My experience includes engineering, system planning, asset investment, construction, operations, maintenance, and emergency restoration. I have also led work on

regulatory compliance, cost recovery, technical standards, and the integration of new grid technologies. I joined PG&E in July 2024.

From October 2021 to July 2024, I served as Senior VP of Transmission and Distribution, Strategy and Sustainability at LUMA Energy in Puerto Rico. I led teams responsible for planning, building, operating, and maintaining the electric grid. My responsibilities included generation, transmission, and distribution planning; engineering standards; investment programs; and reliability improvement. The system included approximately 16,000 miles of transmission and distribution lines and 430 substations.

At LUMA, I was responsible for project initiation, execution, compliance, and cost recovery for more than $16 billion in federal public assistance. I worked with federal and Commonwealth agencies on funding and investment approvals. I also served as system incident commander during a hurricane and the subsequent system black start.

Before joining LUMA, I served as VP of Climate and Resilience Operation at Quanta Technology from February to October 2021. I helped lead the transition to LUMA through work on system remediation, operating principles, and investment strategy. I also developed asset investment, microgrid, and mini-grid strategies for Puerto Rico.

I worked at ComEd from 2013 to 2021, most recently as VP of Engineering and Smart Grid. My responsibilities included engineering design, reliability programs, regulatory reporting, substation design, maintenance inspection programs, standards, and disaster recovery planning. This work supported a system serving more than four million customers, including the City of Chicago. I directed the planning and execution of more than $1 billion in annual distribution system investments. I also served as system incident commander during emergencies and led the development and implementation of a microgrid cluster.

I have provided expert testimony in federal and state proceedings on energy policy, cost recovery, industry standards, distributed energy resources, energy storage, and microgrids. I have also testified in Commonwealth and United States (U.S.) congressional hearings.

I serve on the board of the North American Transmission Forum and on the executive board of CIGRE US. My professional leadership also includes

service as President of the Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society and as an adjunct professor of electrical and computer engineering at the Illinois Institute of Technology.

I have served as principal investigator for U.S. Department of Energy grants involving grid sensors, integrated solar and battery storage, and microgrid controls. I contributed to more than 20 Department of Energy grants between 2016 and 2021.

I have authored or co-authored technical papers and articles on a broad range of topics related to electric power systems and the utility industry. My work has appeared in academic and industry publications, including IEEE publications and transmission and distribution World. My professional recognition includes the Public Utilities Fortnightly Top Innovator award and the IEEE Power & Energy Society Outstanding Young Engineer Award.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 2, “Overview of PG&E Electric System in San Francisco.”

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes. My testimony draws on PG&E’s business records and other information and analyses of the kind I rely on in carrying out my responsibilities. The factual statements are true and correct to the best of my knowledge and information. The opinions and conclusions reflect my best professional judgment based on that information.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF WALTER D. CARNEY

Q 1 Please state your name and business address.

A 1 My name is Walter D. Carney, and my business address Valbridge Property Advisors, 1530 The Alameda, Suite 100, San Jose, California.

Q 2 Briefly describe your responsibilities.

A 2 I have provided valuation services in a wide variety of complex civil litigation including real estate, land-use cases, eminent domain, inverse condemnation, estate matters, property taxation, contract disputes, partnership and corporate disputes, environmental lawsuits, professional negligence cases, construction defects, bankruptcy/creditors matters, failure to maintain, and fraud.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor in Economics degree and an additional Bachelor degree in International Relations from the University of Southern California. Since 2013, I have been Senior Managing Director at Valbridge Property Advisors. Prior to that, I was the Executive Vice President of Hulberg & Associates Inc., which is also the legal entity of Valbridge Property Advisors, Northern California. I have been a real estate appraiser for 45 years. I hold the MAI designation with the Appraisal Institute and the Certified General License with the State of California.

Q 4 What is the purpose of your testimony?

A 4 I am providing testimony in PG&E's Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 4, "Real Property Appraisal"; and
- Chapter 4, Attachment A, "Retrospective Appraisal Report, PG&E Electric Grid Corridor – Real Property."

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF AIMEE CRAWFORD

Q 1 Please state your name and business address.

A 1 My name is Aimee Crawford, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Senior Director for Land Management. The Land Management team is accountable for managing and interpreting land rights, as well as land acquisition and surplus disposition of company lands.

Q 3 Please summarize your educational and professional background.

A 3 I have been a real estate and land management professional for over twenty years. I have a wide range of experience in land transactions, valuation, and securing and interpreting land rights. I have a Bachelor of Arts degree from the University of California (UC) Davis and a Juris Doctor degree from UC College of the Law, San Francisco.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 2, “Overview of PG&E’s Electric System in San Francisco”:
  - Section E.

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DEWEY DAY

Q 1 Please state your name and business address.

A 1 My name is Dewey Day, and my business address is Pacific Gas and Electric Company (PG&E), 1385 East Shaw Avenue, Fresno, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I direct a team that prepares project and program requests for California Public Utilities Commission (CPUC) approval in our General Rate Case (GRC) for telecommunications upgrades within our public and private communication system. The platforms included in our telecommunications upgrades include comm buildings, comm towers, primary and backup power systems, fiber cables and multiplexers, microwave communications systems, routers and switches, audio/video systems, and mission critical radio communications.

Q 3 Please summarize your educational and professional background.

A 3 I have a Bachelor degree from California State University Fresno in electrical engineering along with numerous continuing education certifications from equipment manufacturers on the technologies listed previously. I began my career at PG&E in 1994 as a telecommunications engineer designing and deploying devices for PG&E's network in the southern area, Stockton to Bakersfield, generally. In 1999, I then progressed into a system engineer role designing large telecom projects statewide and leading regional engineers in their detailed designs and implementations. In 2008, I was promoted to a transport architect role that focused on the design of our Fiber optic, microwave, and wireless networks. In this role, I have prepared business cases for the CPUC in PG&E's GRC and for PG&E leadership, justifying budgets and the need for upgrades. In 2023, I became Director of the architect team that is responsible for preparing these testimonies and justifications for the communications network as previously described.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 9, “Physical Severance Damages”:
  - Sections D.6 and E.3.

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MIKE DELANEY

Q 1 Please state your name and business address.

A 1 My name is Mike Delaney, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am Vice President of Strategy and Innovation at PG&E. I lead the company's enterprise strategy and innovation functions, with responsibility for long-term strategy, strategic planning and prioritization, innovation, load flexibility, and decarbonization strategy. My organization develops strategies and new approaches to improve customer affordability, reliability, clean energy outcomes, and PG&E's long-term business performance. I joined PG&E in August 2023 as Vice President of Utility Partnerships and Innovation. In that role, I led an organization spanning innovation and partnerships, vehicle and building electrification, energy efficiency, load flexibility, and new growth initiatives. From the time I joined PG&E until the company's reorganization in June 2026, my organization also included PG&E's New Revenue Development department, which is responsible for non-tariffed products and services, and business development.

Q 3 Please summarize your educational and professional background.

A 3 Before joining PG&E, I spent approximately 17 years at Consumers Energy and DTE Energy in Michigan in roles spanning corporate strategy, regulatory affairs, utility pricing, public policy, venture capital, and business development.

I joined Consumers Energy in 2016, first serving as Director of Research and Analysis and later as Executive Director of Corporate Strategy. In those roles, I worked on enterprise strategy and the development of new utility offerings, including Consumers Energy's electric vehicle program. I subsequently served as Executive Director of Regulatory Affairs and Policy and, from 2020 until joining PG&E in 2023, as Executive Director of Policy, Cost and Pricing. In those positions, I led work involving state regulatory policy, the utility business model, and gas and electric utility rates. While at Consumers Energy, I provided testimony before the Michigan Public Service

Commission, including in Case No. U-20134 concerning Consumers Energy's proposed electric vehicle program.

Prior to Consumers Energy, I spent approximately 10 years at DTE Energy in positions involving strategy and mergers and acquisitions, venture capital, public policy, strategic initiatives, and policy strategy and advocacy.

I received a Bachelor of Science in Engineering Physics and a Master of Public Policy from the University of Michigan and a Master of Science in Nuclear Engineering from the Massachusetts Institute of Technology.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 8.3, "Non-Tariffed Products and Services."

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF RICHARD GERGER

Q 1 Please state your name and business address.

A 1 My name is Richard Gerger, and my business address is Cornell/Gerger Consulting, 6400 La Punta Drive, Los Angeles, California 90068.

Q 2 Briefly describe your responsibilities.

A 2 In this matter, I have assisted Mr. John Williams in preparing the model for the income approach.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts in Business Economics from the University of California, Los Angeles in 1988 and a Master of Business Administration from the University of Texas, Austin in 1990. I have over 30 years of experience consulting with counsel and clients on the financial, valuation, and bankruptcy aspects of business disputes and litigation. My experience includes, among other areas, valuation, and financial damage. I have worked extensively with the state tax authorities in Colorado, Idaho, Ohio, Oregon, and Texas related to the valuation of utility property for ad valorem taxes.

Q 4 What is the purpose of your testimony?

A 4 I am co-sponsoring the following testimony in PG&E's Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 5, "Appraisal of the Subject Assets," with respect to the income-approach model.

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KERRY HEGARTY

Q 1 Please state your name and business address.

A 1 My name is Kerry Hegarty, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Senior Manager of the Capital Recovery and Analysis team in the Capital Accounting department. My team is responsible for the development of: (1) depreciation rates; (2) forecasts of plant, accumulated depreciation, Construction Work In Progress (CWIP), and related corporate items such as depreciation expense and Allowance for Funds Used During Construction (AFUDC); (3) capital related cost of service estimates for ratemaking proceedings and separately funded projects. We also monitor and provide analysis on various capital related items such as recorded rate base, capital additions, depreciation expense, CWIP and AFUDC.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Psychology from the University of California, Berkeley in 2001. I began my career at PG&E in 2015 in the Capital Recovery and Analysis team and have been with the team for the last 11 years. Prior to joining PG&E, I was Lead Data Analyst for the State Bar of California and Director of Business Operations for Paymap, a subsidiary of Western Union Payment Services.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 6, “Subject Asset’s Net Book Value, Rate Base, and Forecast of Capital Expenditures”:
  - Section C.

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SHAUN HOPPES

Q 1 Please state your name and business address.

A 1 My name is Shaun Hoppes, and my business address is Pacific Gas and Electric Company (PG&E), 885 Embarcadero, West Sacramento, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Director of Billing and Revenue Operations for PG&E and have served in this role since December 2023. In this capacity, I oversee PG&E's customer billing and revenue operations, including the issuance of accurate and timely customer bills, the processing and reconciliation of customer payments, billing controls and compliance activities and process improvement initiatives.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Business Management from the University of Phoenix in 2009. I joined PG&E in 2000 and have more than 25 years of experience in customer service, billing, and revenue operations. Between 2000 and 2010, I held various roles within Contact Center Operations, including customer service representative, project manager, and a field service liaison. Since 2010, I have held positions of increasing responsibility within Billing and Revenue Operations, supporting program and project management, regulatory compliance, quality assurance, process improvement, and training and communication. In my current role, I am responsible for developing and implementing billing and revenue strategies designed to support accurate billing, effective revenue management, operational efficiency, regulatory compliance, and a positive customer experience.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 8.1, "Business Severance Damages":
  - Portion of Section H.

1 Q 5 Do you certify under penalty of perjury that the testimony is true and
2 correct?
3 A 5 Yes.
4 Q 6 Does this conclude your statement of qualifications?
5 A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARCUS KELLER

Q 1 Please state your name and business address.

A 1 My name is Marcus Keller, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Director of Portfolio Forecasting and Cost Recovery within the Energy Policy and Procurement organization. In this position I lead a team responsible for preparing, validating, and analyzing energy procurement supply and cost forecasts utilized internally for PG&E's procurement planning purposes, as well as in regulatory proceedings before the California Public Utilities Commission (CPUC) and the California Energy Commission, including the Energy Resource Recovery Account Forecast and Integrated Resource Plan proceedings at the CPUC.

Q 3 Please summarize your educational and professional background.

A 3 I graduated from the University of California, San Diego in 2005 with Bachelor of Science degrees in Environmental Systems and Management Science. I graduated with a Master of Science degree in Environmental Management in 2011 from the University of San Francisco.

In 2011, I joined PG&E as an Analyst on the Competitive Solicitations team before moving to the Contract Management Department in 2013 and ultimately to the Bundled Portfolio Planning and Analysis Department in 2015. While the name of that department was recently updated to Portfolio Forecasting and Cost Recovery, since 2015, my work has included various energy procurement forecasts and related analysis to support PG&E in regulatory proceedings and other business processes. My role at PG&E was initially as an individual contributor before taking on leadership roles of increasing complexity.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 8.1, “Business Severance Damages”:
  - Sections C.2., subsection i and m; D.6, D.9, D.11, and E.1.

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF CARLA PETERMAN

Q 1 Please state your name and business address.

A 1 My name is Carla Peterman, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the President of the PG&E Corporation and the Executive Vice President of Customer & Corporate Affairs. I oversee PG&E's regulatory, legislative, customer experience, and charitable strategies.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree from Howard University, a Master of Science in Environmental Change and Management from Oxford University, a Master of Business Administration degree from Oxford University, where I was a Rhodes Scholar, and a Doctor of Philosophy degree in Energy and Resources from the University of California, Berkeley. I served on the California Energy Commission beginning in 2011, where I was the lead Commissioner for renewables, transportation, and natural gas. In 2013, I was appointed to a 6-year term as a Commissioner of the California Public Utilities Commission, where I was the assigned Commissioner to a number of proceedings including energy efficiency, alternative transportation, and energy storage, among others. In 2019, Governor Newsom appointed me to chair the Commission on Catastrophic Wildfire Cost and Recovery. I joined Southern California Edison in 2019 as the Senior Vice President of Strategy and Regulatory Affairs. I joined PG&E in my present role in 2021. I also currently serve as a member of the Federal Reserve of San Francisco Economic Advisory Council.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 1, "Policy and Summary."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SIENNA ROGERS

Q 1 Please state your name and business address.

A 1 My name is Sienna Rogers, and my business address is Pacific Gas and Electric Company (PG&E) 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am Senior Director of Financial Planning and Analysis for PG&E Corporation. In this role, I am responsible enterprise financial planning, regulatory finance, economic analysis, and strategic financial modeling. Our team is particularly focused on enhancing PG&E's financial resilience and improving customer affordability. I oversee our enterprise financial forecasting of key financial metrics and the evaluation and implementation of financial transactions which can improve PG&E's balance sheet. My team also performs financial analyses concerning strategic and financial questions facing PG&E, and provides economic analysis support to Functional Areas when evaluating large capital projects.

Q 3 Please summarize your educational and professional background.

A 3 I joined PG&E in 2006 through its Leadership Development Program and have held a number of roles across strategy, policy, energy procurement, and finance functions. I have led the formation of several strategy teams focused on the changing energy landscape, including the evolution of the energy supply portfolio and the changing role of distributed energy resources in the energy value chain. Some of those roles include Director of Corporate Strategy, Director of Grid Integration and Innovation Strategy, and Manager of Renewable and Clean Energy Strategy. My finance focused roles at PG&E included Director of Restructuring Strategy, Manager of Enterprise Forecasting and Analysis, and Manager of Investor Relations. Prior to PG&E, I worked in the financial sector—first for Schroder & Co. and then JPMorgan Chase—supporting origination and structuring of corporate transactions, analyzing investment and credit risk of companies in a wide range of industries. I have a Bachelor's degree in Economics and Computer Science from Duke University, and a Master's degree of Business Administration from Dartmouth's Tuck School of Business.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 10, "Allocation of Just Compensation."

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARCELO ROMANO

Q 1 Please state your name and business address.

A 1 My name is Marcelo Romano, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Director of Corporate Real Estate Strategy & Services, in the Workplace Portfolio Strategy group.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor of Science degree in Mechanical Engineering from Hofstra University. I have approximately 20 years of corporate real estate industry experience, working for and consulting Fortune 500 companies on their corporate real estate portfolios. My background and experience span several industries, including the utility, industrial, and high-tech industries.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 2, “Overview of PG&E Electric System in San Francisco”:
  - Section E; and
- Chapter 9, “Physical Severance Damages”:
  - Section E.2.

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DAVID E. RUBIN

Q 1 Please state your name and business address.

A 1 My name is David E. Rubin, and my business address is 2401 Jackson Street, San Francisco, California.

Q 2 Briefly describe your responsibilities.

A 2 I am currently a consultant to Pacific Gas and Electric Company (PG&E).

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Civil Engineering from the University of Maryland in 1978, and a Master of Science degree in engineering/technology and policy from the Massachusetts Institute of Technology in 1984. I worked for the City of San Francisco from 1982-1985, and joined PG&E in 1985, where I held a variety of positions in the Marketing and Rates Departments. I left PG&E in 1992 to join the International Energy Agency and returned to PG&E in 1995 as a director in the Rates Department. From 1995 to 2018, I was the Director of the Service Analysis Department. From 2018 to 2020, I was the Director of Strategy Formulation. I am a registered mechanical engineer in the state of California. I have testified before the California Public Utilities Commission on a variety of matters, including special contract reasonableness, Competitive Transition Charge ratemaking, cost separation, economic development rates, community choice aggregation, distributed generation and PG&E's green tariff.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Property proceeding:

- Chapter 7, "Hypothetical Buyers";
- Chapter 8, "Business Severance Damages Overview"; and
- Chapter 8.1, "Business Severance Damages":
  - Portions of Sections A, B, C, D, E, F, H, I, and J.

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JADWINDAR SINGH

Q 1 Please state your name and business address.

A 1 My name is Jadwindar Singh, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Senior Director of the Electric Asset Knowledge Management Team under Electric Engineering and am accountable for the following programs: Geographic Information System Asset Data Management and Data Management & Analytics.

Q 3 Please summarize your educational and professional background.

A 3 I have a Bachelor of Science degree in Electric Engineering and am a licensed Professional Engineer in Electrical Engineering. I have 23 years' experience in Public and Private Utility operations. I have served as the Electric Asset Knowledge Management Senior Director since its formation in September 2019. Prior to serving in my current role, I led the company's internal investigations into the October Fires and Camp Fire, was Director of the Electric Compliance & Risk team, and served in other capacities within the Electric compliance, risk, and distribution maintenance organizations at PG&E. Previous experience before my time at PG&E includes serving as an Engineer within the California Public Utilities Commission's Consumer Protection and Safety Division.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Property proceeding:

- Chapter 2, "Overview of PG&E's Electric System in San Francisco":
  - Section D.13.

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF STEPHEN TERAN

Q 1 Please state your name and business address.

A 1 My name is Stephen Teran, and my business address 4020 Westchase Boulevard, Suite #200, Raleigh, North Carolina.

Q 2 Briefly describe your responsibilities.

A 2 As Senior Director of Integrated Systems Planning at Quanta Technology, LLC d/b/a Danovo Energy Solutions, I am responsible for managing the Coordinated Studies and Optimization practice area. I support clients and projects that span transmission planning, distribution planning, engineering, and asset management with a focus on regulatory support.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Electrical Engineering from the University of California, Irvine, and my Master of Business Administration degree from California State University, Long Beach.

I have worked in the utility industry for over 20 years, primarily for Southern California Edison Company (SCE) and Danovo Energy Solutions. In my time at SCE, I worked in many roles including distribution engineering, system planning, advanced modeling and research, asset management, and risk analysis. I was involved with multiple rate cases and risk-related filings.

At Danovo Energy Solutions, I have led multiple practices in asset management, distribution planning, and integrated systems planning. My project work has involved support for regulatory filings related to reliability, storm response, eminent domain, and interconnections.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 9, "Physical Severance Damages"; and
- Chapter 9, Attachment A, "Danovo Energy Solutions Report & PG&E Distribution Restoration Plan Details."

1 Q 5 Do you certify under penalty of perjury that the testimony is true and
2 correct?
3 A 5 Yes.
4 Q 6 Does this conclude your statement of qualifications?
5 A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MATTHEW R. THIBODEAU

Q 1 Please state your name and business address.

A 1 My name is Matthew R. Thibodeau, and my business address is Valbridge Property Advisors, 77 West Wacker Drive, Chicago, Illinois.

Q 2 Briefly describe your responsibilities.

A 2 I am a Senior Vice President and Senior Project Director with Sargent & Lundy. My primary duties include serving as the director of consulting engagements and providing subject matter expertise on matters in the energy and utilities sectors. As the director of consulting engagements, I provide executive support to project teams working under my direction and guidance. The practice areas I lead for Sargent & Lundy include utility planning, cost and performance studies, power supply planning, power procurement, electric grid infrastructure planning, generation resource planning, power plant project development and financing, renewable energy integration, and battery energy storage projects.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Science in Mechanical Engineering degree from Worcester Polytechnic Institute in Worcester, Massachusetts in 1994. I earned a Master of Business Administration from the University of Michigan in Ann Arbor, Michigan in 2003. I am a licensed Professional Engineer in Indiana, Illinois, Michigan, and Puerto Rico.

I have worked on, managed, directed, and overseen numerous technical advisory and consulting studies, independent engineering, and owner's engineering engagements for energy infrastructure and projects, including transmission and distribution (T&D) systems, power generation facilities, and energy storage systems throughout the United States (U.S.), including in California. I have managed and directed cost studies and cost estimates for energy infrastructure, including T&D systems, power generation facilities, and energy storage systems. This has included cost studies and cost estimates for utilities, electric system operators, government agencies, lenders, investors, and research organizations. While most of this work is confidential, one publicly available cost study that I led in 2019 was for the

U.S. Energy Information Administration, which is a statistical and analytical agency within the U.S. Department of Energy (DOE) that collects, analyzes, and disseminates independent and impartial energy information. In addition, for each of the past four years, I have been invited by the DOE's National Renewable Energy Laboratory (NREL) to be a member of the Technical Review Committee for NREL's Annual Technology Baseline, which is an online dataset of technology cost and performance information for various types of energy infrastructure.

I have previously provided testimony before regulatory commissions, including the Indiana Utility Regulatory Commission (IURC) and the Puerto Rico Energy Bureau. I provided testimony to the IURC on several different occasions. I provided testimony to the IURC on behalf of Northern Indiana Public Service Company to support the regulatory filing of a seven-year T&D investment plan in September 2021. I also provided testimony to the IURC on behalf of Indianapolis Power & Light Company on two occasions, one time to describe Sargent & Lundy's role in a 2019 all-source request for proposals process and another time to support regulatory approval of a new solar project. In 2020, I provided testimony to the Puerto Rico Energy Bureau on behalf of the Puerto Rico Electric Power Authority on energy procurement matters. I have also provided testimony at the Indiana State House; in 2019, I provided testimony to the Indiana 21st Century Energy Task Force on the future of baseload power.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Selected portions of Chapter 3, "Replacement Cost New Less Depreciation Valuation of Certain PG&E Electric Utility Assets in San Francisco",
- Chapter 3.1, "Replacement Cost New Analysis of Certain PG&E Electric Utility Assets in San Francisco"; and
- Selected portions of Chapter 9, "Physical Severance Damages":
  - Section E.1.

Q 5 Do you certify that the information provided in this Statement of Qualifications is true and accurate to the best of your knowledge as of the date of this Statement of Qualifications?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MICHAEL F. WALDRON

Q 1 Please state your name and business address.

A 1 My name is Michael F. Waldron, and my business address is Waldron & Associates, Inc., 205 South Orange Street, Orange, California 92866.

Q 2 Briefly describe your responsibilities.

A 2 I am the President and Principal Appraiser of Waldron & Associates, Inc. I am responsible for all real property appraisal and consulting assignments conducted by Waldron & Associates, Inc. I am also responsible for all corporate and business operations of the company.

Q 3 Please summarize your educational and professional background.

A 3 In 1981, I received a Bachelor's Degree in Business Administration with a concentration in Finance and an emphasis in Securities and Investments from California State University at Fullerton. Mr. Waldron has been admitted to the Appraisal Institute as an MAI Member. I am licensed by the State of California as a Certified General Real Estate Appraiser. I have completed all continuing education requirements for both the Appraisal Institute and the State of California. I have been providing real property appraisal and consulting services for over 44 years.

As a field appraiser and real property consultant, I have practiced throughout the Western United States, primarily within California. Appraisals and consulting assignments cover properties located in the states of Arizona, California, Hawaii, Minnesota, Nevada, Oregon, and Washington.

Appraisal and consulting assignments cover all types of real property interests for varying purposes for both private and public clientele. Assignments personally completed include appraisals and consultations for all types of real property, including, but not limited to, improved commercial, industrial, residential, mixed-use, and special use properties, as well as vacant land in each of these use categories. Appraisals and consulting cover all property interests including fee simple, leased fee, leasehold, fractional interests, and easement interests. Appraisals have been completed for public projects, including acquisitions for redevelopment,

schools, utilities, transportation, and other right-of-way assignments with consideration due partial and full takings. In addition to real property appraisal, he provides real estate consulting for pre-litigation preparation on behalf of public and private clientele.

Most of my assignments involve complex litigation issues where I have provided expert testimony in the U.S. District Court, the Superior Courts of Contra Costa, Kern, Los Angeles, Monterey, Orange, Riverside, San Bernardino, San Diego, San Francisco, San Luis Obispo, Santa Barbara, Stanislaus, and Ventura counties, as well as the U.S. Bankruptcy Court and various arbitration and mediation panels as expert and arbitrator. In the past, I have been mutually retained by opposing parties as the neutral appraiser to determine compensation for all parties. My application of valuation methodologies and valuation opinions have been tried, held, and affirmed in Superior Courts, Appellate Courts, and the California Supreme Court.

With a focus on eminent domain assignments, I have provided expert testimony in hundreds of depositions and approximately 100 jury trials. In addition to authoring various real property articles, I have been an invited speaker and instructor at various real property seminars, including the Real Property Law Section of The State Bar of California, the International Right-of-Way Association, Appraisal Institute, and other private and public organizations.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 4, “Real Property Appraisal”; and
- Chapter 4, Attachment A, “Retrospective Appraisal Report, PG&E Electric Grid Corridor – Real Property.”

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF TIM B. WEDLAKE

Q 1 Please state your name and business address.

A 1 My name is Tim B. Wedlake, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Tax Analyst in the Research, Audits and Planning Team in the Tax Department at Pacific Gas and Electric Company. I primarily manage PG&E's fixed asset tax depreciation and deferred tax system (PowerTax) and its related work products. I am currently on a rotation with the Law Department; Tax continues as my home department.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Finance from California State University, Hayward in 1980, and received a Master's in Finance degree from the same institution in 1982. In 1992, I received a Juris Doctor degree from Hastings College of the Law, University of California, in San Francisco. I am licensed to practice law in California. From 1983 to 1989, I was employed by Pacific Bell in the Budget Department and Tax Department in a management capacity. I have designed and implemented various budget and tax computer models. Prior to my employment with PG&E, I worked as a consultant for the PG&E Tax Department on a variety of fixed asset tax issues.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Petition of the City and County of San Francisco for a Valuation of Certain PG&E Property proceeding:

- Chapter 6, "Subject Assets Net Book Value, Rate Base, and Forecast of Capital Expenditures":
  - Sections B and C;
- Chapter 8.1, "Business Severance Damages":
  - Sections A, B, C, D, E, F, H, I, and J; and
- Chapter 9, "Physical Severance Damages":
  - Sections C.3 and G.

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JOHN A. WILLIAMS

Q 1 Please state your name and business address.

A 1 My name is John A. Williams, and my business address is EPS Inc., 17455 Douglas Road, South Bend, Indiana 46635.

Q 2 Briefly describe your responsibilities.

A 2 I am the General Manager of EPS, Inc., an engineering and valuation firm I founded in 1995. I conduct engineering and valuation analyses and lead a team of highly skilled professionals in the energy industry.

Q 3 Please summarize your educational and professional background.

A 3 I am an Accredited Senior Appraiser with the American Society of Appraisers in Machinery and Technical Specialties. I have over 40 years of experience in the energy and industrial sectors and have appraised numerous pieces of equipment, systems, and major energy facilities, including electric transmission and distribution systems. My valuation expertise includes developing and reconciling the cost, income, and sales comparison approaches and analyzing physical depreciation, functional obsolescence, economic obsolescence, and intangible assets for energy facilities. Since 1996, I have developed and taught courses in cost estimating, project evaluation, and valuation analysis for the American Institute of Chemical Engineers and the American Society of Mechanical Engineers. These courses cover the fundamentals of the cost and income approaches to valuing energy and industrial property.

I am a licensed Professional Engineer in California and 25 other states. I hold a Ph.D. and a Master of Science degree in Chemical and Fuels Engineering from the University of Utah, a Master of Business Administration in Finance from the University of Chicago, and a Bachelor of Science degree in Chemistry from the University of Delaware. My appraisal training includes the American Society of Appraisers' required machinery and equipment valuation course series, coursework in intangible asset valuation, and instruction in the Uniform Standards of Professional Appraisal Practice.

Q 4 What is the purpose of your testimony?

A 4 My testimony presents my opinion of the fair market value of the Subject Assets as of July 27, 2021, in continued use as an assembled operating system. It explains my appraisal analysis and reconciliation of the cost, income, and sales comparison approaches and addresses the valuation analyses submitted on behalf of the City and County of San Francisco (CCSF).

I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 5, "Appraisal of the Subject Assets"; and
- Chapter 5, Attachment A, "Appraisal Report."

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF BRYON WINGET

Q 1 Please state your name and business address.

A 1 My name is Bryon Winget, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Vice President (VP) of Integrated Planning. In this role, I am responsible for the investment planning of PG&E's gas, electric, Power Generation systems and supporting activities.

Q 3 Please summarize your educational and professional background.

A 3 I have a Bachelor and Master of Science in Material Science Engineering degree, with over 18 years of experience in the utility industry. Prior to my role as VP of Integrated Planning, I was VP of Electric System Planning, the Senior Director of Electric Investment Planning and Maintenance Delivery, the Director of Gas Investment Planning, the Director of the Transmission Integrity Management Program, as well as the Gas Transmission Asset Family Owner. I have a Professional Engineering license in Mechanical Engineering in the state of California. I am a National Association of Corrosion Engineers Cathodic Protection Specialist. I am a Certified Manager of Quality/Organizational Excellence by the American Society of Quality, as well as a Certified Project Management Professional.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Petition of the City and County of San Francisco for a Valuation of Certain PG&E Electric Assets proceeding:

- Chapter 6, "Subject Asset's Net Book Value, Rate Base, and Forecast of Capital Expenditures":
  - Section D.

Q 5 Do you certify under penalty of perjury that the testimony is true and correct?

A 5 Yes.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.