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ALJ:	R. Lirag
Witnesses:	Nelson Bacalao

PREPARED DIRECT TESTIMONY

OF

NELSON BACALAO

ON BEHALF OF

THE CITY AND COUNTY OF SAN FRANCISCO

[PUBLIC VERSION]

APRIL 20, 2026

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Attachment P.2: "Capacitor_Banks_Inv.xlsx,"

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Attachment P.28: "Records List_Inv.xlsx"

Attachment P.29: "Primary_OH_Conductor_Inv"

Attachment Q: PGE000073872.xlsx

Attachment R: January 17, 2026 email from John Major

Attachment S: October 10, 2025 email from John Major

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Attachment C: PG&E 2025 Per Unit Cost Guide

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Attachment K: PGE000111791-CONF.xlsx.

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Workpapers – Unit Cost Master, San Francisco Substation RCN April 2026, and San Francisco Transmission & Distribution Inventory
Folder "Transmission_Substations_RCN_APR-2026"

Attachment O.1: "Unit_Cost_Master.xlsx,"

Attachment O.2: "SF_Substations_RCN_APR-2026.xlsx,"

Attachment O.3: "Substation_Inventory_Check-RCN.xlsx."

Workpapers – Total System
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Workpapers – Lines RCN April 2026 and Lines Unit Costs April 2026
Folder "Transmission_Lines_RCN_APR-2026"

Attachment Q.1: "Lines_RCN_APR-2026.xlsx,"

Attachment Q.2: "Lines-Unit_Costs_APR-2026-V2.3.xlsx."

APPENDIX IV **Proposed Stipulation Exhibits A–I**

APPENDIX V **Resume/CV**

I. INTRODUCTION AND SUMMARY

This testimony provides a description of the inventory that the City and County of San Francisco (the City or San Francisco) intends to acquire and a Replacement Cost New (RCN) value for the inventory. The inventory includes all the Pacific Gas & Electric Company (PG&E) electric transmission and distribution system assets located in the City and certain assets in San Mateo County that are used to provide electric service to the City.

The testimony has four purposes: 1) to provide an inventory of the electric assets the City seeks to acquire, 2) to provide a RCN of those electrical assets, 3) to provide the age of those assets, and 4) to provide a high-level opinion on the condition of a sampling of those assets. The testimony is based on a three-volume report produced for this proceeding: "San Francisco Grid Procurement Engineering Services – Asset Valuation (Advisian-Siemens April 20, 2026), Volume I: Executive Summary, Volume II: Distribution Inventory and RCN, and Volume III: Transmission Inventory and RCN (attached as Appendices I, II, and III) (Report). This Report is based on the assets, data, calculations, and assumptions contained in a set of workpapers (*see* Workpapers in Attachments O and P to Volume II, Workpapers in Attachments O, P, and Q to Volume III, and Criteria and Assumptions in Attachment A to Volume II). This testimony entirely supersedes and replaces my prior testimony that was served on April 10, 2023.

The testimony explains how the Report determined an RCN value of approximately $10.925 billion (2022$) for the PG&E system that the City seeks to acquire consisting of approximately $7.976 billion for the distribution system and $2.949 billion for the transmission system.

The transmission system includes over [redacted] miles of underground transmission lines and seven transmission to distribution substations. The distribution system has approximately [redacted] miles of underground and [redacted] miles of overhead medium voltage (MV) distribution lines, [redacted] MV substations, over [redacted] distribution transformers, over [redacted] miles of low voltage lines and services and more than [redacted] pieces of individual equipment including switches, reclosers and capacitors among others.

II. EXPERIENCE AND QUALIFICATIONS

Q. Please state your name, business affiliation, and title.

A. My name is Nelson Bacalao. My business address is 1401 Enclave Parkway Houston, TX 77077, USA.

Q. By whom are you employed and in what capacity?

A. I am a Principal Consultant at Siemens Power Technologies International ("Siemens PTI"), a division of Siemens Industry Inc.

Q. Please summarize your education and your experience relevant to your testimony.

A. I hold a Ph. D. in Electrical Engineering from the University of British Columbia, Vancouver, BC, Canada, earned in 1987. I hold a Master's Degree in Electrical Engineering from Rensselaer Polytechnic Institute in Troy, NY, earned in 1980. I hold a Degree in Electrical Engineering from Universidad Simon Bolivar in Caracas, Venezuela, earned in 1979.

My professional experience covers technical and strategic consulting services to utilities, governments, regulators, independent project developers, and the financial community, in domestic as well as international assignments. My work has centered on power system planning and in particular transmission and distribution planning. I have conducted multiple transmission planning studies and integrated distribution planning studies.

Of particular relevance to my testimony is my experience in proceedings similar to this one. In 2004–2005, the Sacramento Municipal Utility District conducted a feasibility assessment regarding the annexation of the cities of West Sacramento, Woodland, and Davis in Yolo County. As part of that assessment, I managed and actively participated in the development of an inventory of the transmission and distribution assets proposed to be acquired, and estimated the cost of those assets.

In a separate but highly relevant matter, I serve as manager and lead contributor for the South San Joaquin Irrigation District's Retail Electric Project. This project has important parallels to the present proceeding. Beginning as a feasibility assessment in 2004, it has progressed over the years and continues to this day. Using information provided by PG&E, including a geospatial database and supporting files, my Team and I developed a detailed transmission and distribution system inventory and estimated the corresponding RCN. In addition, I developed the transmission and distribution separation plan and its associated capital costs, as well as short-, medium-, and long-term capital and operating and maintenance expenditure forecasts for South San Joaquin Irrigation District following acquisition of the assets.

I also participated in the City of San Diego Public Power Feasibility Study. For that project, I managed and actively participated in the preparation of the transmission and distribution system inventory using information provided by San Diego Gas & Electric, the estimation of Replacement Cost New (RCN), formulation of the separation plan and associated costs, and the development of long-term capital and operating and maintenance forecasts for the City of San Diego.

My education and experience are also discussed in my resume, a copy of which is attached as Appendix V.

Q. Have you appeared before the California Public Utilities Commission (CPUC) or other public utility commissions?

A. Yes. I participated and made presentations to the CPUC on the 1997-1999 PG&E Capital Expenditure Audit; a study conducted in 2002 by my previous employer Stone & Webster Inc. I presented testimony before the Puerto Rico Energy Bureau on the First Integrated Resource Plan for the Puerto Rico Electric Power Authority in 2015 and the 2018 Puerto Rico Electric Power Authority Integrated Resource Plan, Case Nos. CEPR-AP-2015-0002 and CEPR-AP-2018-0001, on behalf of the Puerto Rico Electric Power Authority. I also testified before the Indiana Utility Regulatory Commission, IURC Case No. 45564, on behalf of CenterPoint Energy to support CenterPoint Indiana South's 2019/2020 Integrated Resource Plan.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of the City and County of San Francisco.

Q. What is your role in this proceeding?

A. I am lead investigator on the Consulting Team hired by the City, led by Advisian with Siemens PTI as a subcontractor, to produce an inventory and RCN of the electrical assets that the City intends to acquire. I am the principal author of the report in Appendices I, II, and III. I have served as a consultant to the City working on an engineering assessment of municipalization since 2019.

Q. Are you sponsoring any Appendices to your testimony?

A. Yes. I am sponsoring the appendices to my testimony, as described below:

- Appendix I: San Francisco Grid Procurement Engineering Services – Asset Valuation (Advisian-Siemens April 20, 2026), Volume I: Executive Summary;
- Appendix II: San Francisco Grid Procurement Engineering Services – Asset Valuation (Advisian-Siemens April 20, 2026), Volume II, Distribution Inventory and RCN;
- Appendix III: San Francisco Grid Procurement Engineering Services – Asset Valuation (Advisian-Siemens April 20, 2026), Volume III: Transmission Inventory and RCN; and
- Appendix IV: Proposed Stipulation Exhibits A–I
- Appendix V: Resume/CV

III. INVENTORY OF ELECTRICAL ASSETS

Q. Please generally describe the components of the inventory of electrical and utility assets that you prepared.

A. The total inventory of assets that the City seeks to acquire includes all of PG&E electrical assets plus other lands, property, and rights that are necessary to provide reliable electric delivery service to San Francisco. The inventory I produced focuses on PG&E's electric transmission and distribution system assets located in the City, and certain assets at, and emanating from, the Martin Substation in San Mateo County, which are necessary to provide electric delivery service to the City. The inventory and RCN also include the documents and records, and spare parts, that are used to operate and maintain the electrical system in the City. The acquisition also includes real property interests, including land where the electrical assets in the inventory are located, that are included in the testimony of other experts.

Q. Which part of the inventory does your testimony address?

A. The electric transmission and distribution assets, related utility equipment, documents and records, and spare parts necessary to own, operate, and maintain the system.

Q. Please provide a general description of the transmission and distribution electrical assets that the City seeks to acquire.

A. The transmission system is the high-voltage system used to deliver power from the bulk electric system outside the City to the distribution system inside the City via high-voltage underground cables and transmission-to-distribution substations.[1]

From the transmission-to-distribution substations, the distribution system delivers this power to the end users using a variety of MV circuits (also called feeders) and MV distribution-to-distribution substations serving multiple customers (general-use), plus two customer dedicated substations. The medium voltage circuits have transformers that step down the voltage for delivery to end users via the low-voltage (secondary) system.

These systems use equipment typical of utility distribution systems, including, but not limited to, wires, poles, cables, conduits, transformers, switches, services, and meters. The downtown area of San Francisco near Market Street is served, in part, by a secondary low-voltage networked system.

The assets also include distribution lines, and their associated equipment, from the Martin Substation, where these distribution circuits (feeders) start, to the San Mateo County border where they go on to supply end users in San Francisco.

Q. Please explain what a bulk electric system is.

A. A bulk electric system refers to the facilities and systems that deliver large amounts of electricity from power plants—both renewable (like solar, wind or hydroelectric) and conventional (such as natural gas or nuclear)—to major transmission substations and then to the distribution system. These sources operate together to deliver electricity to customers. Essentially, the bulk electric system is the backbone of the electric grid, moving electricity over long distances at high voltages before it is distributed locally to homes and businesses.

Q. What is the bulk electric system that PG&E uses to deliver electricity to San Francisco?

A. The bulk electric power is delivered by two sources, the Martin substation in Daly City south of the City's border and the Transbay Cable (TBC) system.

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[1] Note the system includes very short segments of overhead transmission lines totaling less than half a mile.

From Martin, power is delivered into San Francisco via two 230 kV lines connecting directly to Embarcadero Substation and six 115 kV lines connecting directly to Hunters Point, Bayshore, Potrero and Larkin Substations. Mission Substation, another major downtown substation, is interconnected at 115 kV with Larkin, Hunters Point, and Potrero Substations. Embarcadero has a 230 kV submarine connection to Potrero, where the TBC connects to PG&E's transmission system.

Q. Does the inventory that the City seeks to acquire include the Martin substation?

A. Yes, the City is seeking to acquire all electric system assets located at Martin Substation. Martin Substation plays a critical role in supplying customers within the City through both transmission and distribution facilities, and the majority of the equipment located there is used to deliver electricity to the City.

Q. What is the Transbay Cable System?

A. The Transbay Cable (or TBC) is a third party-owned high voltage direct current (HVDC) submarine cable. It supplies power to the City by linking PG&E's 230 kV substation in Pittsburg (Contra Costa County) to PG&E's Potrero substation in the City. The TBC is interconnected with the transmission system in the City at Potrero Substation.

The Transbay Cable is owned by Trans Bay Cable, LLC and is not in the inventory because PG&E does not own it.

Q. What is a transmission to distribution substation?

A. In general terms, this is a substation supplied from the high voltage transmission system that contains transformers which step power down to the MV levels used by distribution circuits extending from the substation to serve customers. A transmission to distribution substation functions much like a major interchange in a highway network. At these substations, high voltage transmission lines— analogous to highways— meet, interconnect, and branch in different directions. At the same location, the electricity's voltage is reduced ("stepped down") so that it can flow through the local distribution system to reach homes and businesses, much like vehicles leaving the highway system through off-ramps to reach local streets.

Q. What transmission to distribution substation does PG&E use to serve the City?

A. Seven transmission-to-distribution substations deliver power to the City's distribution system, and ultimately its customers. Six are located in the City: Potrero, Hunters Point, Bayshore (which is dedicated to the Bay Area Rapid Transit District (BART)), Larkin, Mission, and Embarcadero, and one is located outside the City in San Mateo County (Martin).

Q. What are the assets in those substations?

A. The seven transmission-to-distribution substations have 230 and 115 kV high voltage breakers arranged in switchyards that interconnect the incoming and outgoing transmission lines. These substations also include transformers that step voltage down to the MV distribution levels and supply. At Martin and Potrero Substations there is specialized equipment connected to the 115 kV level to regulate the voltage.

Q. What is a MV distribution substation?

A. A MV distribution substation, sometimes referred to as an MV-to-MV substation, serves as a key point in the electric grid where power is transferred from the MV distribution system to the local distribution system. These substations are supplied from the 12 kV distribution system and may include transformers that reduce the voltage to 4.16 kV. Some of the MV distribution substations in the City receive electricity from the transmission-to-distribution substations through high capacity express circuits, that PG&E calls tie-lines. Distribution circuits from the MV substations extend out to supply power to customers.

Q. What MV distribution substations does PG&E use to serve the City?

A. There are [redacted] MV substations in the City, and there are also two customer dedicated substations: Bank of America and Moscone Center.

Q. Please explain what a secondary network is.

A. Distribution systems can be designed with increasing levels of reliability depending on local requirements. In a secondary network system (or low-voltage network), the load is served by multiple radial primary circuits supplying a common networked secondary load. If a fault occurs, the affected component is automatically isolated while other sources continue to supply power. The loss or disconnection of a single circuit does not result in an interruption of service to the connected load, thereby providing a materially higher level of reliability.

In the more common configuration using a radial system, the load is served by a single circuit. If a fault occurs, such as a line fault or equipment failure, service is temporarily interrupted for the isolation of the affected section (fault isolation) and customer reconnection. This interruption typically lasts from a few seconds to several minutes, depending on the location and nature of the fault. Network systems are one alternative used in dense urban areas—like downtown San Francisco or New York. Most loads in San Francisco are supplied by a radial system.

Q. Are distribution assets in San Mateo County included in the inventory of electrical assets?

A. Yes, the inventory includes overhead and underground distribution circuits that originate at the Martin Substation and serve loads within the City. The assets associated with these circuits—including poles, underground conduits, vaults, and other related equipment—are part of the inventory. We refer to these as the Martin Triangle assets because PG&E uses that designation (they are located within an area shaped like a triangle).

Q. Did you prepare the inventory for the electrical assets necessary to operate and maintain PG&E's electrical system?

A. Yes, I prepared the electrical inventory, with assistance from my colleagues, who worked under my direction and supervision. These colleagues also worked on preparing the electrical asset RCN, the inventory and assisted with the formulation of assumptions (assumptions are addressed in Attachment A to Appendix II). Where appropriate, I refer to this as work conducted by "my Team" or the "Consulting Team."

Q. What sources did you rely on to compile the inventory of electrical assets?

A. The electric inventory is based on PG&E's responses to data requests, including three Geodatabases; one for distribution assets, one for transmission assets, and one for the Martin triangle.[2] PG&E also provided Excel spreadsheets that list inventories for Secondary Meters,[3] Streetlights,[4] Spare Parts, [5] Fiber Optic Cables,[6] Direct Current (DC)

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2 Volume II, Attachment C.

3 Volume II, Attachment E (PGE000066831.xlsx).

4 Volume II, Attachment F (PGE000000732-B.xlsx).

5 Volume II, Attachment Q (PGE000073872.xlsx).

6 Volume II, Attachment P.5, "Fiber_Optic_Inv", tabs Fiber Network Analysis and EDGIS Data.

system,[7] and Substations.[8] I also analyzed single line drawings (SLDs) that PG&E provided for substations,[9] and made visual inspections of substations and cables to complete the inventory. In addition, the inventory reflects the information provided by PG&E during and after workshops with Commission Staff, and the feedback received from PG&E on asset descriptions and counts contained in earlier versions of these Exhibits in subsequent discussions, and exchange of documents.[10] These modifications are reflected in the Proposed Stipulation Exhibits (Attachments A-I in Appendix IV) and my workpapers.

Q: What are the Geodatabases?

A: The Geodatabases provided by PG&E contain extensive layers of data regarding PG&E’s assets and geographic information system coordinates giving the location of those assets. Using specialized software, we processed the Geodatabase to visualize its layers (feature classes) by asset type (for example, overhead conductors, underground conductors, conduits, transformers, switches, and subsurface structures). Each layer includes the asset’s location and descriptive fields such as voltage, equipment ratings, configuration (overhead/underground), and the installation date, if available. The Consulting Team used the geodatabases to compile and confirm much of the electric asset inventory.

Q. Describe the process for extracting data from the distribution Geodatabases.

A. The specialized software that the Consulting Team used is ArcMap from Esri. We used ArcMap to export to Excel each layer component. A layer represents a single component or asset type of the distribution system, such as “Primary Overhead Conductors.” My Team used this procedure to extract the information for the distribution asset inventory

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[7] ~~Volume~~ Appendix II, Attachment O.6~~-~~, “DC-Assets_APR-2026.xlsx” and ~~Volume~~ Appendix II, Attachment G PGE-PropertyValuationPetition-CCSF_DR_CCSF_030-Q001 to 004, PGE000112649-CONF, PGE000112665-CONF and PGE000112489-CONF.

[8] Appendix II, Attachment H (PGE000073870).

[9] Appendix III, Attachment B.

[10] For example, the information on services (customers’ connection) in the Geodatabase is incomplete, and to address this gap PG&E provided additional information on services’ count and conductor by type (overhead and underground) in Workshop II on 7/22/2025~~-2025~~ (*See* “PG&E-Cover Page” tab and all of the subsequent tabs in workpaper Secondary_OH_Conductor_Inv (Appendix II, Attachment P.16)).

into Excel workpapers. My Team developed twenty-one asset types from the distribution Geodatabase, as follows:

1) Primary Overhead Conductors;
2) Support Structures;
3) Primary Underground Conductors;
4) Conduit Systems;
5) Distribution Transformers;
6) Secondary Overhead Conductors;
7) Secondary Overhead Services;
8) Secondary Underground Conductors;
9) Secondary Underground Services;
10) Capacitor Banks;
11) Voltage Regulators;
12) Switches;
13) Fuses;
14) Primary Risers;
15) Secondary Risers;
16) Network Protectors;
17) Primary Meters
18) Smart Meter Network Devices;
19) Padmount Structures;
20) Subsurface Structures; and
21) Reclosers and Interrupters.

In many cases, the asset data PG&E provided includes equipment owned by a customer, rather than PG&E, or that was "proposed to install" but not yet in use. We filtered these out and did not include them in the inventory. By agreement with PG&E, we filtered out Geodatabase or Excel spreadsheet entries where Customer-Owned states "Yes," Status states "Proposed," and for Vaults where "P" is used for privately-owned, but we included entries labeled "Idle" in the inventory. Additionally, for Support Structures where the material is "Tree" it was not included. In a few cases, PG&E clarified that certain "Customer Owned" labeled units in the inventory are actually owned by PG&E, and the City agreed to include them. Each workpaper identifies the filters applied to the data for that asset type.[11]

Q. What type of information did your Team extract from the Distribution Geodatabases?

A. For each asset type, the Team extracted the parameters necessary to support valuation of the assets. The principal differentiating characteristics include the following:

- Installation type (overhead, pad-mounted, or underground): This characteristic reflects how the equipment is installed, whether on a pole, on a concrete pad, or below grade.
- Voltage level: System voltages range from 2.4 kV to 34.5 kV. For valuation purposes, equipment is grouped into voltage classes consisting of 5 kV class (2.4–4.16 kV), 15 kV class (6.9–12.47 kV), and 35 kV class (34.5 kV).
- Rating: The applicable electrical rating of the asset, expressed as kVA, MVA, amperes, or watts, depending on equipment type.
- Number of phases: Assets are classified as single-phase, two-phase, or three-phase, while also accounting for combinations of single-phase units arranged in banks to serve three-phase load. One example is a bank consisting of two 25 kVA single-phase units and one 15 kVA single-phase unit configured to supply a three-phase load. Most of the City's system is either three-phase or two-phase.
- Physical dimensions: Where applicable, the analysis incorporates dimensions such as pole height and class, or vault width, length, and depth.
- Installation date: Where available from the geospatial database, installation date is used to determine asset age and vintage characteristics.

Q. Does the Martin Triangle Geodatabase have the same asset types as the distribution Geodatabase?

A. It does. However, the City will acquire only those assets that comprise the MV distribution circuits serving load within the City, and not any assets that serve customers in San Mateo County. As a result, the inventory of relevant equipment is more limited than in the broader distribution geodatabase. My Team prepared a dedicated Martin

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[11] In each workpaper there is a link within the "inventory" tab that navigates to a pivot table where the filters are listed.

Triangle workpaper that includes a separate inventory tab for each asset type included in the Martin Triangle inventory.

Q. Describe the process for extracting data from the transmission Geodatabase.

A. My Team used the same process for the transmission lines -- extracting data from the transmission Geodatabase to classify the assets by their differentiating characteristics, and preparing an Excel workpaper containing the resulting breakdowns.[12] The transmission Geodatabase includes information on all 230 kV and 115 kV underground transmission lines (cables), including the route alignment, conductor length, cable insulation type (pipe-type or solid dielectric), the location of vaults (sometimes called manholes in the Geodatabase), and the location of oil pumping stations where needed for electrical cable insulation and cooling.

The Geodatabase does not include the conductor size, conductor material (copper or aluminum), conduit system dimensions, vault dimensions, or location and characteristics of special crossings where the underground cables pass under obstacles like highways. PG&E provided most of this information in data request responses, workshops, or information exchanges.

To complement the information provided, my Team developed engineering estimates for the number of ducts and duct-bank dimensions, as well as the length and construction complexity of special crossings.

Q. Are there any other asset types in the inventory that are not in the Geodatabases?

A. Yes. PG&E provided information on secondary meters, streetlights, fiber optic cables, a legacy DC network, spare parts and the assets at the substations in Excel Spreadsheets. PG&E also provided SLDs for the substations and PDF drawings for the DC network. Based on this data, my Team also created workpapers to inventory and value each of these assets.[13]

Q. What process was used for the substations?

A. We used the PG&E provided Excel spreadsheet listing the major equipment at the [redacted] MV substations, the two customer dedicated substations and the seven transmission-to-

[12] Appendix III, Attachment Q.2 (workpaper Lines-Unit_Costs-APR-2026-V2.3).

[13] *See* Workpapers, Attachments O and P to Appendix II and Attachments O, P, and Q to Appendix III.

distribution substations to develop the substation inventories.[14] In addition, I used the SLDs provided for each substation to confirm these inventories. I carried out site inspections at each transmission-to-distribution substation in December 2022, and at a sampling of distribution substations in January 2023, to confirm my understanding of the system and the accuracy of the data that PG&E provided. During the inspections, I observed some differences between actual conditions and the data that PG&E provided. These differences were later reconciled in workshops and subsequent discussions with PG&E.

During the inspections we collected information on the ratings of the main power transformers, which change according to the cooling modes (ONAN, ONAF1, ONAF2). We used the transformer ratings for the inventory and confirmed these in discussions with PG&E.

Q. Is there a cut-off date for placing electrical assets in the inventory?

A. The City sought a list of assets from PG&E as of July 27, 2021, the date the City filed the petition in this proceeding. PG&E only started providing records in response to data requests after the scoping memo was issued on June 22, 2022. As part of PG&E's general objections, PG&E stated, "attempting to produce the responsive information as of July 27, 2021 would be unduly burdensome."[15] With hundreds of thousands of records to review, it would be highly challenging for my Team to try to eliminate items in the PG&E records that were installed after July 27, 2021. As a result, we used the June 2022 data provided by PG&E to reflect the assets that were present in July 2021.

Consequently, the inventory includes all the equipment identified by PG&E in its Geodatabases, diagrams, data request responses, and spreadsheets (unless modified based on discussions between PG&E and the City), and is the most accurate representation of assets present on the Petition date that is feasible for the City to provide.

Q: Does the inventory of assets the City will acquire include any records?

A: Yes, the inventory includes records (documents, diagrams, maps, plans, maintenance records, databases, models, etc.) that the City will need to safely own, operate and

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14 Appendix II, Attachment H (PGE000073870-CONF).

15 Appendix II, Attachment F (PG&E Response to CCSF Data Request Set 2 (September 9, 2022) Q01-02).

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. The inventory includes a list of these records.[16]

Q. Does the inventory include any other assets?

A. It does. PG&E identified spare materials that are available to use for the system in the City. The spare parts that the City will acquire are included as part of the inventory and discussed in Section 3.27 of Volume II and Section 4 of Volume III of the Report. PG&E uses these items to provide operational readiness to address possible equipment failures and emergency events and avoid service interruptions or, if there is an outage, to ensure timely restoration of service.

The City will also acquire the major equipment spares present at some of the substations that the City will acquire. The major equipment spares located at substations (which are generally important, long lead-time items) are listed in the substation inventory.

The inventory also includes the communication equipment associated with PG&E's electrical equipment in the City, including but not limited to communication assets in substations, in vaults and attached to support structures; fiber-optic cables;[17] repeaters; Advanced Metering Infrastructure; Supervisory Control and Data Acquisition (SCADA) systems; and remedial action and protection scheme equipment.

Q. Do the assets described above include everything the City seeks to acquire?

A. No. My testimony includes the electric assets San Francisco seeks to acquire as described. This list does not include the real property interests the City seeks to acquire, including land and buildings located at the sites of the substations identified in the asset inventory. For the avoidance of doubt, enclosures and buildings that are integral to substation operations, such as modular protection and control (MPAC) buildings and gas insulated substations (GIS) buildings, are included in the electric RCN as part of the substation Balance of Plant (BoP) (discussed below). The other property interests the City seeks to acquire are identified in the testimony of Timothy Runde.

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16 Appendix II, Attachment P.28 "Records List_Inv"

17 Appendix II, Attachment P.5 (Fiber_Optic_Inv).

Q. Did you reach any agreements regarding asset descriptions and counts with PG&E?

A. Yes. During discussions (exchange of emails and conference calls) following the inventory workshops with Commission staff, the City and PG&E worked to agree on the description and counts for the substation inventories, and for other assets used to deliver electricity in the City. These agreements are largely reflected in Appendix IV, Proposed Stipulation Exhibits A–I. PG&E provided edits and comments on prior versions of these Proposed Stipulation Exhibits, which the City incorporated into the workpapers for the Reports. However, the City and PG&E did not execute a written agreement regarding the inventory counts because of failure to agree on stipulation language.

Q. Explain what the Proposed Stipulation Exhibits represent.

A. Proposed Stipulation Exhibits A-I use summaries and aggregates (e.g., total miles of conduit, total numbers of meters) rather than itemizing each individual asset. The City incorporated the feedback PG&E provided to modify the asset description and counts presented in the Proposed Stipulation Exhibits.

Q. Did you compile a complete asset list based on a single separation plan?

A. Yes, I did, based on the information provided by PG&E and engineering judgment to bridge information gaps. That doesn't mean that every single nut and bolt is listed separately. Some assets were grouped together in BoP or Construction Units. The Reports and workpapers identify all the assets the City seeks to acquire, and the workpapers provide detailed, itemized asset lists for each asset type.[18] My team and I organized the assets within a master workpaper titled "Start_Here_Asset_Count_Final.xlsx," which presents a summary of inventory quantities by asset type. That master workpaper contains links to each detailed asset type workpaper, labeled as Attachments O.1 through P.28 of Volume II (distribution assets) and Attachments O.1 through Q.2 of Volume III (transmission assets).

Each detailed inventory workpaper includes the original asset data received from PG&E, has a summary table that applies the agreed-upon filters, and provides a breakdown of the assets into similar Construction Units for valuation purposes.

The inventory workpaper files in Volume II are listed below:

[18] Excluding real property, as noted above.

Attachment P.2: Capacitor_Banks_Inv.xlsx

Attachment P.3: ConduitSystem_Inv.xlsx

Attachment P.4: DC-Assets_Inv.xlsx

Attachment P.5: Fiber_Optic_Inv.xlsx

Attachment P.6: Fuses_Inv.xlsx

Attachment P.10: Martin-Feeders-RCN-(Triangle)_Inv.xlsx

Attachment P.7: NetworkProtector_Inv.xlsx

Attachment P.8: PadmountStructure_Inv.xlsx

Attachment P.12: PrimaryMeters_Inv.xlsx

Attachment P.9: Primary_&_Secondary_Risers_Inv.xlsx

Attachment P.29~~10~~ Primary_OH_Conductor_Inv.xlsx

Attachment P.11: Primary_UG_Conductor_Inv.xlsx

Attachment P.13: Recloser&Interrupters_Inv.Xlsx

Attachment P.14: San_Francisco_MV_MV_Substations_Inv.xlsx

Attachment P.15: Secondary_Meters_Inv.xlsx

Attachment P.16: Secondary_OH_Conductor_Inv.xlsx

Attachment P.17: Secondary_UG_Conductor_Inv.xlsx

Attachment P.18: SmartMeterNetworkDevices_Inv.xlsx

Attachment P.~~-~~19: Spare Equipment_Inv.xlsx

Attachment P.20: Street_Lamps_Inv.xlsx

Attachment P.21: SubsurfaceStructures_Inv.xlsx

Attachment P.22: SupportStructure_Inv.xlsx

Attachment P.23: Switch_Inv.xlsx

Attachment P.24: Transformers_Inv.xlsx

Attachment P.25: Transmission lines_Inv.xlsx

Attachment P.26: Transmission Substations_Inv.xlsx

Attachment P.27: VoltageRegulator_Inv.xlsx

Attachment P.28: Records List_Inv~~NV~~.xlsx

Q. Do the asset lists in the workpapers include every item the City will acquire?

A. No. The Consulting Team carefully reviewed hundreds of thousands of individual assets identified in the Geodatabases and the records provided by PG&E. While that inventory is comprehensive as to all material plant, it is neither practical nor necessary to list and price every individual component at each substation and along each transmission line or distribution circuit. The data PG&E provided does not list every single item that makes up the electric system that serves customers in the City.

For example, the substation workpapers include the major equipment at substations, and all the other items at substations that are not expressly identified in the workpapers are accounted for in the BoP. This captures all the equipment and materials used at the substations (which is what the City intends to acquire). I explain this more below.

For the transmission lines, the workpaper identifies the type and length or size of the lines, conduit systems, vaults, cable terminals (transition structures where cables connect to substations), and pumps. The Construction Units for transmission lines include additional supporting equipment, such as splices. Accordingly, the inventory of the transmission lines includes the supporting equipment.

IV. VALUING THE INVENTORY USING A REPLACEMENT COST NEW CALCULATION.

Q. Define replacement cost new ("RCN")?

A. Replacement Cost New (RCN) is the estimated cost, as of a specific date, to construct a functionally equivalent system to PG&E's distribution and transmission system using assets, materials, and construction resources currently available in the market. The RCN is based on replacing the system that exists today and is intended to replicate the same level of service and reliability as the existing infrastructure. It does not incorporate added capacity or enhanced reliability or changes in physical configuration or topology.

In practice, the RCN approach identifies, for each asset type, the cost to replace existing assets with modern equivalents that perform the same function. Where identical equipment is no longer manufactured, or a lower cost but more effective product is preferred (for example, replacing obsolete pipe-type cables with solid dielectric cross-linked polyethylene XLPE cables), the RCN uses the cost of an appropriate comparable replacement.

RCN therefore serves as a baseline for valuing the PG&E system in San Francisco, reflecting the replacement cost of the infrastructure as it stands today, without adjustment for potential improvements or additional equipment to provide greater capacity or reliability, except as noted above or when such improvements are inherently reflected in the modern equivalent. This approach promotes consistency in valuation and aligns with common industry practices for utility asset acquisition and appraisal.

Q. Does the RCN include the 4.16 kV system?

A. Yes. The RCN includes the 4.16 kV distribution system as it exists in San Francisco. Although lower-voltage facilities are often replaced over time with higher-voltage systems (for example 12 kV) in many utility systems, PG&E has continued to invest in 4.16 kV facilities in San Francisco, including replacing older substations with new 4.16 kV substations. Accordingly, for purposes of the RCN, replacement of 4.16 kV facilities is based on a functionally equivalent 4.16 kV system.

Q. Is cost escalation important, and if so, how is it factored into your assessment?

A. Yes. Cost escalation—i.e., the change in construction costs over time—is important in RCN determinations because costs must be stated on a consistent basis (in constant dollars for a specific year). In this assessment, we expressed costs on a consistent basis as end of 2022 dollars (2022$). When costs for this date were not available, we used the closest available cost data and adjusted to end of 2022 using the Handy-Whitman Index of Public Utility Construction Costs – Pacific Region as applicable to the specific equipment type.[19]

I used end of 2022 dollars because that is the date when we downloaded distribution cost data from RSMeans, which provides costs for each quarter of the current year. For transmission substation and transmission lines, the available costs are expressed by year, and when necessary, we adjusted the costs to 2022 dollars using the Handy-Whitman Index. If necessary for additional analysis, all valuation dollars may be converted to 2021 dollars, consistent with the City's Petition filing date.

All dollar values in the rest of this testimony are expressed in 2022$.

Q. What is the RCN for the PG&E system that the City intends to acquire?

A. The RCN estimated by the Consulting Team for all of the PG&E electric assets the City seeks to acquire is approximately $10.925 billion, divided into $7.976 billion for

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19 Handy-Whitman Index of Public Utility Construction Costs for the Pacific Region, published by Whitman, Requardt, and Associates.

distribution assets (73% of the total) and $2.949 billion for transmission assets (27% of the total). I will explain how I arrived at the distribution system RCN in subsection A, and then I will describe how I arrived at the transmission system RCN in subsection B.

A. DISTRIBUTION SYSTEM RCN

Q. Taking the distribution system first, please summarize your results.

A. The RCN of all distribution assets within the City and Martin Triangle is $7,976 million. The table below summarizes the contributions to the RCN by broad category.

Table 1. Distribution RCN Summary[20]

Distribution Network Assets	Total RCN 2022 M $
Feeders	$1,867.2
Conduit System	$1,398.7
Secondary Systems And Services	$753.2
Protective Devices	$719.4
Distribution Transformers	$635.8
Meters	$429.5
DC System	$59.1
Spare Equipment *	$38.6
Streetlight	$15.3
Communications	$8.0
Subtotal Distribution Network	**$5,924.8**

MV/MV Substations	Totals 2022 M US$
Transformers 12/4 kV [redacted]	**$38.6**
Other Elements	[redacted]
12 kV Breakers, Switches & Others	$28.9
4 kV Breakers, Switches & Others	$40.4
Balance of Plant	$16.2
Subtotal	**$124.1**

20 These values are rounded to the nearest million and adding them may result in a rounding error.

Distribution (MV and LV)	Total RCN 2022 M $
Distribution Radial and Network Assets	$5,886.2
Distribution Substations (MV/MV)	$124.1
Distribution Spares	$38.6
Total Distribution	**$6,048.9**
Owner Costs – 20%*	$1,202.1
Contingency – 10%	$725.1
Total RCN in 2022 $	**$7,976.0**

*Owner's Costs are not applied to spares inventory

In this table we include a 20% Owner's Cost and a 10% contingency adder. The contingency is intended to account for assets not directly captured in the inventory or specifically identified in the data provided by PG&E, but necessary for utility operations (e.g., SCADA repeaters or line alarm systems – LAS), as well as unexpected costs that may arise during construction beyond those reflected in the unit cost estimates. The 10% contingency is lower than typical planning-level contingencies and reflects the fact that the majority of the asset inventory is based on detailed and comprehensive data, and PG&E's confirmation of assets descriptions and counts, which reduces the uncertainty of our cost estimates.

The Owner's Cost represents utility-incurred costs necessary to deliver a capital project that are not included in the Engineering, Procurement, & Construction (EPC) contractor's direct construction scope. These costs include, among others, project management and controls, inspection services, owner's engineering, stakeholder outreach and communications, regulatory, legal, and compliance activities, record-keeping, and general and administrative support. Owner-furnished services such as fleet support and traffic control are also included. In our analysis, the Owner's Cost also accounts for the Allowance for Funds Used During Construction (AFUDC), which represents the capitalized financing cost incurred during the construction period.

This assumption is consistent with industry benchmarks and the Consulting Team's experience for Owner's Cost. Owner's Cost on electric utility projects are typically in the range of approximately 15% to 25% for distribution projects and 20% to 35% for transmission projects, depending on project complexity, duration, and regulatory requirements.[21] The Consulting Team used a 20% Owner's Cost for Distribution and as explained below, a 25% Owner's Cost for transmission.

Q. What process did you use to calculate the RCN for distribution assets?

A. I calculated the RCN of the distribution assets following two different procedures, one for the distribution system connecting substations to customers, and another for the substations themselves.

Q. First, please explain how you developed the RCN for distribution assets connecting substations to customers.

A. After exporting all the distribution electrical asset data into workpapers, my Team sorted through hundreds of thousands of records. Given the vast amount of unique equipment with various voltage classes, current ratings, configurations, we categorized the equipment into asset types. Next for each asset type we developed Construction Units to group assets of same or similar size, voltage, capacity, material, etc.

The elements comprising an overhead conductor Construction Unit include the conductor itself, as well as supporting equipment not expressly listed in the Geodatabase, such as the cross-arms and insulators, and the labor and equipment required to string the conductor. To determine a total cost, the other important element is the quantity of each Construction Unit. The distribution workpapers identify all the Construction Units and their quantities.[22] Section 3 of Volume II of my report describes the main Construction Units for distribution asset types.[23]

Once the Construction Units and quantities were established, we calculated a unit cost for every Construction Unit to reflect the material, supporting equipment and labor. The calculation starts from the base Construction Unit costs we retrieved from RSMeans. RSMeans is one of the largest publicly available construction estimating datasets in North

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[21] The Edis~~s~~on Electric Institute (EEI) and other industry benchmarking sources categorize “soft costs” (including engineering, project management, permitting, and other owner-incurred costs) as a material component of total project cost. For distribution projects, these costs are commonly observed in the range of approximately 15% to 25%, depending on project scope, duration, and complexity. *See, e.g.*, Edison Electric Institute, Transmission Projects: At a Glance (various editions), and related EEI benchmarking materials.

[22] Attachments O and P to Appendix II (workpapers in Distribution Folder).

[23] Appendix II, Volume 2, Sections 3.2 – 3.25.

America and was used as the primary EPC cost benchmark due to its breadth, transparent line-item structure, and regional cost localization. The RSMeans cost estimating database is published by Gordian, is available online, and it is updated quarterly. My Team downloaded cost data for estimating on November 2022, representative of end of 2022 costs. The unit prices provided by RS Means are cost estimates per construction task, and include labor, material, and equipment costs for a specific location. I used the specific costs that RSMeans provided for San Francisco. RSMeans adjusts these values to include the contractor overhead and profits, which vary by asset type.

I also further adjusted the values from RSMeans, because its cost only includes the price up to the contractor level, including overhead and profits. An accurate valuation must factor in other costs, such as engineering, construction management, job conditions, local taxes, permits and insurance. The Consulting Team added these costs by adjusting the base cost with specific factors applicable to a given job, depending on the asset type, using the adjustment factors for Engineering, Construction Management, Permits, and Insurance based on project location provided in RSMeans. Those include an additional 4.1% for Engineering; 4.5% for Construction Management, 0.5% for Permits, and 0.44% for Insurance. We also included an adjustment for sales tax, which is 8.625% in San Francisco.[24]

RSMeans also provides an adjustment for job conditions. For almost all assets, the job conditions in the City are considered more difficult than average and RSMeans recommends using a 5% adjustment, which we applied. However, for underground construction, we applied a 35% increase instead because the Job Conditions for the City are considered much more difficult than average because the construction could involve closing roads in a busy city, creating disruption that may require overtime, working overnight during low traffic hours, periodic trench plating, and/or installing underground facilities in streets containing other utilities.

We then used these adjusted unit costs to calculate the asset RCN. The total RCN of a specific Construction Unit equals the quantities included in the inventory multiplied

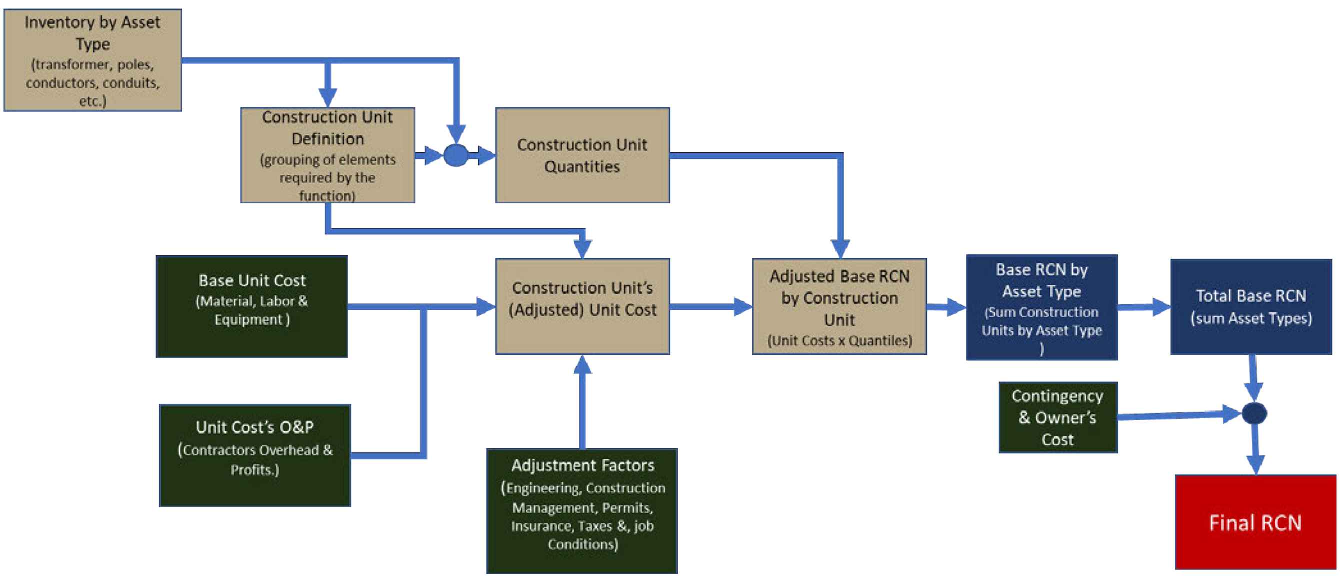
[24] California City & County Sales & Use Tax Rates (effective April 1, 2026), *available at* https://cdtfa.ca.gov/taxes-and-fees/rates.aspx.

by the estimated unit cost, utilizing the adjustments described above. In the last step, we also added a 20% Owner's Cost and 10% contingency adjustment, as I described above.

To provide a second level of verification, my Team cross-checked the unit costs derived by the process above against utility-specific cost data from PG&E.[25] This comparison confirmed that the resulting unit costs are consistent with observed utility construction costs.

Following this methodology, my Team and I analyzed all the asset types in the inventory utilizing Construction Units and unit costs to determine RCN for the asset type. The individual RCNs are then aggregated for each asset type to compute the total RCN for the distribution system. Figure 1 has a flow chart showing the process.

Figure 1. Cost Estimate Methodology



The available cost information for the distribution system assets did not always perfectly align with assets in the PG&E system and many entries in the Geodatabase are missing age, size, voltage or material data. This required making assumptions based on engineering judgment and typical utility practices. These assumptions are discussed in

[25] PG&E 2025 Proposed Generator Interconnection Unit Cost Guide, Attachment C to Appendix III.

Attachment A of Volume II of my report. We generally applied conservative assumptions to err on the side of higher values.

Q. Please explain how you calculated the RCN for the MV substations.

A. The RCN of the MV substations is determined using the totals of each major component in the substation shown in Section 4.2 of Volume II and the relevant Workpaper in Appendix II, Attachment O.18 (San_Francisco_MV_MV_Substations_APR-2026).

For each component of the substation we determined a unit cost using RSMeans. We applied the same adjustment factors that we used for the distribution system assets to the substation unit costs. However, a BoP cost of 15% is added to account for other costs in addition to the major components listed in the substation inventory. This 15% adder accounts for site preparation, fences, ground grid, cabling, protection, and control and communications, among others. Based on my experience and professional judgment 15% is appropriate because the bulk of the value of these smaller substations ~~-~~is in the major components that are individually valued, and the additional items comprising the BoP are much lower cost items. An Owner's Cost allowance of 20% and a 10% contingency are also added to calculate a total RCN.

Based on these calculations, we estimate the RCN value of the [redacted] MV substations ~~RCN~~ and the two customer dedicated substations at approximately $164 million.

Q: Is anything else included in the distribution system RCN?

A: Yes. In some cases, the cost of records that the City will acquire is included in the RCN, as part of the Owner's Cost, or costs of the asset to which the records pertain. These records have no independent value because they are developed under the normal course of business and are either paid for through the operation and maintenance charges that PG&E collects; are covered by the Owner's Cost adder (which includes project's record-keeping); or, for capital expenditures, the preparation of records regarding the installed assets are generally part of the capital expenditure budget for the engineering and construction for the project. Accordingly, no value is added to the RCN for the records.

I also valued the spare parts and added a 10% contingency to the cost, to account for cost uncertainty. However, I did not apply an Owner's Cost adder because these spare parts represent stand-alone inventory assets rather than assets requiring development, permitting, engineering management, construction oversight, AFUDC, or other utility owner costs typically associated with the installation of in-service equipment. In this case, the valuation reflects the value of the spare equipment itself as stored inventory, not the full projected cost of placing new operating facilities into service.

In addition, SCADA communication assets located in substations are included as part of the substation Balance of Plant. SCADA communication assets located in vaults or on support structures are included in the RCN either together with the associated assets (e.g., network protectors or reclosers with SCADA) or they are covered by the 10% contingency.

B. TRANSMISSION SYSTEM RCN

Q. What is the total transmission RCN?

A. The transmission assets RCN is approximately $2,949 million in 2022$.

Q. What process did you use to calculate the transmission system RCN?

A. I calculated the RCN of the Transmission system in two major parts: 1) the transmission lines and 2) seven transmission-to-distribution substations.

Q. How did you calculate the RCN for the transmission lines?

A. I used the transmission line Geodatabase inventory that PG&E provided to calculate the RCN for the 115 kV lines and 230 kV transmission lines, which includes cable lengths, number and location of vaults and cable terminals, and the location of the special crossings. Based on the inventory workshops and subsequent discussions, the City and PG&E agreed on the inventory of cables (both distribution and transmission), vaults[26] and terminals. The unit cost for each cable is determined based on its voltage class, length and type (underground or submarine). For valuing replacements, I considered that the electric power industry has transitioned almost exclusively to the use of solid dielectric XLPE cables, and so those costs are used for modern equivalents. I also assumed that the two small overhead lines on the final approach to Hunters Point substation would be replaced by underground cables all the way into the substation for RCN valuation.

To determine the RCN for the underground transmission cables, I aggregated the costs of all relevant components. This included the cables themselves, the conduit

[26] Transmission vaults typically include two manholes. The cost for the vaults includes the manholes.

system, vaults, and terminal structures. Additionally, I factored in the expenses associated with special crossings—these are instances where the transmission line must pass beneath highways, train tracks, gas pipelines, transition from land to sea, or traverse other difficult-to-access areas. Such crossings require specialized construction methods that increase the overall cost.

My Team and I utilized several sources to develop unit costs for the underground cable components, with primary emphasis on cost data relevant to San Francisco conditions. In particular, we relied on the comprehensive cost information provided by PG&E in support of the Certificate of Public Convenience and Necessity (CPCN) for the Embarcadero–Potrero 230 kV underground cable project. This source provided itemized costs for both the land-based and submarine segments of the cable installation and the acquisition of spare cables. All cost figures were converted to 2022 dollars (2022$) using the Handy-Whitman Index.

The conductor costs developed for the 230 kV cables were then scaled to reflect the lower-voltage 115 kV cable and differences in conductor size, based on industry guidance and benchmarking sources such as the Transmission Infrastructure Cost Estimating Guide: 2021 Update from the Electric Power Research Institute (EPRI).

Civil infrastructure costs (conduits and vaults) in the CPCN were compared to corresponding costs developed from RSMeans, and adjustment factors were applied to the RSMeans costs to align with higher costs in the CPCN which reflect San Francisco-specific construction conditions, including, for example, elevated transportation costs and disposal charges for excavated material, as well as other urban construction constraints.

The Embarcadero-Potrero CPCN cost data also included cost information on Horizontal Directional Drilling (HDD) that we used as the base to value the costs of major special crossings (e.g., long crossings across highways).

For other special crossings we considered alternative options like increasing the depth of the trenches or using lower cost techniques like “pipe ramming,” and based on engineering judgment and to be conservative, we valued this at 80% of the HDD costs.

Consistent with how we arrived at the RCN for distribution assets, we added a 25% to cover Owner’s Costs as well as a contingency of 10% to the estimate. The Owner’s Cost for transmission assets is higher than the 20% used for distribution assets based on the longer duration of construction of these projects. Based on my engineering judgment and experience, the appropriate value is closer to the low end of the range of 20% to 35% used in the industry because the transmission lines in the City are relatively short.

The RCN that I calculated for the 115 kV transmission cables is approximately $996 million, including the Owner's Cost and contingency. The RCN for the 230 kV cables is approximately $445 million, including the Owner's Cost and contingency. The total RCN of the transmission cables is $1,441 million. The workpaper Lines_RCN_APR-2026.xlsx in Appendix III, Attachment Q.1, provides details of the unit costs and RCN calculation for each transmission line.

Q. Please explain how you calculated the RCN for the seven transmission-to-distribution substations?

A. To calculate the transmission substation RCN, my Team and I broke down the substations into component parts and assigned a unit cost for each. I used multiple sources to identify the unit costs of the major components of the transmission substations because RSMeans does not cover all the required components of the high voltage transmission substations. Consequently, I consulted multiple sources as not all unit costs are found in a single source. The sources include:

- 2025 PG&E Proposed Generator Interconnection Unit Cost Guide
- Western Electricity Coordinating Council (WECC) Substation Capital Cost Calculator
- Midwest Independent System O~~o~~perator (MISO) Transmission Expansion Plan (MTEP) Cost Estimating Guide 2025
- RSMeans Electrical Data Cost 2022
- Transmission Infrastructure Cost Estimating Guide_ 2021 Update (EPRI Guide)
- Confidential GIS substation Project
- Siemens Energy Costs for GIS substations

These sources show a range of unit costs, as unit costs are generally influenced by assumptions such as local costs and job conditions, size of the work (the smaller construction projects are more expensive due to less economies of scale), and whether the construction costs include BoP components.

I selected unit costs adjusted for California and San Francisco, based on information in the sources above as well as reasonable assumptions based on my engineering judgment and experience. The Consulting Team gave preference, when data was available, to PG&E costs in the 2025 Interconnection Unit Cost Guide and confirmed its validity by comparing the costs with those of other sources like EPRI and MISO, both adjusted to reflect San Francisco specific conditions.

The workpaper "Unit_Cost_Master.xlsx" shows the unit cost for each Construction Unit, its source and a comparison of the selected cost with other sources.[27]

For each transmission substation, the unit costs include all construction for a turnkey project. In addition, we added a substation BoP to cover costs of equipment and site configuration that are not directly captured under the major equipment costs that are separately identified and valued on an individual basis (such as breakers, transformers, capacitors, switches).

The BoP does not include the cost of land and any buildings, except for those specifically required to house GIS when present, or MPAC buildings.

The BoP includes: (i) the control/MPAC building or its equivalent for GIS or metal-clad substations; (ii) SCADA and communication systems; (iii) substation automation, protection, and control systems; (iv) civil works, including site preparation, ground grid, fencing, and access roads/driveways; and (v) common switchyard structures and bus work, including the structural supports and electrical conductors that interconnect breakers, transformers, and other major equipment within the substation.

The BoP costs were derived from the information on PG&E's Rule 21 costs, when applicable, and the other sources referenced above that are the most appropriate for the particular substation type and voltage.

The analysis develops BoP costs on a per-voltage-level basis and assumes a typical configuration consisting of one control/MPAC building for conventional air-insulated substations or one building for a GIS. For the MV yard of a transmission substation, the BoP reflects a typical configuration with two transformers (one online spare) and accounts for shared infrastructure with the transmission system.

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[27] *See* Attachment O.1 to Appendix III.

Where substations deviate from this typical configuration, the analysis scales BoP accordingly. For example, for substations with multiple control buildings (e.g., Martin 115 kV, which has three), multiple GIS buildings (e.g., Mission 115 kV, which has two), or a larger number of transformers (e.g., Larkin, with six 115/12 kV transformers), the BoP is adjusted to reflect the additional infrastructure requirements. Conversely, for smaller substations (e.g., Bayshore), the analysis applies a fractional BoP value (e.g., 0.5).

BoP costs capture all the equipment and materials used at the transmission substations (which is what the City intends to acquire). We added 25% to cover Owner's Costs and a 10% contingency.

The total RCN for the seven transmission-to-distribution substations is approximately $1,493 million in 2022$.[28]

Q. Does PG&E's upgrade of the Larkin substation affect the RCN for Larkin?

A. No. After the Petition was filed, PG&E began upgrading the Larkin substation with new 12 kV equipment. Even though the calculated RCN includes the former 12 kV assets, this RCN is valid with the upgrades in place. The RCN remains valid because it provides a replacement cost that is based on the same type of construction used in the upgrade (building enclosed switchgear) and the same number of transformers and MV circuits. Therefore, the RCN reflects the cost of the new equipment (which corresponds to what PG&E has already purchased).

Q. Please describe the method for valuing the Martin substation.

A. I used the same methodology for calculating the RCN of Martin as I used for the transmission substations located in the City. There is no difference as the City intends to acquire the entire Martin Substation.

Q. Please describe how you validated your substation RCN calculations.

A. As a validation check on the reasonableness of our RCN calculations, we compared the Martin Substation RCN estimate to actual cost data provided by PG&E.

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[28] Appendix III, Table 1-2 (the RCN for each transmission substation and the total RCN for all transmission substations is presented in the table, separated by voltage level, to represent the major equipment in substations).

The PG&E data reflected a plant-in-service cost of $171.6 million in nominal dollars. We converted this amount to an approximate 2022-dollar equivalent using the Handy-Whitman Index for Station Equipment, together with the reported additions and retirements from 2011 through 2021, and a high-level approximation that the initial 2010 plant-in-service balance reflected, on average, 1995 dollars. This reconciliation produced an estimated historical cost equivalent of approximately $303.3 million in 2022 dollars.

Our estimate of Martin's RCN before contingency and Owner's Costs was $269.3 million. Applying the standard 10% contingency and 25% Owner's Costs results in a fully loaded RCN of $370.3 million, substantially more than PG&E's historical cost.

This comparison indicates that the application of standard contingency and Owner's Cost assumptions is conservative in this context. Martin has undergone significant expansions at an existing site, where many site development, permitting, and support costs are typically lower than for a comparable new site. As a result, the appropriate combined impact of contingency and Owner's Costs for a site such as Martin could reasonably be materially lower, potentially on the order of 15% in total.

Accordingly, the use of the standard 10% contingency and 25% Owner's Cost assumptions, while appropriate for RCN methodological consistency across the system, is expected to produce a conservative RCN indication for Martin Substation, given its brownfield expansion characteristics.

Q. Is PG&E's planned Egbert Switching Station Project included in the RCN?

A. The transmission substation RCN does not include PG&E's planned new 230 kV Egbert switching station. The California Public Utilities Commission issued a CPCN for this project in 2020 in Decision 20-06-037, but PG&E has not yet started construction. This new transmission 230 kV switching station is intended to improve the reliability of PG&E's transmission service to the City by providing an additional route of supply.

Currently, electric supply to the City remains [redacted] dependent on Martin Substation. If Martin were lost due to a major event, the Trans Bay Cable (TBC) would be the only remaining source of supply, and it could provide approximately 300 MW, or about 30% of the City’s peak load.[29] [redacted]

V. AGE OF DISTRIBUTION AND TRANSMISSION ASSETS

Q. Did you assess the age of the PG&E’~~-~~s electrical assets that the City intends to acquire?

A. Yes, while assembling the inventory, my Team and I compiled age information on the distribution and transmission assets based on PG&E’s data, where available. This age data is not directly relevant to my RCN analysis. However, it is information available for use in analysis by other witnesses.

The age analysis is dependent on the quality of information provided by PG&E, and for many assets, PG&E did not provide requested install dates. I used the data provided for hundreds of thousands of assets, including but not limited to data included in the asset Geodatabases, SLDs, spot inspections, and analysis of the system to verify the data to the extent feasible. In a small number of cases, I found discrepancies in the data.

For the transmission assets, PG&E provided install dates for its transmission lines and the major equipment in the seven transmission-to-distribution substations. During the inspections, I verified the age of certain equipment within these substations if it was visible on the nameplate, and for one transformer, I corrected the installation date in my report to align with the nameplate.

PG&E provided install dates for each of the transmission lines. However, I discovered that the 1972 install dates in the Geodatabase for Potrero – Bayshore Martin circuit #1 and circuit #2 (A-H-W # 1 and #2) are incorrect. Documents that PG&E submitted to the California Public Utilities Commission indicate that the current A-H-W #1 cable became operational in 2010. PG&E provided install dates for major equipment in the MV substations, which I used in the report.[30]

For the other distribution assets, there were significant gaps in PG&E’s data. Some asset types have extensive age data, whereas others have a large percentage of

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29 Siemens black-start technology to provide critical back-up for San Francisco's power grid | Press | Company | Siemens, *available at* https://press.siemens.com/global/en/pressrelease/siemens-black-start-technology-provide-critical-back-san-franciscos-power-grid.

30 Appendix II, Attachment H (PGE000073870).

missing age data. For example, on the one hand, the fuses asset type has installation date data for 97% of the total fuses within the asset inventory. On the other hand, the Secondary Underground Conductors asset type has installation date data for approximately ~~36~~27% of the conductor; therefore, the Consulting Team needed to estimate the age of the remaining 73% of secondary underground conductors on the system.[31]

After seeing missing data, the City requested the missing age data or a method for estimating the dates, but PG&E did not provide any significant additional data or a method for estimating the dates.[32]

Due to the variations in the asset types and construction techniques, my Team and I used engineering judgment to derive assumptions on the age data for each asset type with missing data to calculate an average age for distribution asset types in the inventory, as detailed in Volume II of the RCN report.

Where a very large majority of units of similar type had a reported installation date, I used that date for the similar units without dates. For many distribution asset types this was not the case, and to develop estimated installation dates, I assessed the amount of missing data per asset type and created histograms for each asset type using installation dates that were provided.[33] The installation trends illustrated in the histogram informed the selection of an appropriate average installation date for assets without age data. In making this selection, I assumed that assets without age data are older than assets that have records of the installation date, and that the assets without dates should be clustered around the years when there was an appreciable increase in the installations. This is a reasonable assumption and is based on my judgement that record-keeping has improved over time, it is most likely that items without dates were installed at the same time as a

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[31] Appendix II, Section 3.9.3

[32] Appendix II, Attachments F, PropertyValuationPetition-CCSF_DR_CCSF_002-Q01-04Supp01 at 2-4, Attachment M, PGE-PropertyValuationPetition_DR_CCSF_009-Q001-021Supp01 and Attachment N, Letter from Jacob Schlesinger to Kevin Allred (Dec. 3, 2025) and Letter from Kevin Allred to Jake Schlesinger (Dec. 22, 2025).

[33] *See* Section 3 of Appendix II, Volume II (section on "Installation Year Analysis" for each asset type).

large number of the same items were being installed, and that it is more likely to omit date information when there is a large amount of ongoing work.

For some distribution asset types, based on my knowledge of how electrical systems are built, I determined that, where an asset type with a large percent of missing records in practice is installed at the same time as another asset type, it was most appropriate to assume the same average installation date for the two asset types. For instance, pad-mount structures are placed in service at the same time as the equipment they support (pad-mounted transformers), so it makes sense to match the pad-mount install dates with the associated equipment.

For each Construction Unit, we then applied the estimated installation date for units that were missing data and the actual installation date for the units where the date was known. To develop an overall installation date for an asset type, we used a weighted average of the installation dates of each Construction Unit based on the RCN of each Construction Unit (RCN-weighted average). The age data assumptions are described in each of the individual Asset Installation Year Analysis subsections within Section 3 of Appendix II, Volume II. I used the RCN-weighted average, rather than a simple average, so the assets that account for most of the total costs for the asset type have the appropriate proportionate impact on the results.

VI. CONDITION OF PG&E'S DISTRIBUTION AND TRANSMISSION ASSETS

Q. As part of the valuation, did you conduct inspections of PG&E's distribution and transmission assets?

A. Yes. My Team and I inspected a representative sample of the electrical assets that the City intends to acquire but did not conduct a comprehensive inspection of the system. We inspected the seven transmission-to-distribution substations from December 6 to 8, 2023, a sampling of the underground transmission cable facilities from January 18 to 19, 2023, and a sampling of the MV substations on February 2 and 3, 2023. In addition, my colleague, Jorge Matheus, inspected a sampling of distribution manholes from January 30 to February 2, 2023. Collectively, we took thousands of photographs during the inspections. Because these inspections occurred more than three years ago, conditions may have changed. These inspections are described further in Appendix II to my testimony (*See* Appendix II, Volume II, Section 6 and Appendix III, Volume III, Section 8).

Q. What is your opinion of the overall condition~~al~~ of PG&E's distribution assets in the City?

A. In general, my opinion is that, at the time of the inspections, the condition of the distribution assets that I inspected was consistent with their age.

Q. What is your opinion of the condition of PG&E's MV substations in the City?

A. During my observations over three years ago, the assets at the limited number of MV distribution substations that I inspected appeared to be in good condition, consistent with their age. During the inspections of MV substations, I confirmed the expected layout of the assets as well as confirming the reported installation dates of transformers with nameplate information when available. I observed that some substations had spare positions (cells) for future expansion.[34] The transformer(s) at Eighteenth Street (1946 in-service date), Judah, Portola and Randolph (1948, 1949, 1950 and 1959 in-service dates) substations are very old.[35] These transformers may be nearing the end of their operational life and need replacement in the near future.

Q. What is your opinion of the condition of the other PG&E distribution assets in the City?

A. Based on the information provided by my colleagues who inspected a relatively small number of selected vaults over three years ago, and the photographs they took during the inspections, these assets match the respective ages provided by PG&E, and most vaults that were inspected appeared to be in good condition for their age. However, three of the vaults that my colleague inspected indicated some equipment corrosion, and dirt and debris in the vault.

Q. What is your opinion of the condition of the transmission assets?

A. During my inspection, conducted more than three years ago, of the accessible components of a limited number of selected underground transmission cable systems and associated substructures, the equipment I observed appeared to be in good condition.

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34 *See* Section 6.1.3 of Appendix II (Marina (F) MV Substation).

35 *See* Appendix II, Table 4-1.

Some aging and physical deterioration were present, consistent with the age of the facilities.

Overall, the system appeared to be operating as designed, with two noted exceptions: soil-to-pipe voltage measurements obtained during the inspections indicated inadequate cathodic protection at the Bayshore and Potrero Substations.

In general, the transmission-to-distribution substation assets that I inspected appeared to be in good operating condition at the time, consistent with their installation dates. There are some assets at the Hunters Point and Bayshore substations that are very old (dating from 1970s and/or 1980s) and near the end of their useful life.[36] I did not modify any RCN calculations based on assessment of the conditions of the assets.

VII. CONCLUSION

Q. Does that conclude your testimony?

A. Yes.

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[36] *See* Appendix III (Section 8.2.2 (Hunters Point) and Section 8.2.3 (Bayshore)).

APPENDIX I

San Francisco Grid Procurement Engineering Services – Asset Valuation (Advisian-Siemens April 20, 2026), Volume I: Executive Summary

[CONFIDENTIAL]

ATTACHMENT A

Acronyms and Abbreviations

[CONFIDENTIAL]

APPENDIX II

San Francisco Grid Procurement Engineering Services – Asset Valuation (Advisian-Siemens April 20, 2026), Volume II, Distribution Inventory and RCN

[CONFIDENTIAL]

ATTACHMENT A

Criteria and Assumptions for RCN Determinations

[CONFIDENTIAL]

ATTACHMENT B

Network Protector Spare Selection

[CONFIDENTIAL]

ATTACHMENT C

Geodatabase Cover Page

[CONFIDENTIAL]

ATTACHMENT D

MV Single Line Diagrams

[CONFIDENTIAL]

ATTACHMENT E

Excel file
PGE000066831.xlsx

[CONFIDENTIAL]

ATTACHMENT F

CCSF_002-Q01-04 PG&E Data Response (Sept. 9, 2022), Questions 1, 2, and excel file PGE000000732-B.xlsx

[CONFIDENTIAL]

ATTACHMENT G

PGE-PropertyValuationPetition-CCSF_DR_CCSF_030-Q001 to 004, PGE000112649-CONF, excel file PGE000112665-CONF and PGE000112489-CONF

[CONFIDENTIAL]

ATTACHMENT H

Excel file
PGE000073870.xlsx

[CONFIDENTIAL]

ATTACHMENT I

DR_CCSF_010_Q002 and DR CCSF_10_Q003

[CONFIDENTIAL]

ATTACHMENT J

Excel file
PGE000104920-CONF.xlsx

[CONFIDENTIAL]

ATTACHMENT K

Excel file
PGE000104248.xlsx

[CONFIDENTIAL]

ATTACHMENT L

Excel file
PGE000073869.xlsx

[CONFIDENTIAL]

ATTACHMENT M

PGE-PropertyValuationPetition_DR_CCSF_009-Q001-021Supp01 (March 3, 2023); and excel file PGE000103596.xlsx

[CONFIDENTIAL]

ATTACHMENT N

Letter from Jacob Schlesinger to Kevin Allred (Dec. 3, 2025) and Letter from Kevin Allred to Jake Schlesinger (Dec. 22, 2025)

[CONFIDENTIAL]

ATTACHMENT O.1

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"Start_Here_Asset_Count_Final.xlsx"

[CONFIDENTIAL]

ATTACHMENT O.2

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"_SFO_Master_RCN_APR-2026.xlsx"

[CONFIDENTIAL]

ATTACHMENT O.3

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ATTACHMENT O.4

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ATTACHMENT O.5

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ATTACHMENT O.6

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"DC-Assets_APR-2026.xlsx"

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ATTACHMENT O.7

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ATTACHMENT O.8

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ATTACHMENT O.9

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ATTACHMENT O.11

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ATTACHMENT O.14

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ATTACHMENT O.15

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ATTACHMENT O.16

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“Martin-Feeders-RCN-(Triangle)_APR-2026.xlsx”

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ATTACHMENT O.17

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Recloser&Interrupters_APR-2026.xlsx”

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ATTACHMENT O.18

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“San_Francisco_MV_MV_Substations_APR-2026.xlsx”

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ATTACHMENT O.21

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ATTACHMENT O.24

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ATTACHMENT O.25

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ATTACHMENT O.27

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ATTACHMENT P.1

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ATTACHMENT P.2

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ATTACHMENT P.4

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ATTACHMENT P.5

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“Fiber_Optic_Inv.xlsx”

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ATTACHMENT P.6

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ATTACHMENT P.7

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ATTACHMENT P.8

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ATTACHMENT P.9

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ATTACHMENT P.10

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ATTACHMENT P.11

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ATTACHMENT P.12

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ATTACHMENT P.13

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ATTACHMENT P.14

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ATTACHMENT P.15

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ATTACHMENT P.17

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ATTACHMENT P.25

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ATTACHMENT P.26

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ATTACHMENT P.27

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ATTACHMENT P.29

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ATTACHMENT Q

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ATTACHMENT R

January 17, 2026 email from John Major

[CONFIDENTIAL]

ATTACHMENT S

October 10, 2025 email from John Major

[CONFIDENTIAL]

APPENDIX III

Appendix III: San Francisco Grid Procurement Engineering Services – Asset Valuation (Advisian-Siemens April 20, 2026), Volume III: Transmission Inventory and RCN

[CONFIDENTIAL]

ATTACHMENT A

Unit Cost Development

[CONFIDENTIAL]

ATTACHMENT B

Single Line Diagrams

[CONFIDENTIAL]

ATTACHMENT C

PG&E 2025 Per Unit Cost Guide

[CONFIDENTIAL]

ATTACHMENT D

PGE-PropertyValuationPetition_DR_CCSF_019-Q001

[CONFIDENTIAL]

ATTACHMENT E

PGE-PropertyValuationPetition-CCSF_DR_CCSF_031-Q002

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ATTACHMENT F

PGE-PropertyValuationPetition-CCSF_DR_CCSF_032-Q003Supp02

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ATTACHMENT G

PGE-PropertyValuationPetition_DR_CCSF_018-Q058

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ATTACHMENT H

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ATTACHMENT I

PG&E, PGE-PropertyValuationPetition_DR_CCSF_018-Q060

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ATTACHMENT J

PGE-PropertyValuationPetition-CCSF_DR_CCSF_031-Q001

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ATTACHMENT K

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ATTACHMENT L

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ATTACHMENT M

DR_CCSF_018_Q021

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ATTACHMENT P.1

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ATTACHMENT Q.1

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[CONFIDENTIAL]

ATTACHMENT Q.2

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APPENDIX IV

Proposed Stipulation Exhibits A–I

[CONFIDENTIAL]

Proposed Stipulation Exhibit A

Excel File
“Proposed Stipulation Exhibit A - Transmission Substations-CONF FINAL”

[CONFIDENTIAL]

Proposed Stipulation Exhibit B

Excel File
"Proposed Stipulation Exhibit B - Medium Voltage Substations-CONF FINAL"

[CONFIDENTIAL]

Proposed Stipulation Exhibit C

Excel File
"Proposed Stipulation Exhibit C - Distribution Radial and Network Assets-CONF FINAL"

[CONFIDENTIAL]

Proposed Stipulation Exhibit D

Excel File
"Proposed Stipulation Exhibit D - Transmission lines-CONF FINAL"

[CONFIDENTIAL]

Proposed Stipulation Exhibit E

Excel File
“Proposed Stipulation Exhibit E - Distribution Radial Assets- Martin-Border_Detail_CONF FINAL”

[CONFIDENTIAL]

Proposed Stipulation Exhibit F

Excel File
"Proposed Stipulation Exhibit F - Spare Materials and Equipment-CONF FINAL"

[CONFIDENTIAL]

Proposed Stipulation Exhibit G

Excel File
"Proposed Stipulation Exhibit G - Fiber Optics-CONF FINAL"

[CONFIDENTIAL]

Proposed Stipulation Exhibit H

Proposed Stipulation Exhibit H - Earthquake Restoration Supplies_PGE000111426-CONF FINAL

[CONFIDENTIAL]

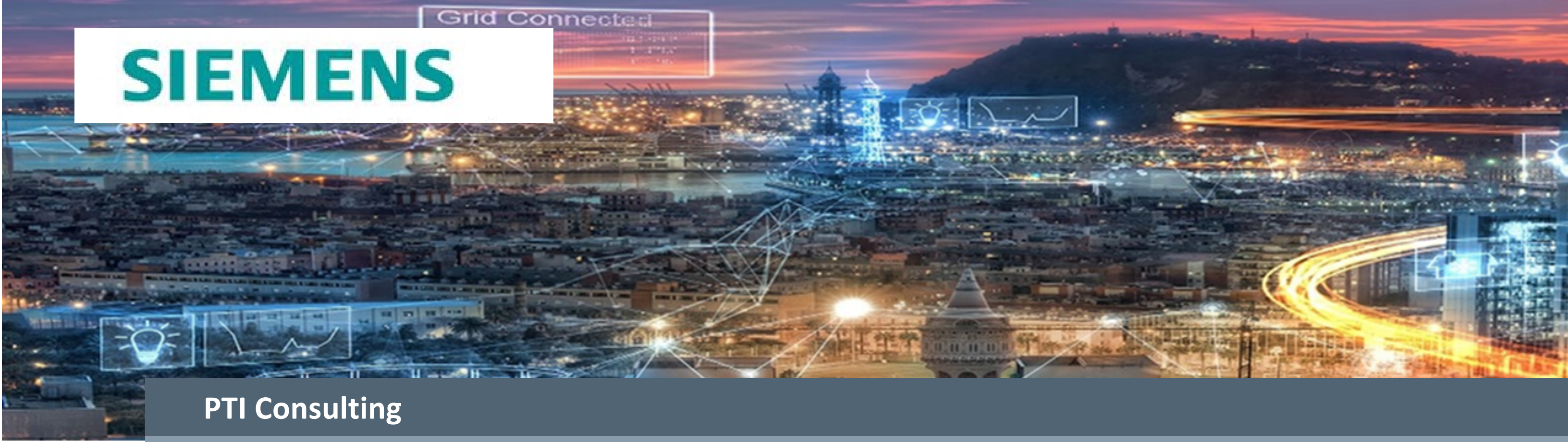
Proposed Stipulation Exhibit I

Excel File
"Proposed Stipulation Exhibit I -- Records List FINAL"

[CONFIDENTIAL]

APPENDIX V

Resume/CV



SIEMENS

PTI Consulting

Nelson Bacalao

Principal Consultant

Career Highlights

Dr. Bacalao has over 40 years of experience providing technical and strategic consulting services to utilities, governments, regulators, independent power developers, and the financial community in the United States and internationally. He combines rigorous academic training in engineering and business with professional experience across utility operations, government, and consulting, encompassing the technical, economic, and regulatory aspects of electric utility systems.

Dr. Bacalao's core competencies include transmission and distribution planning, with extensive experience leading engineering valuation studies in support of public power initiatives. His work spans the full lifecycle of such efforts, including asset inventory assessment, development of construction unit costs, and determination of Replacement Cost New (RCN). His experience also includes the development of separation plans from incumbent utilities and the preparation of short-, medium-, and long-term capital expenditure (CapEx) and operating expenditure (OpEx) forecasts to evaluate the feasibility of public power initiatives.

Dr. Bacalao has managed or participated in multiple public power initiatives, including the SMUD Yolo County annexation effort (West Sacramento, Davis, and Woodland), the South San Joaquin Irrigation District (SSJID) Retail Electric Project, the City and County of San Francisco's PG&E asset acquisition and valuation proceeding, the City of San Diego municipal electric utility feasibility analysis, and the Louisville Jefferson County Metro Government partial municipalization study. His work in these engagements includes asset valuation, separation planning, system planning, and feasibility assessment.

Dr. Bacalao regularly provides consulting services in integrated system planning, combining production cost modeling, long-term generation and distributed energy resources capacity expansion, transmission planning, and distribution planning. These engagements frequently focus on decarbonization strategies, including the development of long-term capacity expansion plans for clean energy and energy storage, and the evaluation of transmission and distribution system requirements associated with high levels of renewable integration.

Dr. Bacalao also provides expert testimony in regulatory proceedings, including in support of public power initiatives and integrated resource plan approvals before regulatory commissions

Representative Engagements

South San Joaquin Irrigation District (SSJID) Retail Electric Project

SSJID is seeking to provide electric distribution service to customers within its service territory currently served by PG&E. Dr. Bacalao serves as lead consultant for the engineering studies supporting this initiative. This multi-year engagement began in 2004, when Dr.

Bacalao and his team developed an initial asset inventory based on field observations and public records, estimated the Replacement Cost New (RCN) of the system, and prepared a preliminary separation plan. These efforts supported advancement of the project through regulatory processes, including approval by the Local Agency Formation Commission (LAFCo). Following subsequent proceedings and challenges, SSJID obtained access to detailed asset information in preparation for litigation. Dr. Bacalao is currently leading the final compilation of the system inventory, determination of RCN, development of a detailed separation plan, and preparation of long-term capital (CapEx) and operating (OpEx) expenditure forecasts.

City and County of San Francisco – Acquisition of the Transmission and Distribution System Supplying the City

The City and County of San Francisco (CCSF) is pursuing acquisition of the electric transmission and distribution system within its boundaries currently owned and operated by PG&E. The assets under consideration include 230 kV and 115 kV transmission facilities supplying the City, as well as the distribution system. Dr. Bacalao has supported CCSF beginning with a high-level feasibility assessment (Phase I), which informed the City's decision to proceed. In Phase I, the work included: (i) estimation of distribution system inventory using sampling and extrapolation techniques, and identification of transmission assets potentially subject to acquisition; (ii) estimation of Replacement Cost New (RCN); and (iii) development of preliminary distribution-level separation cost estimates.

This effort led to the ongoing proceeding before the California Public Utilities Commission (CPUC) to determine asset value and separation costs, where Dr. Bacalao serves as lead expert and continues to support CCSF through: (i) development of a detailed inventory based on PG&E geospatial database records and supporting documentation; (ii) determination of RCN; (iii) development of a detailed separation plan; and (iv) preparation and filing of expert testimony.

Public Power Feasibility Study: Phase I and Phase II – City of San Diego

The City of San Diego initiated a Public Power Feasibility Study in 2022 to evaluate the potential expansion of municipal utility services to include electric delivery consistent with the City's strategic objectives. Dr. Bacalao served as lead consultant for the engineering analysis supporting this effort.

During Phase I, Dr. Bacalao led the evaluation of the transmission (69 kV and 138 kV) and distribution assets that would be required for acquisition from SDG&E, including development of preliminary Replacement Cost New (RCN) estimates, a high-level separation plan, and initial capital expenditure (CapEx) and operating expenditure (OpEx) projections. Phase I concluded that the transaction was feasible and supported advancement to Phase II.

In Phase II (ongoing, expected completion in 2026), Dr. Bacalao is leading the development of a detailed asset inventory based on SDG&E data, refined RCN estimates, evaluation of key risks (including wildfire mitigation requirements), and preparation of long-term CapEx and OpEx forecasts. The study confirms the feasibility of the transaction and supports presentation to the City Council.

SMUD Annexation of Yolo County (West Sacramento, Davis, Woodland, and surrounding areas)

Dr. Bacalao participated in the evaluation of the Sacramento Municipal Utility District (SMUD) annexation of portions of Yolo County, including the cities of West Sacramento, Davis, and Woodland, in the early 2000s. Dr. Bacalao led a team of engineers in the development of an independent inventory of PG&E's distribution assets in the study area based on field inspections and publicly available information, due to the absence of access to utility-provided data at the time.

The work supported the estimation of Replacement Cost New (RCN), assessment of system condition, and development of a preliminary separation plan and capital expenditure requirements to evaluate the feasibility of annexation. The effort advanced through the applicable regulatory process and concluded with a vote of the affected electorate in 2006. This engagement represents an early application of methodologies that were subsequently refined and applied in later public power initiatives.

Louisville-Jefferson County Metro Government (Kentucky) – Municipal Electric Utility Feasibility Study and Conceptual System Design

Dr. Bacalao led a team that completed a municipalization feasibility study for the Louisville-Jefferson County Metro Government (LMG) during 2023–2024. The study evaluated the potential creation of a Municipal Electric Utility (MEU) to provide electric service to municipally owned facilities, with a goal of achieving 100% clean, renewable electricity by 2030.

The analysis was designed to inform LMG decision-making and considered multiple pathways, including continued service from the incumbent utility with a cleaner supply portfolio, as well as the development of an MEU supported by on-site generation and market-based procurement. Dr. Bacalao's team identified the transmission and distribution (T&D) investments required for an MEU that could connect directly to the Midcontinent Independent System Operator (MISO) and evaluated supply options to achieve a carbon-free portfolio through power purchase agreements (PPAs) and renewable energy certificate (REC)-backed purchases.

The work included establishment of study objectives and evaluation metrics, data collection, load forecast updates, development of supply portfolios, and estimation of supply, transmission, and distribution costs. The team leveraged geospatial data, facility locations, service requirements, energy consumption, utility tariffs, and historical billing data to develop a bottom-up conceptual distribution system design and supply portfolio. Conceptual system designs were prepared to serve municipal facilities and participating loads, and the analysis evaluated the conditions under which the MEU's total cost of service could be comparable to that of the incumbent utility.

Columbia, Missouri Water and Light (CWL) – Transmission and Distribution Master Plan and Integrated Resource Planning

Dr. Bacalao led a team that completed a Transmission and Distribution Master Plan for the City of Columbia, Missouri in 2021. The study assessed future system needs and associated capital expenditures to accommodate load growth, including the impacts of electric vehicles, energy efficiency, and distributed energy resources (DER) and changes in the supply portfolio.

The team developed a detailed network model in PSS®SINCAL based on conversion of geospatial database data and a spatial load forecast covering the entire service territory. System performance was evaluated under normal and contingency conditions across short-term (1–5 years), medium-term (10 years), and long-term (20 years) planning horizons. Conventional solutions—including new substations, feeder additions, reconductoring, and system reconfiguration—were identified and prioritized based on the severity and timing of system constraints. Non-wires alternatives, including solar photovoltaic (PV) generation and battery energy storage systems (BESS), were also evaluated and compared to conventional solutions in selected areas. The transmission analysis for the master plan was assessed using PSS®E.

The work resulted in a prioritized capital expenditure program based on multiple evaluation criteria. In parallel, Dr. Bacalao contributed to the Integrated Resource Plan, which evaluated least-regret strategies under uncertainty to transition from coal generation to a portfolio including utility-scale renewables, imports from the Southwest Power Pool (SPP), energy storage, and DER. The IRP results informed the distribution planning assumptions and investment strategy.

Other Representative Experience

In addition to the engagements described above, Dr. Bacalao has led and contributed to numerous studies addressing integrated resource planning, transmission expansion, and system reliability under high renewable penetration.

- **Puerto Rico – Integrated Resource Planning, Fiscal Plan, and Transmission Analysis (2010–Present)**
  Dr. Bacalao has led and supported multiple engagements for the Puerto Rico Electric Power Authority and LUMA Energy, including early planning work beginning around 2010, development of the 2015 Integrated Resource Plan (IRP), the subsequent 2018–2019 IRP update, ongoing support for the Fiscal Plan prepared for the Financial Oversight and Management Board, and transmission system analyses. This work has focused on developing resilient system configurations in a hurricane-prone environment while transitioning to high levels of renewable generation supported by energy storage and flexible thermal resources.
- **New York State – Long-Term Grid Planning Study (2021–2023)**
  Dr. Bacalao led the long-term grid study for the New York State Energy Research and Development Authority, evaluating least-cost pathways to achieve the State's clean energy goals. The study assessed portfolios of onshore wind, offshore wind, solar

photovoltaic (PV), energy storage, and transmission expansion, using production cost modeling to identify cost-effective investment strategies under uncertainty.

Dr. Bacalao has also provided transmission planning and market impact analysis for developers and investors, including NextEra Energy and others, evaluating transmission expansion requirements, congestion mitigation strategies, and generation interconnection impacts across ERCOT, SPP, and MISO. His work includes the design of remedial action schemes (RAS) to alleviate congestion and curtailment, as well as assessments of transmission constraints affecting project economics.

In addition, he has supported large industrial customers, including refining and metals operations, in evaluating transmission and distribution reliability, including probabilistic assessments of supply interruptions and associated operational risks. His experience also includes distribution system planning studies related to electrification for municipal and federal entities, including the City of Denver and the U.S. Department of Energy, addressing the impacts of electric vehicles and building electrification on distribution infrastructure.

Areas of Expertise

- Transmission Planning
- Generation Expansion Planning
- Generation Interconnection Studies
- Distribution System Planning
- Capital Expenditure Evaluations
- Operating Expenditure Evaluations
- Financial and Economic Modeling
- Due Diligence Evaluations
- Load Forecasting
- Uncertainty and Risk Considerations
- Resilience assessments
- Generation Transmission Deliverability Studies
- Production Costing
- Hydro-Thermal Dispatch Forecasts
- Optimal Thermal Unit Commitment
- Estimation of Renewable Generation Impacts on Ancillary Services such as Frequency Regulation, Load Following and Reserves
- Hydro-thermal Scheduling

Education

- MBA level program, Advanced Managerial Program (PAG-VII) Instituto de Estudios Superiores en Administración (IESA), Caracas, Venezuela, 1990
- PhD, Electrical Engineering, University of British Columbia, Vancouver, BC, Canada, 1987
- Master Engineering (Electrical), Rensselaer Polytechnic Institute, Troy, NY, 1980
- Electrical Engineer, Universidad Simón Bolívar, Caracas, Venezuela, 1979

Professional Memberships

- Member of the IEEE and its Power & Energy Society
- Member of the Colegio de Ingenieros de Venezuela

Languages

- English
- Spanish