Application: 24-10-
(U 39 M)
Exhibit No.:
Date: October 23, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

BILLING MODERNIZATION INITIATIVE

PREPARED TESTIMONY

PG&E ®

PACIFIC GAS AND ELECTRIC COMPANY
BILLING MODERNIZATION INITIATIVE
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EXECUTIVE SUMMARY AND BACKGROUND

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EXECUTIVE SUMMARY AND BACKGROUND

A. Introduction

Pacific Gas and Electric Company (PG&E or the Company) respectfully submits, and requests approval to recover, its 2023-2030 forecasted costs for its Billing Modernization Initiative. This Initiative will upgrade and replace PG&E's aging billing systems, which are critical to serving the more than six million[1] PG&E customers in areas of billing, customer service, and customer data management.

PG&E's billing systems are in urgent need of a comprehensive upgrade. Several applications and systems are outdated and unable to keep pace with modern customer, regulatory, and business needs. PG&E first implemented the Advanced Billing System (ABS) in the early 1990s and Customer Care & Billing (CC&B) in 2001. There is an acute need for the Billing Modernization Initiative to address asset failure risks, cyber security vulnerabilities, and the limitations of the legacy billing systems in supporting modern rate structures and programs.

Without the Billing Modernization Initiative, the age of the legacy billing systems and lack of vendor support will disrupt PG&E's ability to interact with customers, impacting services such as customer support, billing and credit services, customer notifications, and timely start/stop/transfer transactions. A disruption caused by asset failure or a cyber intrusion could pose a public safety risk if PG&E was unable to start service before a heatwave or communicate with customers during storms. Simply put, customer needs, regulatory requirements and cyber risk mitigation needs have outgrown the capabilities of the legacy billing systems. It is now critical to modernize these systems, in order for PG&E to continue delivering services which meet customer and regulator expectations, now and into the future.

Billing system upgrades, driven by new technologies, customer expectations and evolving energy policy, have been widespread in recent years. For example, the heavy utilization of interval metering and billing was introduced

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[1] PG&E has 6.3 million accounts and 10.6 million installed meters as of October 2024.

after PG&E's billing systems were installed. Both of PG&E's peer California utilities, SCE and SDG&E, recently launched large billing system upgrades in 2016 and 2017, respectively.[2] More broadly, several major utilities across North America have completed similar projects.[3] These upgrades are driven by increasing implementations and changes to Net Energy Metering, Net Billing, and other complex rate mandates.

In June 2021, PG&E initially sought approval for a billing system upgrade project as part of its 2023 General Rate Case (GRC) Application (A.) 21-06-021 to modernize its billing systems. However, in Decision (D.) 23-11-069, the California Public Utilities Commission (Commission) found that PG&E's 2023 GRC application lacked sufficient detail to support the forecasted cost of its billing system upgrade project and authorized PG&E to file a separate application that includes seven categories of additional information.[4] PG&E submits its new Application today, which provides the requested detail, and urges the Commission's prompt reconsideration of this critical infrastructure need.

PG&E's Billing Modernization Initiative will ultimately move customers to a single unified customer care, service order, metering, and billing system, designed to handle the complexities and challenges associated with a regulated utility in the California marketplace, while minimizing disruption and system instability during the transition.[5] PG&E proposes a three-stage approach, as shown in Figure 1-1, to stabilize and upgrade the billing systems:

- The first stage addresses PG&E's electric complex billing customers through the Billing Cloud Services (BCS) solution and replacement of the ABS. ABS

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2 See A.21-07-009, SCE-01 and SCE-05; A.17-04-027, SDG&E Chapter 4.

3 See*, e.g.*, ComEd and PECO, CC&B Implementation (Sept. 29, 2021), ICC Dockets 22-0486/23-0055, ComEd Ex. 34.11; ConEd, Con Edison Orange and Rockland's Oracle CC&B Implementation Presentation to Vendors (Sept. 13, 2021); Narragansett Electric Company, Information Technology Capital Investment Quarterly Report, Fourth Quarter Attachment 6, RIPUC Docket No. 4770; Virginia Electric and Power Company (Dominion), Final Order (Jan. 7, 2022), Virginia SCC PUR-2021-00127.

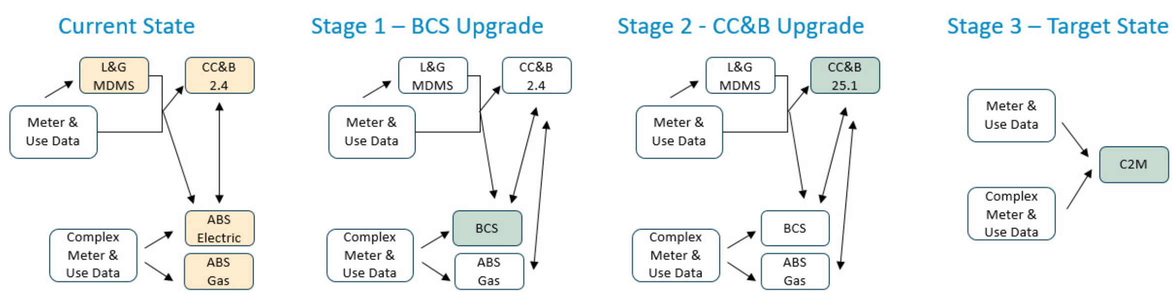
4 D.23-11-069, pp. 546-550.

5 PG&E explains its determination of the appropriate solution to the challenges presented by PG&E's legacy billing systems (including the decision to use a three-stage approach to the Billing Modernization Initiative) and describes the specific features and functionality of the new billing system in Chapter 4.

was developed in-house in the 1990s for a small subset of customers on complex rates such as departed load and standby as well as Net Energy Paired Storage. It relies heavily on customizations and has exceeded its planned capacity of customers.

- The second stage will update the outdated version of Oracle Utilities Customer Care and Billing[6] that PG&E currently uses, version 2.4, to version 25.1 (CC&B 25.1)[7] planned for release in 2025. PG&E is presently four versions behind Oracle's current release, which leaves PG&E outside standard vendor support and unable to remediate cyber vulnerabilities.
- Finally, the third stage is currently planned to complete the implementation of a modernized billing system by replacing all billing components with Oracle's more advanced Customer to Meter (C2M) product and consolidating the electric BCS and gas ABS customers into one system. However, at the conclusion of the 2nd stage PG&E will reassess the billing system landscape to confirm this is still the optimal path.

FIGURE 1-1
BILLING MODERNIZATION INITIATIVE DESIGN ROADMAP



As discussed in Chapter 4, PG&E determined that the proposed three stage approach is necessary in order to first bring CC&B and its integration components into vendor support and to move the complex electric-billed customers out of the aging ABS system before upgrading to C2M. The three-stage approach prioritizes system stability, reduces risks, and improves

6 CC&B was first implemented in 2001 and has gone through multiple upgrades. The current version is not supported by the vendor.

7 Oracle has changed their version numbering scheme to align with calendar years. Version 25.1 will be the first release of 2025.

PG&E's ability to deliver rates and programs in a timely manner while also providing customers improved access to tools, usage and billing data. The specific timeline for each stage, and the phases within each stage are discussed in Chapter 5.

This chapter provides an overview of PG&E's Application and testimony and summarizes PG&E's 2023-2030 cost forecasts.

B. Summary of Request

PG&E requests that the Commission adopt its 2023-2030 Operations and Maintenance (O&M) expense forecast of $92.0 million and its 2023-2030 capital forecast of $669.2 million, ($761.3 million, in total).[8] This represents the entire program cost estimate between 2023 and 2030; PG&E will not include any costs for the execution of the Billing Modernization Initiative in the 2027 GRC, to be filed in Q2 2025, or any expense costs therein incurred prior to 2023. The recorded capital expenditures for 2021 and 2022 are included in PG&E's revenue requirement calculation, which is further described in Chapter 7. Based on the seven focal areas listed below in Table 1-3, it is most practical to deliver the complete Billing Modernization Initiative in a single filing and not spread it out over an off-cycle filing and upcoming GRC.

PG&E's Billing Modernization Initiative roadmap is presented in Chapter 5. It is important to note that at the end of Stage 2, when PG&E completes the upgrade of CC&B 2.4 to CC&B 25.1, PG&E will take a moment and reassess the billing landscape to reconfirm if the final solution, Oracle's C2M, is still the most prudent solution. This prudency check is warranted given the pace of technology change in the industry as well as ensuring vendor performance remains on the levels experienced prior to this Initiative commencing.

Tables 1-1 and 1-2, below, summarize PG&E's 2023-2030 cost forecasts for each stage of the Billing Modernization Initiative.

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8 For additional cost forecast information, see Chapter 6 and associated workpapers.

TABLE 1-1
SUMMARY OF FORECASTED CAPITAL AND O&M COSTS (2023-2030)
(MILLIONS OF 2023 NOMINAL DOLLARS)

Line No.	Stage	Capital Cost	O&M Expense	Total
1	BCS	$124.6	$3.4	$128.0
2	CC&B 25.1	$119.0	$8.5	$127.5
3	C2M	$425.6	$80.1	$505.7
4	Total	$669.2	$92.0	$761.3

TABLE 1-2
SUMMARY OF CAPITAL AND O&M COST FORECAST BY YEAR
(MILLIONS OF 2023 NOMINAL DOLLARS)

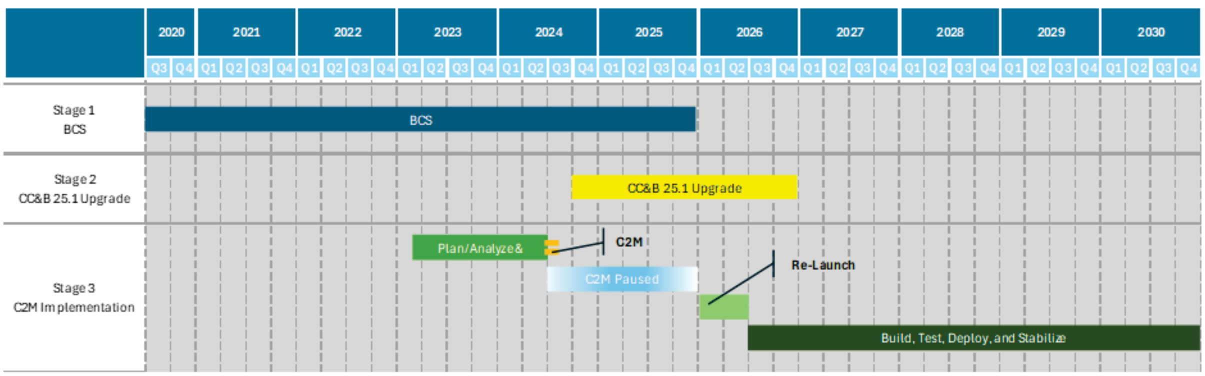
Line No.	Year	2023 (actual)	2024	2025	2026	2027	2028	2029	2030	Total
1	BCS	$41.8	$45.1	$41.1						$128.0
2	CC&B 25.1		9.0	64.8	$53.7					127.6
3	C2M	40.8	39.5	1.9	39.1	$102.0	$110.0	$130.3	$42.0	505.7
4	Total	$82.6	$93.6	$107.8	$92.9	$102.0	$110.0	$130.3	$42.0	$761.3

As discussed above, since submitting the 2023 GRC request, PG&E has continued to reassess and refine its plan for the Billing Modernization Initiative. As a part of this continued effort, PG&E has identified that the legacy system's existing integrations and customizations are more complicated than initially estimated due to the decades of functionality additions and enhancements. Additional detail concerning the resulting challenges of this complexity is detailed in Chapter 2.

PG&E also identified that without prompt action its customers would continue to be exposed to system risks until a complete C2M solution was implemented. As a solution, PG&E has added a technical upgrade of CC&B 25.1 (Stage 2) to reinforce the platform stability, security, and supportability during the full implementation timeframe. The BCS and 25.1 steps are necessary to expeditiously reduce system and implementation risk and successfully complete the Billing Modernization journey.

This Initiative is larger in scope than that requested in the 2023 GRC, however PG&E is confident that this implementation plan, detailed in Chapter 5, best delivers the desired target state of modernizing the billing system while more quickly reducing system and implementation risk. PG&E has expanded the scope and timeline of the project in an effort to stabilize the platform, increase cyber security, and return to vendor supportability while completing the Billing Modernization Initiative. As explained further in Chapter 4, the additional effort to implement CC&B 25.1 is necessary to continue providing an available and reliable platform to customers through implementation of C2M in 2029 and the stabilization that will continue into 2030 as shown in Figure 1-2 below.

FIGURE 1-2
TIMELINE FOR BILLING MODERNIZATION INITIATIVE



With additional complexity, the cost estimates for this implementation have increased as PG&E has continued to deliver initial phases of the project. The current estimates for the project reflect the necessity to address these complexities and risks. In addition, based on the knowledge gained since the Initiative began, the effort is a more significant undertaking than proposed in the 2023 GRC. The cost estimate has increased from an estimate of $176.8 million in the 2023 GRC to $761.3 million. The cost estimate presented in this proceeding covers the full scale of the Initiative (eight years), while the 2023 GRC filing only addressed the first three years of the upgrade process. This increase is the result of a variety of drivers. Factors which have added the CC&B 25.1 phase – including additional complexity and increasing risk-require additional effort to successfully deliver all stages of the implementation. Since the 2023 GRC filing, PG&Es continued work on the Billing Modernization Initiative has provided additional information which has been incorporated to improve the delivery plan quality and cost estimate precision.

The additional stage to implement CC&B 25.1 contributes additional costs that are necessary to address the instability and risk inherent in the aged, unsupported CC&B 2.4 platform. As Chapter 3 describes in detail, increasing risks over the previous years have necessitated the resolution of vulnerabilities in the legacy system. While this change does add approximately $128 million to the overall costs, it is necessary to stabilize PG&E's platform for today's users as we build for the future.

Cost estimates to complete the BCS and C2M stages have similarly increased as PG&E has reviewed its implementation plan during the Plan/Analyze, and Design phases of the BCS and C2M stages. PG&E has identified significantly more complexities than initially anticipated in the legacy platforms. Lessons learned from these experiences indicated an estimated need for additional staffing and completion timelines, increasing estimated costs by $457 million for existing phases. This increased complexity drives impact on ancillary systems including Customer Revenue Critical Reporting, bill print, and middleware and will need to be addressed in this initiative. PG&E has worked to review the timeline and staffing plans to ensure that the selected plan is the most prudent one for customers and will efficiently deliver a Customer Information System (CIS) able to limit cybersecurity and asset failure risk to customer services while meeting regulatory requirements.

Benchmarked CIS projects with complex and customized legacy systems present significant issues when trying to modernize the CIS and remove those customizations. In order to ensure safety, customer and regulatory requirements are met, significant effort is required to deliver a back-to-base solution which optimizes the features and capabilities of a modern CIS. As an example, other California utilities have seen an increase in their costs and timeline of implementation due to similar complexities. While the projected costs are larger than initially filed due to the broader scope and longer timeline, they reflect the realities of legacy systems discovered during the initial phases of ABS and C2M. The proposed Billing Modernization Initiative enables PG&E to plan and deliver a successful and impactful billing modernization for customers.

C. Reasons for Urgency

As PG&E explains in Chapter 2, PG&E's legacy billing systems have aged beyond their expected service life, with numerous resulting inefficiencies and vulnerabilities. ABS is 30 years old and the core billing system, CC&B, is 20 years old. ABS was originally built and designed in the 1990's to handle up to 25,000 accounts but currently has more than 150,000 accounts. The current CC&B version 2.4 has been without standard vendor standard support since 2019.[9] CC&B is currently on extended support, which carries no vendor guarantees and only provides best-effort service should an issue arise. CC&B's extended support ended in November 2020; as of this filing date the sustaining support is expected to end in 2025, leaving CC&B unsupported. Both CC&B and ABS are written in an outdated programming language, making it challenging to find coding expertise to support.

Over recent decades, PG&E has made significant customizations because the base applications were not designed to accommodate modern rates and programs to enhance customer offerings and respond to regulatory requirements. All customizations are PG&E-specific alterations that introduce unique code to the base program or application, further discussed in Chapter 2. While customizations are often necessary to fulfill a specific regulatory or business need, in the long term, customizations make a product more challenging to maintain, support, and eventually upgrade or replace. PG&E now needs to replace these customizations (and limit the number of future customizations) by implementing a modernized billing system.

System age, cybersecurity vulnerabilities, and lack of vendor support drive the need for a capable, stable, and supported platform. For example, ABS bill calculations often run into the middle of the workday from the previous evening to process one day of interval meter usage because the system is oversubscribed. If there is an issue with the billing process it can take multiple days to catch back up to the current day's data processing. CC&B 2.4 is equally in need of an upgrade because it has significant cybersecurity vulnerabilities that cannot be patched or remediated on the outdated version.

Cybersecurity risk has been increasing; attacks have become more frequent and significant. PG&E provides additional detail in Chapter 3, Billing Systems and Risk Management, indicating that between Q1 of 2022 and Q1 of 2023,

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9 Vendor support which includes cybersecurity patches, bug fixes, feature updates, development support, and more.

cyber-attacks on the Power and Utility sector increased 300 percent further driving the urgency to eliminate vulnerabilities in legacy systems.

Ensuring vendor support to resolve cybersecurity vulnerabilities is a critical reason for PG&E upgrading CC&B to version 25.1 as soon as possible. PG&E's proposed plan addresses this reduction of cyber risk at an earlier stage than the target state.

D. Overview of Benefits

The overall benefits associated with the Billing Modernization Initiative, which include both quantified financial benefits and non-quantified benefits (such as risk reduction), outweigh the costs. Risk reduction is a significant benefit to customers, and is discussed in detail in Chapter 3. In response to the Commission's request for a detailed cost-benefit analysis, PG&E led an effort working with unbiased utility industry experts who are familiar with California's regulatory environment from Accenture to evaluate the costs and benefits of the Billing Modernization Initiative. This economic cost-benefit analysis is discussed in detail in Chapter 6.

The Billing Modernization Initiative will result in $596 million quantifiable benefits. Business benefits include process efficiencies in billing operations, customer support, contact center, and credit & collections totaling approximately $212 million over the lifetime of the new billing platform. The Billing Modernization Initiative will also result in quantifiable information technology (IT) benefits including the elimination of legacy architecture costs, the avoidance of future cost increases to maintain legacy architecture, the reduction of costs to implement current project backlogs, the reduction of costs to implement future new projects, the reduction of managed service provider spending, the reduction of unplanned CIS downtime, and IT support process efficiencies totaling approximately $384 million over the lifetime of the new billing platform. Each of these categories of benefits is discussed in more detail in Chapter 6.

In addition to the $596 million quantifiable benefits discussed above, the Billing Modernization Initiative will produce both quantifiable and non-quantifiable risk reduction benefits, as well as experience improvement benefits. In accordance with RAMP methodology, PG&E's cybersecurity risk reduction calculations indicate that $10 million of PG&E's existing enterprise risk will be reduced through mitigation efforts including upgrading CC&B and ABS systems.

When PG&E quantified financial impacts of a non-catastrophic cyber risk event scenario, the potential consequence could result in up to $197 million. These benefits, as well as non-quantifiable benefits relating to cybersecurity and other risk calculations, are detailed further in Chapter 3. The Billing Modernization Initiative will also produce several customer and employee experience benefits that cannot readily be quantified. These are discussed in Chapters 4 and 6 and include improving speed of access to new rates, improving PG&E processes, and empowering customers with timely synchronized data while improving customer self-service.

Accenture's review of the quantifiable benefits and costs found that the Benefit-Cost ratio for the entire Billing Modernization Initiative is 0.31 when discounted according to PG&E's weighted average cost of capital and 0.56 in nominal terms, indicating that quantified benefits represent 31 percent and 56 percent of quantified costs, respectively. These benefits, combined with non-quantified benefits like risk reduction provide significant net benefits to customers. This wholistic evaluation of benefits and costs, therefore, support the business case to replace PG&E's current systems.

E. Response to 2023 General Rate Case Directives

PG&E has used the period since the 2023 GRC to reassess and refine its Billing Modernization Initiative with additional input from both internal subject matter experts and external consultants and vendors. Since filing the 2023 GRC, PG&E has continued to implement a replacement for the ABS electric rates on Oracle's BCS because this solution to calculate complex rates is an urgent need. PG&E has also completed the "plan" and "analyze" phases of upgrading the core billing system, Oracle's CC&B, to Oracle's modern billing platform, C2M.

The 2023 GRC Decision identified seven areas where the Commission directed PG&E to present more specific information regarding billing modernization. This Application addresses each of these areas in detail. Table 1-3, below, indicates which testimony chapter(s) respond to each of the Commission's directives in the 2023 GRC Decision.

TABLE 1-3
RESPONSE TO THE COMMISSIONS DIRECTIVES IN THE 2023 GRC DECISION

Line No.	2023 GRC Commission Directives	Location of Response in PG&E's Testimony
1	A showing of the requirements, features, and functionalities of the new proposed system	Chapter 4
2	A more robust showing of PG&E's proposed project, including the implementation plan, phases of the project (e.g., planning, development, testing and others), resources required for each phase, timeline for each phase, costs anticipated for each phase, and other information	Chapter 5
3	A cost-benefit analysis for the project that considers whether the overall benefits of the project outweigh the overall costs	Chapter 6
4	An accounting of the expected cost savings as a result of the new billing system as well as a proposal for crediting the benefits back to ratepayers	Chapter 6
5	Whether the project would result in stranded investments for ratepayers as a result of previous spending on the current billing system and the dollars associated with such stranded investments	Chapters 2 and 5
6	Which components and how much of the forecasted cost are related to cloud-based solutions	Chapter 5
7	Explain how the upgrade project specifically implements new and complex programs that are beyond the capabilities of the current system	Chapters 2 and 4

F. Organization of Remainder of Testimony

The remainder of testimony in support of PG&E's request is organized as follows:

- Chapter 2: Legacy Billing Systems Overview – Provides an overview of CISs and related systems, explains the history of PG&E's legacy systems, describes the current systems supporting PG&E's metering, customer information, and billing functions, and discusses the challenges resulting from the continued use of legacy systems.
- Chapter 3: Billing Systems and Risk Management – Discusses the risks faced by PG&E and its customers if the Billing Modernization Initiative is not implemented.

- Chapter 4: Target State Billing System – Describes PG&E's process for determining what capabilities and features the target state billing system should provide and how PG&E determined that the proposed Billing Modernization Initiative is the best approach to reach that target state billing system.
- Chapter 5: Billing Modernization Initiative Implementation – Provides a detailed description of the implementation of PG&E's proposed Billing Modernization Initiative, including an explanation of the phases, required staffing resources, timeline, and anticipated costs for each stage of the larger initiative.
- Chapter 6: Description of Cost-Benefit Analysis – Discusses the economic cost-benefit analysis performed on PG&E's proposed Billing Modernization Initiative and provides a detailed description of the costs and benefits considered in the analysis and the supporting methodology for creating the analysis.
- Chapter 7: Results of Operations – Presents PG&E's 2023-2030 revenue requirements for the Billing Modernization Initiative.
- Chapter 8: Cost Recovery – Presents PG&E's proposal for tracking, recording, and recovering the costs of the Billing Modernization Initiative.

G. Conclusion

The Billing Modernization Initiative proposed in this Application is necessary to continue to provide reliable and accurate billing, customer service, risk mitigation, and customer data management services to PG&E's more than 6 million customers. PG&E submits that its forecast costs presented in this testimony are reasonable and should be adopted by the Commission.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

LEGACY BILLING SYSTEMS OVERVIEW

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A. Introduction

1. Scope and Purpose

On November 16, 2023, the California Public Utilities Commission (CPUC or Commission) issued its decision (the Decision) in Pacific Gas and Electric Company's (PG&E) Test Year 2023 General Rate Case (GRC). The Commission found that PG&E's 2023 GRC application lacked sufficient detail to support the forecasted cost of its Billing Modernization Initiative and directed PG&E to file a separate application that includes additional information.

The Decision directed PG&E to "explain how the upgrade project specifically implements new and complex programs that are beyond the capabilities of the current system."[1] This chapter, Chapter 2: Legacy Billing Systems Overview, addresses the Commission's directive by describing capabilities of the current system. It discusses the history of PG&E's legacy systems and describes the current systems supporting PG&E's metering device management, customer information, and billing functions. It also details the challenges resulting from the continued use of legacy systems. The Billing Modernization Initiative is necessary to resolve existing challenges related to rates implementation, aging technology, and cybersecurity vulnerabilities and is an essential step in enabling PG&E's transition to the systems of the future.

The following diagram provides a high-level overview of how the Billing Modernization Initiative will transition PG&E from its current billing platforms (discussed in this chapter) to the new billing system (discussed in Chapters 4 and 5):

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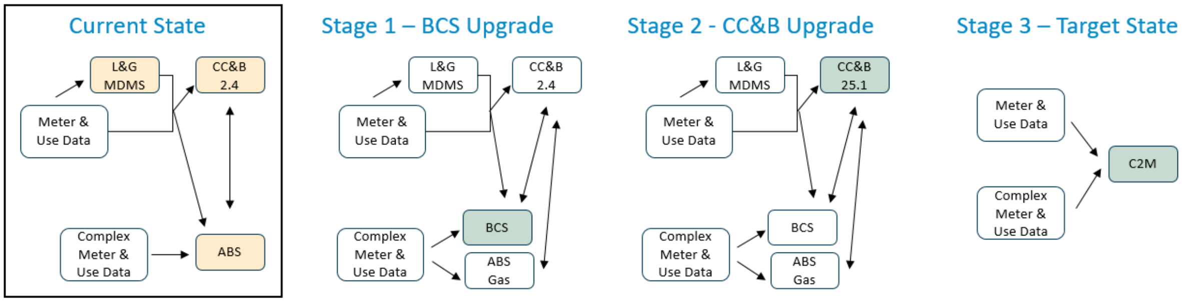
1 D.23-11-069, p. 550.

FIGURE 2-1
BILLING MODERNIZATION INITIATIVE DESIGN ROADMAP



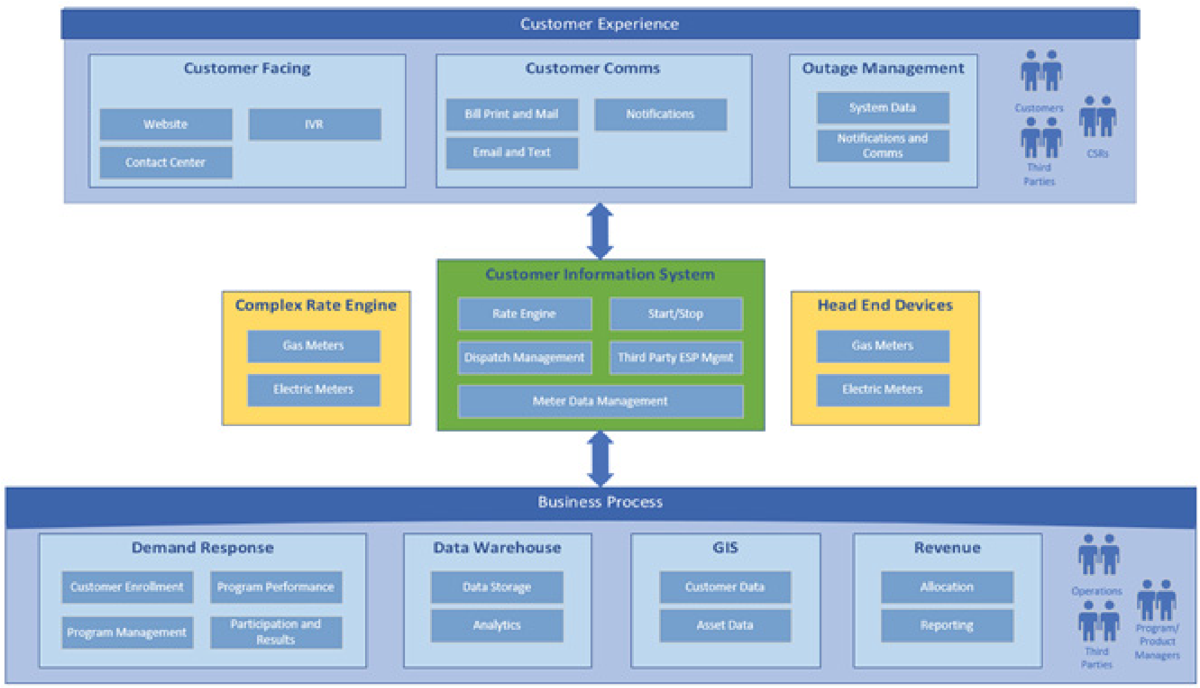
2. Overview of Utility Billing Systems

a. Customer Information Systems and Related Systems

A Customer Information System (CIS) allows a business to store, organize, access, and analyze customer information. CISs are complex and critical to running the business. Any utility function using customer data relies on the CIS. Therefore, implementation of a modern CIS supports not only the billing function, but a variety of other utility functions including safety and improves the customer experience.

CIS applications are often designed and built to serve the specific needs of different industries. For utilities, a CIS is generally used as the system of record for customer information. A CIS is where the customer “record” is first created. That record includes customer information, account history, rates, programs, premise and service location, credit and collections, payment, and other information. The utility leverages this information for device management (i.e., tracking and management of utility devices such as meters), usage management, billing, revenue management, bill presentment and reporting, as well as to share information with external systems (like gas and electric outage management systems or geo-spatial systems, which are used during Public Safety Power Shutoffs and outage restoration). Therefore, customer privacy and data security are necessary features of a CIS to protect customer information like home address, phone numbers, metering identification, customer energy usage data, and other customer identifying information.

FIGURE 2-2
COMPONENTS OF A CIS



Components of a CIS and their related systems include:

- Rate Engine – Utility CISs generally include a "rate engine" which is a computing model used to calculate the billable charges for each customer. Utilities must program rate engines with calculation routines (i.e., all of the calculation steps for a particular rate schedule) for each rate. The capability of the rate engine can vary significantly across CIS products. CIS products without a robust rate engine will require utilities to obtain a secondary rate engine with the capability to handle the billable charge calculation for more complex rates. Rate engines use two main types of calculation routines: linear and modular.
  – Linear vs. Modular Rate Engine[2] – Linear rate engines use a unique, calculation method for each individual rate schedule calculation (i.e., each rate schedule calculation has unique individual steps to determine the cost based on usage and applicable rates). Linear rate engines work well for simple rates

2 Refer to Chapter 2 Attachment A for technical visual comparison on linear and modular rate engines.

with fewer steps in their calculation routines, like implementing a rate that charges a flat dollar amount per kilowatt hour (kWh) of electricity. However, for complex rates with many steps in their calculation routines, like a time-of-use (TOU) rate where the cost of electricity changes based on the time of day that the customer uses electricity, modular billing engines are far more efficient. Modular rate engines use calculation sub-routines called "modules" that can be used in the calculation process for multiple rate schedules. Developing new rates and editing existing rates using a linear rate engine is like writing a physical textbook– to make any changes, the entire book must be recreated. A modular rate engine, on the other hand, would be more like using an online document that allows for editing, copying, pasting and replacing without recreating the entire document. California has many rate programs that can be added to the base rate schedules, making modular rate engines even more beneficial.

- <u>Meter Data Management</u> – A Meter Data Management System (MDMS) is a technology platform that collects, processes, and stores meter data, serving as the link between smart meters and a utility's business applications. Modern MDMSs are required to ingest interval meter reads which became prevalent in 2006 with the proliferation of SmartMeters. PG&E's Advanced Billing System (ABS) and Customer Care and Billing (CC&B) systems were implemented before interval meter reads capabilities were needed. The functions that the MDMS performs allow the billing systems to use meter data to run their billing processes and provide customers with their usage data. More specifically, the primary function of an MDMS is to provide validation, estimation, and editing of incoming meter data for use in bill calculations. An MDMS can be a stand-alone platform that communicates with the CIS to provide the meter data used by the CIS (like the MDMS currently used by PG&E). For more sophisticated systems, the MDMS can be built into the CIS itself (like the Customer-to-Meter (C2M) CIS described in Chapter 4);

- Customer Account Start/Stop/Transfer – The CIS is the main repository for customer information. It provides capabilities to establish new customer accounts and initiate or transfer service, triggering service activation and billing. Moreover, when customers relocate, the system allows for the seamless handling of account closures, including termination of service, service deactivation in the field, and final billing up to the end date;
- Dispatch Management – A utility's CIS also typically integrates with a dispatch management software that allows for the creation and management of field work (e.g., restoring service following customer-reported outages). Synchronization between these systems provides customers and agencies with real time updates of service that is being performed at their location;
- Third-Party Energy Service Provider (ESP) Management – CIS systems can also support and manage third-party billing for scenarios where customers purchase their energy from a third-party provider, and the utility transmits and distributes the energy for the third party. For PG&E, this includes community choice aggregation (CCA), core transport agent, and direct access (DA) partners that act as ESPs for PG&E customers. The CIS logs and has additional custom logic to support the transition to and from these third parties as well as billing and customer data exchanges between the utility and these third parties. California has multiple billing options for these customers, including ESP consolidated, dual billing, rate ready, and bill ready. For ESP consolidated billing, the system calculates PG&E's charges and sends them to the ESP to send a consolidated bill to the customer. In the dual billing scenario, PG&E provides the usage to the ESP and the customer receives separate bills from PG&E and the ESP. With rate ready, PG&E modifies the system to include the rates from the ESP and calculates a single bill with both PG&E and ESP charges. For bill ready, PG&E sends usage data to the ESP, the ESP calculates the charges and sends

back to PG&E, then PG&E sends a single bill to the customer with both PG&E and ESP charges;

- Customer Data Integration with Other Systems – Because a CIS is the system of record for customer data, the system needs to integrate and interface with numerous other systems and processes within the utility, including, but not limited to:
  - Head-end systems, which collect data from meters for processing by the Meter Data Management System;
  - Revenue allocation, which takes the information from the billing system and formats it for financial reporting;
  - Bill print and mail systems, which generate customer bills, letters, and other notifications;
  - Customer communications systems, which process digital communications like emails, text messages, and other digital communications;
  - Customer-facing systems, like the utility's website, Interactive Voice Response, and contact center platforms;
  - Demand response and energy efficiency program management platforms, which manage customer enrollment, performance, and participation in various programs;
  - Geographic information systems (GIS), for syncing of customer and asset locations;
  - Outage management systems;
  - Customer data warehouses, for the storage and use of customer data outside of analytics platforms by billing and revenue operations teams; and
  - For utilities that require an additional rate engine to perform the billable charge calculation for rates and programs too complex for the main linear CIS to implement, the CIS must interface with the complex bill calculation systems.

b. Adding Additional Features or Functionality to a CIS

Implementing a CIS is not a one-and-done process; a utility is able to modify the CIS without replacing the entire system. When a utility needs additional features or functionality for the CIS (e.g., to respond to changing regulatory requirements or business needs), they can be added either through configurations (optional features built into the CIS by the vendor) or customizations (utility-specific alterations).

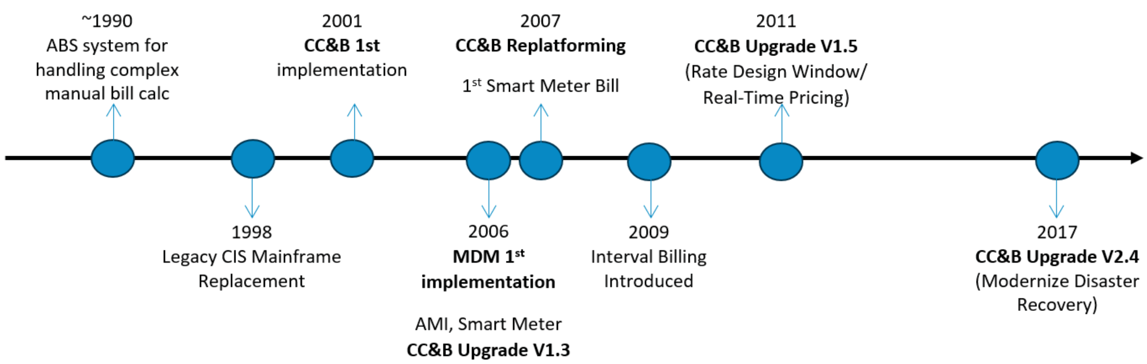
CIS developers and utilities alike prefer using configurations, when possible. The CIS is designed so a foundational process can be replicated and configured to meet multiple business needs. For example, a built-in data sync process can be replicated and configured to (1) sync financial adjustments to customer accounts, and (2) sync payments against a reconciliation file. In both cases the base program is built into the CIS and the utility assigns which data element(s) to sync. Configurations are more cost effective to implement and maintain while enabling functionality to remain aligned with the CIS developer's framework. Additionally, customizations introduce code specific to the utility, which can lead to higher vendor support costs and increased effort to upgrade and remain in support.

However, configurations are not always available to address the utility's specific need, and sometimes customizations are unavoidable in order to support safety, customer, and regulatory requirements. Customizations are necessary when requirements exceed the functionality of the CIS and the business process cannot be augmented. While customizations can often be made more quickly than a vendor adding functionality to their CIS product, they are generally undesirable due to either relatively high development and support costs.

B. History of PG&E Billing Systems

In recent decades, PG&E's Information Technology (IT) and Customer Operations departments have invested in PG&E's CISs regularly to implement new functionality (e.g., smart meter technology, new rates, etc.), but the foundational application has remained the same: Oracle's CC&B system (generally, CC&B, or CC&B 2.4 for PG&E's current version of the system). Investment in customer information and billing systems, including costly customizations, has been necessary each time technology improved or rates became more complex. Below is a high-level summary of the history of PG&E's CC&B systems, ABS, and MDMS.

FIGURE 2-3
HISTORY OF PG&E'S CIS



1. CC&B

PG&E uses Oracle's CC&B system, a vendor-created CIS designed for managing customer service, metering, billing and collection processes. CC&B is a "packaged solution," where PG&E owns the system hardware and licenses for the vendor packages, and the vendor maintains and improves the system for the duration that the system is in support.

PG&E first implemented CC&B in 2001. The CIS upgrade was reviewed in Phase 1 of PG&E's 1999 GRC and resolved in Decision (D.) 00-02-046 with the approval of capital additions and expenses for the project.[3] The Commission noted PG&E's testimony that the CIS billing system in place in 1999 was "old and fragile," and bore "the burden of over 30 years of changes to a monolithic system not originally designed for either its current roles or to accommodate such dramatic business changes"[4] which, At that time, were the restructuring and the introduction of competitive electric supply. The solution to those business changes was an early version of CC&B (version 1.3), which included a billing rate engine designed with simple, linear calculations for each tariff rate component. At the time, most bills were calculated based on monthly manual meter reads with few differentiating customer rate programs (e.g., California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA)). While PG&E

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3 D.00-02-046, 2000 WL 289723 (2000), *238.

4 D.99-06-056, p. 4.

has performed application version upgrades over the past two decades, described below, the underlying framework of CC&B remains the same.

In 2006, PG&E implemented a significant, Commission-approved upgrade to CC&B version 1.5 to enable the CC&B system to adapt to the proliferation of smart meters by implementing Advanced Metering Infrastructure (AMI).[5] The AMI project aimed to enable PG&E to deliver better and more cost-effective service to customers by installing AMI technology on virtually all of its ten million gas and electric meters. The upgrade to CC&B allowed the system to receive processed data from AMI meters and use that data, along with new dynamic pricing structures (e.g., TOU rates), to print and deliver bills to customers. The CC&B version 1.5 upgrade required upgrading the existing software, re-configuring CC&B and its surrounding systems, and re-platforming CC&B from the existing mainframe to a Unix environment. In 2007 the first SmartMeter anchor bill was introduced, followed by the first interval bill in 2009.

In 2011, PG&E upgraded CC&B from version 1.5 to version 2.3, approved by the Commission as part of the 2009 Rate Design Window.[6] This upgrade was performed for two reasons. First, the upgrade was necessary to ensure CC&B remained supported by the vendor (the version 1.5 support was set to expire in 2011). Second, the 2009 Rate Design Window proceeding brought forth plans for real-time pricing (RTP) rates, which could not be supported by version 1.5.

Finally, in 2017, PG&E upgraded CC&B from version 2.3 to version 2.4, which is the version currently in use. This upgrade was necessary because CC&B version 2.3 was nearing the end of vendor support which ended in 2019. The upgrade was included with a project to modernize the disaster

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5 The CIS upgrade was approved as part of PG&E's application for authority to increase revenue requirements to recover the costs to deploy an AMI (A.05-06-028), approved in D.06-07-027 on July 20, 2006. Note that CC&B version 1.5 was called "CorDaptix" at that time.

6 D.10-02-032, pp. 185-186.

recovery functionality for the system[7] and did not change the underlying functionality of CC&B (like the rate engine, dispatch management, customer account management, etc.) nor remove any CC&B customizations. This project moved CC&B into two data centers, allowing a "Mission Critical"[8] disaster recovery platform (which requires return to operation in under four hours). Regular vendor support for version 2.4 ended in 2019, leaving PG&E's CC&B on extended support until 2020, and then Oracle's sustaining support[9] ever since.

2. ABS

In addition to CC&B, PG&E has employed ABS for the last 30 years as the billing engine for rates with a limited customer base for complex rates that couldn't be implemented into PG&E's main customer information system. ABS is a custom-built, small modular rate engine that PG&E developed in-house in the 1990s. As a rate engine, the purpose of ABS is to calculate the bill charges and feed data to CC&B to include on the minimum format statement with a supplemental report. ABS downloads customer information from CC&B for the subset of customers that are billed by the system, then uploads bill charges and cancelations daily.

ABS was originally built for a capacity of 25,000 customers who required more complex rates than the early 1990s CIS could handle. With the introduction of the initial Net Energy Metering tariff, the ABS account number increased rapidly, surpassing 100,000 accounts in 2013. As the popularity

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[7] PG&E included the Disaster Recovery project initially in 2011 GRC, A.09-12-020, Exhibit PG&E-7, Chapter 2. PG&E again included the project in 2014 GRC, A.12-11-009, Hearing Exhibit 30 (Exhibit PG&E-7), Chapter 8, and again in 2017 GRC, A.15-09-001, Exhibit PG&E-7, Chapter 9.

[8] PG&E's Service Availability Criticality Standard defines a Mission Critical system as one that directly supports the safe and reliable delivery of energy to customers. The Standard includes a variety of elements of reliability, as well as a Recovery Time Objective (time to restore the entire system after a disaster) of 4 hours.

[9] Oracle's Sustaining Support does include technical support and access to "My Oracle" support, but it does not include any new updates (tax, legal, regulatory, critical patches), fixes (data, security, etc.), certifications with new Oracle or third-party products, greatly limiting the support of the product. Oracle Technical Support Products, Oracle Lifetime Support Policy (Sept. 18, 2024), available at: <https://www.oracle.com/us/assets/lifetime-support-technology-069183.pdf> (accessed Sept. 23, 2024).

of net energy metering continued to grow, PG&E made the investment to develop net energy metering bill calculation in CC&B and migrate accounts from ABS to CC&B, reducing the total number of accounts in ABS.

This relief only lasted for a few years. As the Commission has implemented more complex rates over time (e.g., Virtual Net Energy Metering, Net Energy Metering Aggregation, and Net Energy Metering Paired Storage), PG&E's reliance on the ABS system has increased due to the inability of CC&B to meet these billing needs. ABS has essentially becoming a mass rate system because these programs have proven to be popular with customers. ABS now has far more accounts than it is designed to accommodate. The ABS account total once again crossed the 100,000 accounts in 2021, and has continued to grow at a rate of two thousand accounts a month.

Because ABS is a modular (as opposed to linear) billing engine, it allows for more flexibility in rate development than CC&B for a limited customer set. But this flexibility comes at the expense of performance in ABS. Currently, ABS has exceeded its planned capacity of customers, which has resulted in latency in processing and performance issues that impact both PG&E's complex billing operations and customers. For example, approximately 30 percent of bills generated through ABS require manual intervention to complete. This manual intervention poses risk of delay for customer bills and increases operational costs as additional staff are required to process the manual interventions.

Because ABS was custom-built by PG&E personnel using a niche application and programming language, operating ABS requires highly specialized skills that are limited to select PG&E employees and a very small number of vendors. As a result, it is challenging for PG&E to replace employees who are familiar with ABS as they retire or otherwise leave the company.

Since ABS is a rate engine, multiple integration functionalities have been implemented to provide the ABS system with the data it needs to calculate accurate customer charges. CC&B provides customer data via a set of text files, which ABS must consume daily at the start of the day to stay in sync. For interval data, ABS requests the usage data from Teradata, a data warehouse that is downstream from MDMS (meaning that the data is received from MDMS after it is processed). Because the data do not come directly from MDMS, it takes an additional 24 hours for interval data to be available in ABS for billing. ABS in turn provides calculated charges back to CC&B via a text file at the end of the business day. ABS lacks the computing power to process the volume of interval data for the increased number of customer accounts.

Due to these multiple issues, the ABS system must be replaced. The complexity of rates is increasing, as is the volume of customers that are choosing to adopt the complex rates. This applies multiple pressures to the ABS system. There are not enough skilled resources to develop new rates and the system cannot handle the additional customers, requiring resources to keep the system functioning, which in turn takes away from the same resources needed to develop rates. PG&E requires a stable, modern rate engine to successfully support complex-billing customers.

3. MDMS

As discussed above, an MDMS performs data processing and management for the vast quantities of data delivered by smart metering systems. The MDMS performs daily validation, estimation and editing (VEE) of customer usage data[10] and serves as an intermediary between the head-end systems and back-office billing systems (e.g., CC&B and its predecessors, the Data Management System, etc.). These functions allow the billing systems to use meter data to run their billing processes and provide customers with their usage data. PG&E's current MDMS is external to the CIS and the vendor is Landis+Gyr.

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10 The MDMS must perform VEE processing daily for PG&E's approximately 10.4 million gas and electric residential and small/medium/large business customers. The VEE rules ensure accuracy and measurement compliance with associated AMI devices and technology.

PG&E uses Commission-established standards[11] for VEE of interval data to check the data accuracy. This standard was needed for Direct Access[12] customers in the late 1990's and now applies to all customers billed on interval data. The legacy systems (CC&B and ABS) cannot perform the required validation, editing, and estimation of usage data, so PG&E has used custom software called EVEE for large Commercial and Industrial customers since the late 1990s. Later, this function moved to the MV90 system for certain customers. MV90 is a type of interval meter that is capable of measuring multiple usage channels for large, complex accounts. These meters were available prior to PG&E's implementation of AMI and these meters are still used today. The MDMS system performs VEE for all non-MV90 customers.

When a faulty meter causes a bad meter reading or disruption of energy distribution (e.g., power outages or other distribution problems), an "event flag" is generated for meter data. The MDMS removes the events that render the data unsuitable for billing. Then, the MDMS uses estimation algorithms and historical data to make an estimated value to replace the invalid data.

PG&E first implemented an MDMS in 2006 when PG&E re-platformed from its mainframe-based system to an Oracle product to enable SmartMeter technology (which was not compatible with the type of coding used on the mainframe-based system) and implement interval billing.[13] PG&E used a separate MDMS to accumulate electric interval usage data and customized the rate schedule calculation routines in its billing system to format the interval usage (i.e., by tier, TOU period, or special program usage

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11 See Standards for Validating, Editing, and Estimating Monthly and Interval Data, available at: <https://www.sdge.com/sites/default/files/documents/VEE.pdf> (accessed Sept. 23, 2024). These standards were established by D.98-12-080 and are generally broad in scope in order to allow an open architecture approach to metering and meter data, expand technology choices, and provide opportunities for all market participants on an equal basis.

12 More information on DA is available at: <https://www.cpuc.ca.gov/consumer-support/consumer-programs-and-services/electrical-energy-and-energy-efficiency/community-choice-aggregation-and-direct-access-/direct-access> (accessed Sept. 23, 2024).

13 See CPUC Electric Rule 1, Electric Rule 9, Gas Rule 1, and Gas Rule 9. These provide guidance to obtain intervals and how estimation could be applied.

period).[14] MDMS was a component of the overall SmartMeter architecture that was, at that time, new to PG&E and the largest of its scale in North America.

4. Cost Recovery History of Legacy Billing Systems

The Commission directed PG&E to identify "[w]hether the project would result in stranded investments for ratepayers as a result of previous spending on the current billing system, and the dollars associated with such stranded investments."[15] Because of how long the legacy billing systems have been in use, these assets are fully depreciated and there is no capital investment remaining to be recovered from customers. Therefore, as described below, there are no stranded investments related to the current billing systems. The asset lives and in-service use of investments for this Billing Modernization Initiative are discussed in Chapter 5.

As discussed in section B.1, the original implementation of CC&B was in 2001, over two decades ago, and the most recent application version update occurred in April 2017. The capitalized investment related to the CC&B upgrades had an asset life of five years, and therefore the capital investment for the 2001 implementation and the upgrades performed in 2006, 2011, and 2017 have all been fully depreciated. Similarly, ABS was first implemented in the 1990s and the MDMS was implemented in 2006. Given these timeframes, the legacy billing systems have more than fulfilled their asset lives and, while they will continue to provide core customer service and billing functionalities until the new system can be deployed and stabilized, they are no longer included in PG&E's rate base.

While there have been costs to operate the system since the most recent version update for CC&B performed in April 2017, those costs were not capitalized and therefore are not in PG&E's rate base. The costs of patching and updating these systems over the past five years have all been recorded as operations and maintenance expenses.

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[14] This formatting and grouping of the interval usage is commonly known as "framing" the usage.

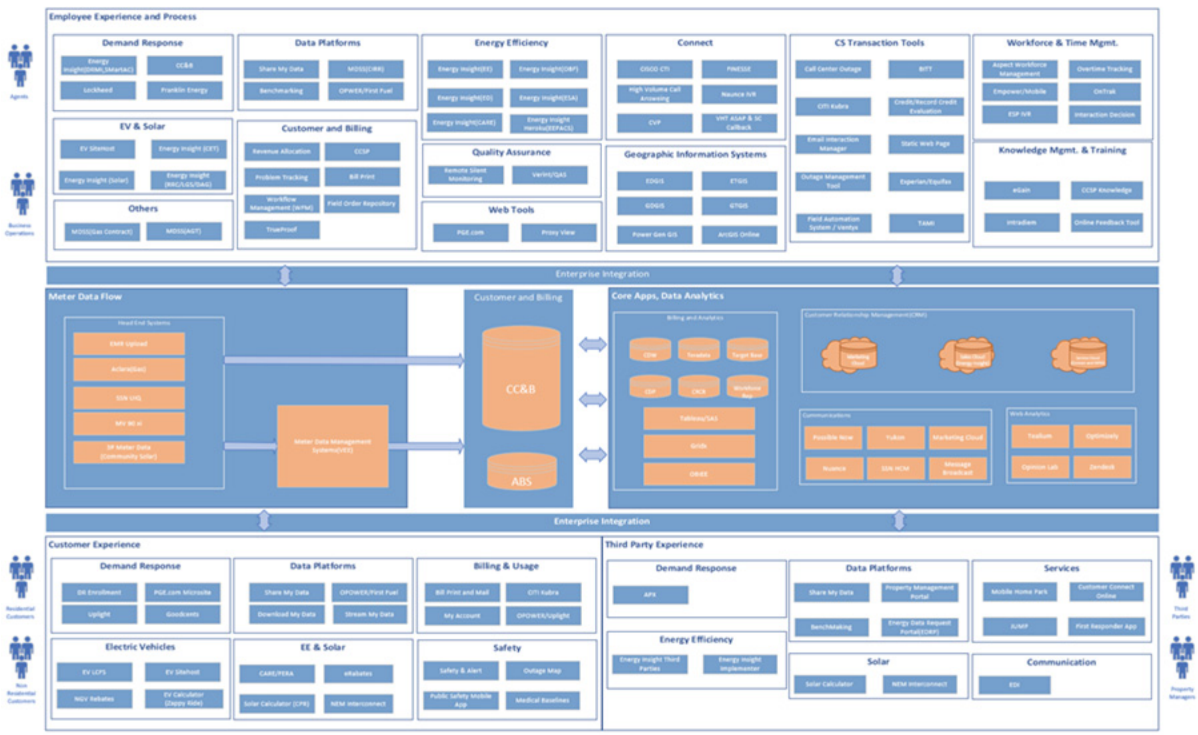
[15] D.23-11-069, p. 548.

Because the capital costs for the legacy billing systems have all reached the end of their asset lives, there are no stranded costs associated with the legacy billing systems (CC&B, ABS, and MDMS).

C. Current State CIS Architecture

Currently, PG&E's billing process relies on a number of different systems interfacing, directly or indirectly, with CC&B. This is also the case for many of the processes that would interact with a customer directly. The diagram below presents a simplified view of how these systems interact with each other:[16]

FIGURE 2-4
CURRENT STATE CIS ARCHITECTURE DIAGRAM



Because a CIS is central to any process related to a customer, CC&B 2.4 is an integral part of the operations at PG&E. Operational systems and tools have been developed to enable PG&E to serve customers in an efficient and cost-effective manner, and CC&B 2.4 and its data are used across the business to enable these operations. Customers engage with PG&E for a variety of reasons, and almost all these interactions require multiple steps across multiple

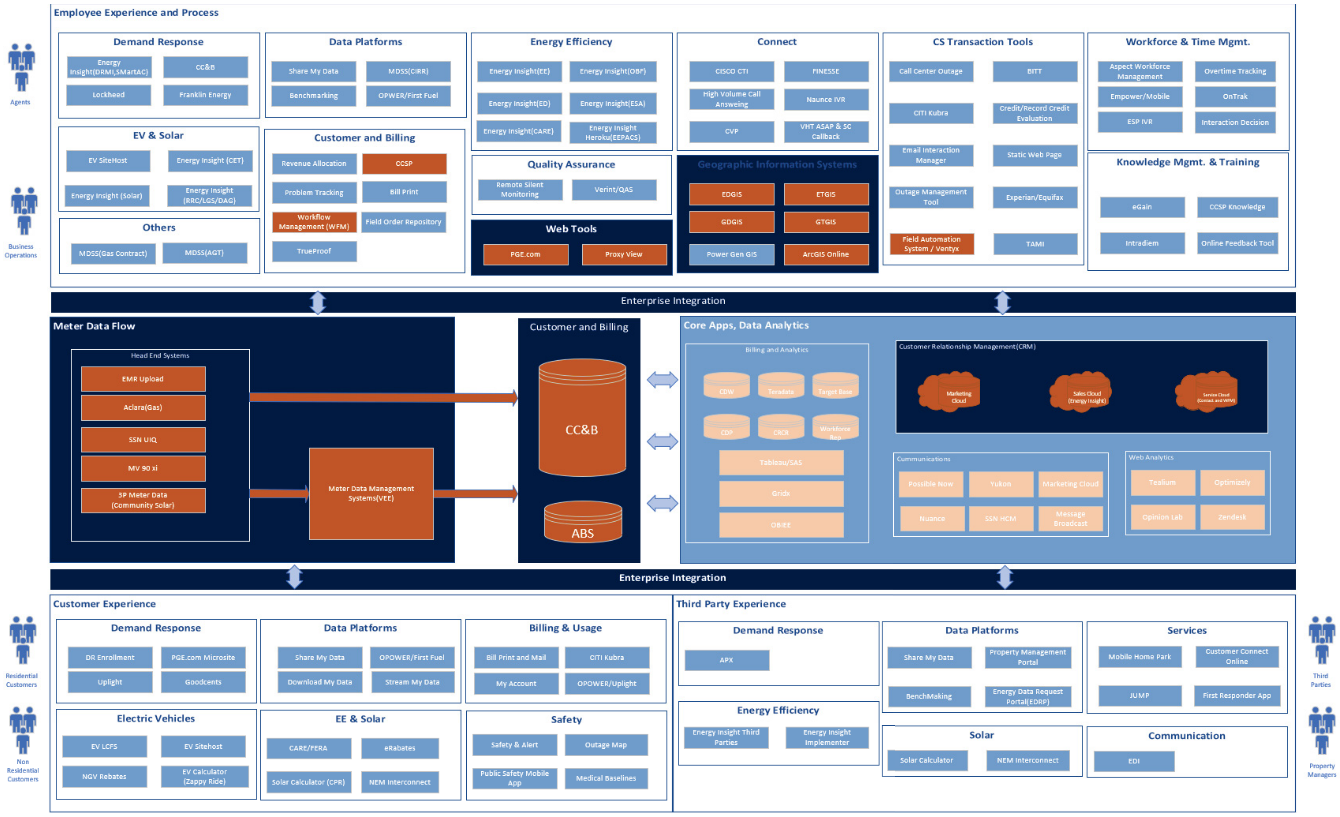
16 Refer to Chapter 2, Attachment B for a detailed Stage 1 architecture diagram.

systems. The following examples demonstrate the complexity of the current CIS.

1. Customer Sign-up

Consider the first interaction that many customers have with PG&E: signing up for service. The customer would engage with PG&E online (via PGE.com) or over the phone (via interactive voice response and cloud call center software). If the customer elects to use the website, they will trigger the authentication process that ensures web and customer security. These systems will rely on PG&E's GIS systems for location identification. Other customer information is gathered and stored in CC&B 2.4 and possibly ABS. Meter head-end systems will be used to determine if the meters at the customer location are active and available for service, and the MDMS system is leveraged to record any meter data at the start of service. PG&E may need to dispatch a worker to check on the meter and connection, which would involve the Field Order system and SAP Work Management. Once service is connected, PG&E would send the customer information electronically or in the mail (using the Bill Print Mail applications). Enterprise integration systems are in place to help all of these systems interface with each other, using a suite of different technology protocols.

FIGURE 2-5
CUSTOMER SIGN-UP PROCESS SYSTEMS

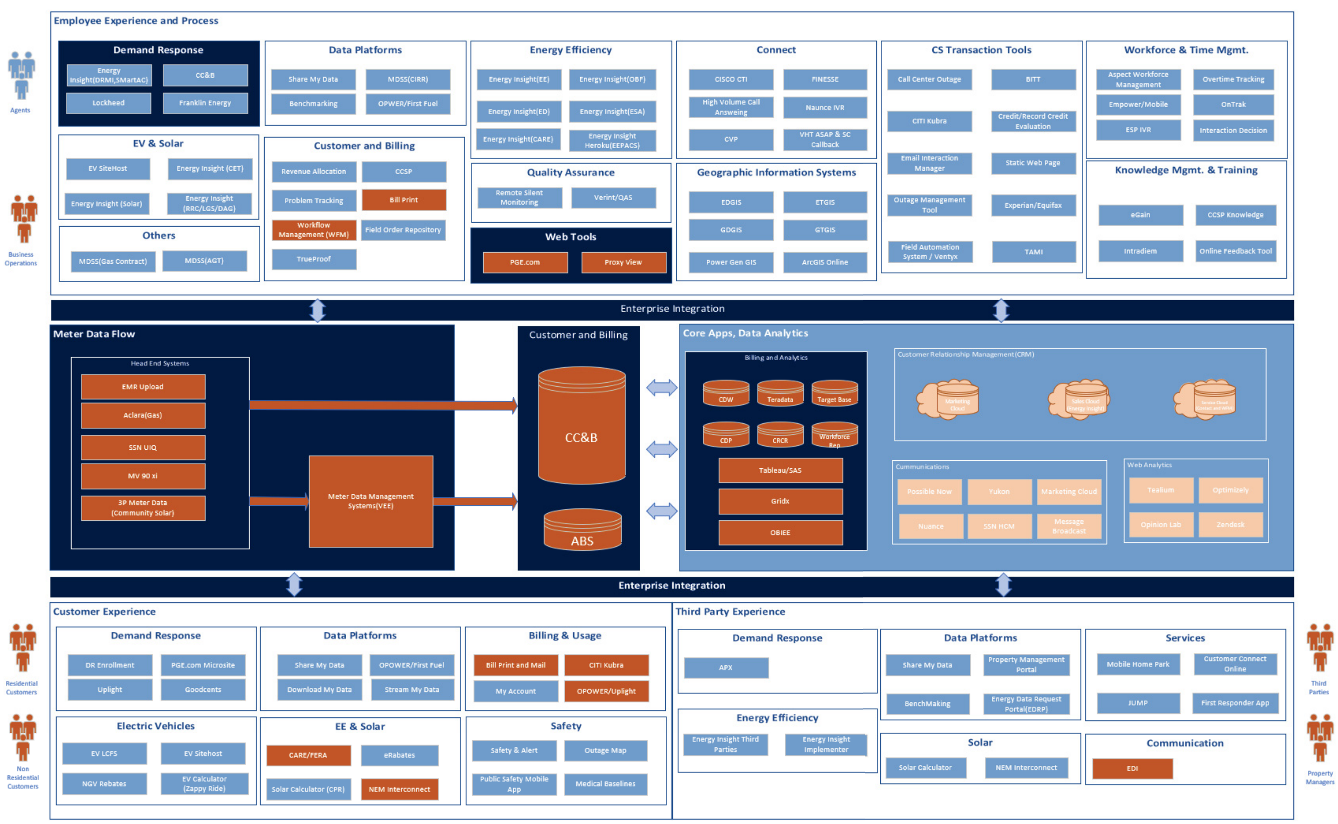


2. Customer Billing

Once service is set up, the next major interaction is when the customer receives a bill. It takes many steps and systems to deliver a bill to a customer. Throughout the month, meter head end systems access the meter and retrieve customer meter data, passing them to the MDMS. The MDMS will validate the data, based on the previously discussed Commission thresholds. In these cases, the MDMS will estimate or edit the data to billing quality standard. The resulting data are then passed to CC&B 2.4 and/or ABS for billable charge calculation. The billing systems will frame the usage into TOU, season, tier, and other dimensions for billing. The billing systems then use the framed usage to calculate the charges and make these data available for bill presentment, revenue reporting, and customer data reporting.

For bill presentment, a customer could receive a paper bill or electronic bill. In rare cases, generally with large commercial customers, the customer receives an electric data interchange (EDI) bill, a bill format that the customer can consume into their systems for processing. For paper bills, bill data are extracted from CC&B and bill messages are added. The bill extract data are sent through the bill print and mail systems, which compose the bill into a printable format and include bill inserts for customer notification. The bill print and mail systems also leverage US Postal Service data to correct customer addresses and to sort the output to simplify delivery by the postal carrier. For electronic bills, the bill print and mail systems also compose the bill and add messages, but the bill file is sent to an external vendor, Kubra (managed by Citibank), to create an online-viewable format of the bill. Kubra also prepares a notification to the customer that the bill is ready for view by using PGE.com. For EDI bills, a third path is leveraged. Once the bill composition is complete, the data is sent through the EDI system. This system is also leveraged to communicate with CCAs.

FIGURE 2-6
CUSTOMER BILLING PROCESS SYSTEMS



3. Revenue Reporting and Data Reporting

Revenue reporting is the process of documenting and analyzing PG&E's revenue. PG&E depends on revenue reporting systems to fulfill business-critical processes related to capture, reporting and management of revenue. These reporting systems are necessary for PG&E to meet its obligations to provide accurate revenue information to the Commission and other state agencies, the Federal Energy Regulatory Commission, and its shareholders (via the Securities and Exchange Commission filings). Data are also provided to comply with various requests such as audits of PG&E's revolving credit facility or Receivables Securitization Program.

For revenue reporting, interface logic extracts data from PG&E's billing system of record, CC&B, at the end of each day. The logic collects various billing and customer data to organize the revenue information by various elements, including customer class, rate schedule, special program, and others. Aggregated revenue information flows to PG&E's accounting systems for use in the financial processes.

Customer data reporting is necessary for timely and accurate billing and for many other data uses. Therefore, PG&E implemented the Customer Revenue Critical Reporting (CRCR) platform which runs on Oracle Utility Analytics platform. This platform is an analytics and reporting platform that leverages/consumes large amounts of customer data from CC&B. The system was intended to provide reporting and analytics capabilities without taxing the workload of CC&B. CRCR would allow users to create revenue reporting data while CC&B processed daily billing activities, both requiring heavy system load but on different platforms. Bill calculation is foundational to the CIS; bill calculation and reporting require separate systems because of the calculation workloads associated with each. Doing tax reporting, revenue reporting, and reports on all Service Agreements or meters is also a significant system resource load. To reduce this burden, utilities often separate the CIS from the analytics system. CC&B produces the customer data using Oracle's Golden Gate[17] replication functionality, then CRCR

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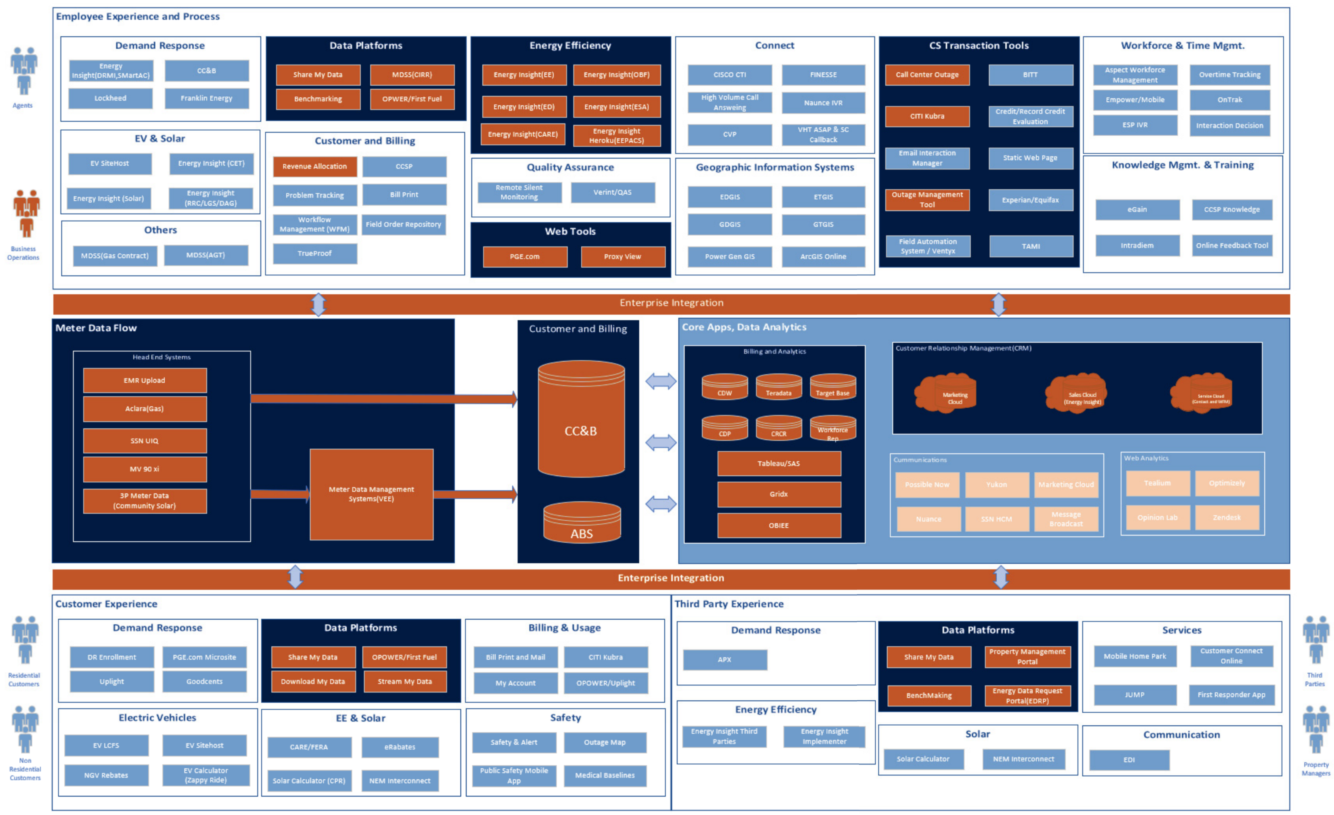
[17] Golden Gate is providing a real-time data mesh platform that is used for data replication and integration.

uses Oracle Data Integrator to extract, transform, and load the source CC&B data into CRCR. Oracle Business Intelligence for Enterprise Edition is then used to generate any necessary reports. Outside of CRCR, customer data is also transferred to the Customer Data Warehouse and Teradata, enabling various analytics to be performed.

Communication and transmitting information between these systems requires various integration technologies to keep the systems in sync and up to date with customer data. CC&B itself uses several integration technologies. This includes direct interfaces, XAI or webservice calls, Oracle Golden Gate replication, Informatica, Mulesoft, and others. Direct interfaces refer to logic that extracts data from one system and passes it to another for consumption. CC&B is both the recipient and the originator of these types of interactions. For example, to transfer customer data to ABS, CC&B extracts customer data for all active ABS accounts and passes a file to ABS for consumption. XAI and web services refer to the process of exposing data from a system for use by another.

CC&B leverages these services to interact with web, IVR, and Contact Center Service Platform (CCSP) systems, enabling customer data to be shared and updated as those systems interact directly with customers. Oracle's Golden Gate functionality is a replication tool used for large amounts of data that need to be transmitted to other systems. In this case Oracle Golden Gate transfers data to CRCR, which consumes large amount of replicated customer data nightly. Informatica and Mulesoft are examples of integration technologies that are employed to enable the sharing of data between systems. Revenue reporting relies on the CIS and will be negatively impacted by any CIS failures or issues.

FIGURE 2-7
REVENUE AND DATA REPORTING PROCESS SYSTEMS



D. Current Challenges Resulting from Legacy Systems

Over the decades, PG&E's billing systems have become incredibly complex, with numerous customizations and workarounds to provide new functionalities as requirements changed. The result is an inefficient and brittle system that imposes costs on customers through the need for manual intervention and creates risks because of the system's complexity and the age of the systems.

1. Rates Implementation

PG&E faces significant challenges implementing new rates because the complexity and volume of new rates requested by customers and the Commission continues to increase beyond the capabilities of PG&E's current systems. PG&E's mass billing system, CC&B 2.4, does not enable PG&E to implement rates within regulatory timeliness. Further, the design of the linear rate engine limits the ability to implement multiple rates and programs simultaneously. PG&E's complex billing system, ABS, is not a viable long-term alternative.

When PG&E implemented CC&B in 2001, most bills were calculated based on monthly manual meter reads. The billing system framework was designed to suit PG&E's tariffs at the time and featured a linear rate engine, which calculated charges with individual calculation routines (i.e., all of the calculation steps for a particular rate schedule) for each rate schedule or special program.

In the two decades since the CC&B system was implemented, there has been a rapid increase in not only the number of rates and programs available to any individual customer, but also the complexity of the calculations required to implement those rate programs. The following table lists rate implementations for the past ten years:

TABLE 2-1
HISTORICAL RATES IMPLEMENTATIONS (2015-2024)

Rate Implementation Project	Target Completion Year
PG&E Solar Choice (Green Option)	2015
SmartMeter Opt Out	2015
TOU-A and TOUB	2015-16
Net Energy Metering (NEM) 2.0 Phase 1	2016
On-Bill Refinance Phase 2	2016
San Bruno Penalty Refund	2016
Commercial NEM with Peak Day Pricing (PDP)	2016
Zero Minimum Bill for Electric California Alternate Rates for Energy (ECARE)	2017
Rate Mailer Onsert	2017
Greenhouse Gas (GHG) Cost Recovery and Climate Credit	2018
Electric Vehicle Rate A (EVA) Opt-In	2018-19
Lighting Service (LS)-1 Streetlight LED Surcharge	2018-19
Renewable Regional Solar Choice (Residential)	2018-19
E19/E20 Storage Rate – ABS	2019
Disadvantaged Community Green Tariff	2019-20
Solar TOU Period Grandfathering	2019-20
Full Residential TOU Default	2019-20
Commercial EV Rate	2019-20
San Francisco Surcharge Tax	2020
Commercial & Agriculture Rates Default	2020-21
Rate Mailer Process Automation	2020-21

Rate Implementation Project	Target Completion Year
Rate Design Window (RDW) 2012 Smart Rates	2015
LS-1 Streetlight LED Surcharge	2015
Electric Time-of-Use Pricing (ETOUP) 1, ETOUP2, and ETOUP3	2016
Three Tier Collapse and RDW Minimum Charge	2015-16
Three-Tier Structure On-Bill	2016
$5 Minimum Bill for FERA/ Non-Care Medical	2016
2-Tier Collapse, Super User Electric (SUE) Surcharge, got replaced with High Energy Surcharge (HUS)	2016-17
New Time-of-Use Option C (TOUC) (Multiple Phases)	2017-18
Gas Season Change	2019
Summer Season Change	2018-19
New Set of TOU Commercial Rates	2018-19
CCA Rate Ready Release 1-4 (Residential, Commercial, Agriculture, Streetlight)	2018-19
TOUC Rate with Bill Protection NEM – CC&B Phase 1	2018-19
Add CARE to Electric Vehicle (EV) rate	2019
Agriculture Rates Redesign	2019-20
New TOUD Rate Phase 1	2019-20
B1 Storage Demand Charge Rate	2019-20
TOUC Bill Protection Elimination for Start/Transfer Customers	2020
NEM 1.0 Grandfather Expiration	2020-21
PDP Change	2020-21
Local Green Saver	2020-21

TABLE 2-1
HISTORICAL RATES IMPLEMENTATIONS (2015-2024)
(CONTINUED)

Rate Implementation Project	Target Completion Year		Rate Implementation Project	Target Completion Year
Medical Baseline Change/Power Charge Indifference Adjustment Exemption Elimination	2020-21		E6 TOU Period and Season Change	2020-22
Non-Residential Flat Rate to TOU Annual Transition	2021-22		Semi-Automation of Food Bank Discount	2021-22
SmartRate™ Redesign	2021-22		PDP Event Hours Change	2021-22
Wildfire Plan of Reorganization (POR) and Capital Securitization Bond	2021-22		Auto Bill Review Rule 17 – Multiple Phases	2021-23
Percentage of Income Payment Pilot (PIPP) Phase 1-2	2022-23		E-Elec – Residential Electrification Rate Phase 1-2	2022-23
Net Billing Tariff (NBT) Phase 1 – Release 1-3	2023-24		NBT Phase 1 – Release 4	2023-25
E-Elec – Residential Electrification Rate Phase 3	2023-25		Dynamic Real Time Pricing	2023-25
Medical Discount on EV TOU Rate Plan 2A (EV2A)	2024		Net Billing Tariff (NBT) Phase 2	2023-26
Income Graduated Fixed Charge – CC&B	2024-26		Income Graduated Fixed Charge – Billing Cloud Service (BCS)	2024-26
Rate Identification Number Code on the Bill Statement (LMS Requirement)	2024		Net Billing Phase 1 Res – simple (exc. SR & SM Opt-Out)	2024

The volume and complexity of rates is projected to continue to increase, as PG&E currently forecasts that approximately 20 new rates will need to be implemented in the next year (this is separate from the ongoing rate maintenance and updates for price changes).[18]

Most significantly, the adoption of AMI devices has transitioned California to collect more detailed usage data (in increments of 15 minutes or hourly rather than just once a month) following the initial design and implementation of the CC&B system. Before 2006, about 90 percent of customers' bills were generated from a single monthly meter reading. With the broad introduction of AMI and smart meters, 99 percent of customers now receive their electric bills based on interval usage data. When issuing a bill, PG&E moved from two readings to between 720 and 3,000-meter intervals and readings per month, varied by rate schedule. This finer usage data allows for diverse billing options such as TOU rates, net energy

18 See Chapter 4, Table 4-1, PG&E's Forecasted Rate Implementation Pipeline.

metering for solar and other customer-based generation technologies, as well as commercial and residential EV rates. Consequently, the rise in the quantity of meter readings each month has significantly expanded the number of calculations needed to process each bill.

As California looks to meet or exceed decarbonization goals with transition to electrification and 100 percent renewables, rate design and customer energy use will continue to shift to more granular interval data and real time pricing rate design. PG&E needs a billing system that can meet and maintain the pace and complexity of future rates and programs as PG&E and regulators work to ensure stability, affordability, and prosperity for customers. PG&E's current systems cannot meet this goal today and will miss the mark in the future without replacement.

a. CC&B Drivers of Rates Implementation Challenges

PG&E's current mass billing system is ill-suited to the implementation of more complex rates and these implementations have become increasingly delayed and more expensive to implement. The complex rate schedules that PG&E maintains and develops in CC&B are difficult and time-consuming to build and maintain on a linear engine. Building these rates also requires extensive customizations, which require additional development time and are costly to maintain. These complex rates, and the customizations built to accommodate them in CC&B, lead to lengthy, complex calculation routines which increase development time, complexity, and costs. A mass billing system with a modular rating engine is required to address these issues.

The linear model implemented in the existing CC&B system is designed to run routines that use a simple set of data and calculations. However, the variety and complexity of today's rate structures do not align with the more simplistic framework technology. As discussed above, linear rating engines use individual, linear calculation methods for each rate schedule calculation (i.e., each residential rate schedule calculation has individual steps to determine the cost based on usage and applicable commodity cost), each of which must be re-written each time there is a new or changed rate.[19] This re-writing process increases the time and cost required for rate implementation.

Implementing new rates requires extensive use of customizations which are difficult to maintain. Due to CC&B's linear engine, the addition of any new rate component requires customization to each and every one of the existing CC&B rate schedule calculation routines, requiring a significant amount of development time and labor expense. Since the initial launch of CC&B, PG&E has implemented over 5,700 customizations of code and extensions of its current billing system – nearly 250 customizations per year over the life of CC&B. Each customization requires specialized programming skills to support the vendor software, and each customization requires ongoing maintenance and, potentially, further customizations. The additional labor and specialized support required to maintain these customizations leads to significant extra expense for PG&E.

The complexity of PG&E rates and their customizations has also led to increasingly complex and lengthy rate calculation routines. PG&E has implemented customized solutions to meet the rapid increase in demand for rate programs and technologies enabled by AMI devices in California, such as time varying rate plans, Net Energy Metering and other customer generation technologies, commercial and residential electric vehicle rates, and battery storage. The result of two decades of customized changes is a calculation framework requiring nearly four times the number of calculation steps to calculate new rates (compared to older, simpler rates) due to the increased complexity of rate programs.[20] This increase in calculation steps introduces

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[19] Most rate upgrades are executed as IT projects, as the requirements generally impact multiple processes. IT teams develop functional/technical designs. Changes could be rate calculation, program enrollment, energy statement display, revenue reporting, customer notification, data integration with other systems (Web, CCSP, etc.). As a project, the development of these changes across systems is managed against a timeline to allow the teams to code/test their changes, then perform integration testing between systems, in time for the changes to be deployed to meet regulatory deadlines.

[20] A.21-06-021, Exhibit (PG&E-06-E), p 10-11, Figure 10-3.

additional complexity and makes it take longer, as well as much more difficult and expensive, to implement any changes.

While PG&E's current CC&B 2.4 version has modular rate engine functionality, it is not feasible to develop rate calculations to leverage the functionality. As noted above, the complexity of the rates that PG&E maintains requires extensive customization. This complexity is compounded by the limited meter configuration options in CC&B 2.4, which requires the creation of separate calculations for EMR, interval, NEM, and NEM2 versions of the rates. Due to the separation of the MDM system and rate calculation, the move to the modular rate engine in CC&B 2.4 would require additional customization to provide the framed usage for the modular rate engine. Limited meter configuration options still require the creation of multiple versions of the rate calculations. Thus, the move to the modular rate engine in CC&B 2.4 would require significant initial implementation investment and significant ongoing investment to support the customizations with limited reduction in subsequent implementation costs or timelines. The resulting solution would not be cost-effective and would not resolve PG&E's inability to meet the demands and timelines of rate implementation. Accordingly, modifying the current system to use the modular rate engine is infeasible and does not resolve the issues related to the outdated software.

b. ABS and Stop-Gap Drivers of Rates Implementation Challenges

The state of PG&E's current systems does not allow for the implementation of some rates in CC&B and has caused PG&E to pursue stop-gap workarounds. For example, on July 14, 2022, the CPUC released an "Order Instituting Rulemaking [OIR] to Advance Demand Flexibility through Electric Rates,"[21] citing a whitepaper issued by the CPUC entitled, "Advanced Strategies for Demand Flexibility Management and Customer DER Compensation," which envisions broad implementation of a "unified, universally-accessible, dynamic,

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21 R.22-07-005, Order Instituting Rulemaking to Advance Demand Flexibility through Electric Rates (July 14, 2022).

economic retail electricity price signal."[22] This requires a complex rate structure and certain elements discussed can only be implemented on a large scale in a modular system. PG&E is currently utilizing a third-party vendor to "shadow bill" RTP rates until the Billing Modernization Initiative is complete and they can be built in C2M.[23] For a small customer population, this is a successful stop-gap strategy. As the customer adoption grows, and as more rates require shadow billing, this strategy becomes impractical, as the amount of data that must be exchanged with the third-party requires significant investment in infrastructure as well as delays to customer bills.

ABS utilizes a more flexible, modular rate engine which allows PG&E to more efficiently build complex rates. Indeed, the most complex rate programs, such as Virtual and Aggregated Net Energy Metering must be built in ABS. But ABS is not a sustainable long-term solution for three reasons. First, ABS is not able to scale to handle the volume of rates or associated customers required in California's energy environment. Second, using ABS requires that PG&E maintain customer data in two separate systems, introducing additional risk and complexity to PG&E's billing operations. Third, ABS is a niche application that does not have a common programming language, resulting in small marketplace of available support resources.

The modular framework that exists in the ABS system was designed with flexibility to handle complexity in rate calculation, resulting in the ability to meet the complexity of today's rate structures. But the framework is not designed for the number of customers that have broadly adopted the complex rates. As discussed in Section B, ABS currently serves as the billing system for over 140,000 customers—over five times its designed capacity. This overcapacity has already led to latency and performance issues, and performance would further

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22 Energy Division, Advanced Strategies for Demand Flexibility Management and Customer DER Compensation (June 22, 2022), p. 103.

23 The way a shadow bill functions is that the external vendor calculates the customer's RTP bill, and then PG&E performs a review annually to reconcile the amount billed through the shadow bills to the total energy statement amount and, in the event the shadow bill was lower, refunds the difference to the customer.

degrade if more rates and customers were housed on ABS. This equates to delays in resolving billing issues and delivering bills to customers.

Additionally, maintaining multiple systems for rate calculation increases cost, risk, and complexity to the implementation and support of rates. When a new rate is implemented, associated changes must be made in both ABS and CC&B, which require separate designs as well as separate development and testing activities. Likewise, maintenance of the rate calculations is performed by separate teams with expertise in the separate systems. These duplications increase costs and complexity. Furthermore, correct billing requires that customer data in the multiple systems be kept in sync. Out of sync data leads to delays in system processes at best, and incorrect billing (requiring rebilling) at worst.

PG&E's current billing system cannot continue to support the implementation of rates to support California's policy goals. The more than 5,700 customizations of code and extensions in the current billing system demonstrate that PG&E and the California utility industry have outgrown the capabilities of CC&B. Scaling the smaller ABS system is infeasible and PG&E's current state with multiple systems has already created an environment of increased costs and duration for implementation of new rates and programs. Therefore, it is critical to modernize its billing system with a new suite of configurable and modular-based calculation routines and rating engines that can address the more complex rates.[24]

2. Technology Integration

As described in Section C (Current State CIS Architecture) above, CC&B is central to PG&E customer operations. Maintaining CC&B, MDMS, ABS (and soon BCS), described in Chapter 4 separately creates additional

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[24] Note that other large utilities in California have already implemented significant billing system upgrades. *See* D.18-08-008, granting San Diego Gas & Electric Company authority to implement CIS Replacement Program; D.22-09-015, adopting a settlement agreement addressing Southern California Edison Company's Customer Service Re-Platform.

complexity, costs and issues for implementing rates, transferring data between systems, integrating systems, and data analytics.

The separation of MDMS and CC&B requires that PG&E maintain integrations between the meter head end systems and MDMS, as well as between MDMS and CC&B. This means that the process to get usage data from the meter to the billing system must go through multiple steps and systems. The data from the meter head end systems flows through MDMS, then on to CC&B, ABS, and some other systems. From CC&B, the data flows to CRCR and other downstream data warehouses. Because CC&B is central to most of the customer data processes at PG&E, the integrated systems must perform many functions within a 24-hour period. A delay in any of these steps leads to downstream delays, ultimately impacting PG&E's ability to produce customer bills in a timely manner or perform business operations utilizing customer data. The issue is further exacerbated with the ABS system, as the usage data for billing must go through additional steps to the system.

On top of these integration challenges between MDMS and CC&B and ABS, the current data retention design for MDMS is for 13 months of data that can be used for VEE. As data age past the 13 months, it is moved to a separate data warehouse. When operations are needed on data older than 13 months, manual intervention must be performed to restore the archived data and perform the VEE steps, leading to longer handling time for older exceptions.

The separation of MDMS and the current billing system also plays a large role in the current impacted rate program delivery. When PG&E began deploying AMI in 2006,[25] it used a separate MDMS to accumulate electric interval usage data and customized the rate schedule calculation routines in its billing system to frame the interval usage (i.e., by tier, TOU period, or special program usage period). As a result, PG&E must deploy customized updates to each applicable rate schedule calculation routine in response to mandated changes to tier calculations or TOU hours to modify the framed usage.

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25 D.06-07-027, p. 68, Ordering Paragraph 1.

Notably, recent rate program changes have seen revisions to TOU rate schedules for residential and non-residential customers, such as the creation of new TOU periods. In the current billing system, these changes require modifications to rate schedule calculation routines for each impacted rate schedule, which typically takes about 9 to 12 months (depending on the rate complexity and other requirements, like enrollment or grandfathering) from the CPUC decision to implementation.[26] This extensive modification process of CC&B customization is due to the MDMS's separation from the billing system, requiring the implementation of customized usage framing code (code that processes the unique usage intervals and applies them to the right TOU bucket for each rate schedule) in CC&B and ABS. For example, the recent implementation of the final step in changing the summer season TOU periods for rate schedule E-6 shifted the peak summer period by one hour and modified the partial-peak period. Using the current system (where CC&B and the MDMS are separate systems), this change took over six months to implement. With an integrated MDMS, implementing changes like these would be much more efficient (as further discussed in Chapter 4). Due to the need for extensive modifications of customizations and the linear rate engine of the customizations, PG&E will not able to meet regulatory obligations for rate implementations.

Similarly, PG&E's CC&B framework is now so heavily customized that PG&E must also customize integrations between CC&B and downstream systems (e.g., CRCR), rather than being able to use more standard adaptors and/or integrations. This has a two-fold impact. First, PG&E must develop a custom, non-standard functionality to extract and transit data to the downstream systems. Second, the downstream systems must develop functionality to support the custom data. In the case of CRCR, which is based on Oracle Utility Analytics, the product is designed to work with base CC&B data framework. As PG&E has implemented custom data tables, CRCR application has had to make the same changes, necessitating the support of multiple systems with the same customization. Another example is the ABS system. Since ABS is a completely custom system, PG&E had

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26 A.21-06-021, Exhibit (PG&E-06-E), p. 10-10, lines 4-8.

to develop custom interfaces to exchange data between the two systems. At a high level, PG&E downloads applicable customer data that ABS consumes, and ABS uploads billable charges that CC&B consumes. When a new customer data element is added, changes must be made to CC&B, ABS, as well as the interfaces between the two.

Integrations between systems also become more complicated when one system is out-of-date because compatibility requirements between systems might prevent PG&E from upgrading systems integrated with one obsolete system to their most recent versions without upgrading all systems. For example, an out-of-date version of CC&B is unable to work with the latest version of middleware (software that different applications use to communicate with each other), so the middleware must also run on outdated, out of support versions as well, causing risk for current operations (risks includes lack of qualified resources, security vulnerabilities, incompatibility with newer developed technologies, etc.) difficulty getting support, and more complicated future upgrades. This issue has become more complex as PG&E has adopted multiple middleware technologies as newer systems have been developed. The current middleware platforms include Oracle Fusion Middleware (including Weblogic), Oracle Service Bus, and J2EE, a JAVA-based platform, Informatica, and Mulesoft. . These disparate technologies require support staff to develop and maintain the various interfaces. The support staff require multiple skillsets of familiarity with outdated coding language and technologies who are often difficult to find.

Having multiple systems also makes data analytics more difficult. For example, on an up-to-date, unified customer information system, an end user in Billing Operations could easily visualize data to monitor operational performance indicators which track the progress of business processes for both end users and customer care managers (e.g., graphs showing created bills, pending bills, and completed bill segments with linked data). Instead, PG&E's current systems require reports and tables to be manually built with data from multiple systems, a labor-intensive and expensive process to develop and maintain. The result is a choice between custom, labor-intensive reporting or no analytics on daily work.

3. Risk Due to Lack of System and Vendor Support

PG&E maintains its current architecture through application version upgrades, building functionality (including via customization) and with vendor support for each system. Utilizing current versions of applications enables the most effective vendor support and is a key step in reducing cybersecurity risks. PG&E's CC&B 2.4 is leveraging out of support applications and architecture due to compatibility limitations. With increasing cybersecurity risks and vulnerabilities, the system is susceptible to a high level of risk.[27]

Application version upgrades are standardized software releases from the vendor that provide new features and functionality and modernize the application. As an example, consider the process of upgrading from Microsoft Windows 7 to Windows 10. Microsoft developed the Windows 7 operating system version and released it to the public in October 2009. Microsoft provided regular software updates until January 2020, when extended support ended. Microsoft released the newer Windows 10 version in July 2015. For users on Windows 7, Microsoft provided a software package update that upgraded the underlying operating system to the new version, Windows 10. This update package allowed Windows 7 users to move to a supported version of the operating system without the need for technical support or outside assistance. Examples of past version upgrades for PG&E's systems are discussed in Section B.1., above.

Generally, Oracle wants their clients to avoid being more than three versions behind the most recent application version. Often, version upgrades are optional, but using an outdated version of software will eventually impact the cost and availability of vendor support.

As these applications and infrastructure reach or surpass their useful lives, the risk of failure increases, compatibility issues become more prevalent, and vendor support (which includes cybersecurity patches, bug fixes, feature updates, development support, and more) becomes more costly and eventually unavailable. Once an application version reaches its end-of-life, vendor support that ensures operability both becomes more

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[27] See Chapter 3 for additional information.

expensive and decreases while the system experiences increased technical issues. Most vendors offer extended support, which includes routine failure analysis for bug fixes, maintenance releases, workarounds, or patches for critical bugs, but this typically comes at a higher cost. Additionally, most vendors focus on support of their most recent, in-support products, meaning resources that can support outdated versions may become scarce.

End-of-life applications and infrastructure also become more costly for internal resources to support as a result of increased troubleshooting and issue remediation associated with the failing system. After extended support ends, vendor support for the application becomes unavailable and security patches are also no longer available, which can create additional cybersecurity risks. Absent this support, the vendor does not release standard patches to PG&E. Instead, PG&E must engage the vendor for custom patching, requiring more time for resolution and at greater expense than if the application was in support. The cybersecurity risks and attacks have increased, leaving PG&E in an untenable position due to outdated systems.

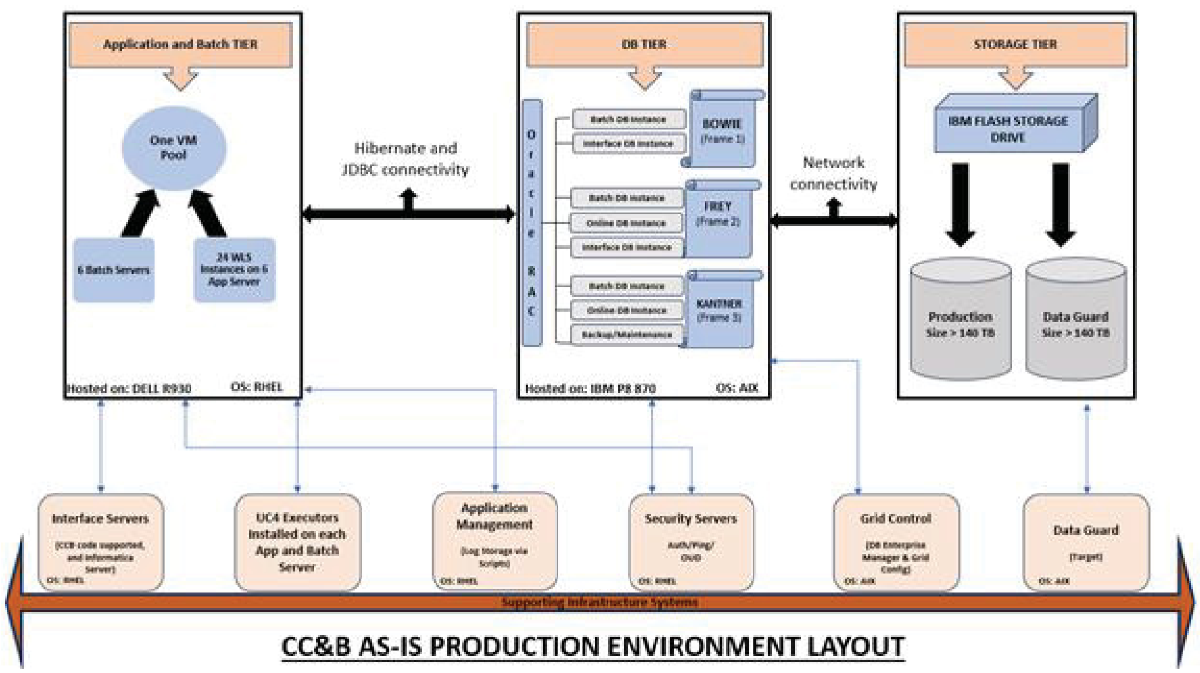
PG&E has a large number of customizations, which are programs built outside of the Oracle framework and require additional support. As discussed in Section A, above, customizations are built when the underlying system lacks the functionality to enable the business requirements. In recent years, PG&E's main areas of customizations include: (i) net energy metering true-up calculations, (ii) rate program eligibility and enrollment logic (e.g., special program eligibility, legacy systems, and calculating end dates of programs), and (iii) credit programs like Arrearage Management Program (AMP), where eligibility is complicated and the program allows a certain number of missed payments, which requires a custom monitoring functionality to keep customers on the payment plans. One of the main challenges facing the current billing system is the complexity of decades of customizations that were necessary to implement various rates and features using the CC&B platform, which was not designed for such tasks. Given the current support model, it is increasingly difficult to find qualified and knowledgeable personnel to support and maintain these customizations.

Other shortcomings associated with over-customization include the fact that PG&E cannot simply upgrade the CC&B system when a version is end of life/end of support. For CC&B, Oracle provides technical upgrade functionality to move the application from a prior version to new version. This functionality supports upgrades of base application processes, database, and application data. Customizations are not supported by the upgrade functionality, requiring a vendor to build custom upgrade processes and subsequent additional testing to confirm the customizations work in the new application version.

The same is true for application patches, in the same way Microsoft releases patches for Windows every couple of months. In the case of Windows, the user downloads the patch, installs it, and Windows is now up to date. With PG&E's highly customized CC&B, each patch must be individually assessed to see if PG&E has implemented a customization for the target patch functionality. If so, PG&E must engage a vendor to provide a custom patch and retest the functionality, or delay patching the system altogether. This makes the system further out-of-date, and further exposes the system to cyber risk.

In addition to CC&B, there are multiple systems required to execute and operate a CIS. For CC&B, the architecture is divided into application servers, database servers, interface servers, and some other miscellaneous servers. The interface and database servers are running on a current, supported version of AIX, a Unix operating system. CC&B application servers, on the other hand, are running on Redhat Linux Server 6.10. This operating system ended support in November 2020. PG&E is also using VMWare on these servers, which relies on ESXi to manage the VMWare (VMWare enables multiple application sessions to be run on the server concurrently). PG&E's version of ESXi ended extended support in November 2023. PG&E is unable to update these components because of application compatibility issues. ESXi cannot be updated to a current version because it won't run on the version of Redhat Linux that PG&E uses. Similarly, Linux and ESXi cannot be updated since CC&B version 2.4 will not work on future versions. PG&E must update all of these systems to reduce cyber risk.

FIGURE 2-8
PG&E'S CC&B AS-IS PRODUCTION ENVIRONMENT LAYOUT



4. Technology/Feature Set Obsolescence

As mentioned above, resources that can support application versions start to dwindle as applications age. For application vendors, this makes sense, as their clients start to upgrade to more current versions to stay in support. In PG&E's case, this poses a two-fold challenge. Given the decades of customizations to the system, PG&E has a limited number of personnel that are knowledgeable about the implemented code. New personnel are not able to support the functionality because much was implemented using Common business-oriented language (COBOL), an outdated coding language which few people are learning today. As the knowledgeable personnel leave or retire, there is a challenge to find replacements to appropriately support PG&E. This is true not just for PG&E, but also for the vendors that supply the underlying operating systems and related architecture that CC&B relies on.

Due to the age of PG&E's CC&B version and the high level of customization, PG&E faces challenges with taking advantage of new technology or features. With customizations, any upgrade requires the support from Oracle and personnel knowledgeable with the customizations to identify all of the changes needed to make them work with the new application version. This becomes a large undertaking due to the scale of customizations across the application. For example, PG&E calculates a large number of charges each night due to the size of PG&E's customer base. Due to the processing power needed to complete this task, PG&E implemented a customization to split the workload across multiple application sessions. This customization reduces the strain on an individual session and reduces the time for completion of the task. Beginning with CC&B version 2.8 this functionality is included in the base product.

In order for PG&E to upgrade to or past version 2.8, analysis must be performed on the implemented PG&E customization to ensure it aligns with the functionality of the base product and does not run afoul of any of the new processing rules. This analysis requires the understanding of both the current base functionality and detailed knowledge of the customization, which greatly limits the pool of people that can support the analysis. Further, this type of analysis is required across all of PG&E's customizations when doing an upgrade.

The age of the current billing system and the underlying technology also prevent PG&E from being able to respond and react to other vendor technologies. For example, Adobe ended support for its flash player on December 31, 2020, and blocked execution of the flash player on January 12, 2021.[28] The current billing system used the flash player to display customer information for call center representatives and other customer service users, necessitating PG&E's customized redevelopment of customer information portals without flash player capability in order for users to support customers.

This issue also impacted the current billing system when Microsoft ended support for the Internet Explorer browser in favor of the Edge

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28 Adobe, Inc., Adobe Flash Player EOL General Information Page, (Updated Jan. 13, 2021), <https://www.adobe.com/products/flashplayer/end-of-life.html#:~:text=the%20EOL%20Date.-,Adobe%20blocked%20Flash%20content%20from%20running%20in%20Flash%20Player%20beginning,running%20after%20the%20EOL%20Date>, (accessed Sept. 23, 2024).

browser.[29] The current billing system is certified for use with the Internet Explorer browser and not for the Edge browser. Until PG&E can deploy a new billing system with the Billing Modernization Initiative, PG&E will need to maintain a compatibility function so that the current billing system works with the Edge browser. As other products are removed from market, PG&E could be required to continue to develop custom patches (at a higher cost and with more system vulnerability) for its existing billing system.

5. Data Privacy

To meet California Consumer Privacy laws, PG&E has developed custom functionality which uses a set of criteria to identify and remove data in batches. Under the current system, the batch disposition of personally identifiable information is not currently available for PG&E. The current versions of the applications do not have built-in capability to purge data based upon a specified retention period. Because CC&B is the system of record for customer information, any record deletion request would flow to the integrated downstream systems, requiring impact analysis to downstream systems before batch deletion of data. For example, within the ABS system, a request requires personnel to manually query data elements across multiple data tables and manually review to ensure deletion will not impact system integrity. The current process requires manual processing and must be performed across multiple systems. It is an inefficient method and cannot scale for large customer requests. Data privacy improvements are further discussed in Chapter 4, Section B.1.d.

E. Conclusion

For the reasons discussed above, PG&E must upgrade, and ultimately replace, its legacy CC&B, ABS, and MDMS systems with the solutions discussed in Chapter 4.

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29 Microsoft Corporation, Internet Explorer 11 desktop application ended support for certain operating systems (Nov. 3, 2022), <https://docs.microsoft.com/en-us/lifecycle/announcements/internet-explorer-11-end-of-support> (accessed Sept. 23, 2024).

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT A

LINEAR VS. MODULAR RATE ENGINE VISUAL

Linear Rate Engine Visual

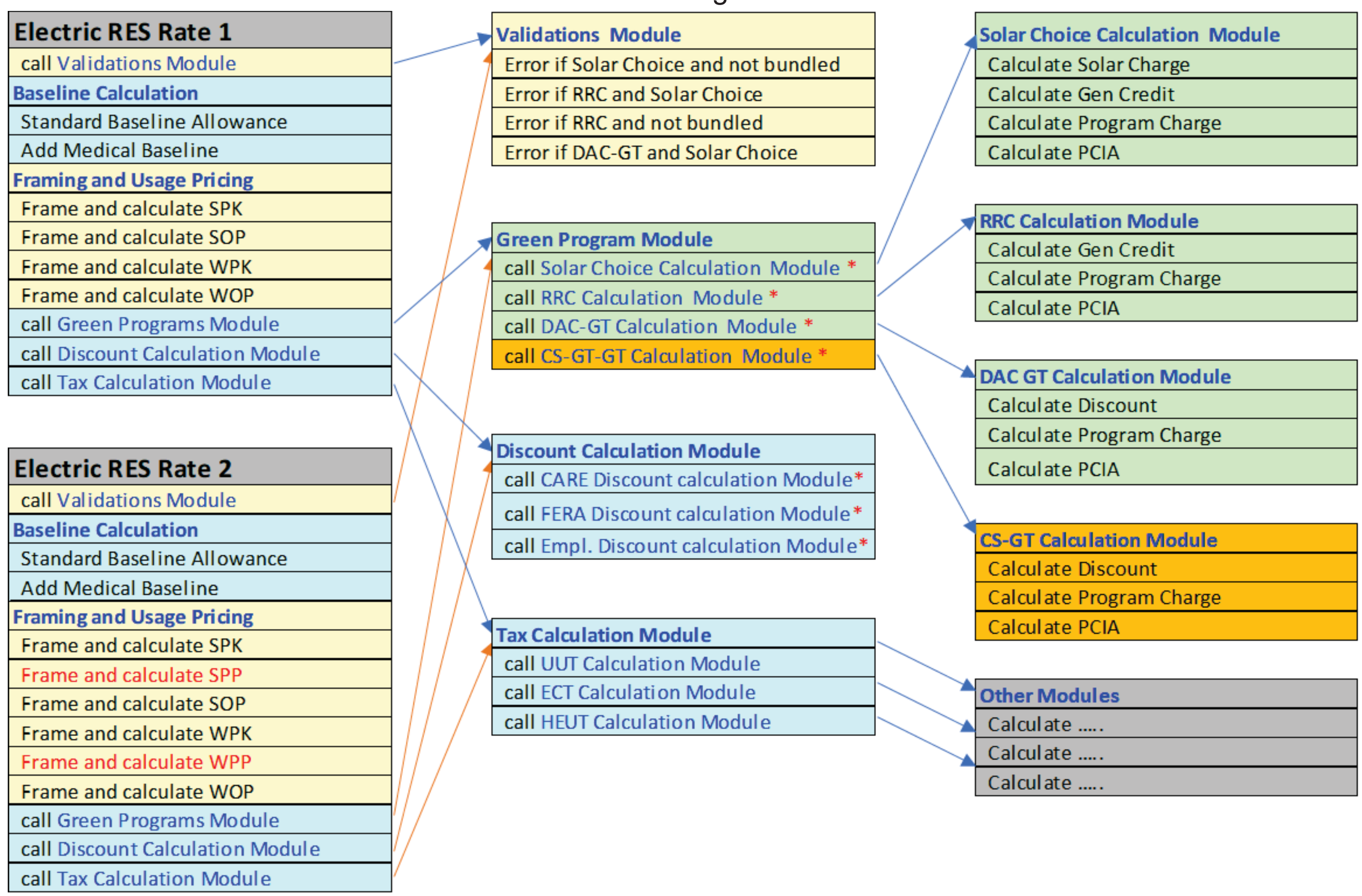
Electric RES Rate 1
Validations:
Error if Solar Choice and not bundled
Error if RRC and Solar Choice
Error if RRC and not bundled
Error if DAC-GT and Solar Choice
Baseline Calculation
Standard Baseline Allowance
Add Medical Baseline
Framing and Usage Pricing
Frame and calculate SPK
Frame and calculate SOP
Frame and calculate WPK
Frame and calculate WOP
Solar Choice Calculation
Calculate Solar Charge *
Calculate Gen Credit *
Calculate Program Charge *
Calculate PCIA *
RRC Calculation
Calculate Gen Credit *
Calculate Program Charge *
Calculate PCIA *
DAC GT Calculation
Calculate Discount *
Calculate Program Charge *
Calculate PCIA *
CARE Discount … */component
FERA Discount … */component
Employee Discount … */component
Taxes …

Electric RES Rate 2
Validations:
Error if Solar Choice and not bundled
Error if RRC and Solar Choice
Error if RRC and not bundled
Error if DAC-GT and Solar Choice
Baseline Calculation
Standard Baseline Allowance
Add Medical Baseline
Framing and Usage Pricing
Frame and calculate SPK
Frame and calculate SPP
Frame and calculate SOP
Frame and calculate WPK
Frame and calculate WPP
Frame and calculate WOP
Solar Choice Calculation
Calculate Solar Charge *
Calculate Gen Credit *
Calculate Program Charge *
Calculate PCIA *
RRC Calculation
Calculate Gen Credit *
Calculate Program Charge *
Calculate PCIA *
DAC GT Calculation
Calculate Discount *
Calculate Program Charge *
Calculate PCIA *
CARE Discount … */component
FERA Discount … */component
Employee Discount … */component
Taxes …

Electric RES Rate 3
Validations:
Error if Solar Choice and not bundled
Error if RRC and Solar Choice
Error if RRC and not bundled
Error if DAC-GT and Solar Choice
Baseline Calculation
Standard Baseline Allowance
Add Medical Baseline
Framing and Usage Pricing
Frame and calculate SPK
Frame and calculate SPP
Frame and calculate SOP
Frame and calculate WPK
Frame and calculate WPP
Frame and calculate WOP
Solar Choice Calculation
Calculate Solar Charge *
Calculate Gen Credit *
Calculate Program Charge *
Calculate PCIA *
RRC Calculation
Calculate Gen Credit *
Calculate Program Charge *
Calculate PCIA *
DAC GT Calculation
Calculate Discount *
Calculate Program Charge *
Calculate PCIA *
CARE Discount … */component
FERA Discount … */component
Employee Discount … */component
Taxes …

In a linear rate engine, all individual components are configured on each rate schedule. Common components on similar rates (e.g., interval vs. EMR, Non-NEM vs. NEM) are configured repeatedly on each rate. When a change is required to a component, all rates have to be updated, tested, etc.

Modular Rate Engine Visual



In a modular rate engine, individual components can be configured within modules called Calculation Groups. Calculation groups can be invoked/used by other groups and the configuration is not repeated. When a change is required to a component, only the module with the affected component requires changes.

PACIFIC GAS AND ELECTRIC COMPANY

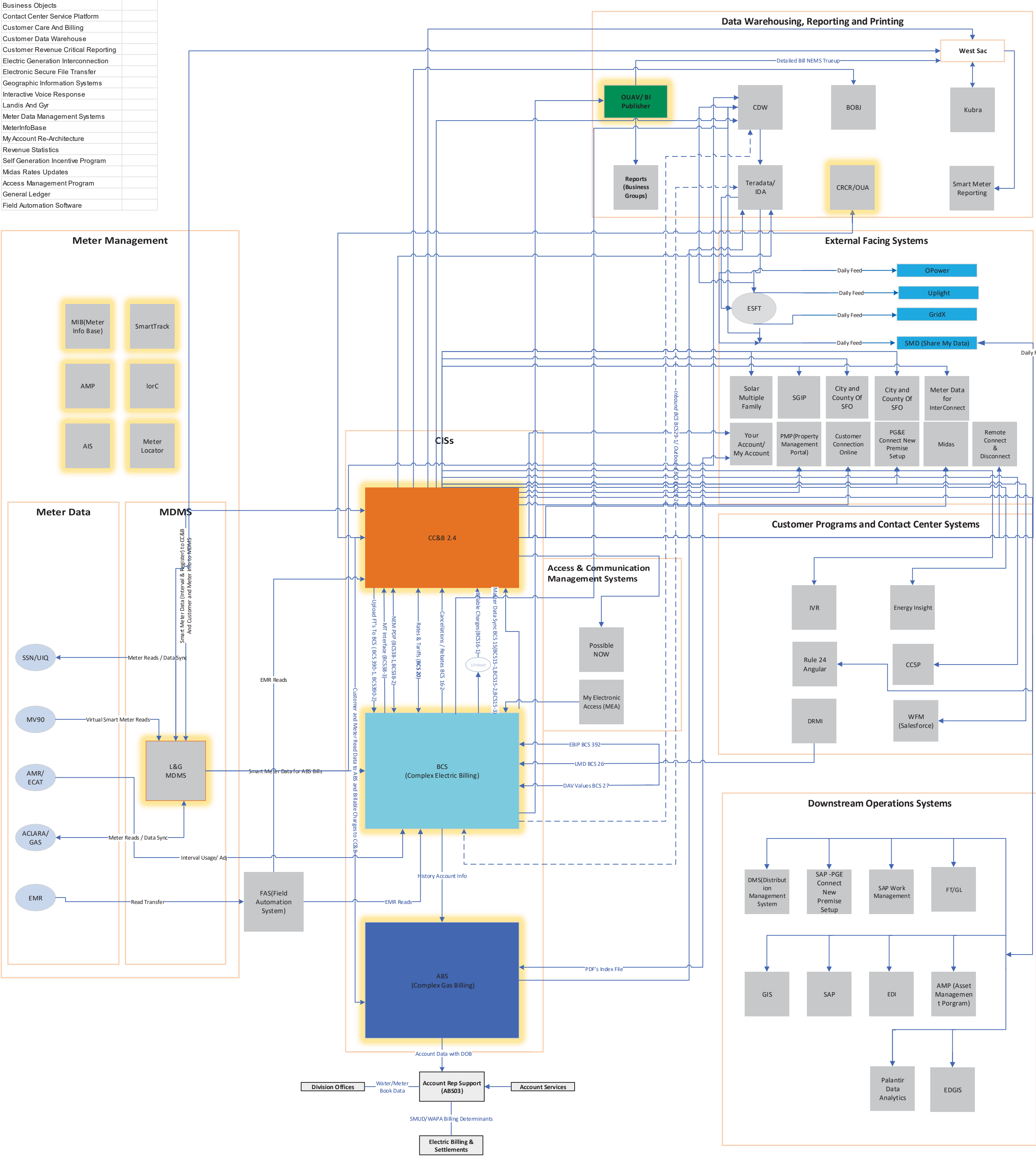
CHAPTER 2

ATTACHMENT B

STAGE 1 ARCHITECTURE DIAGRAM

Billing Modernization
Stage-1 BCS Upgrade

Appraisal System	
Advanced Billing System	
Automated Rate Analysis Program	
Billing Cloud Service	
Business Objects	
Contact Center Service Platform	
Customer Care And Billing	
Customer Data Warehouse	
Customer Revenue Critical Reporting	
Electric Generation Interconnection	
Electronic Secure File Transfer	
Geographic Information Systems	
Interactive Voice Response	
Landis And Gyr	
Meter Data Management Systems	
MeterInfoBase	
My Account Re-Architecture	
Revenue Statistics	
Self Generation Incentive Program	
Midas Rates Updates	
Access Management Program	
General Ledger	
Field Automation Software	



PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

BILLING SYSTEMS AND RISK MANAGEMENT

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BILLING SYSTEMS AND RISK MANAGEMENT

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CHAPTER 3
BILLING SYSTEMS AND RISK MANAGEMENT

A. Introduction

This chapter discusses the risk Pacific Gas and Electric Company (PG&E) faces from its over twenty-year-old billing system and the associated components and the urgent need to replace them. The systems being replaced by the Billing Modernization Initiative are Mission Critical systems. Without the Billing Modernization Initiative, these critical systems are subject to significant cyber and asset failure risks. PG&E has identified these risks through both internal and external assessments.

B. Accenture 2018 and 2022 Risk Mitigation Evaluations

PG&E engaged Accenture in 2018, and again in 2022, to evaluate PG&E's options for mitigating the risks associated with the current billing system. In 2018, through a series of interviews, workshops and blueprint sessions covering over 100 functional cases, Accenture identified over 80 "pain points" – unsatisfied customer needs, operational inefficiencies, and compliance, regulatory, operations, and obsolescence risks.

Compliance risks resulted from the inability of the billing system to implement Commission-mandated rate designs and tariff alternatives. Regulatory risks were identified because of a three-year back-up of regulatory work to implement new rate designs. Accenture concluded operational risks included a lack of vendor support, lack of technical resources, and lack of interoperability with new technologies, resulting in the use of antiquated processes to support the legacy CC&B, ABS, and L&G technologies.

In 2022, Accenture confirmed these same risks and recommended PG&E address these risks by implementing BCS and moving to a fully integrated Customer Information System (CIS) like C2M. As discussed in Chapter 4, Accenture's 2018 review recommended pivot to a fully integrated, leading CIS platform in the medium term; its 2022 review recommended that PG&E continue to pivot to a modern, integrated CIS, and continued use of Oracle products.

Accenture noted “PG&E Meter-to-Cash Platform must continually evolve to address systematic & infrastructure challenges.”[1]

Since Accenture’s 2022 refreshed review, and as discussed in Chapter 4, PG&E continues to consider how its billing system risks have evolved, persisted, or been mitigated. PG&E has undertaken both quantitative and qualitative risk analysis.

C. PG&E Cyber and Asset Failure Risk Evaluation

PG&E has a comprehensive risk management policy, process and practice that is reflected in regular Business Impact Analyses (BIA), disaster recovery testing, and PG&E’s Risk Assessment and Mitigation Phase (RAMP) report, filed with the Commission on a four-year cycle.

1. Business Impact Analysis and Critical Processes

PG&E implemented a BIA process over 20 years ago with the aim of reducing the risk of critical business systems and processes being disrupted. The BIA, similar to ISO, is an outside standard. It is an industry recognized and used methodology for evaluating risks. Scheduling regular BIA updates allows the business, IT, and cybersecurity to audit risks and vulnerabilities against critical company processes. A BIA is a best practice for IT and Business partners to identify critical systems and to assess whether those identified are mission critical, business critical, or significant. These terms are defined as follows:

- Mission Critical: Processes essential to PG&E’s ability to operate in a safe, reliable, and affordable manner. If the processes fail, there is immediate catastrophic impact on PG&E’s ability to fulfill its mission.
- Business Critical: Processes required for PG&E’s long-term survival and success. If processes fail, it brings into question PG&E’s viability.
- Significant: Processes whose outcomes affect PG&E’s business performance. If processes fail, it will be impactful to PG&E’s business functions.

PG&E leadership, using BIA, evaluates four Mission Critical and six as Business Critical processes. The most recent BIA was in February 2024 for Customer Care and Billing (CC&B) and July 2024 for Advanced Billing

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[1] WP 4-5, Accenture, Meter to Cash Strategy Refresh (Jan. 18, 2022).

System (ABS). Together, the processes that fit into the above categories are:

- Customer Contact Center/Workforce Management: Inbound Call Handling and Routing (Mission Critical);
- Public Safety Power Shutoff (Mission Critical);
- Customer Payment Validation (Business Critical);
- Billing Printing & Bill Presentment (Mission Critical);
- Payment Processing Center and Electronic Payment Processing (Mission Critical);
- Customer Refunds (Business Critical);
- Demand Response Programs (Business Critical);
- Revenue & Statistics (Business Critical);
- Revenue Reporting (Business Critical); and
- Market & Credit Risk Management (Business Critical).

This evaluation focuses on seven categories of risk: safety, seismic, financial, environmental, compliance, reliability, and reputation. In addition, according to PG&E's practice and international standards, each of these processes is to be subject to disaster recovery testing.

By upgrading the billing systems proposed in this filing, PG&E will improve the reliability, supportability and reduce the vulnerabilities in the billing systems increasing PG&E's ability to execute these business processes and reduce the risk of a cyber-attack.

2. Disaster Recovery Testing

PG&E is unable to perform disaster recovery testing for many of its critical billing systems.[2] There is a significant risk that if disaster recovery testing was performed a cascading or catastrophic failure could occur when operators move to bring the platform and the various components back to normal operations. For CC&B and the overall billing process, PG&E's standard is to perform an annual disaster recovery test, but PG&E has identified key risks preventing such a test. To avoid the risk of a restart failure, PG&E has delayed undertaking disaster recovery testing for CC&B

2 For the billing process, PG&E is able to perform disaster recovery testing for its bill printing processes; PG&E also completed a disaster recovery test for ABS in June, 2024.

and the overall billing process, which means that certain mission- and business-critical processes identified in the BIA are not subject to disaster recovery testing.

The international standard for business continuity management is ISO 22301:2019, Security and resilience – Business continuity management systems – Requirements (ISO 22301). This standard, a management system standard published by International Organization for Standardization, is a general standard that specifies requirements "to plan, establish, implement, operate, monitor, review, maintain and continually improve … management system[s] to protect against, reduce the likelihood of" occurrence, prepare for, respond to, and recover from disruptive incidents when they arise.[3] This standard notes that effective BIA management recommends companies undertake annual disaster recovery testing to assist in evaluating future plans for critical activities.

Delaying disaster recovery testing creates an additional risk – the mission critical and business critical systems are not being stress tested to determine how they will respond during a failure of normal operations. This means that PG&E's recovery plans are untested and difficult to maintain to generally accepted levels of practice. With CC&B being central to so many processes related to supporting PG&E's customers, this creates risk for the integrated systems as well, as the disaster recovery testing for those systems is incomplete. Additionally, PG&E staff with responsibility for disaster recovery cannot test their skills and their ability to respond to failures.

3. PG&E's 2024 RAMP [Witness: David Lo]

To evaluate the quantifiable risks, PG&E built on the foundation established through PG&E's 2024 RAMP,[4] with specific focus on PG&E's risk "Cyber Risk Event". PG&E defines a cyber risk event as, "[a] coordinated malicious attack targeting PG&E's core business functions resulting in a disruption or damage of systems used for gas, electric and/or

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3 See ISO 22301:2019, available at: https://www.iso.org/standard/75106.html (accessed Oct. 3, 2024).

4 Application 24-05-008,2024 RAMP Report, Exhibit PG&E-7, Chapter 2.

business operations."[5] This definition encompasses the five-mission critical and two business critical billing systems components incorporated in PG&E's BIA.

PG&E's 2024 RAMP provides a detailed, quantifiable enterprise-level analysis of a cyber risk event. The monetized safety risk value is $25 million, and the total risk value is $1.026 billion for a catastrophic cyber risk event. The overall risk value of a cyber risk event is the eighth largest of the 40 risks included in the RAMP with the safety value being eighth and the total risk value being fourth highest. Given the BIA-determined criticality of the PG&E billing systems, the RAMP cyber risk event analysis provides an indication of the exposure PG&E's billing systems have to cyber-attacks.

As noted within the RAMP, PG&E's exposure to attacks is not decreasing but rather is increasing in both volume and in sophistication.[6] For example, on October 3rd, American Water, the largest regulated water and wastewater utility company in the United States, which serves over 14 million people in 24 states and 18 military installations had key systems taken offline due to a cybersecurity incident. The suspected ransomware attack targeted American Water's customer portal including their billing systems. The attack left 14 million customers without access to a service portal and disrupted billing processes.[7]

CC&B 2.4 and ABS are aging systems that subject PG&E to an increasing vulnerability to sophisticated attacks such as malware attacks, ransomware, exploitation of software vulnerabilities, exploitation of unsupported hardware, and Distributed Denial of Service (DDOS).[8] The malware, ransomware, and exploitation consequences of such cyber-attacks could potentially result in data exfiltration and data leakage. These consequences could have reputational, regulatory, customer, and financial

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5 *Id.*, at p. 2-2, lines 7-10.

6 *Id.*, at p. 2-7, lines 2-19.

7 DarkReading, American Water Suffers Network Disruptions After Cyberattack, available at: https://www.darkreading.com/cyberattacks-data-breaches/american-water-network-disruptions-cyberattack (accessed Oct. 22, 2024).

8 DDoS, or Distributed Denial of Service, is a cyberattack that floods a server with internet traffic to make resources unavailable.

impacts with an industry average of $4.88 million per event in 2023 and up into the billions based on PG&E's 16 million customers PG&E services. Additionally, a DDOS attack consequence would deny system availability of the Contact Center's mission and business critical processes that can result in an additional $382,000 in overtime cost every 24 hours to the Contact Centers and $72,000 every 24 hours in additional Information Technology operational cost to restore service. A system failure would result in an inability to process start/stop/transfers and restore/disconnect (e.g., PSPS) service or communicate to customers during a weather event in a quick and efficient manner in order to maintain public safety. Further, it would hinder our ability to efficiently dispatch the appropriate personnel in the event of a potential hazardous situation.

While PG&E has actively sought to mitigate cyber vulnerabilities by deploying security update patches for internal servers and databases and by securing its data center facilities with appropriate controls, their ability to address vulnerabilities within the billing software is limited. The volume growth of identified internal vulnerability issues requiring patches has accelerated considerably in recent years. These data, along with further context on the escalation of cybersecurity threats, is available in workpaper WP 3-1 (Cyber Threat Landscape).

Cybersecurity risk reduction calculations indicate that $10 million (calculated using PG&E Cybersecurity Risk Index Methodology calculating the risk reduction against the 2024 PG&E Cybersecurity Bowtie) of PG&E's existing enterprise risk will be reduced through risk mitigation efforts including upgrading CC&B and ABS systems through the Billing Modernization Initiative. Collateral impacts are difficult to quantify, but would impact public safety, customer service, and PG&E's ability to deliver essential services and could impact the reporting of a hazardous event (e.g., notification of a wildfire event). When PG&E quantified financial impacts of a non-catastrophic cyber risk event scenario, the potential consequence could result in up to $197 million. This includes remediation of highly vulnerable systems and hardware that could not be mitigated in the past without a complete lifecycle upgrade of both.

D. Billing Modernization Initiative Cyber Risk Mitigations

The Billing Modernization Initiative will ensure that the lifecycle systems are built with security best practices and compliance requirements baked into the design which further reduce cyber risk to PG&E. These lifecycle systems will enable advance security capabilities that significantly reduce the likelihood, and impact, of a cyber-attack on PG&E's mission-critical processes. Lastly, the project, in addition to other investments (controls and mitigations listed in the RAMP report), would result in a 2.4[9] Cost Benefit Ratio for PG&E's risk mitigation to demonstrate cost efficiency.

The consequence of not funding Billing Modernization Initiative will be compounding financial, reputational, safety, and reliability impacts. These consequences will continue to rapidly grow as the threat landscape and cyber-attacks on the utility industry is out pacing two times PG&E's internal security controls to protect unsupported systems and hardware. The compensating controls implemented to reduce the cyber risk to PG&E will require additional ongoing operations and maintenance that occurs at an annual cost of $624,000 in expense dollars (calculated by identifying the per hour labor costs of IT staff and the vendor support costs added to the existing cybersecurity compensating control costs).

The compounding impact of not funding the project goes beyond the contact centers' Mission Critical Processes. The vulnerabilities in CC&B 2.4 and ABS could be exploited as entry points to steal credentials to elevate privileged access and move lateral to inject malware into additional systems that support other mission critical processes.

In addition to the risk of a cyber-attack on PG&E's billing systems there is a likelihood of an asset failure which can result in catastrophic consequences for PG&E's customers and operations. Billing system asset failure risks have not been quantified in either PG&E's 2024 RAMP or in the CBA but are likely equal to or greater than the cyber risk. Mitigating the asset failure risks should be considered a major benefit of the billing systems modernization project. The table below includes illustrations of which risks will be mitigated by each stage of the Billing Modernization Initiative:

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[9] *Id.*, at p. 2-25, line 1.

TABLE 3-1
C&B, BCS, AND C2M ASSET FAILURE RISKS AND MITIGATIONS

Line No	CC&B, BCS, and C2M Asset Failure Risks and Mitigations			
	Risks and Potential Consequences	BCS	CC&B	C2M
1	Risk: Current systems are out of support from vendors and ineligible for upgrades or patches. Consequence: Failure to address will create exposure to scenarios in which PG&E is left without specialized support to resolve system failures and is ineligible to receive upgrades or patches to their platforms.	Migration of complex electric customers from ABS to Oracle BCS will establish vendor support by moving away from custom-built platform, extend period of vendor support,[a] and will reduce volume of estimated bills.	Upgrade to CC&B will re-establish vendor support and eligibility for regular patches and upgrades. It will also accelerate the technical capability to migrate to C2M.	Consolidation to C2M migrates remaining complex gas customers from ABS (reducing volume of estimated bills), provides in-support product for CC&B and MDMS, and extends period of vendor support beyond cutoff point of CC&B 25.1,[b] enabling further risk reduction.
2	Risk: Outdated COBOL code base Consequence: Foundation of legacy code language limits the talent pool of specialists who can maintain code, creating supportability risks due to lack of trained resources	Migration of complex electric customers to BCS will include transition of code base to Groovy code language, establishing a foundation rooted in modern code languages.	Migration to CC&B 25.1 will include migration of customizations to Java, establishing a foundation rooted in a modern code language.	Final consolidation to C2M will migrate all customers to modern, Groovy-based platform, establishing a single billing platform with standardized coding language and broad marketplace supportability.

(a) While ABS will undergo an upgrade of its underlying operating system software in 2024, support will expire in January 2029; it is therefore imperative to reach the C2M target state and retire ABS in 2029.

(b) Specific vendor support timelines have not been announced by Oracle but are presumed to extend for 5 years, in line with previous CC&B releases.

TABLE 3-1
C&B, BCS, AND C2M ASSET FAILURE RISKS AND MITIGATIONS
(CONTINUED)

Line No.	CC&B, BCS, and C2M Asset Failure Risks and Mitigations			
	Risks and Potential Consequences	BCS	CC&B	C2M
3	Risk: Lack of interoperability between antiquated, COBOL-based systems with out-of-support integration components (e.g., WebLogic, Oracle Service Bus (OSB)) and modern software. Consequence: Failure to update code base from COBOL results in inability to integrate systems and necessitates additional data conversions.	Migration of complex electric customers to BCS will include a transition of code to a Java-like and Groovy code languages, enhancing interoperability with CC&B and other systems.	Upgrade from 2.4 to 25.1 will modernize from COBOL to Java code base and upgrade underlying integration technologies such as WebLogic and OSB into supported versions, improving interoperability.	Final consolidation of all customers into C2M and enablement of Oracle Service Oriented Architecture (SOA) suite will simplify interoperability with major systems (e.g., SAP S4,[(c)] Geographic Information System (GIS). This will also transition billing systems from a heavily customized current state across multiple logical data models to an improved, centralized logical data model, improving interoperability within CIS domain.
4	Risk: ABS operating beyond intended customer volume. Consequence: System will operate beyond its intended capabilities, leading to degrading performance, delays to billing and rate implementation, impedance of billing processes, and possible system failure.	Upgrade to BCS will transition complex electric customers to a cloud-based service, with inherent ability to accommodate significantly larger customer base, reducing volume of estimated bills.	Not applicable – Upgrade to CC&B 25.1 will not directly impact ABS performance risks.	Final consolidation of ABS and BCS into C2M allows servicing of all complex billing customers in a single platform and reduces volume of estimated bills. Transition of complex electric customers from BCS to C2M moves customer data back into platform housed in PG&E secure data facilities, improving security of customer data.

(c) S/4 HANA is SAP's Enterprise Resource Planning Software.

TABLE 3-1
C&B, BCS, AND C2M ASSET FAILURE RISKS AND MITIGATIONS
(CONTINUED)

Line No.	CC&B, BCS, and C2M Asset Failure Risks and Mitigations			
	Risks and Potential Consequences	BCS	CC&B	C2M
5	Risk: Cascading system failure due to interconnected nature of systems. Consequence: Failure of ABS can jeopardize ability to bill ~25% of revenues; failure of CC&B 2.4 can jeopardize billing of ~75% of revenue, trigger cascading failure, and disrupt data synchronization across other platforms.	Migration of complex electric customers will transition ~25% of billed revenue to vendor supported system (as noted in Risk 1), reducing risk of system downtime.	Upgrade to CC&B 25.1 will re-establish vendor support in event of system failure and enable annual disaster recovery for mass-billing platform, reducing risk of system downtime for customers.	Final consolidation to C2M will enable single platform annual disaster recovery testing, which will reduce likelihood of multiple system failure and system downtime for customers.
6	Risk: Inability to intake level of data resulting from interval billing. Consequence: Large volume of additional data from AMI and interval-billing causes performance degradation for billing platforms.	Migration of complex electric customers to BCS improves performance due to ability to accommodate larger volume of data, reducing volume of estimated bills.	Upgrade to CC&B 25.1 will improve ability to intake data from multi-channel meters and to handle volume of data from complex rates, reducing volume of estimated bills.	Final consolidation to C2M will transition remaining complex gas customers into modern platform, implement a modernized integration suite, and transition complex electric customers to PG&E secure data facilities (improving security of customer data). C2M native data storage expansion will also reduce volume of estimated bills and increase capacity to manage meter measurement data, improving speed of rebills.

TABLE 3-1
C&B, BCS, AND C2M ASSET FAILURE RISKS AND MITIGATIONS
(CONTINUED)

Line No.	CC&B, BCS, and C2M Asset Failure Risks and Mitigations			
	Risks and Potential Consequences	BCS	CC&B	C2M
7	Risk: Incompatibility of billing system with disaster recovery processes creates risk of failure to restart. ABS does not include fail-over protocols between production environments Consequence: Failure of ABS may jeopardize ability to bill ~25% of revenue; failure of CC&B 2.4 can jeopardize billing of ~75% of revenues and could trigger cascading failure and disrupt data synchronization across other Mission Critical platforms.	Transition of complex electric customers to BCS will enable fail-over with two data-center locations, reducing risk of system downtime. This will also enable more rapid upgrades.	Upgrade to CC&B 25.1 will bring mass-billing system into current vendor support and enable annual disaster recovery exercise, reducing risk of system downtime for customers.	Consolidation of platforms allows for disaster recovery to be executed in single exercise. Performance of disaster recovery reduces risk of system downtime for customers and downstream systems.
8	Risk: Inability of mass-billing system to handle increasingly complex rates. Consequence: New rates are forced to be handled by complex billing system, stretching platform beyond intended parameters and degrading performance.	Migration of electric-complex customers to BCS will establish a more robust platform capable of operating with larger customer volumes, reducing operational impacts prior to mass-billing system upgrade, reducing risks of implementing modular rates in mass-billing system, and reducing volume of estimated bills.	PG&E's upgrade to CC&B 25.1 will enable timely implementation of targeted future rate schedules (BCS will be relied upon for electric complex rate implementations prior to C2M go-live).	Upgrade to C2M will enable modular rates for all customer classes, implementation of more complex rates, and integration of configurable MDM, eliminating reliance on complex billing platforms while supporting higher volume of complex billed customers for any service. This will accelerate PG&E's ability to support CPUC strategic decarbonization and electrification objectives by providing customers with faster access to new rates.

E. Conclusion

The implementation of the proposed Billing Modernization Initiative will substantially reduce the consequences of a cyber risk event or an IT asset failure event.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

TARGET STATE BILLING SYSTEM

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TARGET STATE BILLING SYSTEM

A. Introduction

1. Scope and Purpose

This chapter provides a detailed description of the target state billing system resulting from Pacific Gas and Electric Company's (PG&E) proposed Billing Modernization Initiative, in response to the California Public Utilities Commission's (CPUC or Commission) directive to provide additional detail about the proposed billing systems. In particular, this chapter makes "[a] showing of the requirements, features, and functionalities of the new proposed system," and explains, "how the upgrade project specifically implements new and complex programs that are beyond the capabilities of the current system."[1] Further, this chapter describes PG&E's process for determining what capabilities and features the target state billing system should provide and how PG&E determined that the proposed Billing Modernization Initiative is the appropriate approach to reach that target state billing system.

As detailed in Chapter 2, the Billing Modernization Initiative is necessary to improve and maintain systems that are critical to serving over six million customers in areas of billing, customer service, and customer data management. There is an acute need for the Billing Modernization Initiative to support the development of new rates and programs and existing rate structure changes, as well as to address limitations brought on by product obsolescence and a lack of application and customization support. Potential system issues related to the age of the applications, lack of vendor support, and cybersecurity vulnerabilities will lead to problems impacting customer support, billing and credit services, customer notifications, timely start/stop/transfer transactions, and ultimately disrupt the ability of PG&E to interact with customers. The Billing Modernization Initiative is essential to implement a modern, configurable solution that caters not only to the billing

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1 Decision (D.) 23-11-069, pp.549-550.

function but also to additional customer needs. Beyond calculating customer bills, the upcoming system will enable PG&E to continue supporting California's policy ambitions for electrification through sophisticated rate programs. These programs are primarily motivated by the swift transformation of California's electricity framework towards 100 percent renewable energy and electrification of the grid. This complexity is anticipated to continue as California advances its climate policy objectives to cut Greenhouse Gases (GHG) by encouraging the adoption of emerging technologies (e.g., Solar, EV, etc.) and innovative load management strategies. These critical requirements and important objectives necessitate a transformative upgrade to PG&E's systems.

PG&E has operated the legacy billing systems for over 20 years and has carefully examined all the potential ways that it could manage its billing system in the future. Through this analysis, as detailed throughout this chapter, PG&E concluded that modernization of its billing systems is necessary to ultimately move customers to a unified customer care, service order, metering, and billing system designed to handle the complexities and challenges associated with meeting the Commission's expectations for implementing new rate designs and customer programs. Simply put, commission mandates and customer needs have outgrown the capabilities of PG&E's existing versions of billing programs, and it is now critical to upgrade.

This chapter details the appropriate solution to the challenges presented by PG&E's legacy billing systems and the changing business needs related to billing, credit, payments, and usage validation. Section B presents PG&E's desired business outcomes and functional requirements for its target billing system. Section C outlines the gap analysis performed to determine which key capabilities were missing or impacted by the limitations of the legacy billing systems. Section D details the potential paths forward, including the review of options from different vendors and explains the rationale behind a three-stage approach to stabilize and upgrade the billing systems. This three-stage approach, discussed in detail below, includes the following stages:

- The first stage addresses PG&E's electric complex billing customers through the Billing Cloud Services (BCS) solution and replacement of the Advanced Billing System (ABS) electric functionality. There is a separate instance for ABS Gas which has a stable customer base and will remain until C2M.
- The second stage will update the outdated version of Oracle Utilities Customer Care and Billing (CC&B) that PG&E currently uses, version 2.4, to version 25.1,[2] planned for release in 2025.
- Finally, the third stage will complete the implementation of a modernized billing system by replacing all billing components with Oracle's more advanced Customer to Meter (C2M) product and consolidating the electric BCS and gas ABS customers into one system. Between stages two and three PG&E will reconfirm this plan, ensuring it remains the most prudent approach.

Finally, Section E discusses the solution: detailing the capabilities of the new system, the target state architecture, and how PG&E's business processes will be impacted. Further, it will describe how the Billing Modernization initiative will facilitate many of the functional requirements and business outcomes identified, including addressing the operational and technical issues detailed in Chapter 2.

B. Identifying Desired Business Outcomes

Through the process of determining what steps needed to be taken to address the challenges and limitations of the legacy billing systems detailed in Chapter 2, PG&E identified features and goals for its future-state billing solution. The landscape of Customer Information System (CIS) options and their capabilities has changed significantly, and current CIS options provide a variety of features that were either not available in the past or not incorporated into PG&E's existing billing systems. The desired business outcomes can be categorized as functional requirements that must be satisfied by any potential billing system update or replacement, or non-essential features that would nonetheless be desired in a target billing system. PG&E identified non-essential

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[2] Oracle has changed their version numbering scheme to align with calendar years. Version 25.1 will be the first release of 2025. PG&E is presently 4 versions behind Oracle's current release.

and essential requirements which steered the review of the landscape of potential upgrades or replacements available.

1. End State Requirements

The below requirements are necessary features in a target billing system. A number of these requirements address the challenges resulting from the legacy billing systems detailed in Section D of Chapter 2.

a. Ability to Implement Complex Rate Programs

One of the main challenges facing the current billing system is the need to implement various complex rates and features using the CC&B platform, which was not designed for modern bill components and calculations. As described in Chapter 2, this results in a complex system with decades of customizations necessary to implement rates in the CC&B platform, and the need to use a separate rate engine to manage complex billing. As a result, one of the principal features PG&E identified as a requirement for a target billing system was the ability to implement complex rate programs within the main CIS without the need for an additional rate engine. For example, a modern modular rate engine will allow PG&E to more efficiently implement existing complex rate programs. These include solar billing (Net Energy Metering (NEM), Net Billing Tariff (NBT)) and new and emerging rate programs such as Real-Time Pricing (RTP), and other rate programs which may be approved in the future.

PG&E must be able to keep pace with the rapid increase in demand for rate programs and technologies enabled by Advanced Metering Infrastructure (AMI) devices in California, such as Time-of-Use (TOU), NEM and other customer generation technologies, commercial and residential electric vehicle rates, and battery storage. The result of two decades of customized changes is a calculation framework that quadruples the steps to calculate newer, more complex rates. It is anticipated that C2M will significantly reduce the required number of steps in its more modern calculation framework. These complex rate programs are mainly driven by the rapid transformation of California's electricity system on the pathway to 100 percent renewable power and this complexity is expected to continue as California continues to address climate policy goals to reduce GHGs by driving the adoption of emerging technologies and flexible load management approaches.

Specifically, California has developed energy markets that are dynamic and continue to evolve. Senate Bill (SB) No. 100 (2017-2018 Reg. Sess.) requires that renewable and GHG-free resources supply 100 percent of electric retail sales in California by 2045. The CPUC and the California Energy Commission are working in tandem to meet the State's building decarbonization goals established pursuant to Assembly Bill (AB) No. 3232.[3] In addition, state policies such as the Governor's Executive Order No. B-48-18[4] and Public Utilities Code (Pub. Util. Code) § 740.12(a)(1)(H)[5] are advancing decarbonization of the transportation sector through electrification, since transportation is the largest source of GHG emissions in California.[6]

PG&E's billing system must be able to manage the anticipated continued addition of new and more complex rates to support other California policy goals such as customer choice (e.g., facilitating Community Choice Aggregation(CCA) rate-ready and bill-ready options), affordability (e.g., Percentage of Income Payment Plan (PIPP) and Fixed Charge), and sustainability (e.g., electrification rates, adoption of renewables through improvements of interconnection and NEM rates and programs). A modern system designed for the type of complexity seen in modern bill components and calculations will support the type of rates PG&E must implement and expects to implement in the future.

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3 Public Resources Code, § 25403.

4 Governor's Executive Order No. B-48-18 (Jan. 26, 2018) calls for at least 250,000 EV charging stations by 2025, and 5 million zero-emission vehicles by 2030, available at: <https://www.library.ca.gov/wp-content/uploads/GovernmentPublications/executive-order-proclamation/39-B-48-18.pdf>, (accessed Oct. 2, 2024).

5 SB 676 (2019-2020 Reg. Sess.) enacted Pub. Util. Code Section 740.16, which requires the CPUC to establish strategies and quantifiable metrics to maximize the use of feasible and cost-effective EV integration into the electrical grid by January 1, 2030.

6 California Air Resources Board, California GHG Emissions for 2000 to 2020; Trends of Emissions and Other Indicators (Oct. 26, 2022), p. 8, Figure 3, available at: https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf, (accessed Oct. 2, 2024).

To support these efforts, PG&E needs a billing system that allows for implementation of rate programs based on increasingly complex and dynamic rate components. For example, on July 1, 2022, the CPUC released an "Order Instituting Rulemaking [OIR] to Advance Demand Flexibility through Electric Rates,"[7] which cites a whitepaper issued by the CPUC entitled, "Advanced Strategies for Demand Flexibility Management and Customer DER Compensation," which envisions broad implementation of a "unified, universally-accessible, dynamic, economic retail electricity price signal."[8]

This requires a complex rate structure and certain elements discussed can only be implemented on a large scale in a modular system. PG&E is currently utilizing a third-party vendor to “shadow bill” the Dynamic Rates approved in the Expanded Pilots D.24-01-032 until the Billing Modernization Initiative is complete and can be built in C2M. The way a shadow bill functions is that the customer is billed by PG&E on their Otherwise Applicable Tariff (OAT) while an external system also calculates the customer’s shadow bill. PG&E then performs a review annually to reconcile the amount billed to the amount calculated by the shadow billing platform and refunds the difference if the customer was billed an amount higher than their performance on the shadow bill. This works as a stop-gap solution but creates a confusing customer experience, since they are receiving two bills at the same time and delays the financial benefit to the customer since they are still responsible for their PG&E (OAT) bill until the annual reconciliation occurs.

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7 Rulemaking 22-07-005, Order Instituting Rulemaking to Advance Demand Flexibility through Electric Rates, available at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K285/496285639.PDF> (accessed Oct. 2, 2024).

8 Energy Division, Advanced Strategies for Demand Flexibility Management and Customer DER Compensation (June 22, 2022), p. 103, available at: <ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf (ca.gov)> (accessed Oct. 2., 2024).

b. Modular Rate Engine

The target billing solution must allow PG&E to calculate new rates for complex rate programs without requiring added steps or third-party contracting. While the current CC&B system uses separate, linear calculation methods for each rate schedule calculation (i.e., each residential rate schedule calculation has separate steps to determine the cost based on usage and applicable rate value), a modular rate engine uses calculation sub-routines or "modules" that can be used in the calculation process for multiple rate schedules. A modular structure will simplify the calculation design by using shared modules and performing the calculation using the applicable rate schedule rate value, without any customization. Additionally, common calculation rules can be applied across rate schedules which will significantly lower ongoing maintenance and testing efforts. Modularity greatly lowers the barrier to implement and update rates/programs, including complex rates, to meet regulatory compliance. Currently, PG&E is only able to utilize modular rates for limited customers on complex rates and programs which are billed through ABS.

In a modular framework, the rate schedule calculation routines will use an energy charge module with configured rate values (such as prices ($/kwh), tax rates, baseline quantities (kwh/day), etc.). The calculation routines are configured based on effective dates and can be updated relatively easily. Any energy charge calculation changes would then only need to be applied to the module and would only impact rate schedules that call upon that module.

Modular rating engines are now the industry standard. With the exception of modular rates utilized in ABS for certain customers, PG&E has been using the linear rates model in CC&B for over 20 years, which requires each rate calculation, eligibility check, program discount application, or other feature to be built into each rate schedule in a specific sequential order. Any variation of the rate schedules, such as NEM, interval vs. subtractive (anchor) billed, requires a different version of the rate, resulting in over 1,200 rate schedule permutations in PG&E's

billing system built around repetitive streams of code.[9] A modular rate model would allow common calculation rules which can be built once and then used across rate schedules, creating a flexible and efficient rate engine with far fewer rate versions to maintain. Changes to a specific program and/or calculation would only need updates to that particular module without having to update it across all rate variations. CISs with a modular rate engine can also provide data synchronization across calculation modules within a single system (replacing several major, separate systems that duplicate and transmit data between themselves). For the reasons stated above, PG&E has identified this as a requirement of the target billing solution.

c. Integrated Meter Data Management

The target billing solution must also leverage integrated Meter Data Management (MDM) to complement a modular rate engine. The legacy billing systems require PG&E to maintain MDM in a separate system, alongside the CC&B system, which results in data latency and data synchronization issues requiring manual intervention. MDM integration would result in PG&E having both CC&B and MDM functionality on a single platform and therefore significantly reduce or eliminate synchronization issues. Additionally, due to the proliferation of SmartMeter interval data collected and required for billing, as described in Chapter 2, an integrated MDM will eliminate data replication and storage in the two separate systems: the MDM and the CIS.

MDM carries out a suite of functions that encompass handling meter data measurements on energy utilization from Head End Systems (HES),[10] conducting validations, and applying estimation rules to these readings (corresponding with the registered devices). MDM also delivers crucial usage data to the rate engine for the creation of all customer bills for PG&E within one unified platform.

The incorporation of MDM will help to reduce the volume of estimated bills as a result of fewer data synchronization discrepancies.

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[9] For example, the TOU-C rate schedule is built as four rate schedules in CC&B.

[10] See Chapter 2 Attachment B for a diagram of these systems.

Moreover, it enables the detection of estimation stemming from incomplete field work uploads rather than issues tied to communication or the operating environment, which in turn reduces superfluous service vehicle dispatches.

Furthermore, with MDM integration, PG&E could implement tariff adjustments simply by tweaking the usage configuration settings, bypassing any need for alterations, including custom ones, to the core rate schedule computation modules. For instance, PG&E's current approach requires manual changes to each residential rate calculation when updating tier computations or TOU periods in existing billing infrastructures. However, with MDM integration, these adjustments across different rate schedules can be swiftly achieved through changes in the usage setup. Thus, contemplating these benefits, the integration of MDM is a pivotal component for an optimally functioning target billing system, allowing for the advantageous use of integrated MDM features alongside the modular rate engine.

d. Data Privacy Improvements

PG&E is required to comply with the California Consumer Privacy Act (CCPA) and California Privacy Rights Act (CPRA), which impose data protection obligations. The target billing solution must provide features/functionalities to support improved data privacy for customers. Specifically, PG&E identified supporting batch disposition of personal customer data as a requirement. Currently, customers can request de-identification of their data. However, efficient batch disposition of personally identifiable information is not currently in place for PG&E because this functionality is not available in CC&B 2.4 or ABS. At a high level, CCPA allows customers to request information that is collected, deny the sale of information, and request deletion. CPRA extended these rights to include the restriction of use of sensitive information, right to correct information, and the right to prevent the collection of more information than necessary. PG&E is not currently able to efficiently implement automated large-scale disposition of data, but this feature is available in more modern billing systems.

Protection of personally identifiable information is foundational to PG&E, and it is important that PG&E is able to address data protection requirements and privacy concerns quickly and efficiently. For these reasons, improvements in the ability to facilitate data privacy was identified as a requirement of a target billing solution.

e. Improved System Uptime

The target billing solution must be able to support system uptime in line with reliability requirements. Despite its criticality to PG&E operations, the current CC&B system faces system downtime in excess of the system reliability standard for Mission Critical reliability.[11] PG&E's average system uptime for 2022 to 2023 was 99.68 percent (monthly downtime of 139.6 minutes), which falls short of the current Mission Critical standard of 99.95 percent system uptime (monthly downtime of 21.4 minutes).

System availability is vital to customers' access to all the features on PGE.com and, during system downtime, customers experience diminished functionality across all customer service channels including the web, Interactive Voice Response (IVR) and contact center. For example, customers would be unable to initiate start/stop/transfer of service requests, or even check the current balance of their account. Because of the importance of system reliability, PG&E identified improved system uptime as a requirement and set a target of 99.99 system uptime (monthly downtime of 4.21 minutes) for the target billing system.

f. Third Party Energy Provider Functionality

To build a more robust and efficient system for PG&E and its third-party Energy Service Providers (ESP), Community Choice Aggregators (CCA), Core Transport Agents (CTA), and Direct Access (DA) partners, several end-state requirements must be met to ensure

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11 PG&E's Service Availability Criticality Standard defines a Mission Critical system as one that directly supports the safe and reliable delivery of energy to customers. The Standard includes a variety of elements of reliability, as well as a Recovery Time Objective (time to restore the entire system after a disaster) of 4 hours.

consistency, standardization, and process simplification. Some of these requirements include:

- The consolidation of the MDM into one integrated platform will enable PG&E to send more interval data to third-party ESPs. This will allow ESPs to run and support their own demand response programs, hourly and future NEM rates.
- Close to real time processing of inbound and outbound transactions between PG&E and ESPs. In today's world, there are batch processes that only run once a day to process inbound and outbound transactions. The new functionality will allow a full data cycle exchange (usage to billing) to go from 2 to 3 days to as quick as a few hours.
- Single Touch Exceptions - Currently, any billing exception that involves a third-party ESP involves a biller[12] to work the exception. Some of these exceptions are multi-day efforts, after which a biller will have to manually follow up again once data has been sent and received from ESPs to complete the exception. The target state billing system functionality should allow a biller to work the exception and have the system automatically complete the transaction without manual follow up.

2. Non-Essential Beneficial Features

The below features were identified as desired outcomes, but PG&E did not identify them as necessary components of a target billing system. While these features were considered as something to look for in the process of examining options for the target state billing system, they are not considered requirements because they are not necessary to meet PG&E's objectives of the Billing Modernization Initiative.

a. Self-Healing Feature

PG&E identified a "self-healing" feature as a non-essential feature that it would like to see in the target billing solution. Developments in technology have enabled billing systems to incorporate automatic retry for failures (e.g., failed reads, commands, bill determinant calculations, device event failures), also referred to as a "self-healing" feature. A

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12 A position within the Complex Billing group who is responsible for working billing exceptions on large complex accounts, currently billed in ABS.

self-healing feature would be able to automatically close any open exception it resolves thus reducing manual work.

b. Automation Capabilities

PG&E identified developments in automation and machine learning as a non-essential feature that it would like to see in a target billing solution. When a new residential subdivision or apartment complex comes online, the setup work is repetitive in nature. The ability to automate the repetitive routine work like this type of setup is an example of the type of work these technologies can assist with. External applications exist which can integrate with a modern CIS to assist with work management and exception handling.

Currently, one of PG&E's main automation software tools, which operates on top of CC&B, is at its end of life. The software has been acquired by another company, and this company has started decommissioning the software. In 2023, the existing automation software completed approximately 576,000 transactions, resulting in approximately $4 million in cost avoidance due to work avoided due to internal automation tools.

PG&E looked at additional automation tools/software to replace the current version and ran into issues with compatibility due to the outdated build/language in CC&B 2.4. It may be possible that a modern CIS has this functionality embedded in its base capabilities. Whether embedded or integrated from an external application, these emerging technologies are a desired outcome of the target CIS system.

c. Reporting

PG&E identified improvements in reporting, ideally a self-service platform which enables individual business units to design and develop their own reports, as a non-essential feature that it would like to see in a target billing solution. As detailed in Chapter 2, customer data reporting is necessary for timely and accurate billing, as well as many other data uses, including: tax, revenue reporting, device management, and field work purposes. Currently, CIS reports are designed and produced based on individual business needs by a team of IT professionals in a separate reporting platform. Developing new reports, or enhancing existing reports requires use of these limited IT resources and takes time.

C. Legacy System Assessment and Horizon Scanning

PG&E sponsored an external assessment by Accenture to evaluate its CIS platform, focusing on affordability, reliability, and adaptability to meet future business needs. The following is a summary of the engagement, with additional details later in this section.

- PG&E engaged Accenture in 2018 to assess its CIS system, identifying current and future business priorities, evaluating the legacy system, and performing a gap analysis to address challenges while prioritizing affordability and customer experience.
- Accenture evaluated scenarios such as maintaining legacy systems, upgrading/consolidating systems, in-house solutions, and total system replacement, aiming to improve regulatory response time, simplify billing architecture, and reduce costs.
- Accenture concluded that PG&E's legacy systems were insufficient to meet its needs due to inflexibility, high operational efforts, technical debt, and obsolescence risks, including lack of vendor support and integration issues.
- Accenture's recommendation was to pivot to a fully integrated, best-in-industry CIS cloud-first platform, evaluating between SAP and Oracle based on integration, partnership model, buying power, and Total Cost of Ownership (TCO).
- A 2022 refresh confirmed the initial drivers for change and identified an additional driver, operational efficiency risk, recommending PG&E continue with Oracle due to its commitment to utilities products and interoperability benefits.

To inform the best path forward for its billing systems, PG&E sponsored an external assessment of its CIS platform health, capabilities, and ability to meet projected future business needs. The analysis largely reinforced PG&E’s view of the challenges associated with the legacy billing systems based on its own experience, which are further detailed in Chapter 2. PG&E engaged Accenture, an independent consultancy expert familiar with California regulatory landscape, in 2018 to assess its overall CIS system status and strategy. This included identification of current and future business priorities, evaluation of the current state (legacy) CIS system, and a gap analysis to identify and summarize challenges to achieving business priorities with the current technology, while keeping affordability and customer experience at the forefront. Accenture's track record includes over 250 CIS implementations for utilities worldwide staffed by a robust team of 3,000 utility-consulting specialists and 75,000 SAP and Oracle practitioners. They have conducted similar strategic assessments and provided regulatory support to PG&E's utility peers across the United States, including those within the CPUC's jurisdiction.

Accenture worked with PG&E to identify and define three PG&E business priorities – Affordability, Reliability, and Adaptability – and four key forces challenging achievement of these priorities – Policy & Regulatory Factors, Disruptors, Internal Systemic Challenges, and Velocity of Innovation/Obsolescence. For each of the four forces, Accenture evaluated the technical capabilities of the existing billing system and their capacity to respond to future developments, as well as how this would impact each of the three business priorities.

Accenture's analysis concluded that the legacy system was insufficient in meeting PG&E's need for a reliable and cost-effective CIS in a rapidly changing ecosystem with new market entrants such as CCAs, MDM companies and application service providers. Additionally, inflexibility of the billing system architecture drove up operational business efforts and technical debt, as workarounds were often employed to keep up with regulatory demands. Accenture also reviewed the risk of obsolescence related to PG&E's legacy billing systems, including PG&E's core billing system, Oracle CC&B (currently 20 years old), and its MDM system, Landis+Gyr (L&G) MDMS, which was implemented in 2006. While upgrades have been performed, the pace of technology innovation requires companies to frequently ascertain obsolescence risk, which can manifest itself in a variety of ways.

Obsolescence risk can involve lack of support from product vendors, lack of integration and interoperability with new technologies, and inability to attract or retain skilled resources due to competition for talent. Further, large systems like a CIS have certified compatible technology versions for servers, middleware, and related applications. An obsolete or out-of-support CIS is incompatible with current generation supporting systems. This incompatibility prevents the upgrade of any one of these supporting systems and causes their own performance to suffer and for these systems to fall out of vendor support, as well. A CIS, middleware, and database ecosystem running on outdated hardware without vendor support presents a cyber risk and perpetuates and proliferates the risks of obsolescence.

Accenture considered various scenarios to close identified functional gaps and risks, including continued investment in the maintenance of legacy systems to address shortcomings, upgrading and/or consolidating systems, in house solution build out, and total system replacement. Its evaluation of these scenarios was anchored on PG&E achieving three primary goals:

1) Significantly improve (reduce) the time to respond to regulatory requirements and eliminate the rates backlog;
2) Simplify the billing system architecture to improve operational and capital efficiency in customer experience; and
3) Reduce costs to run billing systems and processes across business and IT.

After completing analyses on gap identification, scenario feasibility, and obsolescence risk, Accenture worked with PG&E to develop a proposal to respond to evolving demands and better position PG&E for the future. Its short-term recommendations included the following:

- Replace Landis & Gyr MDMS with Oracle MDMS;
- Re-architect rates (using modular rates) and remove framing within Oracle CC&B;
- Consolidate and simplify rating engines/pricing products to either Oracle or GridX, to be chosen via a proof of value exercise;
- Implement a staging tool to shorten the cycles of development and test comparative validating of rates, accelerating promotion of rates through the system;
- Consolidate ABS into Oracle MDM with a corresponding effort to correct master data, enabling data flow between Oracle and MDM without circumvention to ABS and its subsequent processes; and
- Adopt an agile methodology to manage these efforts.

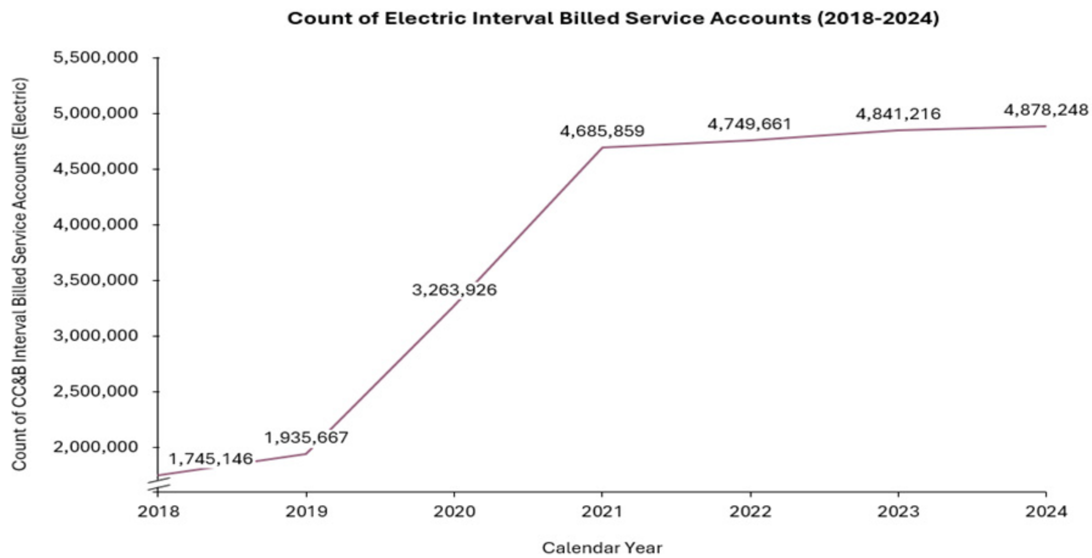
Accenture's mid-term recommendation was to select and pivot to a fully integrated, best-in-industry CIS cloud-first platform. The recommendation outlined a series of considerations for PG&E to evaluate when deciding between SAP and Oracle, including integration with the enterprise, overall partnership model outlook, company buying power, and TCO for implementation and sustainment.

From December 2021 to January 2022, Accenture conducted a rapid refresh on the product considerations component of its 2018 assessment to consider evolutions in customer and regulatory expectations as well as technology innovations. The refresh confirmed the case for change identified in 2018 not only remained valid, but initially identified drivers for change (compliance and reliability risk, economics, and obsolescence) were amplified, based on interviews with billing operations stakeholders and market research. It also identified an additional fourth driver, operational efficiency risk.

The growing volume and complexity of operational pain points was attributed to significant growth in the interval billed customer population, meter failure rates, and external forces such as wildfire risks, Public Safety Power Shutoff (PSPS) events, and third party/CCA scenarios. Additionally, this refresh noted the 2020 start of the Billocity Project to move ABS functions for electric complex billing to Oracle BCS. Taking into consideration both the ecosystem evolutions summarized in this analysis and PG&E's Oracle BCS investment, Accenture's refresh concluded that PG&E should continue its momentum to pivot to a modernized CIS to address the operational pain points reported in 2018 which maintain their validity and continue to grow in impact on the business. Unlike the 2018 assessment, which remained product agnostic and simply outlined considerations for PG&E's selection process, the 2022 refresh recommended PG&E stay the course with Oracle, relying on Oracle's commitment to PG&E to continue investing in its utilities products while recognizing efficiencies in implementation and adoption stemming from interoperability with existing and proposed future Oracle investments.

Assumptions in Accenture's analysis around continually increasing volume and complexity of bills proved to be accurate, demonstrated by the below graphic showing a 19 percent cumulative annual growth rate in number of electric customer interval billed service accounts from 2018 to present.

FIGURE 4-1
COUNT OF ELECTRIC INTERVAL BILLED SERVICE ACCOUNTS (2018-2024)



Note: PG&E anticipates trends in billing complexity and rate project requirements to continue on this growth trajectory as they continue to support various goals set by the CPUC such as promotion of customer choice (e.g., facilitating CCA rate ready and bill ready options and CCA rate comparisons), affordability and arrearage management (e.g., PIPP and Fixed Charge), and sustainability improvements (e.g., adoption of zero emission vehicles, adoption of renewables through improvements of interconnection and NEM rates and programs). Growing demands to maintain compliance are evident in PG&E's historical and forecasted rates implementation pipeline shown below.

TABLE 4-1
PG&E'S FORECASTED RATE IMPLEMENTATION PIPELINE

Line No.	Rate Implementation Project	Planned Completion Year
1	Residential Net Billing for Paired Storage, SmartMeter Opt-out and MV-90 customers in ABS	2025 (in BCS)
2	E-ELEC Standard NEM 1.0, 2.0 and Paired Storage customers in ABS	2025 (in BCS)
3	Residential Fixed Charge	2026 (in BCS and CC&B)
4	Non-Residential Net Billing Simple NEM, Paired Storage, and Medical Discount	2026 (in BCS and CC&B)
5	E-ELEC Complex NEM 1.0 and 2.0 for Virtual NEM, NEM Aggregation and NEM Multi-Tariff in ABS	2027 (in BCS)
7	Net Billing for Complex NEM Aggregation and Virtual NEM	2027 (in BCS)
8	New Agricultural Rates (AG-A3 and AG-B2)	2027 (in BCS)
9	Including a breakout of PCIA on bundled customers billing statements	2028 (in BCS and CC&B)
10	B-20R Solar Rate	2028 (in BCS)
11	EV Submetering	Not Yet Planned – Manual Process in Place - Current Compliance 12/31/24
12	Commercial Electric Vehicle Opt-in RTP rate	Not Yet Planned - Current Compliance 2/28/25
13	Commercial Electric Vehicle Non-NEM Export Rate Pilot	Not Yet Planned - Current Compliance 2/28/25
14	Modified Cost Allocation Methodology for Resource Adequacy for other Load Serving Entities (CCAs, ESPs)	Not Yet Planned – Commitment 2027
15	Load Management Standard Compliant RTP Rates for all customer classes	Not Yet Planned – Expected 2030 or later

TABLE 4-1
PG&E'S FORECASTED RATE IMPLEMENTATION PIPELINE
(CONTINUED)

Line No.	Rate Implementation Project	Planned Completion Year
16	Disadvantaged Communities San Joaquin Valley Electrification Pilot Bill Protection	Not Yet Planned – Workaround in Place
17	Food Bank Discount – Automated Monthly	Not Yet Planned – Workaround in Place
18	Standby Reservation Charge Exemption	Not Yet Planned – Workaround in Place
19	Small and Medium Business GHG Credit	Not Yet Planned – Workaround in Place
20	Decorative Streetlight Rate	Not Yet Planned – Workaround in Place
21	Medical Discount for EV2-A and E-TOU-D customers in ABS	Not Yet Planned – Workaround in Place
22	PCIA Pre-Payment	Not Yet Planned
23	Credits for CCA Customers on Demand Response Programs Duplicative with IOUs Programs	Not Yet Planned
24	PURPA rate for Net Billing Customers whose Solar Contractor did not meet requirements for employees	Not Yet Planned
25	Provider of Last Resort on the Billing Statement	Not Yet Planned
26	NEM and NBT Bill Re-design	Not Yet Planned

D. Determining a Path Forward

PG&E considered several options for the future of its billing system to address its desired business outcomes and the capability gaps in the current system, including whether a billing modernization initiative was necessary to best serve customers, whether an upgrade or overhaul was necessary, what form that should take and what vendors should be utilized. Ultimately, PG&E decided the target solution would be C2M, due to improved integrated architecture, modular rate engine capabilities (including MDM usage framing), along with reduced complexity of data migration and conversion activities due to the current system using similar data model. The C2M product is expected to significantly reduce errors needing manual intervention and enhance the overall customer experience.

Furthermore, PG&E determined that the best approach would be to first upgrade to the most current CC&B version (25.1) to re-establish vendor support and move complex electric-billed customers out of the aging ABS system, into Oracle's BCS, before completing the modernization by implementing C2M. This determination was made after a full review of all potential options, with a focus on which option best serves customers in both the short- and long-term.

1. Whether to Maintain the Current Billing System or Upgrade/Modernize

First, PG&E evaluated the viability of maintaining the legacy billing systems to determine whether it was preferrable to maintain these billing systems as currently structured or to maintain these systems with moderate upgrades that did not amount to a full "modernization." Through a full review of these systems, assisted by Accenture, PG&E identified issues that could not be fixed through piecemeal updates or patches and, as a result, necessitated modernization of the billing systems.

The most significant issue PG&E identified with maintaining its legacy billing system is its code foundation. If PG&E was to keep CC&B 2.4, which is already out of support, it would be continuing to run an antiquated system with a foundation in code that was built in 2002. Due to the advanced age of the system, CC&B 2.4 struggles to be compatible with necessary third-party systems which results in difficulties maintaining compliance with regulatory mandates like rate program implementation as well as addressing cybersecurity vulnerabilities. This creates issues that cannot be resolved without transitioning away from CC&B 2.4.

Many of the issues identified in Chapter 2 and in the legacy system assessment cannot be resolved in the legacy systems because the obsolescence of CC&B 2.4. CC&B 2.4 is written in COBOL, an increasingly out-of-date programming language. It is difficult to identify resources who are skilled in developing and maintaining this code base, and it will become more difficult as time passes and programmers trained in COBOL leave the workforce, forcing PG&E to delay work due to lack of developers. With CC&B 2.4 out-of-support by Oracle, there is no guarantee future issues found with CC&B 2.4 (including in critical areas such as security, compatibility, functionality, and compliance) will be addressed by Oracle.

The linear rate development structure and the customizations required for complex rate calculation in the existing CC&B 2.4 make implementing complex rates, such as NEMA, not possible within this system. The calculation customizations would overload the bill calculation routines, impacting the ability to calculate charges in a timely fashion. The linear rate engine is increasingly untenable to maintain as new rates with complex program riders are increasingly difficult to deliver on time and within regulatory expectations. In the future, this will pose a barrier to PG&E's ability to comply with CPUC requirements and assist California's policy goals.

Implementing rates in ABS, the workaround PG&E relies on to maintain complex rates due to these shortcomings in CC&B 2.4, is also reaching an unmanageable state. Due to CC&B 2.4's linear rate development structure and lack of modular rates, PG&E has increasingly relied on its internally developed complex billing system, ABS. ABS's modular rating engine is inherently superior to CC&B 2.4's linear rating engine in flexibility, causing PG&E to increasingly rely on ABS to perform certain mass billing functions. However, ABS was not designed to handle mass billing functions; ABS was originally developed as a small modular rating engine built for a capacity of up to 25,000 customers. As PG&E adopted increasingly complex rates that were incompatible with CC&B 2.4 or that would be unfeasible to develop in CC&B 2.4, PG&E has increasingly relied on ABS to bill more complex customer accounts and the number of ABS customers is now more than 150,000, with roughly 2,000 new customers added per month. As described in Chapter 2, ABS is simply unable to efficiently process the current volume of customer bills per month, leading to a degradation in system performance, and continuing to utilize ABS for this large (and increasing) number of customers would grow these problems.

The legacy billing systems also experience system availability issues that negatively impact customers' experience. The current CC&B system falls short of the Mission Critical standard of 99.95 percent system uptime and future state target of 99.99 percent system uptime. System availability is vital to customers' access to customer service channels and, during system downtime, customers experience diminished functionality across all channels including the web, IVR, and contact centers. For example, customers would be unable to initiate start/stop/transfer of service requests, or even check the current balance of their account. There is no intermediate fix or patch that can improve these availability issues.

Given these factors, staying on PG&E's current billing systems of ABS and CC&B 2.4 is increasingly untenable and poses risks to PG&E's ability to deliver on new rates, issue customer bills on time, advance the CPUC's future goals, and provide PG&E customers with full access to their customer account. Further, CC&B 2.4's lack of support and performance failing to achieve Mission Critical standards poses a future risk for PG&E's billing system stability and inaction may result in system failure. A system failure would result in an inability to process start/stop/transfers and restore/disconnect (e.g., PSPS) service or communicate to customers during a weather event in a quick and efficient manner in order to maintain public safety. In addition, a system failure would prevent the ability to issue customer bills. As confirmed in Accenture's 2022 system review assessment, PG&E concluded that the existing systems cannot be sustained without substantial risk and need to be modernized immediately.

2. Available Upgrade/Modernization Options

Because of the age of the legacy billing systems, PG&E has evaluated the landscape of upgrade and modernization options from time-to-time, including retaining outside consultants to provide insight into whether, and how, PG&E should modify its billing system. Through these analyses, PG&E determined that there were two areas where significant upgrades or improvement were necessary: (1) PG&E's ABS system, and (2) PG&E's outdated CC&B system.

As referenced above, in 2018 Accenture reviewed the system health of PG&E's legacy billing system landscape and concluded that improvements and upgrades were required. Accenture recommended that PG&E should re-platform to a next generation CIS by no later than 2023/2024, and while it reviewed the landscape of available options it did not make an affirmative recommendation about what PG&E's end-state system should be.

In 2020, PG&E solicited a second opinion and hired an outside consultant, Utilligent,[13] to consider potential solutions to PG&E's aging

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[13] Utilligent was acquired by eSource in 2023.

billing system. Utilligent reviewed PG&E's existing systems, as well as the landscape of solution options, and concluded that PG&E's legacy billing systems did not meet the business' current or future needs, and recommended replacement of both ABS and CC&B 2.4. Utilligent's recommendation for a target billing system that met PG&E's needs was Oracle C2M with the integrated MDM System because it resolves capability gaps, improves the customer experience and further eliminates significant technical debt.

Accenture's 2022 refresh of its analysis confirmed that PG&E needed to re-platform to a new CIS and evaluated Oracle's C2M and SAP's S4/HANA as end-stage CIS options. As discussed in more detail below, Accenture concluded that C2M better aligned with PG&E's priorities and the economic value of the C2M solution was greater.

a. Replace ABS System for Complex Electric-Billing Customers

As described above and detailed in Chapter 2, ABS simply was not built to scale to the volume of complex billing customers that PG&E has added (and continues to add) over the years. This 30-year-old billing system that was intended to be used for a limited number of complex accounts (25,000) now is responsible for ~150,000 services accounting for approximately 25 percent of revenue. These services are on the most complex electric rates and programs, including NEM Paired Storage (onsite batteries), Virtual NEM and Departed Load, etc. Because the system is significantly over its designed capacity, stabilization of this system is necessary. However, any stabilization actions to preserve ABS rather than replace it would necessarily be short-term solutions due to the age of the system. Neither Utilligent nor Accenture identified any feasible billing system solutions that involved maintaining ABS for all complex customers.

To address the unsustainably large number of complex customers billed through ABS, PG&E identified moving electric-billed customers out of ABS as a priority. This is due to the rate complexity and the interval measurement data of the electric-billed customers, and the rate of growth in electric complex-billed customers. In contrast, complex gas-billed customers have a stable market share that is not expected to grow. In other words, PG&E prioritized moving out faster growing customer groups to stay within range of ABS's 25,000 account capacity.

PG&E ran a competitive bid process, issuing a Request for Proposals to solicit bids for a new application to replace the existing ABS system. The process included reaching out to the marketplace to request proposals from application vendors. Provided materials included application functionality presentations, proof of concepts for rate calculation Q/A series, and internal PG&E vendor scoring. The potential applications were scored across 14 categories:

- Business Capabilities;
- Customizations;
- Product Maturity;
- Integration Capabilities;
- Cost to Deploy;
- O&M Cost;
- Scalability;
- Performance;
- User Friendliness;
- Support Model;
- Reporting Capabilities;
- Automation and AI Capabilities;
- PG&E Vendor Investment Strategy; and
- Customer Feedback.

The final two candidates were Salesforce and the Oracle BCS product. Workshops were held to allow the vendors to demonstrate their product and ask questions about specific PG&E requirements. This included explanation of complex scenarios (i.e., NEM Aggregation) followed by the vendors demonstrating their ability to perform those type of calculations. Further, the vendors created a supplemental detail of a bill to demonstrate that the products included functionality in addition to bill calculation. Participants then scored the applications across the 14 categories. Based on the scoring, the Oracle Product was selected, in part due to higher scores for product cost, integration with PG&E systems, and support model.

The BCS solution that PG&E selected—and has begun to implement—is a new modular rate engine that will replace the outdated, overburdened ABS Electric application. BCS will solve many of the problems of the existing ABS system and will bring stability that the outdated infrastructure of ABS lacks. It will be able to handle the bill calculation for over 150,000 accounts with the most complex electric rates. PG&E will be able to more easily train new hires to use BCS because it is built on a more common application language, JAVA, so the skills needed to maintain it are more readily available in the labor market. BCS will have enhanced, more efficient processing, improving data synchronization between BCS and CC&B, as well as reducing data latency of customer and usage data. Automated workflows and additional data validations in BCS will reduce the amount of manual interventions. BCS also offers additional significant improvements for PG&E and for customers, detailed in Section E. In sum, BCS offered a solution to PG&E's issues with ABS at a competitive price, from a vendor that PG&E had experience working with in the past. In addition, BCS offered efficiencies due to the integration of Oracle's systems. BCS's modular rates are based on Oracle's CIS framework and can be used in the target C2M platform, which will make future rate development more efficient.

b. Replace CC&B 2.4 System

As CC&B 2.4 aged, PG&E identified the need to update the system and regularly analyzed replacement options; most recently through the analyses assisted by Utilligent and Accenture. These studies provided PG&E with valuable insight regarding the landscape of potential solutions, as well as the benefits and drawbacks and relative cost of each solution. Ultimately, Utilligent and Accenture each concluded that the appropriate end-state billing system for PG&E's core CIS was Oracle's C2M product.

Utilligent's 2020 analysis considered alternatives including: (i) reconfiguring the current CC&B system (Version 2.4) and adding a modular rate engine, (ii) upgrading to CC&B Version 2.7, (iii) upgrading to C2M, (iv) replacing Oracle with SAP and Siemens products, and

(v) building a “best of breed” solution using a combination of programs from Oracle, L&G, and Siemens. While some of these alternatives included transitioning ABS to BCS, others included transitioning ABS to the core CIS. Utilligent eliminated the SAP/Siemens and “best of breed” solution based on prohibitive cost and unacceptable risk, respectively. After considering the costs, benefits, and strategic alignment of the remaining options, Utilligent recommended C2M, finding that it optimizes costs, benefits, and strategic alignment. In particular, Utilligent found that C2M would significantly reduce technical debt, eliminate the data latency between the separate CC&B and MDM systems, make data centrally available, reduce operational maintenance costs, reduce billing exception handling costs, and reduce IT support costs. Utilligent noted that the alternatives, while cheaper to complete, would not deliver comparable levels of benefits.

The Accenture refresh in 2022 further evaluated potential vendors for the billing system upgrade. Accenture compared two available alternatives, Oracle’s C2M and SAP’s S4/HANA, and concluded that C2M better aligned with PG&E’s priorities. Specifically, Accenture found that the product capabilities of C2M and S4/HANA were similar, but the economic value of the C2M solution was greater given PG&E’s historical investments in Oracle systems over more than 15 years. Accenture also noted that switching from Oracle to SAP would require significant re-training for all users of the billing system.

While PG&E determined that CC&B 2.4 should ultimately be replaced with C2M, this presented the question of how that replacement should be implemented. The following options were considered, whether to: (i) upgrade directly from CC&B 2.4 to C2M, or (ii) implement a stabilizing upgrade to move from CC&B 2.4 to CC&B 25.1, followed by an upgrade from CC&B 25.1 to C2M.

1) Direct Upgrade to C2M

When PG&E initially proposed upgrading to C2M in the 2023 GRC, it proposed going directly from the outdated CC&B 2.4 to C2M. At that time, the C2M implementation schedule would allow C2M to go live in 2024. Under current timelines, C2M will resume implementation in 2026, which would result in CC&B 2.4 being in place for years longer than anticipated.

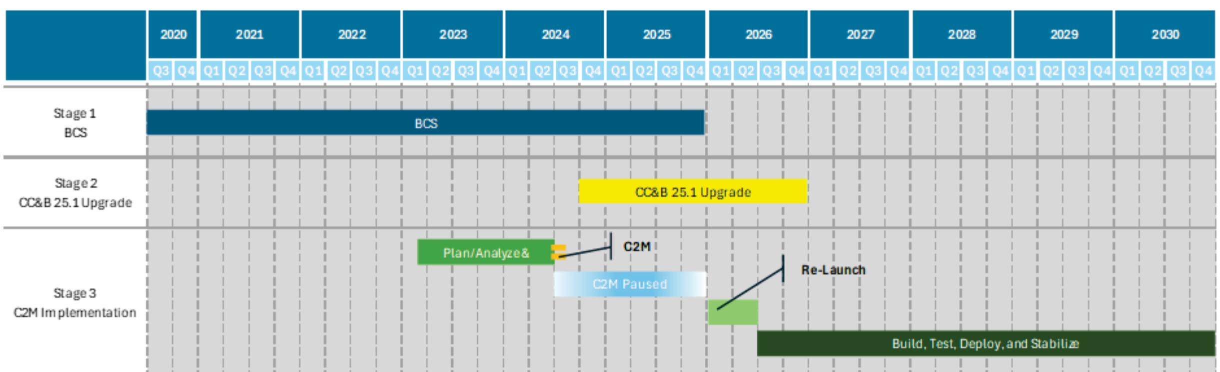
Under PG&E's current timelines, as further described in Chapter 5, BCS is anticipated to go-live in the middle of 2025. PG&E recently completed the Plan, Analyze, and Design phase of C2M with their implementation partner, Infosys. During this process, additional complexities in the move from CC&B 2.4 to C2M were found. Examples of additional complexities include:

- <u>Peak Day Pricing User Interface (known as a portal in CC&B)</u> -- The requirements for the portal included the ability for system users to support customer enrollment and program management, customer event participation, and annual default processing. As the project team evaluated the options to remove customizations, the broad requirements for this portal necessitated changes to multiple functional areas in C2M.
- <u>Bill Print Extract Functionality</u> -- The current system creates informational indicators as part of the bill calculation process that allows the bill print extract process (a customized, COBOL interface process) to consume and perform logic on the resulting bill data. The plan was to utilize the C2M native, configurable extract process instead of the custom process. As the team looked through the technical documents and programs, it became evident that the process contained much more logic than simply formatting the bill for printing, resulting in the need for additional, unplanned analysis.
- <u>Payment Plans</u> – PG&E can set up a customer to pay an average monthly fee instead of a fluctuating energy bill. C2M has the ability to set up these plans with variables for length, credit rating, and other customer features. California has programs that add complications to this functionality, like the Arrearage Management Program which sets up a payment plan to provide customers with debt relief, provided they meet the payments. One important detail of this program is the allowance for a customer to miss a payment but stay on the

plan. This feature requires custom monitoring to be built on top of the base payment plan functionality, increasing the complexity of the solution.

With the delay to the implementation of BCS and the additional complexities found during plan/analyze of C2M, the schedule to implement C2M has been extended. During this period, PG&E would need to rely on an increasingly out-of-date, out-of-support billing system which is both vulnerable to outside cybersecurity threats and faces internal stability issues as it fails to meet current Mission Critical standards for billing system reliability.

FIGURE 4-2
TIMELINE FOR BILLING MODERNIZATION INITIATIVE



Note: It is untenable to stay on CC&B 2.4 for two or more years than expected, due to cybersecurity and system stability concerns. As described in chapter 2, staying on CC&B 2.4 requires multiple applications to stay on out-of-date versions, with either no vendor support or very costly support models. As a result, PG&E determined that a direct upgrade to C2M was no longer a prudent approach under the circumstances.

CC&B has deteriorated, and the C2M timeline has been extended due to previously mentioned complexities. Incorporating the 25.1 upgrade in this trajectory facilitates a smoother transition to C2M by substituting COBOL with Java. Upgrading from 2.4 to 25.1 expedites risk mitigation, supports disaster recovery and enhances platform supportability.

2) Stabilizing Upgrade to CC&B 25.1, Followed by Upgrade to C2M

Rather than upgrade directly to C2M, PG&E evaluated (and ultimately selected) an option to perform an intermediate upgrade to stabilize PG&E's CC&B system by upgrading to the most up-to-date version of Oracle's CC&B program, CC&B 25.1. This stabilization upgrade will address the existing issues that PG&E is facing and the increased issues that are expected if PG&E were to maintain CC&B 2.4 for two or more years while waiting for C2M to go-live. This ensures that PG&E's Billing Modernization Initiative reaches the end goal of C2M while addressing the following issues:

First, it would allow PG&E to remedy the cybersecurity vulnerabilities that are currently open and Oracle's lack of support for the system. The implementation of the newer, supported CC&B and the underlying servers, operating systems, and related technology would allow PG&E to resolve all identified vulnerabilities by either upgrading to newer versions of software or applying current patches. PG&E would subsequently be on a supported version of CC&B and would receive regular security updates as required to ensure the security of the CIS.

Second, due to CC&B 2.4's age, it is incompatible with current versions of Red Hat and VMWare that are integral to its stable functioning. This has led to difficulties in performing disaster recovery exercises. The move to CC&B 25.1 would allow PG&E to integrate with the up-to-date version of Red Hat and VMWare. As CC&B and related applications are brought into support, PG&E would be aligned with Mission Critical availability standards for CIS systems with improved system availability time of 99.99 percent (as with C2M in the future), allowing customers full access to all features virtually all the time.

Third, the move to CC&B 25.1 would also mean a move away from COBOL and on to Java, the language that C2M uses as well. The move away from COBOL would greatly expand the pool of people capable of working on PG&E's billing system, allowing for greater support and improved PG&E efficiency.

Fourth, the move to CC&B 25.1 would bring the associated applications into support along with the CC&B system. The first phase of migrating to CC&B 25.1 will allow PG&E to get the technical components into support prior to migration to C2M (e.g., hardware, databases, integration components such as WebLogic, upgrading coding languages from COBOL to supported languages such as Java, Groovy, etc.). This has a two-fold benefit. The integrated applications and technical components would move to vendor supported versions thereby reducing risk by operating on modern versions, and the ability to call on vendor support. This effort also makes the move to C2M easier, as this final move would be moving from more recent technology/versions that the marketplace has experience working with. For additional information about the challenges associated with operating out-of-support versions, please refer to Chapter 2.

While the stabilizing upgrade provides a solution to several of the issues with the legacy billing systems, the proposed upgrade to CC&B 25.1 is not the target-state solution because it does not enable multiple critical business outcomes that PG&E has identified. For example, the upgrade to CC&B 25.1 will not move from linear rates to modular rates or reduce the number of customizations the way the upgrade to C2M will. CC&B 25.1 would not be integrated with an MDMS solution, nor would it move PG&E to a single modular rate engine as PG&E would still have ABS for gas and BCS for complex electric rates. The CC&B 25.1 upgrade is a stability enhancement, where PG&E is seeking to update its code, patch cybersecurity vulnerabilities, integrate with critical third-party solutions, and reduce technical debt as quickly as possible. The goal of this intermediate step is to keep PG&E's customer data safe and maintain system stability while modernizing the billing systems as quickly as is prudent.

PG&E is cognizant of the extended timeline of this billing modernization process and will continue to monitor technological developments in this space to identify any potential implementation efficiencies that could be passed along to customers. While PG&E is currently confident that C2M is the optimal CIS to satisfy its target state billing needs and is the prudent approach, C2M will not be implemented until after BCS goes live in 2025 and the CC&B upgrade goes live in 2026. While PG&E does not anticipate that this will change, the technology landscape is very dynamic, and should a more cost-effective path emerge, PG&E would seek the Commission's approval to utilize that option and pass the savings on to customers. For example, if one of the options that is currently cost-prohibitive for PG&E, like the SAP CIS, developed in a way that it could meet PG&E's future state billing needs at a materially lower cost than C2M, PG&E would not pass over that option because it was "locked in" to C2M. Having a cost-efficient solution with a high-performing vendor support structure are important objectives for PG&E, its customers, and the CPUC. PG&E will continue to monitor for technological developments or opportunities to obtain these benefits for customers at a lower cost.

c. PG&E's Decision and Rationale

PG&E's proposal for the Billing Modernization Initiative is a three-stage approach: (1) move electric customers from ABS to BCS, (2) upgrade CC&B 2.4 to CC&B 25.1, and finally, (3) implement C2M (the three-stage process is referred to in short as "BCS + CC&B 25.1 + C2M"). As can be seen in Table 4-2, PG&E determined that C2M is the optimal billing system to implement for PG&E's needs, and PG&E's detailed analysis on the risks of moving directly from the current unsupported versions of CC&B 2.4 and ABS with unsupported integration components indicated that an intermediate stabilization upgrade is prudent in order to maintain critical infrastructure and to reduce risk associated with implementing multiple transformation processes at once.

TABLE 4-2
DECISION CRITERIA OPTIONS COMPARISON

Line No.	Decision Criteria	Option 1 – Maintain Legacy Billing Systems	Option 2 – BCS + C2M	Option 3 – BCS + CC&B 25.1 + C2M
1	Stability	ABS continues to run above scoped capacity, further performance degradation likely CC&B 2.4 continues to run unsupported, raising risk of issues that vendor does not guarantee support for	Improved stability from ABS to BCS upgrade in short-term (2025) Improvements to CC&B stability are delayed due to implementation timeline for C2M (2028)	Complex electric billing stabilization in BCS Improved stability of CC&B from 25.1 upgrade in short term (2026) All mass-billing and complex billing is stabilized on one platform
2	Maintenance	CC&B 2.4 is written in COBOL, reducing pool of resources who can maintain Environments are not all the same, causing testing and integration issues.	Delayed transition to Java due to implementation timeline for C2M (2028) Consolidated system will require single rate implementation pathway (2028)	Accelerated transition to Java in CC&B 25.1 (2026) Cloud Maintenance is eliminated and consolidated into C2M, reducing storage costs. All CIS environments will be on same version of Oracle.
3	Vendor Support	No vendor support for ABS or CC&B 2.4 No vendor support on current version of L&G MDMS. End of life is 2024.	Vendor support established for BCS (2025) and C2M (2028)	Vendor support established for BCS (2025), CC&B 25.1 (2026), and C2M (2029)
4	Cybersecurity	Unable to patch cybersecurity vulnerabilities in CC&B 2.4.	Delayed improvement in ability to patch cybersecurity threats due to implementation timeline for C2M (2028)	Ability to accept scheduled and unscheduled cybersecurity patches beginning with CC&B 25.1 (2026) and continuing with C2M (2029)
5	Cost	Ongoing O&M work, but many issues cannot be patched or fixed Not possible to continue to operate regardless of O&M funding	Upgrade costs for BCS + C2M	Upgrade costs for BCS + CC&B 25.1 Cost to migrate from CC&B 25.1 to C2M (with integrated MDM)

TABLE 4-2
DECISION CRITERIA OPTIONS COMPARISON
(CONTINUED)

Line No.	Decision Criteria	Option 1 – Maintain Legacy Billing Systems	Option 2 – BCS + C2M	Option 3 – BCS + CC&B 25.1 + C2M
6	Operational Benefits	No additional operational benefits Significant operational risks/challenges	Some operational efficiencies gained from BCS (2025) Full benefits realization gained from C2M (2028)	Some operational efficiencies gained from BCS (2025) Additional stability benefits gained from CC&B 25.1 (2026) Full benefits realization gained from C2M (2029) with integrated Customer and Metering solutions
7	Customer Experience Impacts	System downtime exceeds Mission Critical standards, resulting in impaired PGE.com functionality Possible failure of systems may disrupt billing	Delay in improvement to system uptime due to implementation timeline for C2M (2028) Improved access to new rate programs (2028)	Accelerated improvement to system uptime in CC&B 25.1 (2026) Improved access to new rate programs (2029)
8	Rate Implementation Impacts	Reliance on linear rate development creates bottleneck for new rate implementation	Scalable modular rates deployment with BCS for complex electric (2025) Deployment of modular rates improves ability to advance CPUC goals (2028)	Scalable modular rates deployment with BCS for complex electric (2025) Deployment of modular rates improves ability to advance CPUC goals (2029)

PG&E determined that the proposed multi-step approach is necessary in order to first bring CC&B and its integration components into vendor support and to move the complex electric-billed customers out of the aging ABS system before upgrading to C2M. Upgrading from the outdated and unsupported CC&B 2.4 system will improve the efficiency, accuracy, and rate change responsiveness of PG&E's billing system, among other benefits. C2M is a unified customer care, service order, metering, and billing system designed to handle the complexities and challenges associated with PG&E's business processes. Given the complexity of energy policy and the utilization of new rate structures in California, having one C2M system will allow PG&E to provide customer service to all customers with any rate structure and any device type from one platform. This will reduce maintenance costs, improve live agent calls and simplify data provided to customers from the consolidated C2M system instead of the fragmented approach used today.

By implementing Option 3 including BCS, CC&B 25.1, and C2M, PG&E will move to its target state CIS in a manner that prioritizes system stability, customer safety, cost prudency, operational efficiency, and the ability for PG&E to continue to respond to an ever-changing energy policy landscape. By upgrading to a stable platform prior to the upgrade to C2M, PG&E will ensure that its CIS' stability is not at odds with internal, customer, and regulatory goals for a clean energy future.

E. Solution

1. Resolving Challenges Presented by Legacy Billing Systems

PG&E's upgrade to C2M, achieved through the three-stage process discussed above, solves the most significant and pressing challenges presented by the legacy billing systems, and satisfies the end state requirements identified by PG&E, described in Section B.

a. Rates Implementation

1) BCS Improvements for Complex Customers

Some of the rate implementation issues related to complex customers will be temporarily resolved with the transition of electric complex customers to BCS, and then remaining critical issues resolved by the implementation of C2M. Currently, complex customers that are billed through ABS receive a different bill format than customers billed through CC&B 2.4. The upgrade to BCS enables a bill format that is more consistent with the bill that CC&B 2.4 customers receive currently. Due to limitations in the data integration between ABS and CC&B 2.4, many customers that are billed in ABS get an "Energy Statement" with minimal detail and total bill values, as well as a secondary statement that shows the full calculation detail. BCS will add a significant number of billing determinants to PG&E's standard energy statement to improve NEM customers' experience. Further, BCS will generate supplemental reports for Standby[14] customers for additional billing information. This standardization will reduce customization and support from PG&E resources to populate this information and will move complex customers closer to the billing experience other customers receive. While customers' bills will be more uniform once C2M is implemented, BCS provides billing benefits to customers before C2M is in place.

The upgrade to BCS will deliver additional improvements to customers' experiences. First, more employees will have access to the data to support issue resolution for customers. Second, the PG&E employees that manage complex customer bills will receive proactive notifications on anticipated billing exceptions for complex customers, enabling faster resolution of issues before bills are delayed. Complex customers will experience fewer issues and a better support experience if issues do arise.

The upgrade to BCS will reduce the time it takes to see data changes, which currently take 24 hours for customers billed through ABS. With BCS, PG&E employees will have the ability to upload information from CC&B to BCS throughout the day. For example, they could update a rate, make the change in CC&B, upload that information to BCS and have it available almost real-time (new information that is flagged in CC&B will be picked up every 10 minutes).

The upgrade to BCS also enables a number of technical improvements, such as enhancing the data synchronization between CIS (CC&B) and the rate engine by automating the process and identifying only those exceptions that need manual intervention in BCS; enabling integrations with customer self-service

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14 Standby customers are those where PG&E will supply electricity and capacity on a standby [noncontinuous] basis under the terms of applicable Tariffs. See Electric Schedule SB, available at: <https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_SB.pdf> (accessed Oct. 2, 2024).

tools for automated rate enrollments (which is currently only available to CC&B customers); moving rate design to meet end-state requirements for all complex rates and programs such as Solar Paired with Storage, Standby, Demand Response programs such as Electric Base Interruptible Program (EBIP),[15] and billing and related reporting requirements will be met via Oracle Utilities Analytics (OUA) Visualization with BCS implementation.

2) Modular Rate Engine

The Billing Modernization Initiative will introduce a new, modular billing structure for rate calculations. PG&E will start by building modular calculation routines for all existing charges across its electric and gas rate schedules. In addition to minimum, energy, and demand charges mentioned previously, PG&E proposes to rebuild all existing calculation routines, such as California Alternative Rates for Energy and Family Electric Rate Assistance Program discounts, the Medical Baseline Program, TOU bill protection, reservation charge, gas transportation and storage charge, Franchise Fee surcharge, Utility Users and Energy Commission taxes, and many others. PG&E intends to rebuild the existing rate schedule calculation routines using the modules in the new billing structure and rate value configurations. By rebuilding the existing calculation routines in a modular fashion, PG&E will enable subsequent rapid rate change implementation and responsiveness.

b. Technology Integration

The Billing Modernization Initiative will implement a single billing system with an integrated MDM, rather than maintaining multiple billing systems and separate MDM. Because a CIS is so central to the business processes related to the customer, the new system will still require integration with multiple systems. The new system improves or

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15 The EBIP is intended to provide load reductions on PG&E system. Customers enrolled in the program will be required to reduce their load down to their Firm Service Level. See Electric Schedule E-BIP, available at: <https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-BIP.pdf> (accessed Oct. 2, 2024).

resolves many of the technology integration and data synchronization challenges discussed in Chapter 2, and PG&E proposes to leverage integrated MDM functionality to complement the modular billing framework.

The C2M system will simplify PG&E's customer technology landscape by providing data synchronization across modules within a single system (replacing several major systems with data currently transmitted and duplicated between systems). The C2M modules that PG&E plans to implement include:

- CC&B Module[16] – The CC&B module manages CIS data for persons, contacts, accounts, gas and electric service agreements and their service points for their gas and electric services. Note that, while similarly named, the CC&B Module replaces the features of the prior CC&B platform with a modernized data model within the larger C2M platform. This modernized data model includes what are now common data elements that are not available in the base product for CC&B 2.4, like interval meters, interval service measurements, meter firmware versions, solar panels, backup generators, electric vehicles, demand response programs, two-way energy exchanges and measurements (e.g., solar) and the rating and/or refunds/rebates for these customer energy programs. Many of these systems and devices were not in existence when CC&B 2.4 was built, and as a result PG&E manages these devices, service measurements, etc. via custom solutions, rather than a part of the base product as they are in C2M.
- MDM Module – MDM receives the device/meter interval data from the HESs via Smart Grid Gateway (SGG) and registers the raw meter reads, applies the Validated, Edited, and Estimated (VEE) rules and frames the usage to calculate the customer bills for services used (e.g., amount of electricity consumed or generated, etc.). Consolidating usage and billing data into the C2M platform eliminates the need for systems integration while providing more timely and more consistent usage data for billing.

[16] Please see Chapter 4, Attachment A for a diagram of the target state system.

- Operational Device Management (ODM) Module – ODM manages the service point and out of service assets, inventory tracking, quality assurance, device testing, orchestrates which devices are available for field deployment, and maintains the registry of firmware on each deployed device. C2M will replace over a dozen home-grown asset management systems (e.g., MIB, SmartTrack, Meter Locator, Meter Tracker, AMP, IorC, AIS) that PG&E currently uses to manage metering information, service point assets, device inventory and tracking, device testing, field deployment availability, and the registry of firmware on each deployed device. Many of these asset management systems were developed by PG&E over a decade ago as part of the initial SmartMeter Project. CC&B (versions 2.4 and 25.1) are not asset management systems, whereas the ODM module in C2M is a complete asset management solution. Streamlined systems and consolidated data sets will allow PG&E's field and back-office teams to provide timely, safe, and efficient customer service. The elimination of these home-grown solutions further eliminates technical debt and improves data governance.
- Service Order Management (SOM) Module – The SOM manages field activities and service orders for customer's start/stop/transfer services and sends the remediation request to the appropriate field or back-office team. This module implements real-time validations on field work entries to reduce billing exceptions, reduce customer impacts, and minimize field truck rolls. It incorporates current edge systems into the module, allowing for greater visibility into the work in queue and bundling of field activities by a single field resource when possible.
- Smart Grid Gateway (SGG) Module – SGG communicates with HESs and the C2M platform with pre-built integration adaptors. These adapters are components designed to connect with multiple HESs available on the market, rather than a custom adapter for each vendor. HESs are systems that collect measurement data and meter events for eventual submission to the MDM module. These systems automatically collect daily reads, usage in intervals (e.g., hour, 15 or 5 minute, etc.) and meter events, which eliminates the need to dispatch a manual

meter reader to collect this information on a monthly basis. PG&E has multiple HES (e.g., Aclara/Hex for gas & Itron/UIQ for electric SmartMeters). A single gateway standardizes and simplifies operational device commands and device communications with the billing system.

- Market Transaction Management (MTM) Module – MTM centrally manages how PG&E's billing system/CIS interacts with third-party (ESPs, CTAs, CCA, and third-party vendor services) providers. MTM introduces configurable business rules for enrollments/de-enrollments, usage, and/ billing transactions which will improve responsiveness and reducing the risk of errors. Additionally, PG&E will substantially reduce the customizations to support third-party ESPs.
- OUA – A mostly base C2M implementation will allow PG&E to leverage Oracle's Utilities Analytics Warehouse. This is a pre-built data warehouse offering that includes C2M data integration, tables, metrics, reports, and dashboards. Using this off the shelf solution will reduce operational costs, reduce CRCR customizations and enable real-time analytics for better informed business decisions. Additionally, OUA can ingest and analyze data sets residing outside of the C2M platform. For example, the Field Automation System (FAS) orchestrates field activities from C2M to SAP, and OUA can be used to analyze subsets of FAS data against SOM data to determine completion of field work required for a customer.

These modules, and the availability of this data synchronization and adapters in general, improves the function of the CIS within the context of the broader support of PG&E's customer. For example, housing both CC&B and MDM functionality on a single platform will allow PG&E to process meter data measurements of energy consumption from the HESs, apply validating and estimating rules on those initial measurement reads (against the registered devices), and provide the usage calculations to the CC&B rate engine in order to calculate all of PG&E's customer bills—all within a single platform. Additionally, this would allow PG&E to move away from read cycles (which are derived from old meter reading routes based on a premise geographical location and only currently used for subtractive billing), leveraging only the bill cycle for both gas and electric service agreements, which would align the bill to/from dates based off when the bill is generated for both commodities.

Under the current systems, data would need to move from the HESs to the external MDM, be processed through VEE, then transferred to two separate billing systems. The integration will eliminate data latency and significantly minimize data duplication and synchronization issues reducing manual intervention and improve the customer experience.

The integrated MDM will also allow the system to identify whether estimation is occurring due to field work which failed to properly upload into the system, or due to a communication or environment issue on AMI preventing the system from having good reads. The resulting business benefits include reduced VEE exceptions which in turn decreases manual intervention and lowers unbilled revenue.

In addition, the integration will enable PG&E to implement rate changes by modifying the usage configuration without any changes, custom or otherwise, to the underlying rate schedule calculation modules. For the previously described E-6 summer season TOU period change implementation (in Chapter 2), had a modular framework been in place, PG&E could have modified the usage framing configuration for all rate schedules, instead of individually modifying each residential rate schedule calculation routine.

Integrations between C2M and other customer data and customer facing systems will also be improved. PG&E will leverage base functionality of C2M, reducing the number of customizations in the system. With reduced customizations, PG&E can take advantage of built-in Application Program Interfaces (API) to make information and processes available to external systems. In this case, the built-in APIs set the definition for how other systems will send requests to interact with C2M. This is especially important for integrated systems that rely on customer information, like Web, IVR, and contact center systems. In general, these systems are accessing the information for a single account. By utilizing the built-in APIs, the request/response time for these interactions is reduced, allowing PG&E to serve customers more quickly. These modernized APIs also come with greater monitoring and security functionality. Since APIs allow access to and from systems outside of the CIS, monitoring and security are important to ensure the safety and privacy of customer data.

For situations where systems need access to larger quantities of customer data, the modern C2M application also provides many benefits. Since the system will reduce the customizations, Oracle's Golden Gate replication functionality will be implemented with less customization and complexity. This in turn applies to the downstream systems that consume the output of the replication.

c. System and Vendor Support

The Billing Modernization Initiative will resolve PG&E's system and vendor support challenges by bringing application and system technology and architecture into the current, supported, modern state. This will allow for more cost-efficient support from vendors, as well as a robust and competitive marketplace for in-house resources.

By moving from CC&B 2.4 to the future supported version of 25.1 and then to C2M with reduced customizations, PG&E achieves two big benefits. First, PG&E can leverage the standard,[17] multi-year support model from Oracle for product support and assistance. In the current system, PG&E must pay a heavy premium for customizations and to continue vendor support for the system. Second, due to the reduction in customizations, PG&E can take advantage of application patches Oracle releases to reduce cyber and asset failure risks, improve operations, and maximize functionality. Oracle releases patches for a variety of reasons, such as resolving security vulnerabilities, fixing product defects, or releasing new functionality. In addition, Oracle releases three code versions per year for its cloud version. While these

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17 Oracle notes that their Sustaining Support model provides "maintenance for as long as you use your Oracle software." While the support continues access to service request platform and the Oracle knowledge base, Oracle will only provide pre-existing fixes. PG&E must pay a premium for Oracle to develop new fixes. Oracle, Lifetime Support for your software, available at: <https://www.oracle.com/support/lifetime-support/software.html> (accessed Oct. 2, 2024).

are different than patches, Oracle could leverage the same code lines to release functionality to PG&E.

Likewise, PG&E would consolidate various applications into C2M, including ABS Gas (which will remain in use for complex gas customers until the transition to C2M), BCS, and the MDMS. This consolidation means that PG&E needs to engage and contract with fewer support suppliers. Given the complicated nature of CIS systems, having fewer support teams enables broader understanding of the ecosystem and increased issue response and decreased resolution time.

PG&E would also realize the benefits of support for current generation technology beyond its applications. Concurrent to PG&E's upgrade to C2M, the underlying technology—servers, operating systems, virtual machines, etc.—will also be upgraded to current versions which were previously incompatible with CC&B 2.4. This benefit further reduces PG&E's risk exposure to vulnerabilities by bringing multiple technologies back into current versions and allows PG&E to keep up with updates. Further, with these technologies updated, PG&E will be able to utilize the deployed architecture for disaster recovery. This will allow PG&E to restore C2M in case of a disaster in less than four hours, allowing PG&E to quickly restore the central system of customer data.[18]

d. Technology/Future Set Obsolescence

The impact of technology obsolescence is mitigated by the simple fact that PG&E's outdated CIS will be replaced with a new version that is in support. While many of these improvements will be obtained through transitioning to C2M, the three-stage approach for the implementation of the Billing Modernization Initiative enables the realization of some of this modernization earlier with the implementation of BCS for certain complex customers and the upgrade of CC&B into a supported version.

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[18] PG&E's Service Availability Criticality Standard defines a Mission Critical system as one that directly supports the safe and reliable delivery of energy to customers. The Standard includes a variety of elements of reliability, as well as a Recovery Time Objective (time to restore the entire system after a disaster) of four hours.

The upgrade from CC&B 2.4 to 25.1 will lead to a host of technology modernization results. This stage will focus on bringing CC&B to a current, supported version, and it will also upgrade underlying and related technologies, like Redhat Linux, VMWare, Unix, etc. Similarly, CC&B 25.1 no longer accepts COBOL customizations, so PG&E will update their customization code to a programming language that has a wider resource marketplace for support and maintenance. Further, the integration APIs for CC&B 25.1 have moved to Inbound Webservices, a more modern version. This enables the system to make more data available to integrated systems. As PG&E continues to modernize its Web and customer-facing systems, the applications can take advantage of the new integration technology.

As mentioned previously, BCS is a cloud-based application. Oracle releases three updates annually for its cloud-based CIS and billing products. PG&E will be regularly upgrading the complex billing system to a current version, with the ability to leverage new functionality that is included in the upgrade.

The move to C2M has a goal of significantly reducing customizations. This reduction of customizations will also streamline analysis required to implement patches, rendering this implementation more cost-effective. Additionally, the reduced customizations would allow PG&E to align with Oracle's roadmap of features and capabilities.

e. Data Governance and Data Privacy

The Billing Modernization Initiative includes data privacy improvements, which PG&E identified as a required outcome. In particular, C2M includes functions called Information Lifecycle Management (ILM), and Object Erasure. ILM identifies transactional information in a database by usage frequency and assigns different types of storage and data compression levels. ILM enables two primary benefits. First, ILM facilitates PG&E compliance with data retention and deletion policies. Second, ILM enables PG&E to reduce storage costs and query times. Object Erasure enables the configuration of master customer data erasure using business rules while also keeping data integrity. In many cases, certain customer identifiers, like an account number, cannot be removed from the system, but the Object Erasure rules can remove the related customer identification information.

With ILM and Object Erasure implemented, PG&E would be able to develop processes to identify data across the system which meets retention period standards, based on usage frequency. This most commonly occurs when the information is no longer necessary for the original purposes for which it was collected and processed. This is usually the case when a customer's accounts have been closed for some time and there is no other activity for that customer.

The implementation of ILM and retention-identification processes will enable PG&E to meet the CCPA/CPRA requirements discussed in Section B, on a broad scale with cost-efficient, automated processes. ILM enables the automated selection of data based on customer and retention criteria, then data deletion without customized programming. When PG&E moves from CC&B to C2M in stage three of the project, PG&E will only convert data still required for its business operations, proactively reducing the amount of data it retains before the implementation of ILM.

f. Improved System Uptime

PG&E's current Mission Critical system uptime target is 99.95 percent, meaning that the system can meet its reliability goal with unplanned outage of 4.38 hours per year, or 21.92 seconds per month. The 2025 target increases to 99.97 percent and the 2026 target increases to 99.99 percent.

With the upgrade to CC&B 25.1, PG&E will be implementing modern, current hardware and software to support CC&B. By moving to modern architecture for the application and database servers, current functionality includes the ability to better handle processing load, error handling, and other issues that lead to server disruption. In addition to CC&B, the project will include integration hardening, which involves bringing the integration systems up to date as well as adding redundancy and recoverability functionality to these systems. While this will not directly improve CC&B servers uptime, it will provide an overall increase to usability of the system.

Implementing C2M will further support the improved uptime. By resolving the separate MDM and billing systems, performing usage and billing processes requires less disparate servers and systems, reducing the likelihood of issues. C2M will be implemented across multiple servers that allows for the spread of processing so as to not overload any one server. This is advantageous over the current system with processing across multiple systems to enable PG&E to support customers whenever they need assistance.

g. Third-Party Energy Provider Functionality

The Billing Modernization Initiative will enhance PG&E's ability to support third-party energy providers with the MTM module introduced above. The MTM streamlines the entire lifecycle (from mass customer enrollment, rate change notifications to exiting the energy markets) of third-party energy providers, including CCAs and CTAs throughout their lifecycle. This ensures smoother integration, better end-to-end visibility, and greater flexibility for PG&E. MTM will enable customers to seamlessly transition to bundled services if a third-party provider voluntarily or involuntarily leaves the market, minimizing service disruptions and maintaining reliable customer experiences. MTM introduces functionality that is expected to allow PG&E to return an entire CCA population to bundled service next day with minimal impacts on billing and the customer experience.[19]

The transition to C2M represents a significant reduction in data complexity. Currently, PG&E manages data through multiple systems, including the MV90 system which has a usage stream sent to CCAs for large and complex customers. This multi-system implementation requires a complex, multi-step process to integrate data from the head-end system with customer data from the CIS to create usage files for CCAs/ESPs. The transition to C2M consolidates all customer,

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[19] In April 2024, the Commission directed PG&E to "describe whether the [Billing Modernization Initiative] would increase the level of automation associated with CCA and ESP customers returning to PG&E's bundled service." D.24-04-009, p. 43. PG&E provides its best current estimate here, noting that PG&E expects to re-start the C2M project in Q3 2026, with a go-live date in Q4 of 2029.

billing, and usage data into a unified system, allowing for a single source of information. This simplifies data retrieval and ensures accuracy, creating a more agile, efficient operation that supports data integrity.

This unified MDM and billing system consolidates previously fragmented data sources, eliminating inefficiencies and costly data silos. By maintaining one integrated system, PG&E can reduce technical debt and provide third-party ESPs with more interval usage data. This not only enables CCAs to offer their own TOU rates and demand response programs, but it also expands the range of services available to customers, providing greater choice and flexibility.

2. Desired Business Outcomes and Additional Benefits

In addition to the functional requirements that are achieved by addressing the issues with the legacy billing systems, the Billing Modernization Initiative provides some of the non-essential beneficial features PG&E identified, described in Section B.

a. Self-Healing Feature

The Billing Modernization Initiative includes the implementation of a self-healing feature within C2M that PG&E identified as a desired business outcome. The self-healing feature involves automatic retry for failures, such as failed reads, commands, bill determinant calculations, or device event failures. This self-healing feature automatically closes any open exception it resolves and reduces manual work and, in some cases, will improve the customer experience by mitigating billing exceptions.

b. Customer 360

Within C2M, Customer 360 exists as a portal to provide customer service agents with a single view of all CIS functions. In addition to standard customer and account information, agents will have a timeline feed of all previous customer interactions from fieldwork to billing and payment events, customer calls, and collections events. This portal will help agents by displaying usage and cost trends for the customer, and present relevant customer insights tailored to address the customer's situation. These customer insights are generally customer programs, such as payment arrangements, arrearage management programs, customer assistance programs, and demand response programs.

c. Bill Format & Self Service

BCS will allow for all electric customers across both billing platforms to receive a standardized Energy Statement, as opposed to receiving a minimum format statement lacking usage and charges detail found on the cumbersome Detail of Bill. Additionally, C2M will allow for service parity among all self-service channels (e.g., IVR and PGE.COM) as complex billing customers will have access to self-service features that are currently only available to CC&B customers.

d. Real-Time Payments

The C2M deployment will realize a real-time payment functionality for select payment channels. Connecting vendor supported payment channels with a near real-time payment interface would allow for streamlined restoration of service following a disconnection for non-payment. Once C2M recognizes a payment (of sufficient value), it can begin a restoration process which calls the customer to read the safety message and then executes the SmartMeter turn-on command.

e. Payment Arrangement Improvements

Payment arrangements, instead of pay plans, will be the default offering for past-due amortization agreements within C2M, which will provide an improved customer experience. Pay plans allow for a past due balance to be spread into multiple future periods but the amount of pay each period and the due date of each period are not printed on the energy statement. Therefore, customers must remember the terms of the pay plan or call PG&E's IVR to obtain this information. Payment arrangements will also spread a past due balance into multiple future bills, but these payments will be included as a printed line item on energy statement indicating the amount due for the arrangement. The due date of a payment arrangement is also aligned with the due date of the energy statement, eliminating the need to remember the date or call in to obtain this information. Adoption of payment arrangements will allow customers to opt for the convenience of recurring payments offered on the PG&E website. Additionally, payment arrangements will allow customers to enroll in Budget Billing to secure greater bill stability.

f. Outage Management

Integration of outage data and demand response programs will result in better accuracy of estimates during both planned and unplanned outages and demand response events. This will provide a better experience for customers, emergency response partners, and regulatory agencies who rely on timely updates.

3. Target State Architecture

When the Billing Modernization Initiative is complete, the complex current state architecture, described in Chapter 2 Section C, will be simplified significantly while reducing technical debt. C2M will integrate numerous processes, as described below, to remove or streamline the process of transferring data out of the CIS to related systems. This simplification can be seen in the comparison of the current state architecture for the legacy billing systems, described in Chapter 2 and provided as Attachment B, and the target state architecture, provided as Attachment A to this chapter.

PG&E will implement C2M at the center of PG&E's customer data ecosystem, and C2M will simplify the integrations to other internal PG&E systems as well as external systems. In particular, there will be simplification as it relates to the need to transmit data to other customer data systems like those used for reporting—in this case OUA and data warehouses. This is in addition to the fact that C2M removes the integrations necessary for separate MDMS and multiple billing systems, as the current separated state of these systems will be consolidated into the single C2M system.

One important note to consider is that PG&E will be implementing the "on-premise" C2M solution rather than Oracle's cloud version. Cloud solutions can offer advantages, including the reduction of hardware in data centers and reduction in technical operating costs; however, PG&E made the decision to stay with the on-premise solution for several reasons. First, Oracle has limited experience operating a system of the size and complexity of PG&E in the cloud environment. This poses operational risks given the scale of processing that occurs on a daily basis. The cloud solution does not allow PG&E to create database tables in any environment. This also poses operational challenges, as PG&E uses system data to monitor system operations, customer data, and improve processing efficiency. Further, Oracle's Golden Gate product is not available with the cloud products. Golden Gate is a critical functionality to extract, replicate, and transform data for other systems that need customer data. Without Golden Gate, PG&E would need to develop and maintain dozens of custom interfaces that process large amounts of customer data, which would increase future operational support costs.

F. Conclusion

For the reasons discussed above, PG&E must upgrade, and ultimately replace, its legacy CC&B, ABS, and MDMS systems through the three-stage approach presented herein.

PACIFIC GAS AND ELECTRIC COMPANY

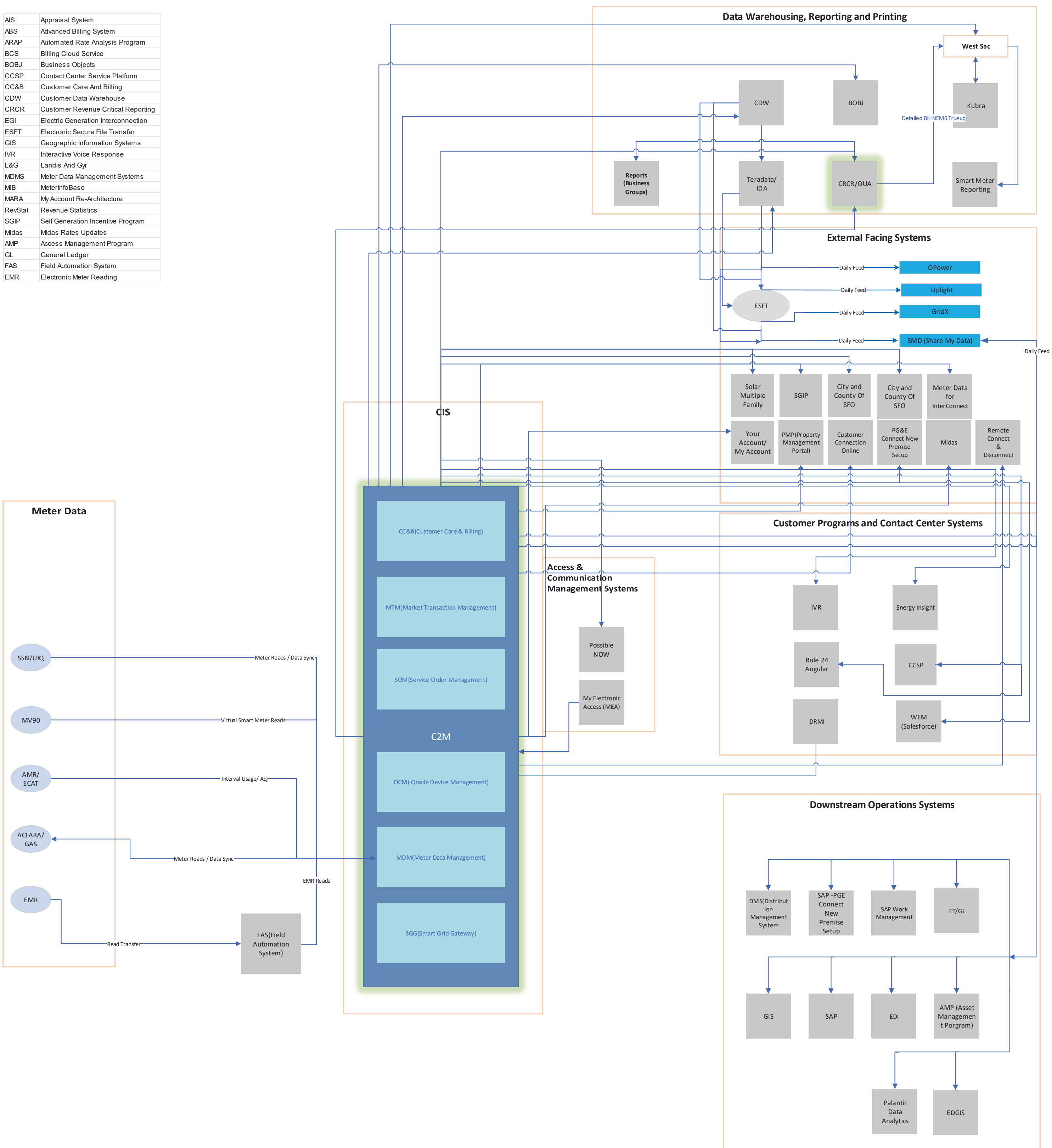
CHAPTER 4

ATTACHMENT A

STAGE 3 ARCHITECTURE DIAGRAM

Billing Modernization
Stage-3 Target State

AIS	Appraisal System
ABS	Advanced Billing System
ARAP	Automated Rate Analysis Program
BCS	Billing Cloud Service
BOBJ	Business Objects
CCSP	Contact Center Service Platform
CC&B	Customer Care And Billing
CDW	Customer Data Warehouse
CRCR	Customer Revenue Critical Reporting
EGI	Electric Generation Interconnection
ESFT	Electronic Secure File Transfer
GIS	Geographic Information Systems
IVR	Interactive Voice Response
L&G	Landis And Gyr
MDMS	Meter Data Management Systems
MIB	MeterInfoBase
MARA	My Account Re-Architecture
RevStat	Revenue Statistics
SGIP	Self Generation Incentive Program
Midas	Midas Rates Updates
AMP	Access Management Program
GL	General Ledger
FAS	Field Automation System
EMR	Electronic Meter Reading



PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

BILLING MODERNIZATION INITIATIVE IMPLEMENTATION

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BILLING MODERNIZATION INITIATIVE IMPLEMENTATION

A. Introduction

This chapter provides a detailed description of the implementation of Pacific Gas and Electric Company's (PG&E) proposed Billing Modernization Initiative, including the stages of the project, implementation plan, resources required, a timeline, and the costs anticipated for each stage. The California Public Utilities Commission's (Commission) November 16, 2023 General Rate Case (GRC) Order directed PG&E to provide additional detail about the implementation plan for the proposed billing systems, including:

> [A] more robust showing of PG&E's proposed project, including the implementation plan, phases of the project (e.g., planning, development, testing, or others), resources required for each phase, timeline for each phase, costs anticipated for each phase, and other information.[1]

This chapter addresses the directive by providing a detailed roadmap of the Billing Modernization Initiative.

As detailed in Chapter 4, PG&E proposes a three-stage approach to stabilize and upgrade the billing systems through three projects:

- The first stage, which began in 2020 and is currently in progress, moves PG&E's electric customers with complex billing (referred to as "electric complex billing customers") that are currently billed in the Advanced Billing System Electric (ABS Electric) to a new system, Oracle's Billing Cloud Services (BCS). The BCS implementation is scheduled to be deployed (referred to as "go live") in Q2 of 2025.
- The second stage will update the outdated version of Oracle Utilities Customer Care and Billing (CC&B) Version 2.4 (CC&B 2.4), to the current Version 25.1 (CC&B 25.1).[2] The CC&B 25.1 upgrade is scheduled to begin in Q3 2024 and scheduled to go live in Q3 of 2026.

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1 Decision (D.) 23-11-069, p. 549.

2 Oracle recently updated its CC&B version numbering system to align with that of C2M, and Oracle's next version is CC&B 25.1 (to be released in 2025).

- Finally, the third stage will complete the implementation of a modernized billing system by upgrading from CC&B to Oracle's more advanced Customer-to-Meter (C2M) product and consolidating all customers to one system, including the electric complex-billing customers that were moved to BCS and the gas complex-billing customers that remained in ABS. PG&E will also integrate the Meter Data Management System (MDMS) into C2M. The C2M implementation began in 2021 and paused in Q2 2024. The project is scheduled to resume in Q3 2026 and go live is expected in Q4 of 2029.

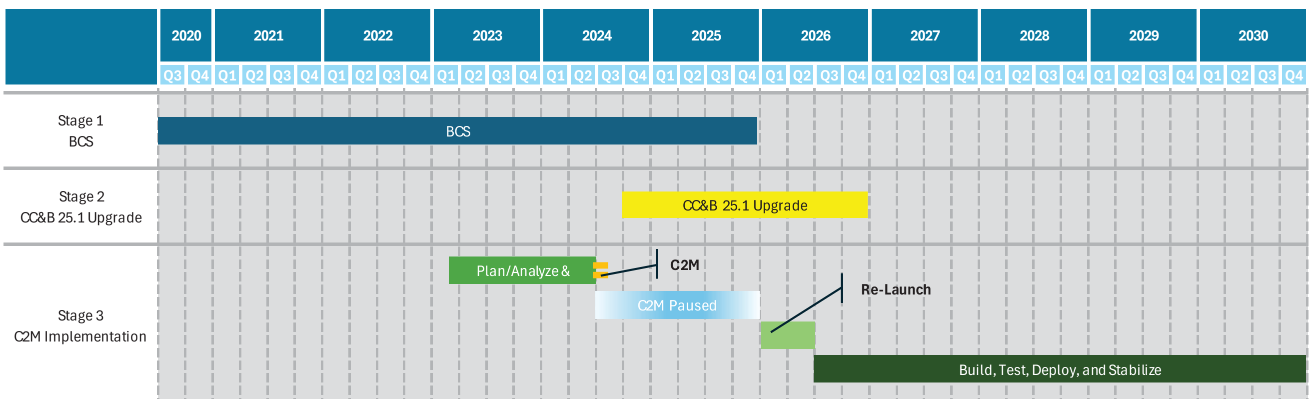
The original Billing Modernization Initiative submitted in the 2023 GRC included only two of these stages: replacing ABS with BCS and moving everything to C2M. The BCS project was originally planned to go live at the beginning of 2023 but has faced a number of challenges due to the complexity of California's rates and programs, as well as the complexity of moving from a custom-built data model (ABS data architecture) to a standard Customer Information System (CIS) data model (Oracle data architecture). Throughout the execution of the project, PG&E has made prudent decisions to overcome the challenges and made directional changes to deliver a correct solution for customers. PG&E recognizes that the current timeline is longer than what was initially planned. This chapter will describe challenges faced during the execution of various Billing Modernization Initiative stages, prudent decisions and lessons applied to future activities and plans, and changes to the delivery operating model that conveys confidence in the plans and enables consistent delivery of the Billing Modernization Initiative.

Although the stages of the Billing Modernization Initiative overlap in time—and will inevitably have certain interdependencies—PG&E has elected to organize the staffing, vendor partners, and performance of related activities into individual, independent projects to better manage contracting, finances, execution, communication, and risk. This approach is prudent due to the complexity of the projects and scope, multiple vendors and future solutions involved, and scale of resources and activities for each project. PG&E has developed initial implementation plans and timelines for each project and combined these into a single delivery roadmap presented in this chapter (discussed in Section B, below). Each project is divided into phases, with distinct sets of activities and specific timelines unique to each system (discussed in Section D, below). PG&E has also prepared detailed plans for addressing the internal and external staffing needs to complete each project (discussed in Section E below).

B. Billing Modernization Initiative Overview

PG&E estimates that the Billing Modernization Initiative will take a total of 123 months, beginning August 2020 with launch of the BCS project through the support phase of the C2M implementation (ending in November 2030), as shown in Figure 5-1 below.

FIGURE 5-1
TIMELINE FOR BILLING MODERNIZATION INITIATIVE



PG&E worked with Information Technology (IT) consultants from utility industry vendors to develop the implementation schedule for each of the projects. For the BCS project, Oracle was the primary vendor supporting the creation of the schedule and deliverables, with recent project management support from Utilligent resources. For the CC&B 25.1 upgrade project, PG&E again worked with Oracle and Utilligent resources for planning, albeit different resources from those that supported the BCS project. For the C2M implementation project, PG&E worked with Infosys. Infosys provided recommendations based on their extensive experience implementing similar customer system upgrades and the specific scope of the Billing Modernization Initiative. PG&E has used different planning and organizational approaches for the CC&B 25.1 and C2M projects compared to the BCS project, in large part due to lessons learned from the execution of the early phases of the BCS project. These approaches are explained in more detail in the sections below.

C. Overview of PG&E IT Implementation Framework

All three projects will be deployed utilizing PG&E's standard IT Methodology,[3] which organizes the seven project phases into a 5-step governance process. PG&E's IT Methodology combines the Build and Test project phases into a single governance step called "Execute/Construct." The project activities are the same for these two project phases. Similarly, the IT Methodology "Closeout" governance step combines the Deploy and Support project phases. Each phase aims to achieve a specific objective, as listed below:

1) <u>Pre-Planning</u>: Lay the groundwork for the entire project by understanding the objectives of the project, establishing key delivery parameters and implementing the governance model and operating infrastructure;
2) <u>Plan/Analyze</u>: Identify and document the functional and technical requirements of the final solution. This includes defining both the current-state and target-state business processes;
3) <u>Design</u>: Create and document a design of the overall structure as well as individual components of the system to address the functional and technical requirements, operating specifications, and architectural considerations;
4) <u>Execute/Construct</u>: Develop and test the solution.
    - <u>Build (also referred to as Development)</u>: Translate the design specifications into working software components for the final solution to meet the stated requirements. This also includes early-stage unit test activities to ensure development is meeting quality objectives;
    - <u>Test</u>: Validate the system's performance—both functional and technical—against the stated requirements and documented designs. Testing is performed in multiple stages with varying purposes and approaches to ensure the quality of all aspects of the implemented system. This phase allows PG&E to identify and address any issues

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3 PG&E's IT Methodology is based on PG&E Utility Standard PM-1010S: Project Management Governance Standard document. The document can be made available upon request.

with new technology before they impact customers—a critical step for complex systems like PG&E's billing systems;

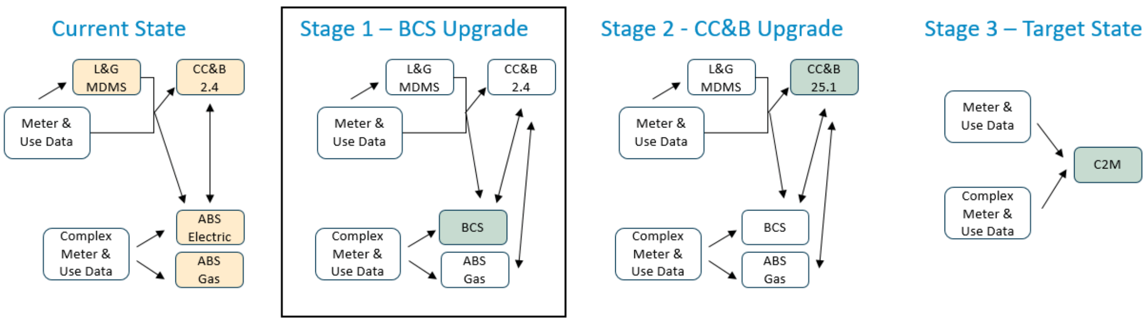
5) Closeout: Deploy the solution and support it until stabilized.
   - Deploy: Prepare all aspects of the system (software, data, infrastructure, resources) from deployment to production (an environment where the application and data are operationalized for end-user usage). The phase ends with the production deployment, and includes activities such as mock migrations, infrastructure preparations, end-user training, and operational readiness evaluations; and
   - Support (also referred to as Stabilization): Ensure the system is operating within the defined functional and technical performance parameters (which includes defect resolution and data repairs as necessary) and transition ownership of the system and all related components from the project team (which includes selected vendors and PG&E business and IT staff responsible for implementing the project) to PG&E's business and IT operations teams.

While the objectives and outcomes of each phase are defined by PG&E's standard process, the activities and deliverables within each phase are specific to the respective project. Phases are generally sequential, but, depending on the needs of the project, some phases may overlap or be repeated as part of an iterative process. If significant issues are identified in the Test phase, additional phases may be added to the process to resolve the issues before deploying new technology (e.g., the BCS project, described below, had several phases added to resolve issues identified in testing). The next section outlines – for each project – the major phase-based activities, deliverables, outcomes, and prudent execution adjustments as they apply to the respective project.

D. Project-Specific Implementation Plans

1. BCS – ABS Electric Replacement

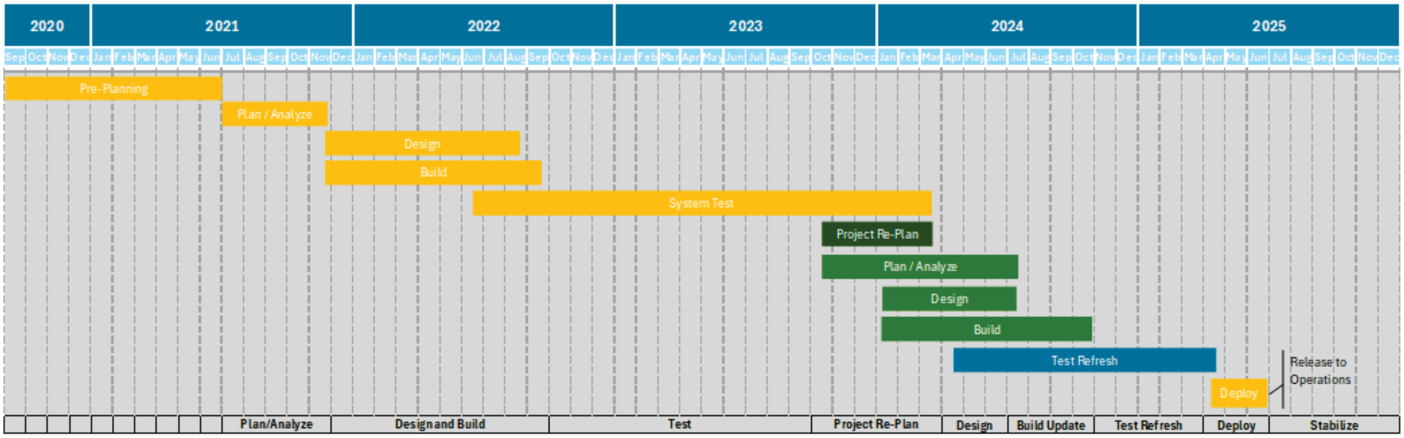
FIGURE 5-2
BCS UPGRADE



BCS is a new modular rate engine that will replace the outdated, overburdened ABS application (described in detail in Chapter 2) for electric complex billing customers. The BCS project is in progress and is currently expected to be deployed by Q2 of 2025. The project began in 2020 as PG&E identified the risks of continuing on the ABS system were too great.

As described in Chapter 2, the ABS system is home to the most complex rate programs (e.g., Virtual Net Energy Metering (NEM), NEM Aggregation, NEM Paired Storage). PG&E's base rate schedules generally follow industry rate design practices, but the complex programs in the California marketplace are different than industry standards. This complexity caused misunderstandings in the early stages of the project, leading to gaps in designs and other challenges. As detailed in Section D.1.e, the challenges became great enough that the project needed to reevaluate and initiate prudent changes to be successful. These challenges were an unavoidable outcome from unwinding three decades of technology implementations in ABS. The project phases, both before and after the replanning effort, are described below:

FIGURE 5-3
BCS UPGRADE PROJECT PHASES



a. Pre-Planning

In the Pre-Planning phase, which has already been completed, the BCS project team aimed to select a product to replace the ABS system, select a system integrator to manage and execute many of the project activities, and develop business requirements. The pre-planning phase lasted from September 2020 to June 2021.

The first major activity in the Pre-Planning phase was the selection of a new product for PG&E's complex billing system. PG&E performed a competitive Request for Proposal (RFP) process to select the product. First, PG&E began by documenting the business requirements, focusing on PG&E's rate tariffs and the integration needs with CC&B and other systems. Next, PG&E created selection criteria for the new product. Finally, PG&E released the RFP to the marketplace.

A cross-functional team of IT, business, and technical operations personnel evaluated the vendors and products as part of the RFP process. Initially, five vendor products were considered, but the PG&E team reduced the potential vendors to two based on review of product maturity and each product's ability to meet a majority of PG&E's requirements. Finalist vendors performed multiple presentations demonstrating their product's ability to meet the rate schedule calculation requirements and special program requirements. Ultimately, the Oracle BCS product was selected, in large part due to its cost-effectiveness, ability to integrate with PG&E systems, and product support model.

With the product selected, PG&E turned its attention to selecting the system integrator. PG&E decided to work with Oracle Consulting Services (OCS), a team from the same vendor as the BCS product. OCS was selected due to the newness of the BCS product, lack of other vendors experienced with its implementation, and PG&E's previous positive experience working with OCS. PG&E contracted OCS to lead the project management, design, build, and test functions for the remainder of the project. This initial contracting strategy has been modified for future projects due to challenges experienced during the BCS project (detailed more in Section D.1.f).

b. Plan/Analyze

The Plan/Analyze phase of the BCS project began in July 2021 and was completed in November 2021. The project kickoff was held in July 2021 to establish the context for the project and inform project team members of the upcoming plan. In the Plan/Analyze phase, PG&E provided the full suite of its business requirements, including an inventory of rates and charges and a detailed view of PG&E's tariffs, to Oracle. PG&E agreed with Oracle's recommendation to produce a "MoSCoW" list, (an acronym short for "Must have Should have Could have Won't Have" in the context of requirements development) a document used during configuration workshops that contained itemized business requirements from PG&E and the resulting disposition. The MoSCoW list was developed in place of functional requirements (a decision that was later reversed). The project team organized workshops across workstreams for billing and usage, rates, and system interfaces with Oracle as the delivery vendor and PG&E resources with requirements expertise. Retrospectives on the workshop execution indicated that workshops could have been executed in a more effective manner by presenting the scope and desired outcomes of the workshops, allowing for the right participants and successful execution.

For the rates workstream, the rates development was planned into eight iterations per Oracle guidance, with the simplest rates in the first iteration and future iteration groups expected to build upon the initial set. The billing/usage and system interface workstreams were not iterative in this manner, as the functionality had less overlapping development. The workshops focused on reviewing the requirements documents and knowledge transfer to the Oracle personnel.

Parallel to the workshops, the project team worked on delivering various project strategy documents, including the rates configuration strategy, testing strategy, and integrated project plan.

During the Plan/Analyze phase, the project witnessed internal under-resourcing and Oracle resource turnover in the area of project management, technical and functional architects, and designers. This caused delays in the execution of certain project activities and deliverables as the new members had to get up to speed. Project leadership took steps to adjust resource commitments and reduce resource transition impacts, including contract modification to enforce commitments.

c. Design

The Design phase began in December 2021 and was completed in August 2022. For the Design phase, the project team created design documents for the different workstreams. For the rates workstream, this included design documents for shared rates modules. Since the project was developing the rate calculation in the modular rate engine, certain modules (like the delivery charge calculation, for example) would be used in multiple rate calculations, and thus shared across development efforts. Shared modules built in to the initial development iterations would be modified and updated during the development in later iterations.

The BCS project was the first project to be executed with resources mainly working remotely due to the Covid-19 pandemic. During the Design phase, the project team identified that the lack of in-person interaction was leading to challenges collaborating, especially for scope like shared modules. Project leadership agreed to pivot to more in-person working days to enable better cooperative outcomes as the pandemic working conditions eased.

Based on the iterative rates implementation strategy, the rate calculation development was executed using iterative design, build, and unit test activities. When the design of the first iteration was complete, the design team moved onto Iteration 2 rates while the build team worked on the development for Iteration 1 rates. Because of the iterative execution plan and the nature of shared rate engine modules, the project plan included multiple rates development activities modifying the same shared modules. The plan did not include proper organization and management for the design and development of the shared modules, leading to gaps in the solutions across rates. The project team would later adjust plans to ensure all rates development was completed before moving to subsequent iteration development.

d. Build

As noted above in the Design phase section, the Build phase was part of an iterative development process. The Build phase began in December 2021 and was completed in September 2022. The Build phase was characterized by the creation of configuration and code for the BCS system and pre-release testing by the development team. During the Build phase, the project team developed calculations for combinations of 68 rates and 34 programs, as well as over 30 interfaces between BCS and CC&B. The project team further modified existing downstream interfaces that use the data from the complex billing system (e.g., Bill Print and Revenue Reporting). The Build phase also saw the preparation for the Test phase with the creation of test plans and test cases.

e. Test

The Test phase began in June 2022, about four months before the Design and Build phases were completed. Due to the iterative nature of the Build phase, some system functionality was ready for testing before the Build phase was completed. The Test phase lasted through September 2023.

In the Test phase, the project team performed several types of testing activities. The development team performed pre-release testing on the code that they created. This type of testing is also known as "unit testing" and was performed by testing individual components of the broader system functionality to ensure that each unit works properly. For example, this testing would execute a single module calculation as opposed to an entire rate calculation.

The Test phase also included functional and end-to-end integration testing. Functional testing used an Oracle rate check functionality to confirm rate calculations were correct. This was supplemented with tests that executed the batch billing function of the BCS system. As noted previously, the Oracle contract assigned Oracle the responsibility for designing and executing the Test phase. PG&E made the sensible decision to supplement the Oracle testing activities with independent PG&E testing to ensure a complete and correct solution.

The initial testing plan included the use of converted customer data for test execution, but the complexity of the conversion process to move from the ABS data model to the Oracle data model was under-estimated and the conversion workstream was behind schedule. The project team and leadership considered various options, including delaying the project, as potential solutions. The team ultimately decided to use manually created data (referred to as contrived data) in lieu of the converted data. At the time, the team recognized that this added risk to the project, so the team made the decision to add additional rounds of testing to re-execute the contrived data test cases using converted data as a risk mitigation.

The contrived test data was created based on the project designs. Due to the lack of documented functional requirements, the project designs did not adequately reflect the needs of the system. Initially, the testing was successful because the contrived data matched the calculation scenarios from the designs. However, once the converted data became available to use in the testing, the project team identified gaps in the designs, leading to scenarios that were not covered and an unacceptable level of defects for the test cases.

End-to-end integration testing ensures that all the components of the billing system work together as designed. For this type of testing, data was created in the test CC&B environment. The interface code was executed to extract and transfer the data to the test BCS system where billing was performed. The resulting charges were then uploaded to CC&B for inclusion in Bill Print, Revenue Reporting, and other billing processes. As described above, the designs did not account for all customer and billing scenarios present in the current system. The integration testing further revealed issues with the solution because gaps existed in the interfacing code as well, exacerbating the unacceptable frequency of defects.

By September 2023, the project team had identified over 200 high severity (fatal execution errors) defects and many test cases that could not be executed because defects prevented them from completing. Further, as defects were resolved with changes to the developed code, new defects were found. This increasing frequency of defects meant that the number of defects continued to grow even as defects were being fixed. The team also identified a significant flaw in the NEM true-up functionality that prevented correct calculation. While the defects impacted many of the rates, the root cause of the defects was the inability for the project to correctly document and develop the complexity of the rates and programs in the BCS system.

Many of the base rate schedules have been developed in CC&B, but the complex rate programs (e.g., Virtual NEM, NEM Aggregation, NEM Paired Storage) have not because of the complexity and level of customization required to implement in the CC&B linear rate engine. These complex rate programs were developed in ABS Electric instead. The ultimate complexity of the rates and programs was a key driver of the gaps in the solution and resulting high frequency of defects. The base rate schedules generally follow industry rate design practices, but the complex programs in the California marketplace are different than industry standards. For programs like NEM, monthly rate calculation follows industry norms, but the annual bill true-up process is more complicated. Further, certain NEM programs require monthly reconciliation (essentially a monthly true-up process), adding complexity to the monthly calculation. Other complex programs, like NEM

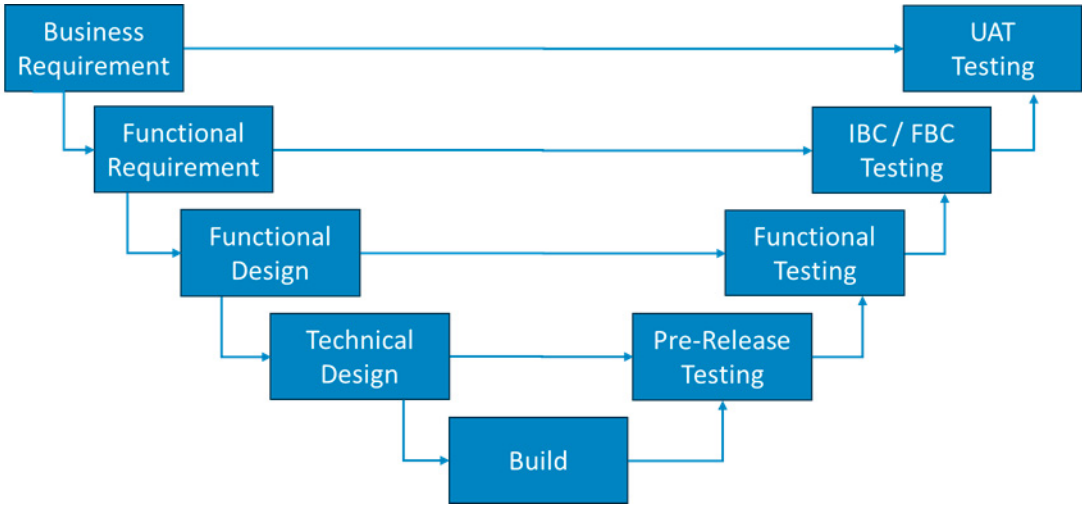
Aggregation, perform a number of usage reconciliations across related customer accounts prior to rate calculation. This process is unique and undefined in existing meter and usage framing functionality.

Without a complete understanding of all aspects of the rates and programs, the initial plans and designs that leveraged the modular rate engine did not adequately account for the complexity of these types of programs, which resulted in developed code with large gaps in functionality. In order to resolve these issues before deploying BCS, PG&E added a Re-Evaluation and Re-Plan phase to the BCS implementation process.

f. Project Re-Evaluation and Re-Plan

In October 2023, PG&E began a Re-Evaluation and Re-Plan effort to resolve the issues identified in the Test phase of the BCS project, which concluded in March 2024. The first step was to identify all of the gaps in the requirements and designs. Assigning dedicated project resources, without responsibilities for other projects or operations, was a key lesson learned in earlier phases of the BCS project. PG&E created a new dedicated team with a broad understanding of the requirements and functionality of complex billing, as well as CC&B billing and data. The team analyzed the defects and gaps identified during the Test phase to identify the root cause of the problem. Ultimately, the team identified issues in three major areas—requirements, data, and testing.

FIGURE 5-4
PROJECT TRACEABILITY ILLUSTRATION



For requirements, the team identified that there was a lack of traceability from the business requirements to the designs and ultimately the developed solutions. Traceability is important because it enables validation at every step in the project. Functional requirements can be traced back to business requirements to ensure requirements completeness. Similarly, Individual Bill Compare and Financial Bill Compare (see Section D.1.i which explains in more depth how these tests are used to confirm application functionality) test cases are mapped back to the functional requirements, ensuring the solution works for all requirements. The project had created business requirements, designs, and test cases, but lacked functional requirements and the traceability between individual functional requirements, designs, and test cases. This resulted in the subsequent deliverables (designs, developed code, and functional test plans) to be incomplete because they were related to each other instead of traced back to the individual functional requirements. A Requirements Traceability Matrix (RTM) is a common tool used to connect the high-level business requirements to functional requirements and provide the ability to trace back to these functional requirements in the Design, Build, and Test phases. PG&E determined that the existing MoSCoW list was insufficient for the project needs and adding an RTM to the BCS project would allow PG&E to better resolve gaps in requirements, designs, or developed code and reduce the number of defects and blocked test cases. Further, the team identified that test cases should be built using more detailed functional requirements and include additional testing scenarios.

In the data workstream, the project team identified discrepancies in the data mapping between BCS, ABS Electric, and CC&B. The CC&B and BCS data models are similar owing to both being Oracle products. The ABS data model was completely custom and developed in-house at PG&E over the last three decades. The differences in data models between the systems and complexity of data in ABS (due to complex rates and programs) led to the mapping discrepancies. This was further complicated by data discrepancies identified between the ABS and CC&B systems. It was discovered that users in ABS have occasionally created or edited information without updating CC&B, the system of record for the information (this is possible due to the separate systems but will be mitigated with access restrictions in BCS and eliminated with the single C2M system). Customer bills would be calculated correctly, but data would not match between the two systems. The resulting scale of production data discrepancy issues required modifications to the conversion tools to ensure proper validations were in place for successful data conversion. The additional validations were another root cause for the complexity in data conversion processes, and a key area where dedicated resources would be beneficial. Finally, the project team identified the need for additional resources with ABS expertise and CC&B data structure expertise to resolve data issues as they surfaced.

For the testing workstream, gaps were identified related to the lack of requirements traceability and the use of contrived data as described above. It was determined that converted data should be used for all testing activities, and contrived data used only in exception cases (for example, NEM bills with a minimum average rate limiter triggered, a very uncommon scenario). In addition, the project had created separate testing strategies for functional, system integration, and financial bill compare testing, rather than a unified testing strategy. Without the unified strategy, duplicate test cases were being executed in the various testing cycles. If these testing gaps could be remediated, PG&E would be able to map the defects to the problem code, allowing PG&E to resolve test cases that could not be executed due to the mass defects.

With this information in hand, PG&E evaluated the current strategy for the Billing Modernization Initiative, including the feasibility of re-planning and continuing the BCS project. PG&E reviewed several data points in this analysis. The BCS project would be implementing a modular rate engine, which PG&E would leverage for other regulatory rate programs in the future. As such, regulatory commitments were already dependent on the completion of BCS. Further, the modular rate engine in BCS would be the foundation for the later C2M project. Implementing a sub-par foundation would potentially delay the C2M project in later years. PG&E also identified major resource constraints with executing two major billing transformational projects (ABS to BCS, BCS and CC&B to C2M) concurrently, as both projects had need for the same expert resources. Along with other risk and financial considerations, PG&E decided to pause the C2M project (covered in Section D.3.d) and complete the BCS project with some key changes.

PG&E changed the project responsibilities for the Oracle team. Previously, Oracle had been responsible for project management, requirements, designs, development, testing—essentially all project responsibilities. PG&E has a long, successful history of Oracle providing complex designs and solutions to PG&E, so PG&E decided to focus their responsibilities on design and development activities. PG&E turned the testing responsibility to PG&E's internal Testing Center of Excellence (TCOE) organization. The TCOE team uses standard industry methodology and already has experience creating and executing test cases for PG&E rates and programs. PG&E also changed the project management team from Oracle to Utilligent, a vendor with demonstrated success managing projects at PG&E.

With the pause of the C2M project, PG&E moved additional personnel from C2M to BCS to support the data and rates workstreams. The new team members have experience with CC&B rates development as well as data and integration, which is helpful because the BCS system is similar in construct to CC&B. These new team members helped bridge the gap between the vendor developers (who know the Oracle BCS product) and the PG&E team members (who know the ABS Electric system).

To correct the gaps in requirements, data, and testing, the project team started by reviewing all requirements documentation and creating functional requirements, ultimately developing over 800 detailed functional requirements and creating the RTM. With the RTM in place, the team mapped subsequent deliverables and activities to each item in the RTM (e.g., mapping each test case to a specific requirement). The team updated test plans and implemented daily defect triage working sessions. For data, the additional personnel enabled a detailed review of the data model components, bolstering the data conversion process and completeness of data. The team also reviewed the entire data design to make sure all components matched across systems, which led to the creation of additional data validation routines to identify data issues and support remediation. The data team also made sure that the testing strategies would use real, converted data instead of contrived data.

In addition to previously identified gaps, the project team accelerated activities that normally occur in the later stages of the project, such as organization readiness planning, deployment and cutover planning, and business process documentation. By starting these activities early, PG&E could leverage the additional Subject Matter Experts (SME) and expertise to ensure future project activities and deliverables would meet the timelines and quality metrics, as well as uncover additional challenges earlier than normal.

The Re-Plan phase was completed in March of 2024. The project exited this phase with a revised project plan and activities, as well as additional confidence in the plan based on the RTM creation, use of real, converted data, and a revised integrated testing strategy. Ultimately, the project implemented a revised project execution operating model, creating detailed plans to enable daily, weekly, and monthly operating reviews with data-driven metrics to identify any activities that were off-track and enable the team to take immediate corrective actions before impacts to project cost and timelines.

As part of the Re-Evaluation and Re-Plan efforts detailed above, the project team prepared schedules and milestones to measure project progress along a critical path to the target deployment date. This critical path analysis had been done previously, but the revised schedules were based on estimates and timelines developed from the detailed deliverables discussed in Section D.1.g. The more granular level of detail in the deliverables enabled higher quality estimates, and an updated execution operating model provided visual representation of interim checkpoints and catch-back opportunities to ensure the project stays on course to the deployment date. The revised plans support a higher level of confidence in the schedule.

g. Design Update

The second Design phase started in April 2024 and was completed in June 2024. With the Re-Evaluation and Re-Plan activities complete, PG&E needed to either update existing designs or create new ones for the revised functional requirements. Like the original plan, the revised plan included iterative design and build activities, but the revised plan was split into three waves, each traceable to specific requirements in the RTM. The first wave included additional requirements for NEM (including NEM Paired Storage and monthly reconciliation calculations), revenue reporting, Peak Day Pricing, Utility Users Tax, and manual billing. The second wave included requirements for RES-BCT (Local Government Renewable Energy Self-Generation Bill Credit Transfer), generation billing, usage calculation and framing, Standby Rate Option 4, NEM portal, and Electric Base Interruptible Program. The third wave included requirements for other variations of the Standby Rate, Energy Statement changes, and special contract billing (26 existing contracts, including special contracts for water, Sacramento Municipal Utilities District, Placer County Water Agency, and Western Area Power Administration). These waves occurred sequentially (i.e., the first wave was completed before the second wave began, a lesson learned from the previous Design phase) to allow PG&E to make additional code changes for the downstream systems like Bill Print and Revenue Reporting prior to the next wave beginning, ensuring that the overall solution was complete. Further, the second Design phase incorporated the development of additional deliverables—high-level designs, functional designs, and detailed designs. Each of these design documents has an increasing level of detail. Since these design documents can all trace back to the RTM and functional requirements, the result is a highly detailed design that can be built and tested to enable a high level of certainty that the BCS solution will function as planned. With the additional detail for deliverables, the project is able to formulate higher detailed plans and estimates, enabling greater predictability of future project activities and overall project success. This additional detail is already paying off, as revised test execution activities are passing at a higher rate and revised timelines are being met.

h. Build Update

The second Build phase started April 2024 and will complete in October 2024. The activities of the second Build phase are similar to the prior Build phase but were guided by a much higher level of requirement and design clarity as a result of the Re-Plan and second Design phases. For example, one of the primary issues driving the Re-Plan was the Net Energy Metering true up calculation issue. PG&E determined that the ultimate root cause of this issue was a mixture of incorrect and missing calculations. The updated, more detailed functional requirements and designs enabled the developers to build complete solutions to address the issue. Furthermore, the updated project execution operating model included visual representation of the rate development and testing. Known as the “Bingo Card,” the project team developed a matrix view of every rate schedule and program combination, with indicators to represent when certain combinations were starting to deviate from plan.

Data conversion development and execution was another major focus of the updated Build phase. The data conversion team created a data dashboard with specific information on data conversion execution targets, dependencies, and metrics related to conversion defects, errors, and conversion population. The added resources and metrics have already started to pay off, reducing the defect count by over 50 percent in the first two months.

i. Test Refresh

The refreshed second Test phase is scheduled to begin at the completion of the second Build phase in October 2024 and be completed in March 2025. As noted in the Re-Plan phase, PG&E switched responsibility for testing to the TCOE team. The team brings industry standard testing practices to the project, in addition to PG&E-specific knowledge related to rates and system integrations. The second Test phase will leverage the refreshed and integrated functional, integration, and Performance Testing (PT) strategies, as well as individual bill and financial comparison. This phase will include updating existing test cases, creating new test cases, mapping all back to the RTM, and executing all test cases. In this Test phase, the project will use real, converted data for the testing efforts. Converted data will enable compliance with traceability requirements and the execution of code leveraging production scenarios and data to facilitate improved test coverage across scenarios.

The Test phase will involve the comparison of bills generated in ABS and BCS to verify that BCS is functioning properly (commonly known as “Individual Bill Compare” testing). PG&E will use accounts that passed functional testing again for end-to-end integration testing, in accordance with the integrated testing strategy. In this test execution, the resulting BCS charges are compared to the ABS charges. In the initial testing scenarios, this will be done with a selection of accounts and test cases. In the later stage of the Test phase, the financial comparison effort will do this comparison on a broad, production scale level (commonly known as Financial Bill Compare testing). This testing will ensure that the new BCS system is operating correctly, delivering accurate charges.

j. Deploy

The Deploy phase will start in April 2025 and last until the BCS go-live date (the date on which the BCS system is live and operational in the production environment) in Q2 2025 pending coordination with end-of-quarter activities. The end result of this phase will be a successful go-live of the new system, which includes ensuring that the system is ready to be deployed and rehearsing deployment. During the Deploy phase, the project team will execute the deployment plan (as noted earlier, the development of the plan has been accelerated and will complete before needed in the Deploy phase) that documents the steps and timing of activities to cutover to the new system. The deployment plan will include criteria for a final "go/no-go" decision (defined metrics that the project team will review to ensure the system is ready to perform at a satisfactory level for production execution).

In the Deploy phase, the team will need to rehearse deployment activities to ensure that the system and team are able to perform the deployment during the cutover window (scheduled for approximately 4 days during Q2 2025). In preparation for the deployment, the project team will execute full scale PT in the BCS environment.

After PT, the project team will perform Operational Readiness Testing (ORT). During cutover, the project plan requires PG&E to shut down the ABS system for approximately one week. ORT activities will verify that the cutover period is sufficient to complete all activities needed for go live. The goal of ORT is to run data conversion, BCS batch billing, upload to CC&B, and CC&B batch billing, all within the normal 24-hour daily window.

In order to prepare for full-scale ORT execution, the team will practice the steps during Full-Scale Test Environment (FSTE) refreshes. First, CC&B will download data to BCS and the team will validate the data. Then, the BCS system will process 12 months of usage data from ABS and the team will validate. These activities require executing the new interfaces and data conversion processes at a production scale. A snapshot of CC&B data is taken and moved to FSTE. The project will then extract data from ABS for the same period, validate the data, import into the FSTE environment, validate the data there, and then download from FSTE to BCS and execute billing. The project plans to leverage four refresh efforts prior to go live in Q2 2025 to ensure accuracy, quality, and completeness.

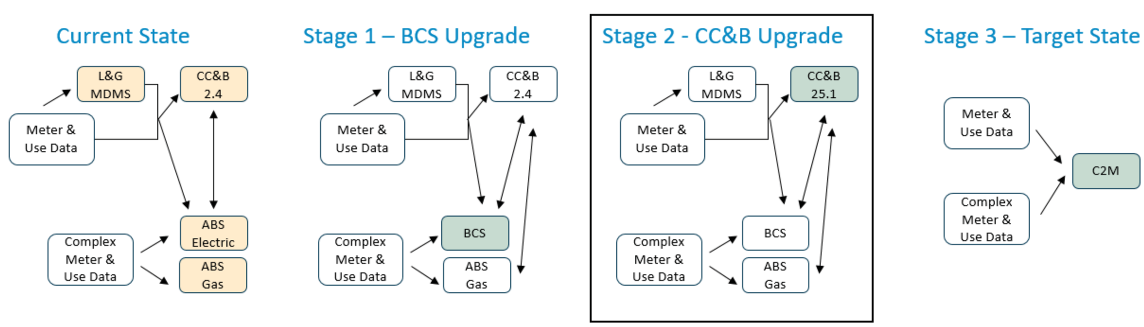
The project team will evaluate the project readiness throughout the Deploy phase. Once all criteria for a final go/no-go decision are met (as defined in the project deployment plan), the project team and related operations teams will execute the go-live cutover and complete the deployment.

k. Support

PG&E plans for a 3-month Stabilization and Support phase for the BCS project after the go-live in mid-2025, which is scheduled to be completed in Q4 2025. During the Support phase, the project will leverage a service introduction plan, which details the production support staff and roles and responsibilities post go-live. The development vendor will provide resources to quickly resolve issues found in production. As the production issues decrease, the vendor will perform handoff to the production operations teams.

2. CC&B 2.4 Upgrade to CC&B 25.1

FIGURE 5-5
CUSTOMER CARE & BILLING UPGRADE



As discussed in Chapter 4, PG&E determined that, in order to achieve a fully modernized billing solution and minimize the risks of utilizing an outdated CC&B version for two or more additional years, it is necessary to first upgrade CC&B, its infrastructure and the ecosystem of integrated components to the vendor-supported version. Oracle recently updated its CC&B version numbering system to align with that of C2M, and Oracle's next version is CC&B 25.1 (to be released in 2025). PG&E has elected to perform a technical stabilizing upgrade of CC&B to Version 25.1 to reduce risks caused by the existing system and underlying technologies being outdated and lacking support.

Multiple activities must be performed to CC&B to move to the new version. The CC&B application and underlying databases will be upgraded to the newer version. Any customizations or underlying components relying on incompatible coding languages will be converted to modern, compatible languages. The project will also resolve any framework changes to the data structure or functionality, modifying the new system to perform as CC&B 2.4 does today. Further, the version upgrades for other related components (i.e., hardware, middle-ware platforms, related applications, etc.) will be determined based on compatibility requirements of CC&B 25.1.[4] The CC&B 25.1 upgrade plan was developed in partnership between PG&E SMEs, the Oracle product team, and other external consultants with technical upgrade experience. This upgrade is expected to take approximately 28 months beginning in Q3 2024 with the Pre-Planning effort—and concluding by Q4 of 2026. While the project will be executed using the standard seven phases of the PG&E IT methodology, as an upgrade effort, the activities in each phase will be tailored to more technical development and testing outcomes. The project phases are described below:

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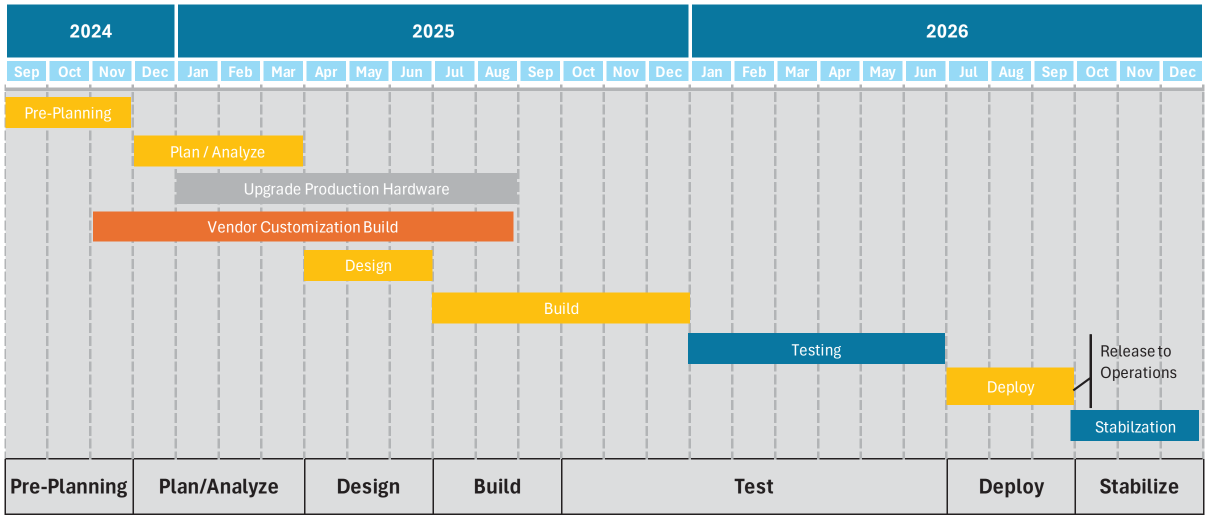
4 Currently, CC&B 2.4 is compatible with AIX 7.1 and WebLogic Server 10.3.6, while CC&B 2.9 is compatible with AIX 8.x and WebLogic Server 12.2.1.4; the project will review compatibility versions once Oracle releases them in Q1 2025.

FIGURE 5-6
EXPECTED CC&B UPGRADE PROJECT PHASES AND TIMELINE



a. Pre-Planning

The Pre-Planning activities of the effort to upgrade to CC&B 25.1 will start with PG&E conducting a full review of the base capability enhancements available with CC&B 25.1. This review will identify all business or technical functions which are expected to work differently in the new system. As this project is a technical stabilizing upgrade, the identification and documentation of these changes to business or technical functionality is critical to developing the proper project scope and plan. The identification will enable further analysis and design early in the project, enabling a more detailed level of build, testing, and change management review for more defined project success. The outputs of this Pre-Planning phase analysis will define the scope of the 25.1 upgrade effort. The Pre-Planning phase of the CC&B 25.1 project began in Q3 2024 and will be completed in Q4 2024. Building on lessons learned from the BCS project, PG&E will assign dedicated resources at this stage of the project, enabling the early allocation of SMEs and resource consistency throughout the rest of the project.

In addition, more typical Project Management Office (PMO)-related pre-planning activities (such as developing a project plan, establishing project delivery infrastructure, and gaining approval of the governance model) will be performed as part of this Pre-planning phase. The following key deliverables will be produced as outcomes of the Pre-Planning phase:

- High-Level Fit/Gap Analysis;
- Detailed Project Plan (DPP);
- Risks, Actions, Issues, and Decisions Log;
- Governance Model; and
- Organization Chart and Baseline Staffing Plan.

b. Plan/Analyze

In the Plan/Analyze phase, PG&E will evaluate required customizations and analyze functionality and design changes. PG&E will work with Oracle product development team to download upgrade scripts and protocols to move from CC&B 2.4 to 25.1. PG&E considers the scope of the CC&B upgrade project (Version 2.4 to 25.1) as primarily technical—customized improvements are out-of-scope. However, some data tables and new features in CC&B 25.1 will require PG&E to change or remove some customizations. PG&E will evaluate required customization changes during the Plan/Analyze phase. PG&E will select and engage a vendor to complete any identified customization changes. Additionally, PG&E will analyze potential changes to the functionality and/or designs of existing integrations to downstream applications. The Plan/Analyze phase of the CC&B 25.1 project is anticipated to begin in Q4 2024 and will be completed in Q1 2025.

The following key deliverables will be produced as outcomes of the Plan/Analyze phase activities:

- Detailed Fit/Gap Analysis;
- Data Migration Strategy;
- Environment Requirements; and
- Change Readiness Assessment.

In addition, the long duration between upgrades will require that PG&E undertake three efforts to clear the way for future phase activities: (1) upgrade existing hardware, (2) upgrade the production database, and (3) COBOL-to-JAVA translations. Although there are aspects of the Build phase in each of these endeavors, the duration required and down-stream activities' dependency on these efforts necessitates that they are initiated and executed in line with the Plan/Analyze Phase.

1) Upgrade Existing Production Hardware

The CC&B 25.1 project requires a hardware upgrade because PG&E's current production hardware (including servers and related operating and application software) is out of support and CC&B 25.1 compatibility specifications require newer hardware versions. PG&E's current hardware is incompatible with the software PG&E is seeking to implement; therefore, PG&E must upgrade its hardware early in the project.

Changing production application hardware requires significant due diligence to ensure that the new hardware will be compatible with PG&E's systems. This will be a multistep process to provision, install, and test the production version under the new architecture. PG&E will provision additional servers to hold the full capacity of the production server and run PT on the full-scale test environment along with a disaster recovery test to ensure that the system is stable and operating within expected parameters.

2) Upgrade CC&B Production Database

A database upgrade is a necessary component of the overall application upgrade project. CC&B is built upon the Oracle database, and the current CC&B 2.4 is on database Version 12c. PG&E must upgrade its database ecosystem to meet the compatibility requirements of CC&B 25.1. Initially, PG&E will upgrade the current database to Version 19c, since it is compatible with the current CC&B 2.4. During the subsequent phases of the project where CC&B is upgraded to 25.1, the project team will upgrade to the vendor-recommended compatible version as newer stable versions are released.

Additionally, the Customer Revenue Critical Reporting (CRCR) system discussed in Chapter 2 depends on an independent Oracle database, which must be separately upgraded in a standalone environment to enable compatibility. The CRCR database will also be upgraded to Version 19c, and will be kept in sync with the CC&B database version throughout the project.

Similar to the hardware upgrade effort above, the database upgrade will include a comprehensive set of tests to ensure complete compatibility with any/all dependent applications. This effort will need to begin in conjunction with the Plan/Analyze phase and continue in parallel with other upgrade activities.

PG&E will leverage the TCOE team in the planning and execution of the testing activities for this project. PG&E will apply lessons learned from the BCS project related to testing and leverage the TCOE team for the industry best practices and demonstrated ability to support PG&E's CIS System Testing (ST).

3) Translate Customizations From COBOL to JAVA

One significant change Oracle made to CC&B since Version 2.4 was to phase out compatibility with customizations written in COBOL, an outdated computer programming language. CC&B Version 2.5 and subsequent releases have all used the more common Java programming language. In order for PG&E's customizations (currently written in COBOL) to be compatible with Version 25.1, and subsequently with C2M, they will need to be translated to Java. To do this, PG&E will engage a vendor to perform the COBOL-to-Java translations. This is projected to be a multi-month effort up to 12 months, necessitating the start of execution in parallel with the Plan/Analyze phase to conform to the proposed schedule. At the conclusion of the conversion timeline, the vendor will deliver a completed code package to PG&E with all customizations ready to be added to PG&E's CC&B 25.1 application prior to testing and go-live.

c. Design

The Design phase of the CC&B 25.1 project will focus on three areas: (1) customization changes driven by base code functionality and compatibility requirements, (2) downstream applications and their integrations, and (3) data enhancements (i.e., table changes, added/deleted fields, source cleansing, etc.). In each case, the team will progress from high-level designs to detailed application designs that are sufficient for developers to construct the necessary code. Working through functional requirements, PG&E will produce detailed design documents as the key deliverable of this phase.

While normally considered Build activities, PG&E will engage a vendor to develop data scripts focused on importing/transforming necessary data into the CC&B 25.1 system during the Design phase. PG&E expects that the vendor will build on experience with other investor-owned utilities that have successfully completed similar data transformations. The project plans to have infrastructure available at the end of Plan/Analyze to enable the data activities to be executed during the Design phase. It is important to complete this work during the Design phase so the output can be used during the overlapping Build and Test phases to confirm the functionality of the system on realistic data.

During the Design phase, the Organizational Readiness team will conduct an analysis of the potential change impacts of the project on PG&E and its customers. This early activity is a lesson learned from the BCS project, where there was less focus on change impacts early in the project. This analysis will inform both PG&E stakeholders and subsequent training activities to ensure the necessary preparatory work is performed to affect a smooth transition to the new product version. The Design phase of the CC&B 25.1 project will begin at the conclusion of the Plan/Analyze phase in Q1 2025 and will be completed in at the end of Q2 2025.

Since this will be a technical stabilizing upgrade, the following key deliverables will be produced in this Design phase:

- Functional Specification Documents (FSD);
- Updated Master Configuration Workbook (MCW);
- RTM;
- Master Data Alterations;
- Updated Application Architecture; and
- Organizational Change Impact Analysis.

d. Build

Since the CC&B 25.1 upgrade is considered a technical stabilizing upgrade, the Build phase will not be as extensive as Build phases for other projects that introduce or update processes and functionality. The intent is not to develop new functionality; rather, only rebuild key items that have been deprecated (i.e., removed from the system and no longer supported) or that need adjustment to make work with the new system.[5] The Build phase of the CC&B 25.1 project will begin in Q3 2025 and will be completed in Q4 2025.

There are two major development activities that will be delivered as part of the CC&B 25.1 upgrade: (1) remediation of existing capabilities to meet 25.1 updates; and (2) migration of eXtended Application Interface (XAI) functionality to Inbound Web Services (IWS).

1) Existing Capability Remediation

Beyond required changes to various customizations, there are several changes in CC&B 25.1 that will drive remediation of PG&E developed interfaces, extensions and tables. There are new tables embedded in CC&B 25.1 that do not exist in version 2.4, which will need to be populated. Some new features included in CC&B 25.1 will require minor adjustments to existing, PG&E-developed extensions to enable these features. Additionally, existing integrations with Bill Print, the Financial Transaction General Ledger, and Contact Center Service Platform (CCSP) integration layer will need to be modified to work with the latest version of MuleSoft (a software PG&E uses to enable integration between systems). Finally, PG&E will modify some reporting structures during this phase to align with the underlying components that have

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[5] While it is recognized that the Oracle COBOL-to-JAVA translation is inherently a software "effort" and will likely require modifications to specific customizations, the intent is neither to develop new functionality nor re-platform existing functionality requiring significant new code development. Additionally, as stated earlier, due to timeline dependencies, the COBOL-to-JAVA translation effort will begin in conjunction with the Plan/Analyze phase and be delivered as an independent set of work. Thus, the COBOL-to-JAVA translation effort is not considered in scope of the Build phase.

been altered by Oracle since CC&B Version 2.4. This work will be completed as needed by the PG&E development teams.

2) XAI to IWS Migration

With Version 2.6 of CC&B, Oracle changed its integration technology from XAI to IWS. XAI and IWS are Application Programming Interfaces (APIs), a set of rules and protocols that allow different applications to communicate with each other. The replacement of XAI with the newer IWS APIs will involve transitioning from a decentralized, API-based communication model to a more centralized, inbound web service that offers improved efficiency, management, and automation capabilities.

In order to meet the CC&B 25.1 project timeline, PG&E expects to begin early test cycles of specific system components as the Build phase progresses. While there is no current plan to execute Build in specific cycles, the development activities will be planned and managed to ensure the necessary testing sequences of functionality, compatibility and performance can be successfully executed.

Additionally, PG&E will develop test scenarios, scripts and cases in parallel with technical development activities. This, too, will be planned, prioritized and managed to ensure that—along with the necessary system components—the testing infrastructure is in place to support testing of functionality, compatibility and system performance in parallel with on-going development activities.

The following key deliverables will be produced as outcomes of the Build Phase activities:

- System Configuration Modifications;
- Updated Software Components (i.e., extensions, IWS, populated tables);
- Unit Test Results;
- Data Transformation Scripts;
- Data Cleansing Report;
- Test Scenarios, Cases and Scripts; and
- Training Need Analysis Report.

e. Test

The Test phase for the CC&B 25.1 project will deploy the same model of testing PG&E uses in other large-scale software implementations, but with a focus on the nuances of a technical upgrade. The Test phase of the CC&B 25.1 project will begin in Q4 2025 and will be completed in Q2 2026. This phase will include functional, integration, technical, and compatibility testing.

Functional testing (including unit, string, and system tests) will be an important part of ensuring all solution changes perform as required and designed without defects. However, the scope and emphasis of this functional testing will be focused on any new CC&B 25.1 features, necessary customization alterations, and data/table changes driven by the new CC&B framework. The primary purpose of functional testing will be to ensure that all rates continue to calculate as expected and that the new system will be capable of reliably supporting the business and our customers in the same way that CC&B 2.4 does now. Key components of functional testing include regression testing to verify that existing functionality—features and processes working prior to the upgrade—still work after the upgrade. This ensures that the upgrade has not introduced any unintended changes or issues.

Integration testing will focus on two areas: ensuring any integrations impacted by alterations to customizations or data/tables are functioning properly and ensuring previously existing applications integrated with CC&B continue to function as before. This is especially important due to the previously mentioned XAI to IWS conversion. The IWS technology can perform the same or better than the current XAI APIs, with additional monitoring and security functionality. The integration testing will ensure that the integrated applications (e.g., the web, Interactive Voice Response, and CCSP) work as good or better than current performance.

Technical testing will be of particular focus because migrating from CC&B 2.4 to Version 25.1 is intended to be a technical upgrade. PT, security testing, disaster recovery testing and ORT will all be performed as part of the overall technical testing strategy.

Compatibility testing will be particularly important to the CC&B 25.1 upgrade project. As described in earlier sections, this project will also include version upgrades to hardware, middleware, the database and other ecosystem applications. Compatibility testing will ensure that all updated components are version compatible, any protocol enhancements have been addressed, and all components of the solution work in harmony.

f. Deploy

The Deploy phase will prepare the system for deployment to production and concludes with the production system cutover. The Deploy phase of the CC&B 25.1 project will begin in Q3 2026 and will be completed in Q3 2026. This phase will include mock migrations, infrastructure preparations, end-user training, and operational readiness evaluations.

Mock migrations are essentially practice production migrations to ensure the transition to the production system is well understood by all involved parties, and PG&E will conduct several rehearsals of the migration process. Each migration will leverage the implemented infrastructure to also ensure preparations are complete for full production processing. PG&E will thoroughly evaluate the outcome of each mock migration to ensure any challenges are understood and addressed in advance of the next mock migration.

PG&E will also conduct training and proficiency evaluations to ensure the PG&E workforce is ready for cutover and post-go-live support. Key deliverables of this phase include:

- Multiple mock migrations (Go-Live practice);
- Well-defined Go-live and Stabilization Plan;
- Actively engaged and involved stakeholders; and
- Go-live Readiness Criteria Met.

g. Support

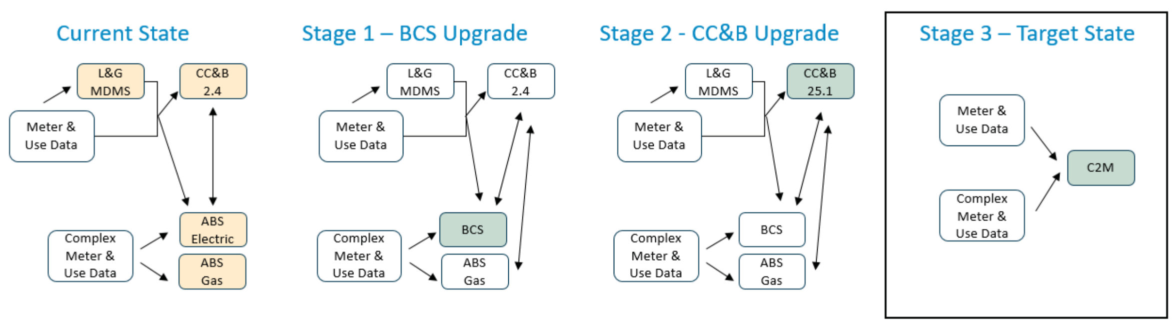
The Support phase of the CC&B 25.1 upgrade will accomplish two objectives: (1) ensure the system is stable and operating properly in production, and (2) transition system ownership from the project team to

PG&E business and IT resources. The Support phase is projected to last three months following go-live (from about Q3 2026 to Q4 2026) and will include hyper care and stabilization.

The initial period will be hyper care where Oracle product team, vendor developers, and technical staff will work with the project team to resolve system issues, defects, and ultimately ensure the system meets agreed-upon performance criteria. Hyper care will generally focus on high impact defects with short turn-around timeframes. Stabilization activities will immediately follow, where the project team continues to resolve system issues and defects, but will shift focus to include lower impact issues.

3. C2M Implementation Project

FIGURE 5-7
BILLING MODERNIZATION INITIATIVE TARGET STATE

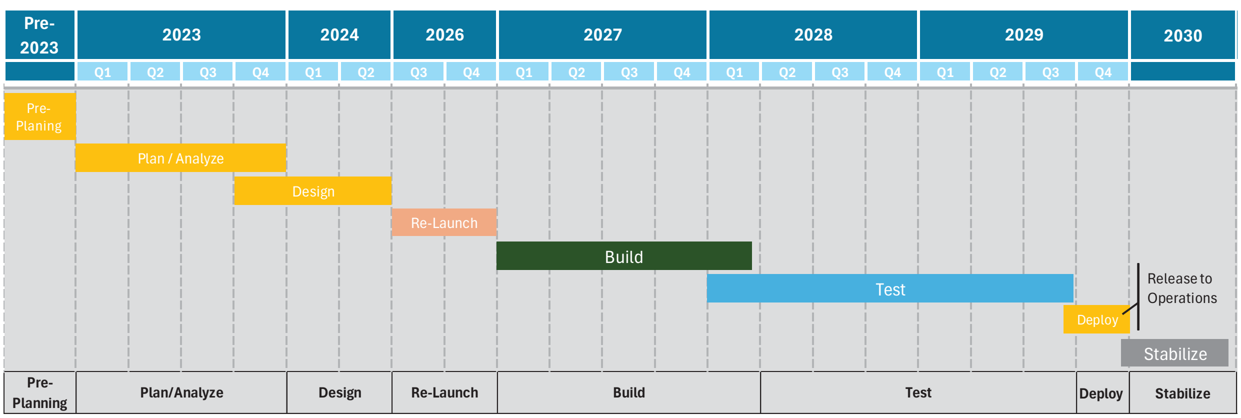


The C2M implementation project is the culmination of the Billing Modernization Initiative and will combine the modular rate enhancements of the BCS project and technical platform upgrades of the CC&B 25.1 project with the integrated Meter Data Management System and dispatch capabilities of the C2M platform as well as the remaining ABS Gas platform. The end result will be a single, modernized CIS solution (the specific features and functionalities of the final C2M product are discussed in more detail in Chapter 4).

The phases of the C2M implementation will be slightly different than PG&E's standard implementation process because of the history of this project. Prior to the 2024 Billing Modernization Initiative strategy change, which put the original C2M implementation on hold, PG&E had already completed the Pre-Planning phase of the project and looked to complete the Plan/Analyze and Design phases of the project.

As a result, the C2M project will restart by reassessing the CIS landscape, ensuring the C2M product is still the most relevant for PG&E's goals, followed with a Re-Launch phase to revisit and build upon PG&E's prior C2M-related work (described in more detail below). This includes a process to confirm that the planned C2M solution is still the correct final solution for the Billing Modernization Initiative. PG&E expects to re-start the C2M project in Q3 2026, with a go-live date in Q4 of 2029. The project phases are described below:

FIGURE 5-8
TARGET STATE PROJECT PHASES



a. Pre-Planning

The Pre-Planning phase of the C2M project began in November 2021 and ended in December 2022. During the Pre-Planning phase, PG&E selected and onboarded a system integrator to lead the Plan/Analyze and Design phases.

For the C2M project, PG&E initially considered six potential suppliers. Of those, three had existing master service agreements with PG&E and all had confirmed experience implementing CC&B and C2M systems. PG&E conducted a multi-phase RFP for system integration in Q1 2022, including initial questions, scoring, shortlisted suppliers, and contract negotiation, and identified the top two preferred suppliers based on all responses. PG&E then engaged West Monroe, a consulting firm, to evaluate the two preferred suppliers and support negotiations with the selected vendor.

PG&E ultimately selected Infosys (with Ernst and Young providing subcontractor expertise) based on their superior performance in several key factors:

1) Milestone-Based Payments: Infosys was able to commit to milestone-based payments during the award negotiation phase, with holdbacks for milestone delays and missed deliverable criteria, which were designed to protect PG&E from delays in delivery and associated increases in total project costs.
2) Increased Resource Commitment: Infosys committed approximately 523,900 person-hours to the C2M project, including 87 percent senior team members using a largely onshore mix for initial phase and then more heavily leveraging offshore talent in future phases.
3) Advantageous Pricing: Infosys was the lowest cost bidder, with a blended rate for resources significantly lower than competing offers.
4) PG&E Resource Requirements: Infosys built a plan which required less PG&E resource commitments, reducing the financial and managerial requirements that would be needed to successfully complete the application upgrade.

PG&E chose to use an external system integrator in order to minimize uncertainty and inefficiency in the Plan/Analyze and Design phases. While not required for all IT implementation projects, the use of a system integrator is appropriate here because the extensive level of customization in the current CC&B 2.4 system[6] would otherwise create an unacceptable amount of uncertainty in the scope, timeline, and cost of the implementation. To reduce this cost and timeline uncertainty risk, PG&E chose to implement a two-stage strategy: (1) leverage the experience of a system integrator to lead the Plan/Analyze and Design phase activities—with the additional objective of producing a refined

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6 The decision to change the Billing Modernization Initiative to a three-stage approach occurred during the Design phase of the C2M Implementation project. As such, Plan/Analyze and Design activities focused on changes to CC&B 2.4 functionality instead of CC&B 25.1.

cost and timeline estimate for the remainder of the project, and (2) contract and execute the Build, Test, Deploy and Support phase activities as a separate effort based on this more definitive data from the first stage. This contracting strategy was based on lessons learned on the BCS project and other large-scale implementations at PG&E.

b. Plan/Analyze

The Plan/Analyze phase of the C2M project began in January 2023 and was closed in December 2023. During the Plan/Analyze phase, the system integrator, Infosys, facilitated over 200 functional, technical, and RICEFW-focused (i.e., reports, interfaces, conversions, enhancements, forms, and workflows) workshops. The work products produced as a result of the workshops and ancillary activities included a full list of functional and technical requirements, a fit-gap analysis of the product's ability to address PG&E business needs, and a change readiness assessment of the organization.

Prior to the commencement of workshops, PG&E team members participated in C2M training and demonstrations by Oracle. PG&E reviewed proposed starter requirements from Infosys to ensure they aligned with PG&E requirements and business processes. By engaging with business SMEs, these were refined multiple times to ensure both pain points of the current system and processes and desired process improvements were documented.

The system integrator facilitated workshops over many months with engagement by SMEs (both internal and external) and members of PG&E's various lines of business and IT organizations to confirm and document functional and technical requirements and review or update business processes in light of C2M functionality. Through process mapping, cross project impacts were identified which necessitated additional deep dive working sessions. Separate breakout sessions were held with smaller teams to document RICEFW items (reporting, integrations, configurations, customizations).

In parallel, the Organizational Readiness teams were conducting change impact analyses to ensure all impacts on PG&E co-workers and contractors were being appropriately considered in the Plan/Analyze phase while the PMO was developing the necessary governance infrastructure and deliverables to support the project execution. Overall project governance, in addition to the defined PMO, was a prudent addition to the C2M Program, based on experience on other programs, including BCS. When a vendor is performing a large amount of the project work on a new system, additional governance processes need to be in place to ensure success.

From there, PG&E reviewed the edge systems (systems outside of the current CIS systems that will interface with the target C2M system) that could be impacted through C2M implementation and what process improvements or updates were in flight prior to go live to remove redundancies.

The following key deliverables were produced as outcomes of the Plan/Analyze Phase activities:

- Integrated Project Plan;
- Risks, Actions, Issues, and Decisions Log;
- Governance Model;
- Organization Chart and Baseline Staffing Plan;
- Facilitated Workshop Schedule;
- Business Process Hierarchies;
- Process Design Documents;
- Fit/Gap Analysis;
- Data Conversion Strategy;
- Environment Requirements; and
- Change Readiness Assessment.

c. Design

The Design phase of the C2M project began in January 2024 and was closed in May 2024. During the Design phase, Infosys translated the requirements from Plan/Analyze into functional design specifications (i.e., FSDs) and produced numerous other design related work products to support subsequent development activities.

Amongst the functional workstreams, requirements were organized into configurations, extensions, interfaces, reports/letters and—where applicable—customizations. The two key technical workstreams, conversion and integration, translated both functional and technical requirements into the designs for their related work. As PG&E and Infosys produced FSDs, the conversion team reviewed the FSDs for potential data impacts and, in parallel, developed data mappings between the CC&B, ABS, BCS, and C2M data models. Resources knowledgeable with the data structures were added to the set of activities due to the challenges experienced on the BCS project. The integration workstream focused on creating FSDs for both new and modified interfaces.

Another key activity of the Design phase was the deployment of the Design Authority. The Design Authority is a governing body responsible for evaluating and rejecting or approving key design options (or decisions) produced by the project team as they relate to PG&E's needs and application capabilities. While the use of a project Design Authority is a normal component of the IT process, there were three key drivers to its deployment in the C2M project: (1) PG&E's goal to use as much base C2M functionality as possible, (2) the sunsetting and integration of various CIS edge system applications, and (3) PG&E's relationship and influence with Oracle as the product vendor.

First, emphasis on base functionality (i.e., reducing the number of custom and non-industry standard components) supports future application maintenance updates enabling a variety of cost and effort saving opportunities. Therefore, unless California regulatory rate or operational expectations require a customization, PG&E will endeavor to use C2M's base functionality.

Second, as discussed in Chapter 4, C2M will replace a number of edge-system applications (applications that interface with the CIS and provide functionality or data that the CIS does not) with applications that are integrated into C2M. As a result, PG&E must sunset (i.e., decommission) a number of the existing applications. Due to the complexity of PG&E's existing CIS ecosystem, ancillary application changes, such as the sunsetting and integrations, were inevitable.

Finally, PG&E engaged with the Oracle product team to understand the product development roadmap and attempt to align Oracle's roadmap with PG&E's broader technology roadmap related to transitioning to the energy systems of the future. As a major Oracle customer, PG&E was able to negotiate for enhancements to the product roadmap based on a design review process.

With these goals in mind, the project employed a Design Authority Review (DAR) process in which proposed changes were reviewed by a leadership advisory panel for validation and confirmation. The DAR process brought together project SMEs, project leaders, Oracle C2M product team experts, and business SMEs to review the business need or drivers, potential solutions, and decide on the best fit solution for PG&E and its customers.

The Design phase also included a re-estimation of project costs. In order to have an auditable understanding of the cost and timeline estimate, during the RFP process to select the system integrator, PG&E produced a baseline model of costs per estimated system changes for the overall program. At the conclusion of the Design phase, PG&E re-estimated costs using the same model while including changes in system build components and any related cost deltas. The costs, timeline and staffing plan presented in this filing are a direct reflection of the information developed in the re-estimation effort. It represents an effort and timeline focused on the Build, Test, Deploy and Support phase activities based on the requirements and designs developed during the Plan/Analyze and Design phases.

The following key deliverables were produced as outcomes of the Design phase activities:

- FSDs;
- Development Object Inventory;
- Master Configuration Workbook;
- RTM;
- Master Data Design;
- To-Be Application Architecture; and
- Organizational Change Impact Analysis.

d. Pause and Re-Launch

When PG&E made the decision to change the Billing Modernization Initiative strategy to three stages, it was prudent to pause the work on the C2M project. Due to the complexity of the projects and the high number of resources for each project, executing these projects concurrently introduces an unacceptable level of risk. Thus, the C2M project was paused in Q2 2024. This involved the completion of deliverables in the Design phase, saving project documentation for use during Re-Launch, and resource reallocation to other efforts.

During the Re-Launch phase, PG&E will evaluate the Plan/Analyze and Design work performed to date against the outcomes and lessons learned from the BCS and 25.1 upgrade projects and familiarize the project team and vendor with the objectives and outcomes of the project. Specifically, the team will analyze the electric rate calculation from BCS and integrations from 25.1 for changes needed in the C2M system. As discussed in Chapter 4, PG&E decided to delay the C2M project—prioritizing instead the delivery of the modular rate capability (through the BCS project) and upgraded infrastructure (through the CC&B 25.1 project). As a result, it is prudent to perform a re-launch effort prior to resuming C2M-focused work. The Re-Launch phase is scheduled to begin in Q3 2026.

There are five key objectives of the Re-Launch phase: (1) evaluate and confirm that the C2M product is still the correct end solution for the Billing Modernization Initiative; (2) review and incorporate any design changes or new gaps identified since the completion of the Design phase; (3) evaluate the existing system integrator and vendor partner relationships and select, negotiate and contract with additional vendors as necessary; (4) mobilize PG&E personnel to support the project and backfill operational roles as necessary; and (5) re-familiarize the project teams with the decisions, supporting material and the design specifications produced in the original Plan/Analyze and Design phase activities.

e. Build

The development activities in the Build phase will be executed in three progressive cycles, each lasting approximately four months. The cycles will build upon prior cycles and target a specific subset of the overall functional and technical solution requirements. Each development cycle will include the creation of detailed design documents to guide configuration and component development, system configuration and component development, and unit testing of the built components. The Build phase will also include data conversion scripting, integration construction, and report/letter creation. The Build phase is scheduled to begin in Q4 2026 and conclude in Q1 2028.

In parallel with these three development cycles, PG&E will proceed with test script generation to support the planned execution of each of the various segments of the Test phase, outlined in the next section. Test scenarios will be developed to match the business processes defined in Plan/Analyze with respective scripts formulated to address the various conditions that can occur within a given scenario.

Additionally, the Organizational Readiness Training teams will begin developing training material during the Build phase. Training material will combine information regarding system functionality with PG&E-specific configuration based on the outcome of the fit/gap analysis to best develop a training curriculum that matches content with need.

Mid-way through the second build cycle, the project will begin independent ST, verifying that the functionality defined by the business requirements works as intended. Unit testing will validate that individual configuration elements, development objects, and process workflows accurately reflect the intended outcomes of the detailed designs.

The following key deliverables will be produced as outcomes of the Build phase activities:

- System Configuration;
- Software Components (i.e., Code);
- Unit Test Results;
- Data Conversion/Migration Scripts;

- Integrations;
- Reports/Letters;
- Test Scenarios, Cases and Scripts;
- System Integration Testing (SIT) Scenarios;
- Training Need Analysis Report; and
- Training Materials.

f. Test

The Test phase will confirm that the system performs the functional and technical requirements reflected in the RTM and FSDs and is satisfactory to enable PG&E to deploy C2M. The Test phase is scheduled to begin in Q2 2028 and complete in Q3 2029.

Testing scenarios will encompass both business processes and requirements. The Test phase will include the following 12 forms of testing:

- String Testing;
- ST (three cycles);
- SIT, including End-to-End Testing and Report Testing (three cycles);
- Smoke Testing;
- Regression Testing (Automation);
- Parallel Bill Testing (two full monthly cycles);
- PT;
- Disaster Recovery Testing;
- Security/Controls/Segregation Of Duties Testing;
- ORT (two cycles); and
- User Acceptance Testing (UAT) (two cycles).

Starting with SIT, all test processes will use full volume converted data (real-world data that has been converted from CC&B 25.1, ABS Gas, BCS Electric and Landis+Gyr MDMS to C2M for testing purposes). This recognizes that—just as in system components—defects are expected to occur in the conversion process and must also be thoroughly tested and remedied. As a result, the data conversion process—legacy-to-target—must be developed and tested prior to the start of SIT and executed at the beginning of each SIT cycle. As described in the BCS section, the use of converted data is vitally important to ensuring that test execution is covering the full gamut of use cases for the production system. While converted data will be tested as part of all the other test activities, data testing alone is insufficient to ensure the quality of the conversion process. As such, numerous comparative reports will be run as part of each conversion to assess the accuracy of all aspects of the data (i.e., financial transactions and summaries, account and record counts, etc.), reconciled and remediated, as necessary.

The test categories will be organized to build upon one another. Unit and string testing of the individual components and modules will ensure the success of the broader ST. Comprehensive ST of all aspects of the CIS ecosystem will ensure smooth SIT. Smoke and regression testing will be leveraged to ensure all defect resolutions are properly deployed in the system. Parallel bill, performance, disaster recovery, and security testing will all be performed to ensure ORT accurately reflects the readiness of the system to support PG&E's operational/production needs and those of our customers.

During the Test phase, PG&E will also conduct extensive end-user training. This will include developing training material, proficiency and reference guides. PG&E will also educate trainers to prepare them to successfully deliver training to a large/diverse PG&E end-user population.

The following key deliverables will be produced as outcomes of the Test phase activities:

- Daily and Weekly Test Execution and Defect Remediation Reports;
- System and SIT Test Closure Reports;
- Data Conversion Reconciliation Report;
- Data Cleansing Report;
- UAT Execution and Closure Reports;
- End-User Training Materials;
- Train the Trainer Training Materials;
- End-User Course and Proficiency Materials; and
- User Group Reference Guide.

g. Deploy

The objective of the C2M Deploy phase will be to prepare all aspects of the system (e.g., software, data, infrastructure, and personnel) for deployment and ultimately deploy the new system. These activities will include mock migrations, infrastructure preparations, end-user training, and operational readiness evaluations. The Deploy phase is scheduled to begin in Q3 2029 and be completed in Q4 of 2029.

PG&E will perform several iterations of cut-over process rehearsals with increasing fidelity to ensure the transition to production is well understood by involved stakeholders. The outcome of each rehearsal will be thoroughly evaluated and reviewed to ensure any and all challenges are understood and addressed in advance of the next rehearsal. This will include various forms of regression testing, execution of certain operational processes, catch-up activities and reconciliation reports.

PG&E will also conduct training and proficiency evaluations to ensure the PG&E workforce is ready for cutover and post go live support. Key success factors of this phase include:

- Multiple Dress Rehearsals (Go-Live Practice);
- Well-defined Go-live and Stabilization Plan;
- Actively engage and involve stakeholders;
- Practice, Practice and Practice some more; and
- Go-live Readiness Criteria Met.

h. Support

The Support phase of the C2M project will accomplish two objectives: (1) ensure the system—and related ecosystem applications/integrations—is stable and operating properly in production, and (2) affect a transition of system ownership from the project team to PG&E business and IT resources. The Support phase is scheduled to begin in Q4 2029 and be completed in Q4 2030.

During the first three months after C2M goes live, the system integrator and project team members will provide hyper care support, where the system integrator developers and technical consultants resolve system issues, defects, and ultimately ensure the system meets agreed-upon success criteria. The project will exit from hyper-care once it meets system performance criteria related to the volume and severity of defects, system exception volume, and other operational criteria.

Immediately after the hyper care period ends, approximately three months of stabilization activities will begin. In general, high impact defects will be resolved during the hyper care phase. Lower impact defects, usually with manual workarounds, will be fixed during the stabilization phase.

To ensure the system is working as intended, the system integrator and PG&E will complete specific project close-out activities to transition support of the system to PG&E. This will include the turn-over of technical and functional knowledge, documentation, operational metric processing, and other service introduction activities.

Following the planned six months of hyper care and stabilization, the project plans to continue surge staffing support (see Section E below). During the Test phase, additional resources will be brought in to learn the new system and supplement existing business and system operations staff during the Deploy and Support phases. It is anticipated that PG&E will need up to 12 months of surge staffing following the deployment and cutover to the new C2M system in Q4 2029.

4. Change Management

Change management—coordinating the people, processes, and systems to achieve a desired outcome—will be a key component of the transition to BCS, CC&B 25.1, and C2M. Many of PG&E's business and operations organizations regularly interact with the CIS to perform or support specific business operations. These organizations will all be impacted by each new component of the Billing Modernization Initiative. For example, users of the current ABS Electric complex billing application will now use BCS, a significantly different system. Application and infrastructure support staff will need to adjust to the nuances of updated hardware, databases, and middleware with the CC&B 25.1 Upgrade. In addition, many billing and call center end-users will need to learn to interact with a significantly different interface, new functionality, and enhanced automation and business processes after the C2M Implementation. PG&E has worked with its implementation vendors to develop a change management plan to ensure a smooth launch of all three systems. This plan includes strategies to socialize coming changes across the PG&E organization, train impacted team members and ensure that the organization is prepared for the transition to each of the three new systems prior to go-live.

The training program for impacted PG&E team members will be a collaboration between PG&E, its implementation vendor, and Oracle. BCS, CC&B Version 2.4 (PG&E's current billing system), CC&B 25.1, and C2M are all Oracle products. As a result, the amount of training required to transition to 25.1 and C2M will be lower than the amount required for a net new system because both are Oracle products with operational and technical similarities to CC&B 2.4. The training program will consist of overviews of business processes and hands-on trainings with PG&E team members to ensure they are comfortable with the system at go-live.

To ensure that customers are aware of the changes that the Billing Modernization Initiative will create, PG&E will include a coordinated change management strategy for the entire initiative focusing on the unique needs of each stage. These plans will include internal and external communications strategies to complement the Billing Modernization Initiative implementation plans.

The three project stages will have varying effects to PG&E operations staff and customers, so each project will need to adjust their approach and depth of communication appropriately to reach the target stakeholders, with primary focus on noticeable improvements customers will experience. The BCS project will impact a small portion of PG&E's customers, including many large companies. For this audience, PG&E will leverage the existing customer account representatives to engage and educate the customers on upcoming changes. However, most PG&E customers do not have account representatives, so the C2M project will need to differentiate its approach to communicate the changes to customers. PG&E's goal is to make the modernization effort transparent to customers and ensure customers do not have negative safety and customer service experiences as a result of the Billing Modernization Initiative.

E. Project Staffing Plans and Costs

PG&E will utilize both internal PG&E personnel and external contractors (from vendors and system integrators) to execute the Billing Modernization Initiative. PG&E team members will serve as business and IT SMEs, as well as technical developers. External contractors will provide in-depth functional and technical expertise and implementation experience. The staffing resources and costs discussed below reflect the internal and external labor required to facilitate the development, implementation and production migration of each project.

PG&E has conducted two vendor selections to date and will conduct another, competitively sourcing the work to ensure selection of the partner with the best possible pricing, contractual terms, and capabilities.

Two RFPs Conducted:

1) BCS product selection; and
2) C2M system integrator for Plan, Analyze, and Design phases.

Still to be accomplished:

1) C2M Implementation Phases (Planned for 2026).

The following sections present detailed staffing plans and cost projections for internal and external labor for each project in the Billing Modernization Initiative.

1. BCS – ABS Electric Replacement

The following table reflects the detailed labor Full-Time Equivalent Employees (FTE) and costs by phase for the BCS project (to replace ABS for electric complex billing customers). Labor is further detailed into external labor (i.e., all contracted labor—system integrator, staff augmentation, SMEs, etc.—to support both business and IT workstreams), internal labor (i.e., all PG&E personnel either assigned to the project or tasked with specific support activities), and surge staffing (i.e., additional staff temporarily contracted to support business or IT functions during post-go-live stabilization).

TABLE 5-1
LABOR COST ESTIMATES FOR BCS PROJECT

	Pre-Planning	Plan/Analyze	Design/Build	Test	Replan	Design Upd.	Build Upd.	Test Refresh	Deploy	Support
External Labor *										
Avg. FTE	1.5	8.0	31.8	40.3	45.7	90.3	99.7	74.2	73.2	71.5
Peak FTE	3.8	13.5	43.6	56.9	85.1	95.9	110.9	83.3	79.3	74.3
Internal Labor										
Avg. FTE	1.5	8.0	8.5	11.0	9.4	14.5	25.2	18.7	15.6	15.4
Peak FTE	3.6	7.8	11.9	16.4	10.2	19.5	28.4	25.2	15.8	15.4
Surge Staffing										
Avg. FTE								10	10	10
Peak FTE								10	10	10
Phase Cost (,000s)										
Cap	$ -	$ 6,448	$ 11,066	$ 21,439	$ 10,835	$ 11,678	$ 17,075	$ 20,317	$ 13,928	$ 11,840
Exp	$ 1,165	$ 8	$ 557	$ 649	$ -	$ 89	$ 313	$ 838	$ 240	$ 1,920

(*) The External Labor total for the Plan/Analyze and Design/Build phases do not include the count of Oracle resources due to the nature of the contract. The contract agreement changed during the Test phase, resulting in Oracle resources being included in the labor count from that point forward.

The total projected cost of the BCS project is expected to be $130,400,000. Of that, $124,624,000 will be capitalized and $5,778,000 will be expensed. Project staffing will gradually increase through the replan and updated design activities, peaking at 139.3 total FTEs during the Build phase. An additional 10 surge staff resources will be required to support post-go-live activities.

Note that, as described in Section D.1 above, the BCS project has completed the replan effort to reassess the timeline, costs, and expectations to complete the remainder of the BCS project. As such, Table 5-1 (above) reflects actual labor capacity and costs through the original Pre-Planning, Plan/Analyze, Design/Build and Test Phases. Labor capacity and costs for the remaining phases are based on the current project plan.

a. Systems Integrator/Vendor Resources

Oracle will remain in place as the development vendor for the BCS project given their unique knowledge of the BCS system architecture. As they have already been engaged in the project to date, their staffing profile is projected to remain as is—with minor adjustments for specific technical expertise—through deployment with a continued level of support post-go-live. PG&E also leverages various vendor resources for project management, change management, and overall governance support.

b. PG&E Resources

PG&E forecasts the need for a functional team of product owners and business SMEs, as well as a technical team of: architects, developers, Database Administrators (DBA), technical support, and IT SMEs of up to 28.4 FTEs to support the project.

2. CC&B Upgrade to Version 25.1

The following table reflects the detailed labor FTEs and costs by phase for the CC&B 25.1 Upgrade project, broken down by external and internal labor.

TABLE 5-2
LABOR COST ESTIMATES FOR CC&B 25.1

	Pre-Planning	Plan/Analyze	Design	Build	Test	Deploy	Support
External Labor							
Avg. FTE	1.3	14.8	19.2	36.0	59.1	59.1	59.1
Peak FTE	2.5	24.5	21.5	59.1	59.1	59.1	59.1
Internal Labor							
Avg. FTE	16.8	41.0	58.3	75.7	81.3	81.3	79.3
Peak FTE	18.3	58.3	58.3	83.8	81.3	81.3	79.3
Phase Cost (,000s)							
Cap	$ 2,323	$ 30,750	$ 10,612	$ 26,670	$ 29,572	$ 14,532	$ 4,532
Exp	$ -	$ 771	$ 880	$ 1,802	$ 3,824	$ 943	$ 314

The total projected cost of the CC&B 25.1 Upgrade project is $127,525,000. Of that, $118,992,000 will be capitalized and $8,522,000 will be expensed. Project staffing will gradually increase from as few as 5 FTEs during the Pre-Planning Phase to a peak of 143 total FTEs during the last months of the Build Phase; and carrying into the Test and Deploy phases. Staffing will gradually decline through the Support Phase based on how quickly stabilization is achieved.

a. Systems Integrator/Vendor Resources

As stated in the project description, a vendor will be selected to perform the COBOL-to-JAVA translation. To match delivery obligations to the task duration and project timeline, significant vendor staffing is expected to begin early in the Plan/Analyze Phase and staff will continue to support activities well into the Support Phase. In addition to the customization conversion resources, PG&E will rely on other technical SMEs to support the project, including change management, DBAs, testing, integration, and project management.

b. PG&E Resources

PG&E forecasts the need for a functional team of product owners and business SMEs as well as a technical team of architects, developers, DBAs, technical support and IT SMEs of up to 59.1 FTEs to support the project. The project will leverage a higher percentage of PG&E resources compared to the other projects because PG&E has experience executing this type of project, the target solution (CC&B 25.1) is similar to the existing CC&B, and many of the technical resource skill sets already exist at PG&E.

3. C2M Implementation Project

The following table reflects the detailed labor FTEs and costs by phase for the C2M Implementation project, broken down by external and internal labor.

TABLE 5-3
LABOR COST ESTIMATES FOR C2M PROJECT

	Pre-Planning	Plan/Analyze	Design	Build	Test	Deploy	Support	Ext. Support
External Labor *								
Avg. FTE	1.4	4.9	10.6	26.9	30.7	23.1	11.7	-
Peak FTE	4.0	9.5	15.3	31.3	31.8	23.3	18.8	-
Internal Labor								
Avg. FTE	0.7	37.9	46.5	78.8	85.0	87.7	65.3	-
Peak FTE	3.1	46.9	67.8	79.6	90.2	87.9	86.7	-
Surge Staffing								
Avg. FTE	-	-	-	-	82.9	335.3	298.8	240.0
Peak FTE	-	-	-	-	298.0	354.0	299.0	240.0
Phase Cost (,000s)								
Cap	$ 7,626	$ 32,244	$ 67,446	$ 130,004	$ 141,827	$ 26,949	$ 19,494	$ -
Exp	$ 2,025	$ 890	$ 11,470	$ 15,086	$ 19,668	$ 9,111	$ 15,051	$ 8,837

(*) The External Labor total does not include the system integrator resources due to the nature of the contract.

The total projected cost of the C2M Implementation project is $507,727,000. Of that, $425,589,000 will be capitalized and $82,137,000 will be expensed. Project staffing will gradually increase from as few as

7 FTEs during the Pre-Planning Phase to a peak of 129 total FTEs in the early months of the Build Phase; and carrying into the Test and Deploy phases. Implementation staffing will gradually decline through the Support Phase based on how quickly stabilization is achieved. One unique aspect of the C2M Implementation plan is the projected need to extend billing and call center operations surge support beyond the typical stabilization period; this will average approximately 300 temporary resources during that time.

As discussed in Section D.3, above, the Plan/Analyze and Design phases were completed in May 2024, therefore Table 5-3 reflects actual labor capacity and costs through the original Pre-Planning, Plan/Analyze, and Design phases. Labor capacity and costs for the remaining phases are based on the current detailed plan.

a. Systems Integrator/Vendor Resources

PG&E chose to engage Infosys for only the Plan/Analyze and Design phases to optimize vendor costs and reduce delivery risk. PG&E will separately evaluate potential vendors for future Build/Test/Deploy/Support activities after the successful completion of the Plan/Analyze and Design Phase. PG&E also leveraged various vendor resources to support project management, technical SMEs, and governance support.

b. PG&E Resources

1) Project Delivery Resources

PG&E forecasts the need for a functional team of product owners and business SMEs, as well as a technical team of architects, developers, DBAs, technical support and IT SMEs of up to 90.15 FTEs to support Build, Test, and Deploy activities. This capacity will be maintained into the early stage of Support before scaling back to 65 FTEs in the latter stage of stabilization.

2) Surge Staffing Resources

PG&E plans to use surge staffing for the C2M Implementation project to ensure a seamless migration and a successful transition of business operations to the new platform, particularly from the customer perspective. To migrate the new solution into PG&E's

production environment and subsequently maintain the continuity of business operations and customer service at (or near) current service levels, PG&E will use surge staff support in three key areas:

- Technical Operations and Database Support;
- Billing Operations; and
- Call Center Operations.

Surge staffing for all three areas will begin approximately half-way through the test phase (in about Q1 2029). For Billing Operations and Call Center support, this coincides with the early stages of end-user training delivery and is intended to ensure the teams are properly trained/prepared with sufficient time to transition into the new roles. In contrast, while the initiation of the Technical Operations surge staffing begins at roughly the same time, it will extend through the Deployment and post-go-live Support phases (expected to conclude in Q2 2030).

With the exception of Call Center customer service representatives, the onboarding profile for each of the surge staff teams will reach planned capacity very quickly once staffing begins. Call Center customer service representatives will take slightly longer to ramp up because: (1) it will be administratively difficult to recruit and onboard the number of people needed to fill these roles, and (2) the requirements and capacity of PG&E's training program for customer service representatives will impose constraints on how quickly new hires can begin work.

4. Depreciated Costs of the Billing Modernization Initiative

As stated in Chapter 2 Section B.4, the costs of implementation of the legacy systems of the Billing Modernization Initiative have been fully depreciated.

The total capital cost of the BCS project is forecasted to be $124,624,000. Based on an operative date of July 2025 and asset lifetime retirement in July 2030, greater than 75 percent of the costs will be depreciated at the time of December 2029 (C2M implementation target). The net book value is $30,000,000 by 2029 and 40 percent of the software cost would not be utilized by C2M. This results in forecasted stranded cost of $12,000,000.

The total capital cost of the CC&B 25.1 project is forecasted to be $118,992,000. The project will have two operative dates: December 2024 (initial hardware deployment) and October 2026 (full project deployment). The initial hardware deployed for the project at a cost of $4,700,000 will not have stranded costs as it will be fully depreciated before C2M goes live. The amount included in the subsequent stranded costs analysis is $114,292,000.

The CC&B 25.1 project is forecast to have costs with a book value of $10,980,000 in the CMP30304 13-year software asset class and $4,480,000 in the CMP39101 5-year hardware asset class in 2029. All of these assets will be utilized by C2M, resulting in no forecasted stranded costs.

The CC&B 25.1 project is forecasted to have capital costs of $98,825,000 in the CMP30302 5-year software asset class. Net book value is forecast to be $43,600,00 by 2029 and 25 percent of the software asset cost would not be utilized by C2M, resulting in forecasted stranded costs of $10,900,000.

See Chapter 5 workpapers for additional detail on stranded cost analysis.

F. Conclusion

This chapter details the implementation plan for the billing Modernization Initiative, including providing the specific additional detail about the implementation plan for the proposed billing systems upgrade requested by the Commission in the 2023 GRC Decision. In particular, it provides a more robust showing of PG&E’s proposed project, including the implementation plan, phases of the project (e.g., planning, development, testing, or others), resources required for each phase, timeline for each phase, costs anticipated for each phase, and other information.[7]

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[7] D.23-11-069, p. 549.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

DESCRIPTION OF COST-BENEFIT ANALYSIS

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DESCRIPTION OF COST-BENEFIT ANALYSIS

A. Introduction

This chapter provides a discussion of the cost-benefit analysis performed on Pacific Gas and Electric Company's (PG&E) implementation of three Oracle-based Customer Information System (CIS) platforms and their related subsystems as part of its Billing Modernization Initiative: Billing Cloud Services (BCS), Customer Care and Billing v 25.1 (CC&B 25.1), and Customer-to-Meter (C2M).[1] This chapter will address the California Public Utilities Commission's (CPUC or Commission) directive to provide a discussion of: (1) the risks associated with the continued use of the CIS platforms, and the rationale for upgrade, which were previously described in detail in Chapter 3, (2) an overview of the Cost-Benefit Analysis (CBA), including objectives and methodology, (3) a summary of the benefits and costs identified throughout the CBA process, and (4) a discussion on the final results of the CBA analysis and the impacts of discount rates applied.

The wholistic benefits associated with the Billing Modernization Initiative, including quantified financial benefits and non-quantified benefits such as risk reduction and customer benefits, outweigh the costs. As described in Chapters 2 and 3, PG&E's current billing systems are obsolete and the risks of not upgrading these systems are substantial. These unquantified risk and experience benefits warrant PG&E's Billing Modernization investment. Additionally, as discussed in further detail below, PG&E and Accenture conducted a thorough and rigorous review of potential benefits associated with the Billing Modernization Initiative and found that additional quantifiable benefits represent 31 percent of costs when discounted according to PG&E's weighted average cost of capital and, and 56 percent in nominal terms, leading to a Benefit-Cost Ratio (BCR) of 0.31 and 0.56, respectively. A BCR of 1.00 would

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[1] The Commission's November 16, 2023, General Rate Case Decision specifically directed PG&E to provide additional detail about the proposed billing systems, including "[a] cost benefit analysis for the project that considers whether the overall benefits of the project outweigh the overall costs." D.23-11-069, p. 549, No. 3.

indicate that these quantifiable benefits exactly offset costs. See Table 6-1 for a comprehensive summary of benefits considered:

TABLE 6-1
SUMMARY OF BENEFITS CONSIDERED

Line No	Benefit	Quantification Status
1	B.1: Billing Operations Process Efficiencies	Quantified
2	B.2: Customer Support Operations Process Efficiencies	Quantified
3	B.3: Contact Center Operations Process Efficiencies	Quantified
4	B.4: Credit & Collections Process Efficiencies	Quantified
5	IT.1: Eliminate Legacy Architecture Costs	Quantified
6	IT.2: Avoid Future Increased Cost to Maintain Legacy Architecture	Quantified
7	IT.3: Reduce Cost to Implement Current Project Backlog	Quantified
8	IT.4: Reduce Cost to Implement Future New Projects	Quantified
9	IT.5: Reduce Managed Service Provider (MSP) Spend	Quantified
10	IT.6: Reduce Unplanned CIS System Downtime	Quantified
11	IT.7: IT Support Process Efficiencies	Quantified
12	IT.8: Smart Meter Operations Center Process Efficiencies	Quantified
13	Cybersecurity Risk Reduction	Not Quantified
14	Asset Failure Risk Reduction	Not Quantified
15	Support California policy goals through improved speed to test and program new rates	Not Quantified
16	Improved speed of customer bill issuance	Not Quantified
17	Improved tracking of assets and customer service	Not Quantified
18	Improved customer self-service capabilities	Not Quantified
19	Reduced delays to account updates	Not Quantified
20	Reduced meter verification costs	Not Quantified

The combination of risks associated with PG&E's current CIS platforms and financial benefits associated with the Billing Modernization Initiative support the business case to replace PG&E's current systems.

B. Cost-Benefit Analysis Scope

The scope of the CBA covers two parts: (1) the costs of implementing and operating each upgrade; and (2) the financial benefits enabled by each system upgrade. As discussed in more detail in Chapter 4, the Billing Modernization Initiative includes three platform upgrades, including: (1) an upgrade from Advanced Billing System (ABS) to Oracle BCS, (2) upgrade from Oracle

CC&B 2.4 to Oracle CC&B 25.1, and (3) consolidation of ABS Gas, BCS, C&B 25.1 and L&G Meter Data Management Systems (MDMS) into C2M. The cost-benefit analysis includes all costs associated with the implementation and ongoing operation of each of the three systems. As outlined in Section D, the analysis considers financial benefits enabled by each system across both business and Information Technology (IT) functions. Unless otherwise noted, any benefits enabled by BCS or CC&B 25.1 are presumed to be subsumed into C2M after the final upgrade is completed.

An important consideration that is outside the scope of this CBA is the quantification of the risks posed by PG&E not upgrading its current billing systems and the benefits of the risk reduction and system stabilization of the first two upgrades. As discussed in more detail in Chapter 3, PG&E faces numerous risks if it does not upgrade its current billing systems, including risk of catastrophic mission failure. The primary objective of the first two projects, the BCS and CC&B 25.1 upgrades, is to address and reduce these risks, especially IT asset failure and cybersecurity risks. These risk-reduction and system stabilization initiatives are required to maintain the overall health of PG&E's billing platform resulting in a lower financial benefit-cost ratio associated with both of these systems as the risk reduction benefits associated with them are not quantified by the CBA. Risk quantification is possible in some circumstances, but the methodology of assigning a financial value to risk reduction does not always fully capture the benefit of avoiding a potentially catastrophic cybersecurity or IT asset failure risk. CIS are core to business operations and a CIS system failure would have cascading impacts across PG&E's operations, impacting PG&E's ability to serve customers.[2]

C. Cost-Benefit Analysis Overview and Methodology

1. What is a CBA?

The Cost-Benefit Analysis is a tool to compare the projected costs of implementing and maintaining PG&E's proposed systems with the benefits associated with their implementation. Cost and benefit analyses are used within and beyond the utility industry to evaluate the prudence of an

[2] See Chapter 3 for additional detail regarding potential risks associated with PG&E's current billing systems.

investment decision on its financial merits. The analysis discussed in this chapter uncovers the quantitative net financial impact of pursuing the Billing Modernization Initiative on PG&E's operations. This analysis is designed to function as one input among several to enable PG&E, the Commission, and additional stakeholders to make informed, evidence-based decisions relating to this investment.

It is important to note that the CBA can only compare *quantifiable* benefits and costs. The CBA provides one objective measure of the prudence of the investment and the due diligence behind the proposal and serves as a quantified input summarizing the impact of the initiative; the CBA does not capture the non-quantifiable benefits which the Billing Modernization Initiative will provide. As discussed in Chapter 3, PG&E faces significant obstacles and risks if it maintains its legacy systems—such risks are the primary drivers for PG&E's pursuit of the initiative. Therefore, future-proofing PG&E's existing architecture to avoid system outages represents a significant benefit of the initiative that is not quantified in the CBA. The initiative will also drive reductions in cyber-related risks and reduce the possibility of IT asset life failure. Additionally, the initiative will lead to significant non-quantifiable benefits, including improved customer experience and improved compatibility with third-party applications.

2. CBA Methodology

PG&E partnered with third-party industry experts familiar with the California regulatory environment from Accenture to develop a robust, evidence-based Cost-Benefit Analysis model. Accenture worked with PG&E to identify key gaps in its existing CIS infrastructure, map these gaps to novel capabilities of the planned platforms to surface benefits, and develop quantification methodologies and estimates for each benefit identified.

Accenture and PG&E teams worked with vendors and internal resources to gather cost estimates for all three systems. The CBA considers all implementation and ongoing costs associated with each system throughout each system's projected lifetime. PG&E developed cost estimates for the implementation and ongoing maintenance of each of the billing system upgrades that are part of the Billing Modernization Initiative by utilizing its internal cost estimation tools and working with its implementation and system vendors.[3] PG&E projects that BCS will go-live in 2025, CC&B 25.1 will go-live in 2026 and C2M will go-live in 2029.

Similarly, Accenture and PG&E projected the value of each benefit throughout the same period. The methodology for calculating the value of each benefit varied according to the specific characteristics of each benefit. For benefits associated with the complete elimination of a cost, the value of the benefit was considered to be the value of that avoided cost in each year. For benefits derived from a business process efficiency, benefit values are generally derived by estimating the costs of performing the process on the current system and estimating the reduction in time under the target system. Note that the specific calculations to estimate the value of each benefit vary according to the characteristics of the benefit.

Benefits associated with each of these platforms are recognized as early as the launch of the corresponding platform, though some benefits are recognized gradually to reflect time required for PG&E team members to learn elements of the target system and fully integrate and realize the benefits of new business processes. ABS Gas, BCS, CC&B 25.1 and L&G MDMS will be replaced by C2M in 2029. Any benefits associated with BCS and CC&B 25.1 continue to be realized throughout the anticipated life of C2M—through 2042[4]—because the functionality triggering those benefits in BCS and CC&B 25.1 remains in C2M.

These benefit and cost projections were then used to develop a ratio for all quantifiable costs and benefits realized through the pursuit of the Billing Modernization Initiative. Benefits and costs are provided throughout this chapter in 2023 dollars. Inflation rates are projected through the lifetime of C2M (2042) and applied to both costs and benefits, before being discounted to a base year of 2023.

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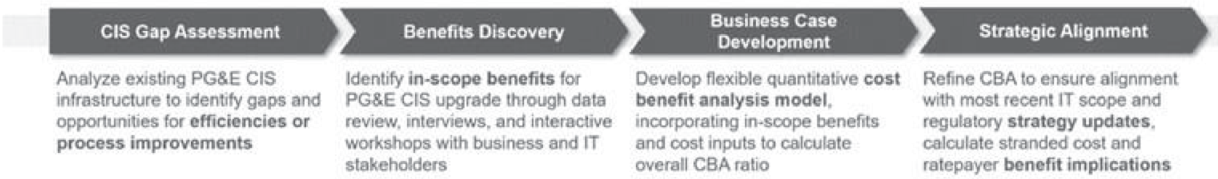
3 PG&E generally follows a standard procedure for estimating the costs of large-scale implementations like those discussed in this chapter. This process involves first developing a staffing plan that forecasts resources required to complete the implementation, then estimates the costs associated with that staffing plan. This process is described in more detail in section E.1.

4 Note that this analysis assumes a 13-year asset life. Benefits are realized through the end of C2M’s asset life, which is on November 30, 2042.

FIGURE 6-1
CBA CREATION PROCESS FLOW



D. Overview of Benefits:

1. Overall Approach to Benefits Discovery and Quantification

Accenture and PG&E stakeholders worked together to identify, refine, and quantify potential benefits. The benefit identification process began with a thorough analysis of the incremental capabilities of the platforms that PG&E had planned to implement. Accenture and PG&E then conducted interviews with internal experts to understand gaps in current billing system capabilities and how the new platforms would address those gaps. Accenture worked with PG&E teams to develop methodologies for quantifying each of the benefits identified and gather inputs to develop initial value estimates. PG&E and Accenture regularly pressure-tested and refined the set of benefits it considered and their quantification methodologies by socializing benefits and processes with PG&E stakeholders—surfacing new benefits, removing non-applicable benefits, and updating the calculation methodology for each benefit.

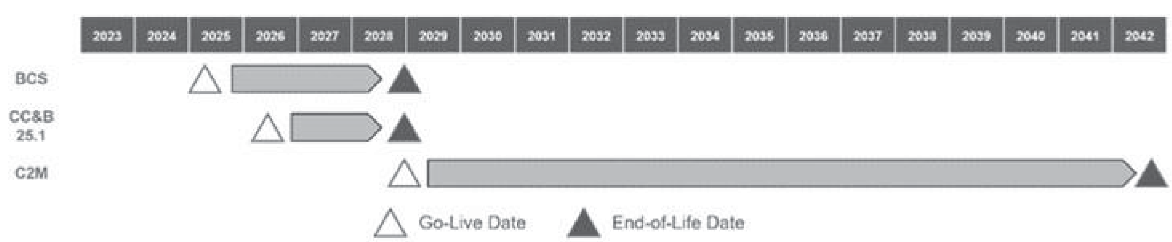
In addition to the process outlined for quantifying the annual value of each benefit, PG&E and Accenture projected the evolution of input values that underlie benefit calculations to capture the full value of each benefit across the lifetime of the system. Accenture also worked with PG&E to develop benefit realization “ramp curves” to capture the portion of each benefit realized in each year and account for any delays between the implementation of a capability and the full realization of benefits.

The quantifiable benefits identified through the process described above are the result of extensive diligence and analysis. They are well-supported and appropriately tailored. Along with the risk reduction benefits discussed in Chapter 3, they comprehensively represent the impacts of the Billing Modernization Initiative.

2. Core Assumptions Underlying Estimation

When providing discounted values, all benefits and costs are discounted to 2023 as the base year. Discounting these values allows the CBA to reflect the relative value of benefits and costs realized in the future to PG&E and its customers today, accounting for the time value of money and its potential to earn a return when invested elsewhere. PG&E's Weighted Average Cost of Capital (WACC) and the Social Rate of Time Preference both serve as the discount rates in this analysis and are presumed to remain constant throughout the forecast period, as are inflation and overall electric customer growth rates.[5] Benefits are calculated either using a three-year rolling average of relevant inputs or single-year annual values, according to which is the most representative baseline for projected volumes based on input from PG&E stakeholders. As discussed in section C.2, these inputs are projected over the lifetime of the platforms. The realization of benefits is discounted in the go-live year according to the portion of the year that the benefit is realized.

FIGURE 6-2
ANTICIPATED ASSET LIFE TIMELINES



3. Business Benefits

The CBA considers four key categories of quantifiable business benefits:

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[5] In R.20-07-013, the S-MAP Order Instituting Rulemaking (OIR) Phase 3 Decision , the CPUC considered the value of utilizing multiple discount rates to evaluate programs (in that specific case, mitigations). The Commission noted that the appropriate discount rate may differ according to the program evaluated; discount rates considered include the social rate of time preference and utility financial metrics such as the weighted average cost of capital (D.24-05-064, pp. 102-103). The CBA uses 7.8 percent for WACC. PG&E Advice Letter (AL) 4813-G/7046-E, p. 3.

- **B.1 - Billing Operations Process Efficiencies:** This category includes benefits resulting from automated or streamlined processing of delayed bills, errors, complex rates, and other complex billing processes. These benefits are driven partially by the transition from a billing system designed to support subtractive billing (using monthly meter reads), to one optimized for interval billing enabled by advanced metering infrastructure. This category also includes benefits from increased automation to reduce risk of manual error and reduce effort to resolve exceptions and process delayed bills, as well as reduction in redundant processes from consolidation of billing platforms;
- **B.2 - Customer Support Operations Process Efficiencies:** This category includes benefits resulting from automation of Medical Baseline application processing. Under PG&E's current CIS infrastructure, Medical Baseline applications, recertifications, and self-certifications are manually processed. The Billing Modernization Initiative will automate these processes leading to significant reductions in manual labor over the lifetime of the systems;
- **B.3 - Contact Center Operations Process Efficiencies:** This category includes benefits resulting from reductions in call volume to the PG&E contact center due to the billing system upgrade. A portion of calls currently received by the PG&E contact center is driven by billing system anomalies, such as delayed bills. The CIS upgrade will decrease the delays driving these calls, leading to reductions in labor costs to support this call volume; and
- **B.4 - Credit & Collections Process Efficiencies:** This category includes benefits resulting from reductions in volume of write-off process errors and debit or credit adjustments. The CIS upgrade will reduce errors among written off accounts receiving service from third-party providers and enable improved distribution of credits, reducing the degree of manual intervention required under the current billing platforms.

The total nominal estimated value of business benefits to be realized through the Billing Modernization Initiative is $212 million.

TABLE 6-2
FORECASTED BUSINESS BENEFITS – NOMINAL AND WACC DISCOUNTED
(CONSTANT 2023 MILLIONS OF DOLLARS)

Line No.	Benefits Category	BCS Benefits (Millions of Dollars)	CC&B 25.1 Benefits (Millions of Dollars)	C2M Benefits (Millions of Dollars)	Total Nominal Benefits (Millions of Dollars)	Total WACC Discounted Benefits (Millions of Dollars)
1	B.1	3.9	3.4	178.3	185.6	73.0
2	B.2	–	–	14.7	14.7	5.6
3	B.3	–	–	5.3	5.3	2.0
4	B.4	–	–	6.3	6.3	2.4
5	Total Business Benefits	3.9	3.4	204.6	211.9	83.0

4. IT Benefits

The CBA includes seven key categories of quantifiable IT benefits resulting from the CIS upgrade:

- **IT.1 - Eliminate Legacy Architecture Costs:** This category includes benefits resulting from the elimination of IT support costs and licensure costs to support legacy systems. With the implementation of a single integrated CIS platform, PG&E will no longer pay for individual licenses for customer care and billing and MDMS and the ancillary applications that support them. This category includes gross reductions in internal application support, capital expenditures associated with the systems, and licensure costs.
- **IT.2 - Avoid Future Increased Cost to Maintain Legacy Architecture:** This category includes benefits from eliminating the growing costs of continuing to maintain obsolete legacy technologies. PG&E's system will become more expensive to operate and maintain as it continues to age due to the complexity associated with maintaining an out-of-date, unsupported technology languages, features and capabilities. Replacing PG&E's legacy systems eliminates these costs.
- **IT.3 - Reduce Cost to Implement Current Project Backlog:** This category includes benefits resulting from increased labor efficiency and decreased capital costs required to implement planned rates currently in the PG&E backlog. The Billing Modernization Initiative will allow for a new, more efficient method of rate development: PG&E will only need to develop, code, and test rates in a single system rather than in multiple

and will be further enabled by the move to modular rates and the elimination of customizations for rate developments. By enabling a singular modular rating engine, PG&E will be able to implement the 16 projects that are not currently planned for either BCS or CC&B, as detailed in Table 4-1 of Chapter 4, in its current and projected backlog more efficiently than it would without the Billing Modernization Initiative.

- **IT.4 - Reduce Cost to Implement Future New Projects:** This category includes benefits resulting from increased labor efficiency and decreased capital costs to implement *future* projects, enabled by the same improved rate development processes that enable PG&E to address its project backlog. This benefit category includes both capital and expense spend.
- **IT.5 - Reduce Managed Service Provider Spend:** This category includes reductions in managed service provider spend to support legacy systems. PG&E's current legacy customer care and billing system relies on several thousand customizations that require extensive vendor support. The Billing Modernization Initiative will integrate PG&E's customer care and billing system with its meter data management system. The Billing Modernization Initiative will allow for the retirement of PG&E's architecture and the managed service provider spend associated with its support.
- **IT.6 - Reduce Unplanned CIS System Downtime:** This category includes benefits resulting from a reduction in annual unplanned CIS system downtime and the costs associated with addressing outages. PG&E's current system is not fully supported by its vendor due to its age. This lack of support has led system downtime to extend beyond Mission Critical reliability standards.[6] The Billing Modernization Initiative will move PG&E to a modern, vendor-supported CIS, reducing total system downtime each year in line with Mission Critical reliability standards.

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6 PG&E's 2026 target for Mission Critical applications is a 99.99 percent reliability/uptime standard. C2M is expected to meet this application standard for reliability and this has been scoped into C2M's design.

- **IT.7 - IT Support Process Efficiencies:** This category includes reductions in training costs and IT systems access reviews for PG&E's current systems. Since PG&E will be staying within the Oracle billing ecosystem and CC&B and C2M are built off similar foundations, there will be less of a need to perform introductory training days. System access reviews will decrease because PG&E is moving the capabilities of 11 different systems to one, leading to less time required to grant resources access to appropriate systems. PG&E will also realize benefits from only needing to grant new hires access to one system rather than to 11.
- **IT.8 - SmartMeter™ Operations Center (SMOC) Process Efficiencies:** This category includes benefits from SMOC labor efficiencies associated with reductions in Data Correction Routines (DCR). Current native data storage in billing systems is restricted to 13 months, limiting the ability of the billing teams to perform actions such as retroactive start / stops and requiring DCRs to be performed by the SMOC team. The Billing Modernization Initiative will expand native storage to 37 months, reducing the need for DCRs

The total nominal estimated value of IT benefits to be realized through the Billing Modernization Initiative is $384 million.

TABLE 6-3
FORECASTED IT BENEFITS – NOMINAL AND WACC DISCOUNTED
(CONSTANT 2023 MILLIONS OF DOLLARS)

Line No.	Benefits Category	Nominal BCS Benefits (Millions of Dollars)	Nominal CC&B 25.1 Benefits (Millions of Dollars)	Nominal C2M Benefits (Millions of Dollars)	Total Nominal Benefits (Millions of Dollars)	Total WACC Discounted Benefits (Millions of Dollars)
1	IT.1	–	–	206.7	206.7	79.3
2	IT.2	–	–	2.8	2.8	1.1
3	IT.3	–	–	10.9	10.9	5.8
4	IT.4	–	–	55.0	55.0	20.9
5	IT.5	–	–	93.8	93.8	36.0
6	IT.6	–	0.2	0.9	1.1	0.5
7	IT.7	–	–	6.2	6.2	2.5
8	IT.8	–	1.1	6.8	7.9	3.4
9	Total IT Benefits	–	1.3	383.2	384.4	149.4

5. Total System Benefits

Through the projected life of these three systems, between 2024 and 2042, the total nominal value of the benefits realized is $596.4 million.[7] These benefits are driven primarily by reductions in manual operations to address exceptions or errors, by reductions in costs to support complex legacy systems, and by reductions in legacy CIS system licensures.

The primary objective of implementing BCS and CC&B 25.1 is to enhance system stability and protect against a potential system failure which would lead to an inability to bill customers. These implementations provide a subset of total financial benefits realized throughout the forecast period. The total nominal value of financial benefits associated with BCS is $3.9 million. The total nominal value of financial benefits associated with CC&B 25.1 is $4.7 million. The majority of quantified benefits, and their corresponding financial value, is realized by the upgrade to C2M, which integrates customer billing with MDMS. The total nominal value of benefits associated with C2M is $587.7 million. These values (and the values in Tables 6-2 and 6-3, above) reflect the attribution to C2M of benefit values realized in time periods after its go-live date. Therefore, the benefits attributed to BCS and CC&B 25.1 are realized from 2025 to 2029 and 2026 to 2029, respectively, before being attributed to C2M beginning in 2029. The distribution of lifetime benefit values is shown in Figure 6-3, below.

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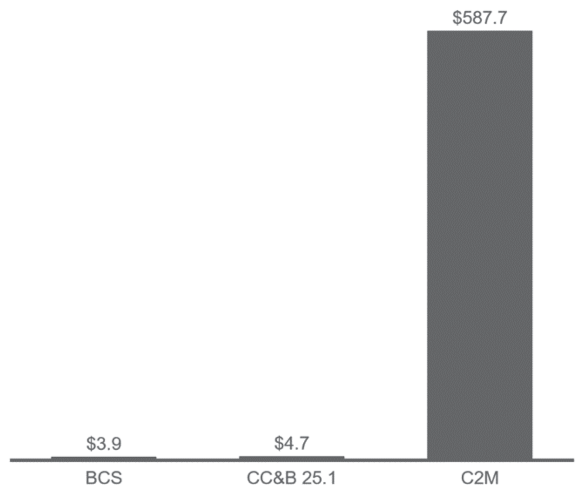
7 See Figure 6-2 above.

FIGURE 6-3
FORECASTED BENEFITS BY SYSTEM
(CONSTANT 2023 MIILIONS OF DOLLARS)



As discussed, the BCS and CC&B 25.1 upgrades are driven by the need to address some of the non-quantifiable benefits such as the need to reduce cybersecurity and asset failure risk and the majority of quantified benefits associated with the Billing Modernization Initiative are concentrated after the go-live of C2M, in 2029. Therefore, the discount rate used to calculate the present value of benefits over the lifetime of the initiative impacts the total benefits estimated. The total nominal (*non-discounted*) value of benefits across the three systems is $596.4 million. The value of these benefits *discounted* according to PG&E’s Weighted Average Cost of Capital is $232.4 million.

TABLE 6-4
FORECASTED BENEFITS – NOMINAL AND WACC DISCOUNTED
(CONSTANT 2023 MIILIONS OF DOLLARS)

Line No.	Benefits Category	BCS Benefits (Millions of Dollars)	CC&B 25.1 Benefits (Millions of Dollars)	C2M Benefits (Millions of Dollars)	Total Nominal Benefits (Millions of Dollars)	Total WACC Discounted Benefits (Millions of Dollars)
1	Total Business Benefits	3.9	3.4	204.6	211.9	83.0
2	Total IT Benefits	–	1.3	383.1	384.4	149.4
3	Total Benefits	3.9	4.7	587.7	596.4	232.4

FIGURE 6-4
FORECASTED BENEFITS – BUSINESS AND IT BENEFIT DECOMPOSITION
(CONSTANT 2023 MIILIONS OF DOLLARS)

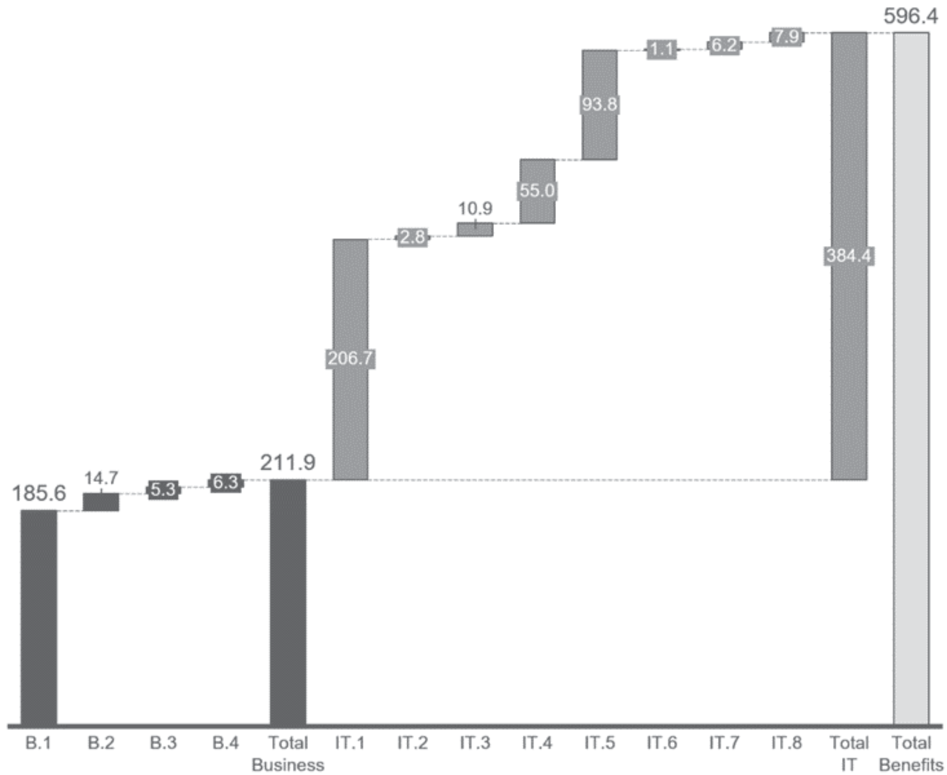
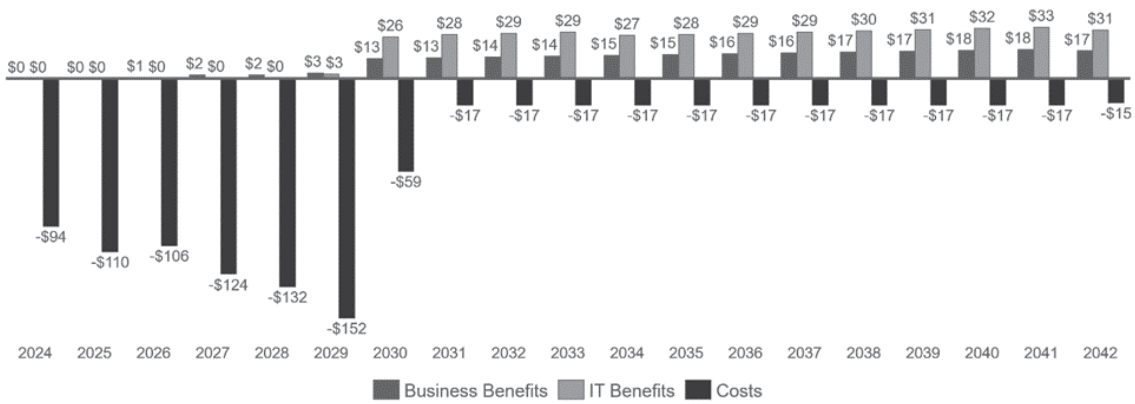


FIGURE 6-5
FORECASTED NOMINAL CASH FLOWS
(CONSTANT 2023 MIILIONS OF DOLLARS)



6. Risk Reduction Benefits

In addition to the quantifiable benefits discussed above, the Billing Modernization Initiative will produce benefits relating to cybersecurity and IT asset failure risk reduction. These and other risks are further detailed in Chapter 3 – Billing Systems and Risk Management.

7. Experience Improvements

The Billing Modernization Initiative will produce several customer and employee experience benefits by improving speed of access to new rates, improving PG&E processes, and empowering customers with better tools and access to information.

The upgrade from ABS Electric to BCS will enable improved rate change value testing capabilities that will enable the complex billing team to more quickly test and program new rates. The current billing systems require new rates to be programmed into both CC&B 2.4 and ABS independently. Consolidation of systems through the C2M upgrade will reduce these duplicative rate programming requirements. C2M will also enable a modular rate engine, which will reduce the time and effort required to implement new rate designs. Through these upgrades, PG&E will be better positioned to support the policy goals of the CPUC and enable faster customer access to new rate designs and customer programs.

Billing Modernization upgrades will also improve several PG&E processes. C2M will integrate billing and MDMS, which will reduce the volume of interval billing exceptions, improved data synchronization and reduce delayed bills post stabilization. Improved native data storage will decrease the requirement for requests of data to complete retroactive corrections, improving PG&E's ability to quickly correct customer bills. C2M will also enhance data transfers with GIS systems to better help transformer mappings and outage management teams, allowing for improved tracking of assets and customer service in the event of both planned and unplanned outages.

Finally, the Billing Modernization Initiative will enable digital strategies to improve customer experiences and PG&E processes. C2M includes improved self-service capabilities, allowing customers to engage on-demand and enabling easier account management, service requests, and access to information. These benefits will reduce the need for customers to engage with service channels, which will remove a pain point for these customers while freeing service representatives to focus on remaining customer calls.

Finally, C2M will enable customer service representatives to process various account changes for complex billing customers, which previously required generation of a request to be handled by complex billing operations staff. This previous process introduced delays to account updates which will now be resolved by allowing immediate changes to be implemented, increasing customer faith in PG&E's responsiveness to their needs and reducing frustration.

8. Additional Benefits Not Quantified

Throughout the CBA process, several benefits were identified across business groups that could not be directly quantified due to lack of available data. These include meter verification, where the requisite data to calculate benefits to an appropriate degree of certainty are not tracked, and select risk reductions. In addition, there are benefits described in Chapter 4 that will provide benefits to customers that cannot be quantified and are therefore not reflected in this CBA.

PG&E will realize meter verification benefits due to reductions in truck rolls—dispatches of PG&E technicians or crews—required to verify meter data. The billing operations group bears budgetary impacts from truck rolls sent to verify meter information. Although data is available reflecting the volume of dispatches, assumptions would have to be made to gauge the proportion of dispatches that could be prevented by the upgrades to the CIS platform to quantify this benefit. While there will be a financial benefit tied to this activity, it is not quantified in this analysis.

The Billing Modernization Initiative will also address the cyber vulnerabilities and IT asset life failure risks associated with the existing systems. Upgrades to CC&B 25.1 will address the security vulnerabilities on the CC&B 2.4 system and bring PG&E systems back into vendor support. The risks of existing systems are described in more detail in Chapter 3.

E. Overview of Costs

1. Cost Methodology

PG&E has used multiple robust forecasting methodologies to develop cost projections for the Billing Modernization Initiative, utilizing its internal proprietary tools and input from its partners and implementation vendors to develop a granular resource forecast and inform its estimates for costs to implement and maintain all three new systems. In the Plan/Analyze phases of its implementations for each system, PG&E and its partners develop cost estimates for each proceeding phase based on PG&E-specific inputs, and extensive vendor industry knowledge and experience in implementing similar CIS upgrades at other large North American utilities.[8] This experience and understanding has informed PG&E's staffing plan detailed in Chapter 5, which is the basis for its cost estimates for each project.

PG&E followed its standard procedure for estimating the costs of implementations to develop its cost estimates for the C2M and BCS implementations. PG&E first developed a concept estimate, based on forecasts of users impacted by the implementation, the number of teams involved, and projected complexity. PG&E then worked with project management subject matter experts from its vendors and third-party system integrators to develop a robust staffing and resource plan, including forecasts of internal and external resources required, and to refine the initial concept estimate. This staffing and resources plan served as an input to PG&E's forecasting tool, which applied forecasted resource and overhead costs to inform PG&E's final cost estimate, which is reflected in this application.

PG&E followed a similar procedure for developing cost estimates for CC&B 25.1. However, the 25.1 project has not yet completed its plan/analyze phase. The 25.1 cost estimate accordingly has a higher contingency associated with it than the other projects to account for potential project developments and new functionality associated with 25.1. PG&E has augmented its cost estimation process for 25.1 by drawing on its experience implementing Oracle CC&B version upgrades in the past. PG&E has implemented multiple versions of Oracle CC&B systems, and thus was able to leverage internal expertise that had worked on the upgrade

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8 Note that PG&E's cost estimates used for its cost-benefit analysis include Allowance for Funds Used During Construction (AFUDC) costs for all programs; this inclusion may differ from the CBA methodology utilized by other California utilities for the evaluation of their billing system upgrades.

previously in tandem with Oracle and other external expertise to develop its labor forecasts.

For each project, PG&E estimated a high and expected cost by using their internal American Association of Cost Engineering tool, which calculates the expected value of identified and future risks. For all three projects, PG&E seeks recovery for the expected value. For each potential risk identified, PG&E estimates the impact of the realization of the risk on the project's budget and the probability of realization. PG&E calculates the estimated budget impact of the realization of the risk by calculating the run rate cost of the project and estimating the delay in the project schedule caused by the realization of that risk, informed by prior implementation experience. PG&E multiplies the project's run rate by this estimated delay to calculate the budget impact of the risk. Similarly, PG&E determines the probability of the realization of a risk by evaluating the project and assigning it a "high", "medium", or "low" likelihood of occurring and applying a corresponding probability value. The impact of a risk and the likelihood of the risk occurring produce an expected value for each risk. High and expected cost values differ by the different probabilities assigned to the realization of each risk identified.

2. Nominal Project Implementation Costs

The total costs of the implementation of BCS, CC&B 25.1, and C2M is $765.7 million, of which PG&E is seeking to recover $761.3 million.[9] This estimate includes capital costs associated with building and implementing all three systems, along with one-time expense costs associated with the Initiative, which include change management costs, training, surge staffing, or similar activities. Core activities will be consistent across the three systems, with some differences according to the scale of the implementation and the resources available and required to execute key activities. The distinction between costs associated with Capital and Expense is in line with generally accepted accounting principles.

9 PG&E is not seeking recovery for $4.4 million of expense costs incurred in 2020-2022. Throughout Section E, PG&E provides total project implementation costs, inclusive of 2020-2022 expense costs.

TABLE 6-5
NOMINAL IMPLEMENTATION CAPITAL AND O&M COST FORECAST
(CONSTANT 2023 MILLIONS OF DOLLARS)

Line No.	Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
1	Capital	–	$8.8	$25.6	$47.3	$89.3	$77.0	$66.7	$83.9	$83.5	$86.8	$15.7	$584.5
2	Expense	$0.2	$1.8	$2.4	$0.9	$4.3	$7.8	$13.6	$8.0	$9.2	$26.2	$22.0	$96.4
3	Contingency	–	–	–	–	–	$23.1	$12.6	$10.1	$17.3	$17.3	$4.3	$84.7

Some of the key drivers of costs across the three system implementations include:

- Costs of 3rd Parties to support the integration of the new system;
- Costs of PG&E Labor required to support the implementation;
- Costs of temporary staffing increases (Surge Staffing)[10] to support the Customer Contact Center, Billing Operations, and IT teams around the go-live of C2M;
- Allowance for Funds Used During Construction;
- Licensing costs; and
- Contract costs, inclusive of consulting services.

3. Billing Cloud Services – ABS Electric Replacement

BCS is expected to cost a total of $130.4 million to implement between 2020 and 2025.[11] This includes a projected $116.7 million in capital costs, $5.8 million in expense, and $7.9 million in forecast contingency.[12]

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10 As noted in Chapter 5, surge staffing resources are additional resources brought in to learn the new system and supplement existing operations resources during the Deploy and Support phases.

11 While the expected cost for BCS is $130.4 million, PG&E calculated the high-cost value as $157.9 million.

12 PG&E is not seeking to recover $2.4 million in expense incurred in 2020-2022.

TABLE 6-6
NOMINAL COST FORECAST – BCS
(CONSTANT 2023 MILLIONS OF DOLLARS)

Line No.	Year	2020	2021	2022	2023	2024	2025	Total
1	Capital	–	$8.0	$18.8	$15.0	$44.1	$30.8	$116.7
2	Expense	$0.2	$1.0	$1.2	–	$1.0	$2.4	$5.8
3	Contingency	–	–	–	–	–	$7.9	$7.9

a. Nominal Capital Costs Forecast

BCS capital costs are expected to total $116.7 million, incurred between 2021 and 2025. These costs include PG&E labor costs, third party contractor labor costs, and non-labor costs, which include costs of financing, license, materials, and other costs.

TABLE 6-7
CAPITAL COST FORECAST – BCS
(CONSTANT 2023 MILLIONS OF DOLLARS)

Line No.	Year	2021	2022	2023	2024	2025	Total
1	PG&E Labor Costs	$1.14	$2.85	$3.08	$6.63	$5.26	$18.97
2	Non-Labor Costs	$6.86	$15.97	$11.92	$37.47	$25.54	$97.76
3	Contractor Costs	$6.72	$14.97	$8.85	$30.25	$22.36	$83.15
4	Hardware/Software/Financing/Other	$0.14	$1.01	$3.07	$7.22	$3.18	$14.62
5	PG&E Labor Costs	$1.14	$2.85	$3.08	$6.63	$5.26	$18.97

Both PG&E internal resources and external system implementation contractors and other labor augmentation will be required to successfully design, build, and implement BCS. PG&E resources will fill many roles throughout the implementation of BCS, including project management, software development, and application development and enhancement, among others. Additional information regarding the staffing plan and the specific activities performed during the implementation of BCS, and of all programs, can be found in Chapter 5. Beyond labor, the BCS project will incur financing, licensing, and contract capital costs.

b. Nominal Expense Forecast

The one-time expense costs associated with the implementation of BCS total $5.8 million between 2020 and 2025. These include PG&E

labor costs to support the program's implementation, as well as non-labor costs such as material, and other costs.

TABLE 6-8
EXPENSE COST FORECAST – BCS
(CONSTANT 2023 MILLIONS OF DOLLARS)

Line No.	Year	2020	2021	2022	2023	2024	2025	Total
1	PG&E Labor Costs	$0.10	$0.34	–	–	–	$0.13	$0.57
2	Non-Labor Costs	$0.10	$0.68	$1.16	–	$1.00	$2.27	$5.21
3	Contractor Costs	$0.10	$0.69	–	–	$0.54	$1.54	$4.02
4	Material/Other	–	–[(a)]	–	–	$0.46	$0.73	$1.19

(a) PG&E realized a small cash discount in 2021, reducing total non-labor expense costs.

Expense costs for BCS are driven in particular by labor costs to execute data conversion and data clean-up. Third party resources will also support non-capitalized activities in earlier phases of the project.

c. Contingency

PG&E estimated contingency for CC&B 25.1 in accordance with the process described in section E.1. The estimated contingency associated with the BCS implementation is $7.9 million. This contingency is derived from four primary identified risks: (1) Unknown Requirements and Design Gaps; (2) Data Conversion Issues; (3) Resource constraints/Attrition; (4) General Project Uncertainty. PG&E will make every effort to mitigate the impact and likelihood of any of these risks, but each risk will remain present due to the nature of a technical implementation of this size.

4. Upgrade CC&B 2.4 to CC&B 25.1

The total cost to implement CC&B 25.1 is forecast to be $127.5 million, inclusive of $91.2 million in capital costs, $8.5 million in expense costs, and $27.8 million in contingency.[13] These costs are incurred between 2024 and 2026, and represent the costs of building, customizing, and integrating the

13 PG&E calculated the high-cost value for CC&B 25.1 as $192.5 million.

new system, as well as any additional project management costs associated with the implementation.

TABLE 6-9
CC&B 25.1 COST FORECAST
(CONSTANT 2023 MILLIONS OF DOLLARS)

Line No.	Year	2024	2025	2026	Total
1	Capital Cost	$9.0	$46.2	$36.0	$91.2
2	Expense	–	$3.5	$5.1	$8.5
3	Contingency	–	$15.2	$12.6	$27.8

a. Nominal Capital Costs Forecast

Capital costs to implement CC&B 25.1 are projected to total $91.2 million between 2024 and 2026. These costs include PG&E internal labor and non-labor costs, which include contractor labor, and additional non-labor costs like financing and material costs.

TABLE 6-10
CAPITAL COST FORECAST – CC&B 25.1
(CONSTANT 2023 MILLIONS OF DOLLARS)

Line No.	Year	2024	2025	2026	Total
1	PG&E Labor Costs	$1.38	$23.88	$25.47	$50.73
2	Non-Labor Costs	$2.93	$22.28	$10.53	$35.74
3	Contractor Costs	$2.92	$16.21	$8.08	$27.20
4	Financing/Material	$0.01	$6.07	$2.45	$8.54
5	DR Mitigation	$4.71	–	–	$4.71

As with the BCS implementation, PG&E internal and external resources will be integral to the successful implementation of CC&B 25.1. PG&E plans to lean more heavily on internal resources for customizing and integrating 25.1 compared with BCS and C2M. As detailed in Chapter 5, key activities performed for the implementation of CC&B will involve translating existing code to a new language, integrating 25.1 with other PG&E systems, and testing the new system to ensure a successful go-live. Capital costs also include non-labor costs associated with the implementation, including, material, AFUDC, and contractor labor costs. Disaster Recovery mitigation costs associated with the 25.1 Upgrade are also a capital cost incurred in 2024.

b. Nominal Expense Forecast

The one-time expense costs associated with the implementation of CC&B 25.1 total $8.5 million between 2024 and 2026. These include both labor costs to support the program's implementation, as well as non-labor costs such as material costs.

TABLE 6-11
EXPENSE COST FORECAST – CC&B 25.1
(CONSTANT 2023 MILLIONS OF DOLLARS)

Line No.	Year	2024	2025	2026	Total
1	PG&E Labor Costs	–	$2.05	$1.95	$4.01
2	Non-Labor Costs	–	$1.40	$3.13	$4.53
3	Contractor Costs	–	$1.40	$1.19	$2.59
4	Material Costs	–	–	$1.94	$1.94

CC&B 25.1 will not incur significant expense costs related to change management and organizational readiness because of the similarity in processes and interface between CC&B 25.1 and the existing CC&B 2.4. CC&B 25.1 will also not require significant data conversion execution and clean up. CC&B expense costs are driven largely by business and IT process expert costs to inform the execution of the upgrade in the Build and Test phases.

c. Contingency

PG&E estimated contingency for CC&B 25.1 is in accordance with the process described in section E.1. The estimated contingency associated with the CC&B implementation is $27.8 million. PG&E teams identified three primary execution risks driving this contingency estimate: (1) risk of extension of the design phase; (2) risk of the extension of the Build/ Test Defects phase; and (3) risk associated with a change of scope of the project. All three would increase resource costs required to successfully complete the upgrade.

5. Customer-to-Meter Implementation Project

The total cost to implement C2M is forecast to be $507.7 million, inclusive of capital, expense, and contingency costs.[14] These costs are incurred between 2021 and 2030, and represent the costs of building and integrating the new system, as well as change management or project management costs associated with the implementation.

TABLE 6-12
C2M NOMINAL COST FORECAST
(CONSTANT 2023 MILLIONS OF DOLLARS)[15]

Line No.	Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
1	Capital	$0.8	$6.8	$32.2	$36.2	–	$30.7	$83.9	$83.5	$86.8	$15.7	$376.6
2	Expense	$0.8	$1.2	$0.9	$3.3	$1.9	$8.5	$8.0	$9.2	$26.2	$22.0	$82.1
3	Contingency	–	–	–	–	–	–	$10.1	$17.3	$17.3	$4.3	$49.0

a. Nominal Capital Costs Forecast

Capital costs to implement C2M are projected to total $377 million between 2021 and 2029. These costs include PG&E labor and non-labor costs, which includes external labor, and other non-labor costs – including material, licensing, and AFUDC.

TABLE 6-13
CAPITAL NOMINAL COST FORECAST – C2M
(CONSTANT 2023 MILLIONS OF DOLLARS)

Line No.	Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
1	PG&E Labor Costs	$0.11	$0.53	$7.11	$2.78	–	$5.65	$17.92	$17.20	$20.80	$6.24	$78.32
2	Non-Labor Costs	$0.73	$6.26	$25.14	$33.40	–	$25.02	$66.01	$66.32	$65.96	$9.43	$298.27
3	Contractor Costs	$0.73	$1.03	$17.38	$18.73	–	$23.11	$58.14	$52.46	$48.83	$9.43	$229.83
4	License/Material/AFUDC/Other	$0.01	$5.23	$7.76	$14.67	–	$1.91	$7.87	$13.87	$17.13	–	$68.44

The implementation of C2M is an exceptionally large and complex undertaking—larger than both the BCS and CC&B 25.1

[14] PG&E estimated the high cost for C2M at $664.1 million.

[15] PG&E is not seeking to recover $2 million in expenses incurred in 2020-2022.

implementations—and will require support from internal PG&E resources as well as external partner resources, including system implementation contractors, to achieve a successful implementation. The majority of both PG&E and vendor resources will be concentrated in the Build and Test phases of the C2M project, which will involve developing the system to suit PG&E’s specific needs and facilitating its successful integration with PG&E’s existing environments. Additional costs associated with the C2M implementation include materials, contracts, and licensing costs associated with the initiative.

b. Nominal Expense Forecast

The one-time expense costs associated with the implementation of C2M total $82.1 million between 2021 and 2030. These include both labor costs to support the program’s implementation, as well as non-labor costs such as material and licenses.

TABLE 6-14
NOMINAL EXPENSE COST FORECAST – C2M
(CONSTANT 2023 MILLIONS OF DOLLARS)

Line No.	Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
1	PG&E Labor Costs	$0.22	$0.05	$0.09	–	–	$0.35	$1.51	$1.67	$16.94	$18.27	$39.11
2	Non-Labor Costs	$0.60	$1.15	$0.80	$3.34	$1.95	$8.12	$6.48	$7.55	$9.29	$3.75	$43.03
3	Contractor Costs	$0.60	$1.15	$0.04	$2.92	–	$4.37	$2.68	$3.74	$5.49	–	$21.00
4	License/Material/ Other	–	–	$0.76	$0.42	$1.95	$3.75	$3.81	$3.81	$3.80	$3.75	$22.04

As discussed in Chapter 5, C2M is an umbrella project that consolidates PG&E’s existing customer care and billing systems, and meter data management system, ABS Gas, and BCS Electric. The scale and scope of this transition inform PG&E’s projections for expense costs, which include costs of change management, training, cut-over execution, and project management. Change management and organizational readiness costs, in particular, drive C2M expense costs, due to the high number of users and processes impacted by the new system. C2M expense costs also include costs to execute data conversion and clean-up. PG&E will utilize additional resources in its

Billing Operations, Customer Contact, and IT organizations to supplement its teams in the Test, Deploy, and Stabilize phases. Non-labor expense costs include many of the same categories as capital expenses, and also include support activities that aren't associated with capitalized costs. Expense costs will include costs incurred during the transition and stabilization periods of the initiative, in particular.

c. Contingency

PG&E estimated contingency for C2M using the same process as BCS and CC&B 25.1, as described above. The estimated contingency associated with the C2M implementation is $49 million, which represents 13 percent of total forecasted capital costs. This contingency is derived from execution risks associated with the initiative's implementation schedule, specifically the costs associated with the extension of several different phases of implementation. These are the costs of the expected value of the extension or delay to various phases of PG&E's implementation plan. These include the costs of a Build or Test phase extension, a delay to the start of the build phase, or a delay to any other part of the critical path of the implementation.

6. Ongoing Costs

To comprehensively evaluate the lifetime benefit-cost ratio of the Billing Modernization Initiative, costs associated with operating and maintaining each of the three systems must also be incorporated. PG&E derived the BCS ongoing costs from estimates for the costs to license the system, in addition to labor costs required to support and maintain it. Ongoing costs for BCS are forecast to be $4 million per year and are applied in each year of BCS's anticipated useful life, which includes 2025-2029. In 2025 and 2029, ongoing costs are prorated according to the planned BCS go-live month in 2025 and retirement month in 2029, which aligns with C2M's planned go-live. The CC&B 25.1 and C2M ongoing costs are forecast to be $17.97 million per year and $16.85 million per year, respectively. CC&B 25.1 ongoing costs are more expensive than C2M ongoing costs because of the costs to maintain customizations in 25.1 and are incurred between 2026 and 2029. Both estimates were derived by extrapolating from current ongoing costs associated with CC&B 2.4, and they include costs to maintain and support hardware, software, and integrations, as well as licensing costs. C2M ongoing costs begin in 2029 and end in 2042. Ongoing costs are pro-rated in beginning and ending years to reflect partial year operation.

F. Benefits Cost Ratio and Discussion

1. Final Benefit-Cost Ratio

The business case to modernize PG&E's billing systems is urgent and the risks to operations from inaction are substantial. The age of the current CC&B system places it outside of support from Oracle and the complex billing system, ABS, is operating far beyond its intended boundaries. With increasingly complex rates and increasing cybersecurity threats, the risks posed by remaining on these systems grow with each passing year.

By conducting a rigorous cost-benefit analysis and targeting only the most defensible benefits with clear supporting data, PG&E has sought to develop a prudent technology strategy. The Cost-Benefit Analysis comprehensively evaluates all benefits associated with the Initiative and maintains a high level of analytical rigor. CIS upgrades like the Billing Modernization Initiative often primarily aim to address technology obsolescence, system instability, and business process risks. Therefore, CIS upgrades may not always require a benefit to cost ratio equal to or greater than 1.0 to be justified as a prudent investment.[16] The CBA and the ratios it produces only include implementation costs for which PG&E is seeking recovery.

The cost-benefit analysis for the whole Billing Modernization Initiative results in a benefit-cost ratio of 0.31 when discounted at PG&Es WACC of 7.8 percent.[17] Discounting at the Social Rate of Time Preference (SRTP) of 2 percent yields a benefit-cost ratio of 0.48.

The third (final) upgrade, C2M, yields a benefit-cost ratio of 0.50 when discounted at the PG&E WACC and a ratio of 0.71 when discounted at the

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16 See, e.g., A.16-09-001, Exhibit SCE-04, Vol. 3, p. 48, lines 4-26.

17 PG&E AL 4813-G/7046-E, p. 3.

SRTP. This result reflects that the majority of the distribution of financial benefits across systems are realized by the C2M upgrade. This result best represents the financial benefit cost ratio of PG&E's moving to a current generation billing system, because it does not take into account the costs or benefits of the separate but necessary stabilization upgrades.

The upgrades from ABS Electric to BCS, and CC&B 2.4 to CC&B 25.1, both result in a benefit-cost ratio of 0.02 when discounted at PG&E's WACC, and discounting at the social rate of time preference also yields a benefit-cost ratio of 0.03 for the BCS upgrade and 0.02 for the CC&B 25.1 upgrade. While both upgrades carry relatively lower financial benefits, both upgrades are required for stabilization and risk mitigation relating to the billing systems.

As discussed in Chapter 4, PG&E chose to pursue the three-stage Billing Modernization project because it best reduces risk to PG&E operations while enabling financial benefits that represent a significant portion of project costs. In doing so, PG&E has identified a cost-effective strategy that stabilizes its systems in the near term and realizes operational efficiencies and real savings in the intermediate to long term.

TABLE 6-15
FORECASTED BENEFIT-COST-RATIO – BY SYSTEM
(MILLIONS OF DOLLARS, NOMINAL)[(a)]

Line No.		Billing Modernization	BCS	CC&B 25.1	C2M
1	Total Nominal Project Capital Costs	$584	$117	$91	$377
2	Total Nominal Project Expense Costs	92	3	9	80
3	Nominal Project Contingency	85	8	28	49
4	Total Nominal Project Costs	$761	$128	$128	$506
5	Nominal Ongoing Costs	$298	$18	$61	$219
6	Total Nominal Project Benefits	$596	$4	$5	$588
7	Project Benefit-Cost Ratio (Nominal)[(b)]	0.56	0.03	0.02	0.81
8	Project Benefit-Cost Ratio (WACC-Discounted)	0.31	0.02	0.02	0.50

(a) Note that cost figures in this table only reflect costs for which PG&E is seeking (or is planning to seek) recovery; they do not include 2020-2022 expense costs.

(b) Row 7 is calculated with the following equation: row 7 = row 6 / (row 4+row 5).

2. Discount Rates Applied

A recent decision in Rulemaking (R.) 20-07-013 considered the value of utilizing multiple discount rates to evaluate programs (in that specific case, mitigations). The Commission noted that it is difficult to determine which discount rates are most appropriate for a given program, such as a social rate of time preference vs utility financial metrics such as the weighted average cost of capital.[18]

By considering multiple discount rates, PG&E acknowledges that the present value of a program's future benefits may be different when evaluated from a lens of customer time preference versus traditional utility financials. Especially in the case of this program where the impact of the Billing Modernization Initiative will deliver benefits to customers by decreasing the issues with complex bills and delayed bills through moving to a new supported CIS and the future move to C2M (which will integrate an MDM). Therefore, PG&E has evaluated the program both in line with the CPUC's chosen rate of the Social Rate of Time Preference (as defined by the United States Office of Management and Budget (OMB))[19] to represent customer preferences and then PG&E's pre-tax WACC to represent traditional utility financial preferences and also aligns with the discount rate used by PG&E for its 2024 RAMP filing.[20]

3. Sensitivity Analysis to Discount Rates

As part of the cost-benefit analysis efforts undertaken, PG&E has performed an additional sensitivity analysis to demonstrate the relationship between discount rates applied and the resulting benefit-cost ratio. This sensitivity analysis aids in examining the potential risks associated with the

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18 D.24-05-064, pp. 102-103. The CPUC decision also references a hybrid discount rate however this hybrid discount rate is contextualized in part to the value of traditional utility infrastructure projects such as grid reliability and would apply different discount rates to the numerator and denominator. Given this program's focus is not that of a traditional grid program we do not feel that this discount rate makes sense to apply.

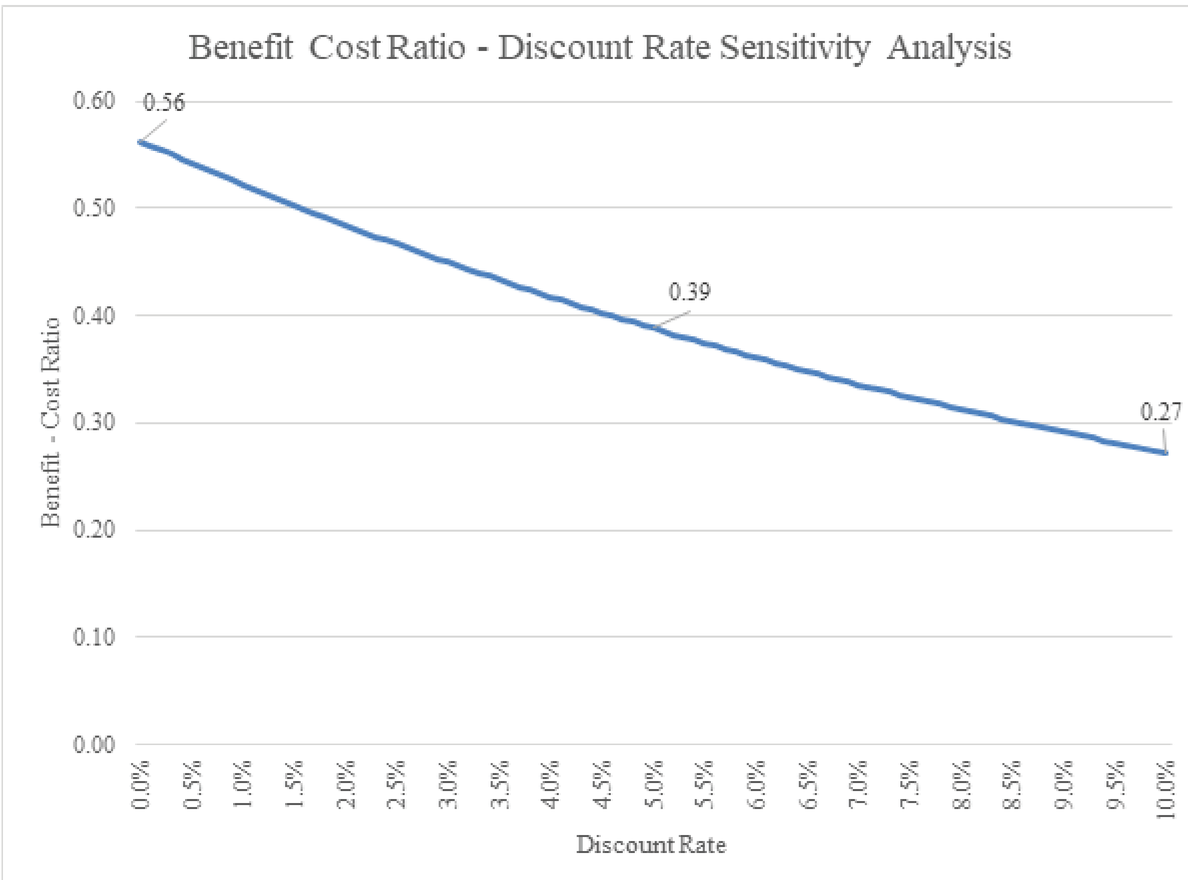
19 OMB, Circular No. A-4, Current and Historical Estimates of the Social Rate of Time Preference (Nov. 9, 2023), available at: https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4DiscountHistory.pdf (accessed Oct. 16, 2024).

20 A.24-05-008, p. 2-39, line 21 to p. 2-40, line 2.

investments under varying economic conditions, interest rate environments, and project-specific factors.

The sensitivity analysis conducted shows a range of benefit-cost ratios, ranging from a high of 0.56 when cash flows are not discounted, down to 0.27 when discounted at 10 percent, a rate well in excess of PG&E's current weighted average cost of capital of 7.8 percent.

FIGURE 6-6
BENEFIT COST RATIO – DISCOUNT RATE SENSITIVITY



G. Conclusion

This chapter includes an evaluation of the benefits and costs of all three projects of the Billing Modernization Initiative. The benefits quantified here total $596.4 million and represent a subset of all benefits of the initiative. The benefit profile of the first two stages of the Billing Modernization Initiative, in particular, is weighted towards benefits from the reduction of catastrophic risk. The final stage—the implementation of C2M—is projected to lead to the majority quantified financial benefits. The analysis discussed in this chapter supports the conclusion that the wholistic benefits—including those quantified in the CBA and those not quantified, like risk reduction—of the Billing Modernization Initiative outweigh the costs.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

RESULTS OF OPERATIONS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
RESULTS OF OPERATIONS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
RESULTS OF OPERATIONS

This chapter presents Pacific Gas and Electric Company's (PG&E) 2023-2030 revenue requirements for its Billing Modernization Initiative. The revenue requirements for the Billing Modernization Initiative are calculated using methods approved by the California Public Utilities Commission (CPUC or Commission) and should be adopted.

A. Summary of Request

PG&E calculated the revenue requirements for 2023 through 2030 using the mini-Results of Operations (RO) model. The mini-RO model compiles all capital costs and expenses as presented in Chapter 5 to calculate the revenue requirements that PG&E needs to recover for work presented in this Billing Modernization Application (Application), the elements of which are further described in Section C of this chapter.

The total revenue requirement for the Billing Modernization Initiative requested in this filing for the period 2023-2030 is $393.1 million, excluding Revenue Fees and Uncollectibles (RF&U). It was calculated based on PG&E's cost forecast of $669.2 million in capital expenditures and $96.5 million in operating expenses presented in Chapter 5, while excluding expense costs prior to January 1, 2023. These estimates are based on recorded costs through July 2024 and forecasted costs through 2030.

Table 7-1 presents the revenue requirements for 2023-2030 associated with the Billing Modernization Initiative using the methodology and assumptions described in this section.

TABLE 7-1
REVENUE REQUIREMENTS EXCLUDING RF&U
(MILLIONS OF DOLLARS)

Line No.	Description	2023	2024	2025	2026	2027	2028	2029	2030	Total
1	Capital Revenue Requirement	–	1.7	10.0	36.8	59.2	53.7	29.8	120.1	311.2
2	Expense Revenue Requirement	0.8	3.9	7.0	12.0	7.1	8.2	23.3	19.6	81.9
3	Total Revenue Requirement	0.8	5.7	17.0	48.8	66.3	61.9	53.1	139.7	393.1

At the end of this chapter, Table 7-4 presents the revenue requirement by functional area.

B. Elements of the RO Calculation

1. Expenses

In this Application, PG&E seeks to recover a total expense revenue requirement of $81.9 million excluding RF&U, for the Billing Modernization Initiative costs presented in Chapter 5. This amount is associated with project activities including third-party support for system integration, PG&E labor, temporary staffing increases, licensing costs, and contract costs. Please refer to Chapter 5 for a description of project costs.

2. Capital Related Inputs

a. Capital Expenditures

Capital expenditures are incurred when PG&E spends funds on capital projects that are necessary to install new utility plant or replace its existing utility plant. This Application includes $669.2 million of capital expenditures from 2023-2030 for the Billing Modernization Initiative.

b. Capital Additions

As capital work is performed, the capital expenditures, net of removal costs, are accumulated and recorded to Construction Work in Progress (CWIP) until the project is operational and providing utility service. While in CWIP, projects that last over 30 days accrue an Allowance for Funds Used During Construction (AFUDC). Projects that last less than 30 days do not accrue AFUDC and are treated as "operative as installed." When a specific capital project becomes operational, the CWIP balance is transferred to plant-in-service, and the capital expenditures and associated AFUDC become part of capital additions. Once a project is transferred to plant-in-service, the associated capital additions are included in rate base and a revenue requirement is calculated.

The Billing Modernization Initiative has multiple associated operative dates for when a project's capital expenditures will transfer to plant-in-service for rate base recovery. Table 7-2 below provides the forecast operative dates for each of the three distinct systems, specifically Billing Cloud Service (BCS), Customer Care and Billing (CC&B) 25.1, and Customer-to-Meter (C2M).

TABLE 7-2
BILLING MODERNIZATION INITIATIVE
FORECAST OPERATIVE DATES

Line No.	System	Forecast Operative Date[(a)]	
		Software	Hardware
1	BCS	7/1/2025	n/a (no hardware)
2	CC&B 25.1	10/1/2026	12/1/2024; 9/1/2026
3	C2M	6/1/2024; 12/1/2029	6/1/2024

(a) Multiple operative dates for a program indicate separate discrete scopes of work with unique schedules.

c. Cost of Removal and Gross Salvage

The portion of capital expenditures associated with the retirement of existing assets, known as removal cost, is recorded in Accumulated Depreciation (AD), which decreases the amount of AD in rate base. Gross salvage generally refers to any value received for retired plant and increases the amount of AD in rate base. In this application, there are no forecast retirements, cost of removal, or gross salvage as the forecast capital expenditures in this filing are capital additions only.

C. Capital Revenue Requirement Components

CPUC Resolution E-3238 provides that "[i]n addition to direct expenses, utilities could also book capital-related costs such as depreciation and return on capitalized additions."[1] Consistent with this resolution, PG&E's capital-related revenue requirement includes depreciation expense, a return on rate base, related federal and state income taxes, and property taxes. The various capital-related components of the RO calculation are discussed below.

In this Application, PG&E seeks recovery of a total capital-related revenue requirement of $311.2 million excluding RF&U, which is associated with the forecast capital expenditures of $669.2 million.

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1 Resolution E-3238, p. 2.

1. Depreciation

Depreciation is included in the revenue requirement calculation, as both depreciation expense and through AD, a component of rate base. Depreciation expense forecast is calculated per the straight-line, remaining life method (in accordance with the Commission's Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals[2]) using Commission approved rates from depreciation accrual rate schedules effective during the period for which the revenue requirement calculations are made. Depreciation expense forecast is calculated by multiplying the forecasted end of month plant in service balance by the corresponding book depreciation rates.

In this Application, PG&E used the depreciation rates adopted in PG&E's General Rate Case (GRC) for each asset type. See below table for each type of asset associated with its corresponding 2023 GRC Decision (D.) 23-11-069 adopted depreciation rate.[3]

TABLE 7-3
DEPRECIATION RATE BY ASSET TYPE

Line No.	Asset	Asset Class	Asset Life (Years)	Depreciation Rate
1	Software	CMP30302	5	17.19%
2	Software Computer Information System	CMP30304	13	10.05%
3	Other Machines and Computer Equipment	CMP39101	5	24.87%

2. Rate of Return on Rate Base

The forecasted rate base is calculated using utility plant less adjustments for deferred taxes, depreciation reserve, and other rate base components. Utility plant consists of the forecast cost of investment in plant and equipment for rendering utility services. In developing the forecasted rate base associated with utility plant for purposes of this filing, certain

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2 Commission Standard Practice U-4: Determination of Straight-Line Remaining Life Depreciation Accruals, Revised January 3, 1961, p. 11.

3 Depreciation rates will be updated with those adopted by the Commission in the 2027 GRC.

deductions are made. A deduction is made for the accumulated deferred income taxes associated with these assets. These deferred income taxes primarily result from the Modified Accelerated Cost Recovery System (MACRS) tax depreciation method.

Rate base is also reduced by the amount of depreciation reserve (i.e., the AD already taken in prior years). PG&E multiplied the currently adopted composite Rate of Return (ROR) by the weighted average rate base forecast for each year to calculate the Net for Return. This calculation uses the ROR of 7.28 percent and capital structure adopted in PG&E's 2023 authorized Cost of Capital (COC) decision[4] for years 2023, and 2026 through 2030.

For the years 2024 and 2025, PG&E uses the increased ROR of 7.80 percent which was approved in Advice Letter (AL) 4813-G/7046-E[5] (COC Formula Adjustment Mechanism), increasing the ROR for the remaining 2023 Test Year COC cycle (2024-2025) pursuant to D.08-05-035.[6] PG&E will update the return on rate base to the authorized ROR if the Commission adopts a new ROR in Track 2 of the 2023 COC proceeding, future COC proceeding, or other CPUC docket. PG&E will update the return on rate base to the authorized ROR either through this proceeding or via a Tier 1 advice letter filing.

3. Income Taxes

This section describes the assumptions and calculations used in the revenue requirement calculation for forecasted Federal Income Tax (FIT), the associated deferred FIT, and California Corporation Franchise Taxes (CCFT or state income tax) expenses.

PG&E estimates current FIT and CCFT on net operating income before income taxes. Current FIT expense forecast is the product of the currently effective corporate income tax rate (21 percent) and forecasted federal taxable income. Likewise, current state income tax expense is the product of the statutory rate (8.84 percent) and the forecasted state taxable income.

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4 D.23-01-002, p. 1.

5 PG&E AL 4813-G/7046-E (Dec. 22, 2023), p. 4.

6 D.08-05-035, pp. 21-22, Ordering Paragraph 2.

Additionally, for FIT, a deduction for prior year CCFT[7] is also factored into the FIT calculation and given flow-through treatment.

a. FIT and CCFT Depreciation Adjustments

PG&E follows MACRS and Asset Depreciation Range (ADR)[8] guidelines for classifying capital additions and calculating federal and state tax depreciation, respectively. Federal MACRS tax deductions are computed on a normalized basis. This allows PG&E to recognize the timing differences between book tax and these federal tax deductions. This difference multiplied by the federal tax rate is called deferred FITs and is included as an adjustment to current federal tax expense and a credit to rate base. State income taxes are generally calculated using flow-through treatment, whereby customers receive an immediate benefit from the use of accelerated state tax deductions, such as state depreciation calculated under ADR. For flow-through treatment, there is no deferred state taxes and therefore no associated deduction to rate base.

b. FIT and CCFT Capitalized Software Adjustments

For federal tax purposes, under the 2017 Tax Cuts and Jobs Act (TCJA),[9] beginning in 2022, self-developed software under Internal Revenue Code (IRC) Section 174 must be capitalized and amortized over 5 years generally[10] for federal purposes. For state tax purposes, California did not conform to the Section 174 changes from the 2017 TCJA and therefore, such self-developed costs continue to be deductible for state tax purposes. To the extent this self-developed software is capitalized differently for book purposes, a timing difference

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7 Section 801 of the Tax Reform Act (TRA) of 1986 requires taxpayers such as PG&E to deduct CCFT on a privilege year basis—i.e., prior year CCFT becomes deductible on the first day of each new year, when PG&E exercises its franchise privilege to do business in California. For example, CCFT estimated for 2022 (income year) would be deductible for FIT purposes on January 1, 2023 (privilege year).

8 Uses Sum of Years Digits method.

9 IRC Section 174 as modified by Section 13206 of the TCJA.

10 Foreign self-developed software is capitalized and amortized over 15 years.

is created in the year software is ready for service. This book/tax timing difference is reversed with book depreciation of the capitalized software.

For Federal (pre-2022) and California tax purposes, for self-developed software costs that are deducted, PG&E uses flow-through treatment for these costs. For federal (post-2021) tax purposes, self-developed software costs that are required to be capitalized and amortized are given normalization treatment.

Also, IRC Section 167(f) requires taxpayers to capitalize and depreciate certain software acquired in the open market. To the extent this software is expensed for book purposes, a timing difference is created in the year the software is ready for service. The timing difference reverses with tax depreciation of the capitalized software. The tax effects of Section 167(f) timing differences follow the normalized tax accounting treatment.

4. Property Taxes

Property tax calculations are determined by multiplying the forecasted taxable Plant Less Depreciation (Net Plant) by the composite property tax factor. The composite property tax factor is based on PG&E's 2023 GRC levelized average property tax factor for attrition years 2024 through 2026. The property tax factor is comprised of the adjusted base year market to cost ratio multiplied by the composite tax rate. The adjusted market-to-cost ratio is the relationship between the most current assessment (adjusted) and the taxable Net Plant.

D. Common Cost Allocation

D.23-11-069 adopted a methodology of allocating certain Common, General, and Intangible (CGI) costs among other functional areas within PG&E. In this Application, the Billing Modernization Initiative capital costs are considered CGI costs and subject to common cost allocation. Similar to PG&E's practice adopted in its 2023 GRC, these costs are allocated to different functional areas (Electric Distribution, Gas Distribution, Electric Generation, Gas Transmission and Storage, and Electric Transmission) using the authorized Operations and Maintenance labor allocation factors adopted in D.23-11-069. The revenue requirement presented in this chapter for years 2023 through 2030 incorporates the allocation of the CGI portion of the revenue requirement into the separate functional areas under the CPUC jurisdiction (all functional areas, excluding Federal Energy Regulatory Commission jurisdictional Electric Transmission).

E. Cost Recovery

PG&E proposes to recover a total revenue requirement of $393.1 million (excluding RF&U) for the Billing Modernization Initiative costs presented in Chapter 5. In this proceeding, the total revenue requirement covers 2023 through 2030. PG&E proposes to recover ongoing revenue requirements past 2030, including the forecast capital additions and the associated plant that remains undepreciated, in its future GRCs beginning with the 2031 GRC Application.

The revenue requirement calculation in this filing excludes RF&U and Interest. PG&E proposes to recover the forecast revenue requirement described herein upon receipt of a final decision from the CPUC, and prior to that record actuals to the proposed new Billing Modernization Memorandum Account (i.e., actual expenses plus the capital revenue requirement based on actual capital costs).

PG&E's final cost recovery will include interest expense based on the applicable interest rates, timing of the final decision and the approved cost recovery. PG&E will accrue interest associated with the authorized revenue requirement based on the latest available interest rates.[11]

Additional details on cost recovery are provided in Chapter 8, "Cost Recovery."

F. Conclusion

PG&E respectfully requests that the Commission adopt a total revenue requirement of $393.1 million (excluding RF&U) for the Billing Modernization

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11 PG&E proposes to use the "interest rate on 11 three-month Commercial Paper for the previous month, as reported in the 12 Federal Reserve Statistical Release, G.13, or its successor", consistent with the methodology used for recent Wildfire Mitigation and Catastrophic Event filings (see for example Electric Preliminary Statement Part G, CEMA, https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_G.pdf; Gas Preliminary Statement Part AC, CEMA, https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_AC.pdf (as of Nov. 21, 2022)).

Initiative costs presented in Chapter 5. The revenue requirement set forth in this Application was calculated using the RO Model for separately funded rate applications and was based on the forecast costs presented in Chapter 5. The detailed revenue requirement calculation is provided in the workpapers supporting this chapter.

TABLE 7-4
REVENUE REQUIREMENT BY FUNCTIONAL AREA – SUMMATION OF ALL YEARS (2023-2030)
(MILLIONS OF DOLLARS)

Line No.	Description	Electric Generation	Electric Distribution	Gas Distribution	Gas Transmission and Gas Storage	Total Functional Areas
1	Capital Revenue Requirement	$31.3	$157.2	$83.1	$39.6	$311.2
2	Expense Revenue Requirement	9.2	40.9	21.6	10.3	81.9
3	Total Revenue Requirement (Excluding RF&U)	$40.5	$198.1	$104.7	$49.9	$393.1

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

COST RECOVERY

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COST RECOVERY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
COST RECOVERY

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) proposal for tracking, recording, and recovering the costs of PG&E's Billing Modernization Initiative.

PG&E's total revenue requirement forecast for the Billing Modernization Initiative is included in Chapter 7. Adoption of PG&E's cost recovery proposal presented in this chapter will assure timely recovery of the reasonable costs of the Billing Modernization Initiative.

In summary, PG&E requests that the California Public Utilities Commission (Commission):

- Approve PG&E's motion, which PG&E plans to file promptly after assignment of an application number, to establish Billing Modernization Memorandum Accounts (BMMAs)[1] and authorize PG&E to track and record its actual revenue requirements for its costs from January 1, 2023 through the effective date of the final decision on this application;
- Authorize PG&E to recover all amounts recorded to the BMMA through the next available rate change or the next Annual Electric True-Up (AET) and Annual Gas True-Up (AGT) following the Commission's decision on this Application; and
- Authorize PG&E to recover through rates on a forecast basis the adopted revenue requirements from the effective date of the final decision on this Application through 2030.

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[1] PG&E proposes to establish two accounts, BMMA-G for gas and BMMA-E for electric, together referred to as the BMMAs.

B. Cost Recovery

1. Summary of Costs

As discussed in Chapter 7, PG&E requests authorization to recover $393.1 million in total 2023--2030 revenue requirements,[2] of which $81.9 million is expense revenue requirement and $311.2 million is capital revenue requirement. These amounts are incremental and not included in costs recorded in any other balancing accounts, or in revenue requirements adopted by the 2023 General Rate Case (GRC) Decision, Decision (D.) 23-11-069.

2. Memorandum Account

In its 2023 GRC Application (A.) 21-06-021, PG&E requested rate recovery for its Billing System Upgrade project. On November 17, 2023, the Commission issued D.23-11-069, which adopted a forecast of $0 for the BillingSystem Upgrade, but allowed PG&E to file a separate application seeking cost recovery for the upgrade project. [3] Contemporaneously with this application, PG&E is filing a *Motion to Establish Billing Modernization Memorandum Accounts* (gas and electric), to request that the Commission authorize PG&E to track and record its actual revenue requirements for its Billing Modernization Initiative costs beginning on January 1, 2023 (the GRC effective date) through the effective date of the final decision on this application. Upon approval of the motion, PG&E will file a Tier 1 advice letter to establish the BMMAs, effective as of January 1, 2023, and track Billing Modernization Initiative project costs in these accounts through the effective date of a final decision on this application.

PG&E proposes, upon a final decision on this application, to transfer the balance of the BMMAs to the applicable revenue adjustment mechanisms for recovery from customers in rates[4] through the next available rate change

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2 As discussed in more detail below and upon approval by the Commission, PG&E would record and recover its actual revenue requirement from January 1, 2023 through the final decision effective date in the BMMAs and then recover its forecast revenue requirement from the final decision effective date through 2030.

3 Decision (D.) 23-11-069, p. 548-549.

4 The related revenue adjustment mechanisms and rate components are identified and discussed in Section 3 below.

or the next AET and AGT. Actual costs recorded to the BMMAs up to the adopted forecast amounts in this Application shall be deemed reasonable since the Commission has approved the adopted amounts.[5] Therefore, PG&E seeks cost recovery of the balances recorded in the BMMAs through this Application. All costs recorded to the BMMAs and recovered through rates would be subject to the Commission's final decision on this Application authorizing revenue requirements to be recovered in rates. PG&E proposes that the total of the actual costs recorded to the BMMAs and the amounts recovered on a forecast basis from the final decision date through 2030 may not exceed the total adopted amounts.

3. Recovery of Functional Revenue Requirements

a. Existing Revenue Adjustment Mechanisms To Be Used to Recover Billing Modernization Initiative Project Adopted Revenue Requirements

PG&E proposes to recover through rates the following: (1) the balance in the BMMAs for the period from January 1, 2023 through the date of a final decision; and (2) the forecast revenue requirement for the period from the date of a final decision through 2030. As described in Chapter 7, the Billing Modernization Initiative project costs are common costs, the recovery of which is allocated to all functional areas.[6]

Chapter 7 also describes PG&E's proposal to allocate these common costs across PG&E's base GRC revenue requirements as approved in its 2023 GRC decision. Specifically, PG&E proposes to use its existing revenue adjustment mechanisms to recover the Billing Modernization Initiative project adopted revenue requirements through the related rate components/revenue adjustment mechanisms over which common costs are allocated. PG&E will utilize the existing accounting procedures used to record and recover the adopted GRC revenue requirements to similarly record and recover the adopted Billing

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5 Actual costs beyond January 1, 2023 recorded to the BMMAs, up to the adopted forecast amounts, through the date of the final decision in this Application will be recovered from customers, rather than the adopted amounts.

6 As described in Chapter 7, the Federal Energy Regulatory Commission jurisdictional portion of the allocated revenue requirements is not included in this Application.

Modernization Initiative revenue requirements. The tables below indicate the accounts where the adopted functional revenue requirements will be recorded.

TABLE 8-1
ELECTRIC REVENUE ADJUSTMENT MECHANISMS FOR RECOVERY BY COMPONENT

<table>
<tr><th>Line No.</th><th>Component</th><th>Revenue Adjustment Mechanisms for Recovery</th><th>Preliminary Statement</th></tr>
<tr><td>1</td><td>Electric Distribution</td><td>Distribution Revenue Adjustment Mechanism</td><td>ELEC_PRELIM_CZ</td></tr>
<tr><td>2</td><td rowspan="3">Electric Generation</td><td>Energy Resource Recovery Account</td><td>ELEC_PRELIM_CP</td></tr>
<tr><td>3</td><td>New System Generation Balancing Account</td><td>ELEC_PRELIM_FS</td></tr>
<tr><td>4</td><td>Portfolio Allocation Balancing Account</td><td>ELEC_PRELIM_HS</td></tr>
</table>

TABLE 8-2
GAS REVENUE ADJUSTMENT MECHANISMS FOR RECOVERY BY COMPONENT AND CUSTOMER CLASS

<table>
<tr><th>Line No.</th><th>Component</th><th>Revenue Adjustment Mechanisms for Recovery</th><th>Preliminary Statement</th></tr>
<tr><td>1</td><td rowspan="2">Gas Distribution</td><td>Core Fixed Cost Account (CFCA), Distribution Subaccount</td><td>GAS_PRELIM_F</td></tr>
<tr><td>2</td><td>Noncore Customer Class Charge Account (NCA), Distribution Subaccount</td><td>GAS_PRELIM_J</td></tr>
<tr><td>3</td><td rowspan="2">Gas Transmission and Storage</td><td>CFCA, Core Cost Subaccount</td><td>GAS_PRELIM_F</td></tr>
<tr><td>4</td><td>NCA, Noncore Subaccount</td><td>GAS_PRELIM_J</td></tr>
<tr><td>5</td><td rowspan="2">Gas Local Transmission</td><td>CFCA, Core Cost Subaccount</td><td>GAS_PRELIM_F</td></tr>
<tr><td>6</td><td>NCA, Local Transmission Subaccount</td><td>GAS_PRELIM_J</td></tr>
</table>

C. Conclusion

PG&E requests that the Commission approve the cost recovery described in this chapter for the reasons described above. Specifically, PG&E requests that the Commission:

- Approve PG&E's motion, which will be filed following the assignment of an application number, to establish the BMMAs and authorize PG&E to track and record its actual revenue requirements for its costs from January 1, 2023 through the effective date of the final decision on this application;
- Authorize PG&E to recover all costs recorded to the BMMAs through the next available rate change or the next AET and AGT following the Commission's decision on this Application; and

- Authorize PG&E to recover through rates on a forecast basis the adopted revenue requirements from the date of a final decision through 2030.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENT OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MATT BRIEL

Q 1 Please state your name and business address.

A 1 My name is Matt Briel, and my business address is Pacific Gas and Electric Company (PG&E), 2740 Gateway Oaks Dr. Sacramento, CA 95833.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I have been leading major customer service improvements for the past six years including the implementation of the Contact Center Service Platform and governance of the PGE.com upgrade and billing modernization. For the past ten years I have provided business leadership to PG&E's customer care technology implementations and operations. My current title is Director of Performance Improvement and I have held this role for 6 years.

Q 3 Please summarize your educational and professional background.

A 3 After graduating with a bachelor's degree in Managerial Economics from the University of California at Davis I spent 11 years working in Contact Centers and managing contact center technology for AT&T. I next spent 6 years with Intel Corporation leading global telecom and network services procurement before joining PG&E. While at PG&E I have lead contact center Workforce Management and Customer Care Technology. I was the General Rate Case witness to the 2023 Customer Service technology chapter.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Billing Modernization Initiative Application:

- Chapter 1, "Executive Summary and Background";
- Chapter 3, "Billing Systems and Risk Management":
  - All sections except Section C.3; and
- Chapter 6, "Description of Cost Benefit Analysis."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MATTHEW HEDGES

Q 1 Please state your name and business address.

A 1 My name is Matthew Hedges, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Senior Manager of Billing Technology in the Customer Systems and Solutions organization. As such, I oversee technical team members of the Billing Modernization Initiative who review and deliver solutions for the Initiative projects.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Industrial Engineering and Operations Research from the University of California, Berkeley in 2003. I joined PG&E in 2003 as a Programmer Analyst/Developer on the Advanced Billing Solutions team, where I spent approximately nine years.

I transitioned to the position of Application Development Supervisor in the Meter to Cash Systems department in 2012, at which time I was in charge of supervising development teams responsible for bill printing, payments, revenue reporting, and complex billing.

I transitioned to the position of Manager of Planning and Project Management in the Meter to Cash Systems department in 2016, at which time I was responsible for the oversight of department projects and enhancements, as well as the department representative for PG&E's annual planning process.

In 2020, I transitioned to the position of Manager of the Customer team in the Meter to Cash Systems department, at which time I was responsible for the operations, development, and delivery of solutions for PG&E's customer information and billing systems.

In 2023, I assumed my current role.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Billing Modernization Initiative Application:

- Chapter 4, "Target State Billing System"; and
- Chapter 5, "Billing Modernization Initiative Implementation."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DAVID LO

Q 1 Please state your name and business address.

A 1 My name is David Lo, and my business address is Pacific Gas and Electric Company (PG&E), 5555 Florin Perkins Road, Sacramento, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Director of the Cybersecurity Risk Management department for PG&E's Enterprise Protection organization. This includes overseeing the core functions of Cybersecurity Risk Management, which entails working with business stakeholders to identify the company's cybersecurity risks and developing enterprise strategies to appropriately manage those risks.

Q 3 Please summarize your educational and professional background.

A 3 I have over 17 years of experience working in the fields of technology, risk management, compliance, and cybersecurity within the utility industry.

I have spent the last 16 years in various leadership roles, including 10 years within PG&E's Cybersecurity organization. I hold a Bachelor of Arts degree in History from California State University, Fresno, and a Master of Business Administration degree from University of Phoenix. In addition, I hold a Certified Information Security Manager and Certified Risk and Information System Control certifications.

Q 4 What is the purpose of your testimony?

A 3 I am sponsoring the following testimony in PG&E's Billing Modernization Initiative Application:

- Chapter 3, "Billing Systems and Risk Management":
  - Section C.3.

Q 5 Does this conclude your statement of qualifications?

A 4 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KELLIE REEM

Q 1 Please state your name and business address.

A 1 My name is Kellie Reem, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I have been a Director in the Meter to Cash team in the Customer Systems and Solutions organization since March 2020. I was previously the Information Technology (IT) Director for the Billing Modernization Initiative. I have worked in the Meter to Cash organization since 2011. As a leader in IT, I am responsible for the overall Customer Information System (CIS) operations and delivering the best customer technology solutions for our customers.

Q 3 Please summarize your educational and professional background.

A 3 I earned my Bachelor of Science degree in Finance from Cal State East Bay, a Master Business Administration degree in Operations Management, and a Project and Systems Management Graduate Certificate from Golden Gate University. For over 25 years at PG&E, I have held various technical and key leadership roles. In 2001, I was part of the CIS Replacement Project, leading a team in implementing new PG&E Rates and Energy Statements in our new billing system. From 2002 to 2011, I was a Product Owner and a Manager in the SmartMeter initiative and Interval Billing programs.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Billing Modernization Initiative Application:

- Chapter 2, "Legacy Billing Systems Overview."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SHANNON L. SIMS

Q 1 Please state your name and business address.

A 1 My name is Shannon L. Sims, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 I am a Cost Recovery and Regulatory Analysis Expert in the Energy Accounting Department at PG&E. My responsibilities include developing testimony in support of proceedings filed at the California Public Utilities Commission on matters related to cost recovery.

Q 3 Please summarize your educational and professional background.

A 2 I received a Bachelor of Science degree in business administration from the University of California at Berkeley. I received my certified public accountant license in the state of California while working for Deloitte & Touche LLP. I began my career with PG&E in 2001 as a Senior Accounting Analyst within the Technical Accounting section of the Controllers' Department. I joined the Regulatory Affairs Department in 2004. In this department, my responsibilities included project managing and drafting PG&E's Annual Electric True-Up and Annual Gas True-Up advice letters. I rejoined the Controllers' Department in 2017 and assumed my current position in 2019.

Q 4 What is the purpose of your testimony?

A 3 I am sponsoring the following testimony in PG&E's Billing Modernization Initiative Application:

- Chapter 8, "Cost Recovery."

Q 5 Does this conclude your statement of qualifications?

A 4 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF LEO YANG

Q 1 Please state your name and business address.

A 1 My name is Leo Yang, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Financial Analyst in the Revenue Requirements and Cost Analysis section of the Finance and Risk Department, where I am responsible for the analysis and preparation of electric and gas operations and maintenance and administrative and general expenses, as well as estimates and studies required for PG&E's various rate cases.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Science in Accounting from San Jose State University in 2011 and a Master of Business Administration from San Francisco State University in 2016. From 2011-2013, I worked at Sony Interactive Entertainment (formerly Sony Computer Entertainment) in the Accounting Department. I started as an Accounting Intern and progressed to a Senior Accounting Analyst. From 2016-present, I have been working at PG&E. In 2016, I started as a Business Finance Analyst supporting Electric Operations in Budgeting and Forecasting. In 2018, I worked as a Senior Business Finance Analyst supporting Corporate Services in Budgeting, Forecasting and the 2020 GRC. In 2020, I worked as an Expert Financial Analyst for the Revenue Requirements team. I supported the Administrative and General expense recovery as a Witness Assistant for the 2023 General Rate Case (GRC), supported Electric Distribution expense recovery for the 2023 GRC, and 2022 Wildfire Mitigations and Catastrophic Events (WMCE) filing as a Witness Assistant/Co-Witness, as well as the 2023 WMCE. Since 2023, I have been working as a Principal Financial Analyst for the Revenue Requirements team.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony PG&E's Billing Modernization Initiative Application:

- Chapter 7, "Results of Operations."

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

GLOSSARY OF KEY TERMS

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX B
GLOSSARY OF KEY TERMS

Acronym/Term	Definition
ABS	Advanced Billing System is the complex customer billing system customized internally by Pacific Gas and Electric Company (PG&E).
AI	Artificial Intelligence
AIS	AIS is an application to generate and manage a six-digit AIS number based on division code and associate it with all Powerspring Gas meters
AIX	Advanced Interactive eXecutive, is a series of proprietary Unix operating systems developed and sold by IBM
AMI	Advanced Metering Infrastructure
AMP	Asset Management Program is an application that stores asset and application information
API	Application Program Interface, a software protocol that allows different applications to communicate
Batch Billing	The system process that selects accounts ready to bill based on the current bill cycle, then processes multiple batches of bill calculations
BCS	Billing Cloud System (BCS) is a modern cloud-based complex customer billing system developed by Oracle
BIA	Business Impact Analysis, used to determine the criticality of a system or process within PG&E
BMI	Billing Modernization Initiative
C2M	Customer to Meter, an Oracle Customer Information System
CARE	California Alternate Rates for Energy: Low-income customers that are enrolled in the CARE program receive a 30-35 percent discount on their electric bill and a 20 percent discount on their natural gas bill.
CC&B	Customer Care & Billing (a legacy Oracle Customer Information System)
CCA	Community Choice Aggregation (CCA) is a program that allows cities, counties and other qualifying governmental entities available within the service areas of investor-owned utilities (IOU), to purchase and/or generate electricity for their residents and businesses.
CCPA	California Consumer Privacy Act
CEC	California Energy Commission
CIS	Customer Information System
COBOL	Common Business Oriented Language
Compatibility Testing	A testing method to ensure application versions can perform operations with each other, thus ensuring compatibility. Additional testing is performed to ensure the applications are functioning as intended.
Contrived Data	Data that has been generated or made up to execute a test case.
CPRA	California Privacy Rights Act
CPUC	The California Public Utilities Commission (CPUC) regulates public utilities in California to ensure safe, reliable, affordable utility services.

Acronym/Term	Definition
	They are responsible for approving recovery of expenditures that will impact customer rates.
CRCR	Customer Revenue Critical Reporting is a customized Oracle Utilities Analytics (OUA) solution that provides certain types of reporting while also providing business users analytic capabilities using CC&B as the primary data source
CTA	Core Transport Agents (CTA) are alternative natural gas suppliers to Local Distribution Companies (LDC) such as PG&E, SoCalGas, SDG&E, and Southwest Gas. CTAs are non-utility suppliers who purchase gas on behalf of customers for their homes or businesses, directly.
DA	Direct Access is a retail electric service option where customers can purchase electricity from a competitive non-utility entity called an Energy Service Provider (ESP). The investor-owned utility is still responsible for the transmission and distribution for Direct Access customers.
DAR	Design Authority Review, a process used to review complex project designs by engaging technical experts from the vendor product team to analyze alternatives
Data Warehouse	A system that collects, stores, and organizes data from multiple sources.
DBA	Database Administrator
DDOS	Distributed Denial of Service – a type of cyber attack
DER	Distributed Energy Resource
DR Testing	Disaster recovery testing, generally performed by executing the steps of a disaster recovery plan by transitioning the production system to the back-up systems in place.
EBIP	Electric Base Interruptible Program
EDI	Electronic Data Interchange, a system by which businesses can exchange information (like bill charges, usage, etc) electronically
EMR	Electric Meter Read. The term is used to define non-interval metering, where meter dial reads are performed monthly for bill calculation.
End to End Testing	A test method where a process is executed from beginning to end. This test method validates that all parts of the process (and system) are working as intended.
ESP	Energy Service Provider – an energy service provider is a non-utility entity that offers electric service to customers within the service territory of an investor-owned utility.
ESXi	VMware ESXi is a software tool that allows multiple virtual machines (server instances) to be created on a server.
EV	Electric Vehicle
EVEE	An application that performs validation, estimation, and editing on interval usage for large commercial and industrial meters (non- SmartMeter).
FAS	Field Automation Service – Used to dispatch field personnel

Acronym/Term	Definition
FERA	Family Electric Rate Assistance Program: Families whose household income slightly exceeds the CARE allowances will qualify to receive FERA discounts, which bills applies an 18% discount on their electricity bill.
Framing	The process to calculate data into buckets by time of use, season, tier, or other usage delimiters.
FSDs	Functional Specification Designs, documents that detail the business and regulatory requirements, desired functionality, data requirements, batch jobs, security and controls requirements (IT controls, SOX, segregation of duties, and business process framework), and the test requirements for each development object
FSTE	Full Scale Test Environment, a production-like environment used to perform tests using full scale data and processing loads.
FTEs	Full Time Equivalents
Functional Testing	A test method to verify that software performs as expected by testing individual functions of the software.
GHG	Green House Gas
GRC	A General Rate Case (GRC) is regulatory process in which a utility requests approval from a public utility commission (such as the CPUC) to adjust its rates to cover operating expenses and infrastructure investments.
HES	A head-end system (HES) is a critical component of advanced metering infrastructure (AMI) systems that collects, stores, processes, and analyzes data from smart meters. HESs are hardware and software that act as a hub for incoming data, verifying it and forwarding it to the meter data management system (MDMS) for further processing.
IBC	Individual Bill Compare
ILM	Information Lifecycle Management is designed to address data management issues, with a combination of processes and policies so that the appropriate solution can be applied to each phase of the data's lifecycle.
Informatica	A vendor that provides integration technologies, enabling systems to communicate with each other.
IorC	Installation or Change Database (I or C database) creates the meter Channel ID that is the identifier in the MV90 system.
IVR	Interactive Voice Response is an automated phone system for customers to obtain information and process transactions through voice and/or keypad input.
IWS	Inbound Web Service, an API technology that is replacing XAIs in the recent Oracle products. The web service stores the configuration that enables access to information by the calling system.
J2EE	Jave 2 Platform, Enterprise Edition (J2EE), a platform for developing enterprise-level solutions.
JAVA	An object-oriented programming language that is designed to enable complied programs to be executed on many different platforms.
L&G	Landis+Gyr is a publicly listed company which makes meters and related software for electricity and gas utilities. PG&E uses a MDM from L&G.

Acronym/Term	Definition
MDM	Meter Data Management, a term for the processes that meter data and usage, including validation, estimation, and other data quality processes.
MDMS	Meter Data Management System, a system that performs the MDM processes and stores meter data.
MIB	Meter Info Base is a home-grown application used to generate meter information reports.
Middleware	A software that connects systems. When discussing integrations between systems, middleware technologies are often used to enable simpler integrations.
Mission Critical	Mission Critical refers to processes that are essential to PG&E's ability to operate in a safe, reliable and affordable manner. If the process fails there is an immediate catastrophic impact on PG&E's ability to fulfill their mission. Mission Critical systems directly support these processes and must meet a variety of reliability criteria.
MoSCoW List	A document used during configuration workshops to itemize business requirements and group them into Must have, Should have, Could have, and Won't have categories.
MTM	Market Transaction Management is a module within Oracle's C2M.
MuleSoft	An integration and API middleware technology that also enables process automation.
MV-90	Head end system for specialized meters, generally installed at large commercial and industrial customers or complex metering scenarios.
NBT	Net Billing Tariff
NEM	Net Energy Metering
O&M	Operations and Maintenance
OBIEE	Oracle Business Intelligence Enterprise Edition, a platform that stores data and enables the visualization of data on an enterprise level.
OCI	Oracle Cloud Infrastructure (OCI)
OCS	Oracle Consulting Services, engaged to provide project delivery for the BCS project.
ODM	Operational Device Management is a module within Oracle's C2M.
OIR	Order Instituting Rulemaking
Oracle Fusion Middleware	A set of integration technology products that includes developer tools, business intelligence, collaboration, and content management.
Oracle Golden Gate (OGG)	Oracle Golden Gate provides data synchronization across systems.
ORT	Operational Readiness Testing, a test method that ensures the application or system is ready to operate at production parameters. The testing may include backup and restore, disaster recovery, maintenance activities, and other production-type activities.
OUA	Oracle Utilities Analytics is an analytics application for on-premise solutions of CC&B/C2M; OUA is the underlying framework for CRCR
OUAV	Oracle Utilities Analytics Visualization is an analytics application for cloud-based solutions of CC&B/C2M.

Acronym/Term	Definition
Parallel Bill Testing	A test method where large batches of bills are calculated in the test system and compared against the same bills that have been produced in the production system.
PCIA	Power Charge Indifference Adjustment.
Performance Testing	A test method to where normal system loads (or higher than normal loads) are executed on the system to validate that the system can perform as intended against performance metrics.
PG&E	Pacific Gas and Electric Company
PIPP	Percentage of Income Payment Plan
PMO	Project Management Office
PossibleNow	A customer consent and preferences management software solution
Pre-Release Testing	Pre-release testing is generally defined as a test method to validate that a specific product version fulfills the specified requirements. As it relates to Chapter 5, pre-release testing was more akin to unit testing by the vendor before the code version was released into the PG&E environments.
PSPS	Public Safety Power Shutoff
PURPA	Public Utility Regulatory Policies Act
RAMP	Risk Assessment and Mitigation Phase
Regression Testing	A test method that executes processes for existing functionality to ensure that newly developed functionality and processes does not adversely affect existing processes.
Report Testing	A test method to ensure systems and operational reports are gathering and displaying the correct data in the correct formats.
RFP	Request for Proposal
RICEFW	Reports, Interfaces, Conversions, Enhancements, Forms, and Workflows
RTM	Requirements Traceability Matrix
RTP	Real-time Pricing
Scripting	A script is a computing term to describe a short and simple of instructions, normally used to automate process.
Security Testing	A test method that ensures that a system meets or exceeds security requirements. Security testing usually includes various forms of penetration testing, simulated cyber-attacks on the system to identify flaws or weaknesses.
SGG	Smart Grid Gateway is a module within Oracle's C2M.
SME	Subject Matter Expert
Smoke Testing	A test method that validates the critical components of a system are in working order. Smoke testing is used to validate that a system is ready for intensive test methods like functional testing.
SOA	Service Oriented Architecture, a software architecture style that focuses on individual, discrete service processes instead of large, multi-process systems. SOA designs are normally leveraged in system integration designs.

Acronym/Term	Definition
SOD Testing	Segregation of Duties, a test method to validate that system user profiles correctly allow users to perform processes that they have access to and do not allow users where they do not have access.
SOM	Service Order Management is a module within Oracle's C2M.
String Testing	A test method that focuses on the input and output strings for processes.
SIT	System Integration Testing, a test method that ensures all systems, interfaces, and integrated applications are performing as intended.
System Testing	A test method to ensure that all of the functional components of the system are built per the requirements.
TCO	Total Cost of Ownership
TCOE	PG&E's internal Testing Center of Excellence organization.
Technical Debt	Implied cost of additional work caused by choosing a quicker or easier solution today, instead of a more comprehensive and cleaner one that would last longer. This "debt" must eventually be "paid off" through refactoring or additional development to avoid future issues, such as bugs, inefficiencies, or difficulties in scaling.
Technical Testing	A test method or strategy that focuses on the technical aspects of a system. Performance testing, security testing, disaster recovery testing, and ORT are generally components of technical testing.
Teradata	A data warehouse system.
TOU	Time of Use
UAT	User Acceptance Testing, a test method whereby users of the system perform normal business processes in the test environment. This test method validates a variety of aspects of the system, including process functionality, user access and security, system usability, and others.
Unit Testing	A test method performed by developers to identify defects prior to independent testing phases. Unit testing is generally performed on subsets of the system.
VEE	Validated, Edited, and Estimated
WebLogic	Short for Oracle WebLogic Server, a platform for developing, deploying and running enterprise applications.
XAI	eXtended Application Interface, a type of API technology.