Application: 15-09-
(U 39 M)
Exhibit No.: (PG&E-5)
Date: September 1, 2015
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2017 GENERAL RATE CASE

PREPARED TESTIMONY

EXHIBIT (PG&E-5)

ENERGY SUPPLY

PACIFIC GAS AND ELECTRIC COMPANY
2017 GENERAL RATE CASE
EXHIBIT (PG&E-5)
ENERGY SUPPLY

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

ENERGY SUPPLY OPERATIONS POLICY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ENERGY SUPPLY OPERATIONS POLICY

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ENERGY SUPPLY OPERATIONS POLICY

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ENERGY SUPPLY OPERATIONS POLICY

A. Introduction

1. Overview of Energy Supply Operations

In this exhibit, Pacific Gas & Electric Company (PG&E or the Company) requests that the California Public Utilities Commission (CPUC or Commission) authorize the forecasted expense and capital costs for the Energy Supply (ES) function for the 2017-2019 GRC period. This chapter provides an overview of the purpose of, resource needs for, and key issues facing the departments that carry out the Energy Supply function.

PG&E's Energy Supply activities are performed by the following operations functions: Nuclear Generation (Nuclear), Power Generation,[1] and Energy Procurement (EP). PG&E delivers energy to approximately 5.3 million electric and 4.4 million natural gas households and businesses 24 hours a day. Working together, these three organizations provide a safe, reliable, clean, and affordable supply of energy to meet our customers' demands.

The Nuclear function operates the Diablo Canyon Power Plant (DCPP or Diablo Canyon) and provides 2,240 megawatts (MW) of baseload electric capacity, serving approximately 22 percent[2] of PG&E's bundled customer load.

The Power Generation function operates PG&E's fleet of 67 hydro, 3 fossil, 3 fuel cell and 13 solar power plants that provide 5,456 MW of electric capacity serving approximately 17 percent[3] of PG&E's bundled customer load.

The EP function procures electricity, capacity and ancillary services from third-party generation and in the energy markets to serve the needs of

---

1 The Power Generation function and request is described in this exhibit in two chapters: Chapter 4 covers hydroelectric operations; Chapter 5 covers fossil-fueled and other generation plant operations.

2 See WP 6-14, Line 6, Exhibit (PG&E-5).

3 See WP 6-14, Lines 7-8, Exhibit (PG&E-5).

electric customers. Approximately 61 percent[4] of PG&E's bundled customer load is served through procured generation. In addition, EP procures natural gas on behalf of core customers and for both fossil-fueled utility-owned generation (UOG) and electric procurement contracts with third-party generators in which PG&E has agreed to provide natural gas.

Energy Supply operations are supported by Energy Supply Business Technology (ESBT) that develops and maintains the technology systems that ES operations relies upon to conduct its business, and as is described in Chapter 7 of this exhibit.

2. Overview of Key Energy Supply Challenges

Nuclear, Power Generation and EP serve customers by safely and efficiently operating UOG resources, administering PG&E's electric and gas supply portfolio and implementing comprehensive, long-term energy resource strategies and plans to meet PG&E's customers' needs.

State and federal regulatory requirements and mandates continue to increase in the areas of safety, renewable and clean energy, and other operational requirements impacting Energy Supply activities. The following represents a list of some of the key issues and challenges managed by the ES functions.

a. Increasing Safety and Regulatory Compliance Requirements

- Assuring the safe, reliable and efficient operations of PG&E's generation assets is foundational to PG&E and the ES functions. Executing on asset and risk management programs for PG&E's generation facilities requires continued investment and maintenance in plant and technology to operate safely, reliably, and in full compliance with regulatory requirements.
- Implementing and revising processes, procedures, asset management, and technology systems in response to changing Nuclear Regulatory Commission (NRC) and North American Energy Reliability Corporation (NERC) regulations and/or mandates at Diablo Canyon for emergency response, physical security and cybersecurity.

---

4 See WP 6-14, Line 9, Exhibit (PG&E-5).

- Addressing changing Federal Energy Regulatory Commission (FERC) and California Department of Water Resources (CDWR) Division of Safety of Dams (DSOD) for additional compliance and mitigation activities within Hydro Operations, including increased dam and waterway inspections, assessments and mitigations.
- Identifying and mitigating safety risks and regulatory compliance issues identified through PG&E's Enterprise and Operational Risk Management Program. The risk management program has assessed enterprise risks for DCPP and for Hydro Operations and operational risks in all of the Energy Supply functions. As a result of these assessments, additional mitigation activities and supporting technology solutions are being evaluated and implemented.

b. Increasing Energy Policy Mandates

New and evolving energy policy mandates, policies and programs, including clean energy policy initiatives designed to reduce greenhouse gas (GHG) emissions, and increased energy storage and renewable energy systems penetration mandates, each introduce considerable complexity to ES operations.

- Increasing number of new programs requires that PG&E actively participate in formal proceedings and stakeholder processes and technology systems modifications to enable PG&E to implement programs cost effectively.
- Increasing number of energy products (e.g., energy storage), require additional procurement analysis for transactional activity and technology systems enhancements. These products also require greater communication and processes integration within PG&E due to their effects on grid operations.
- Managing the operational challenges of integrating increasing volumes of intermittent energy resources like wind and solar requires PG&E to operate its own generation facilities more flexibly, make additional reliability investments and modify the processes and technology systems that PG&E uses to schedule its generation portfolio.

- Integration challenges also require PG&E to participate actively in proceedings at the CPUC and FERC, as well as in stakeholder processes at the California Independent System Operator (CAISO), to ensure that policies, processes, and technology systems reflect and address the operational challenges that PG&E is facing.

c. Other Regulatory Impacts on Operations

- FERC license conditions on recently and soon-to-be issued hydro licenses will require PG&E to implement additional monitoring, make facility modifications to increase water flows and upgrade or build new recreation facilities and roads as conditions of the new licenses. Ongoing relicensing proceedings are likely to result in similar requirements.
- Changes to regulatory requirements and new energy policy mandates impact technology systems and can necessitate, among other things, new systems to support new processes, upgrades to existing systems and elimination of legacy systems.

PG&E's objective is to meet these challenges efficiently while continuously improving current operations to continue providing a safe, reliable, clean, and affordable supply of energy for its customers.

3. Overview of Energy Supply Request

PG&E's forecast for the Energy Supply function covers:

- The cost of safely operating and maintaining DCPP, 67 hydroelectric powerhouses, 3 fossil generation facilities, 13 photovoltaic (PV) facilities, and 3 fuel cell facilities, including capital outlays for necessary investments in these facilities.
- The administrative costs of managing PG&E's portfolio of contracted resources, including:
  - Power trading.
  - Settlements.
  - Administering PG&E's existing contracts with renewable resources, QF and other PPAs.
  - Renewable Portfolio Standard (RPS) compliance costs.
  - GHG regulation implementation costs.

- Acquisition costs associated with obtaining long-term electric resources for PG&E customers.

- Costs associated with renewal of licenses for existing hydro facilities or implementation of new requirements resulting from license renewals and/or amendments.
- The cost to acquire and develop, upgrade, and enhance technology systems, including cybersecurity systems, that support the Energy Supply function.[5]

To continue to meet customer needs, the Company must invest in its generating facilities to keep them operating safely, efficiently, and in full compliance with legal and regulatory requirements. PG&E will also need to invest in its employees to ensure that they have the talents and skills and technology needed to analyze, implement, transact, administer, and operate in evolving markets. The General Rate Case (GRC) forecast for the Energy Supply function provides the necessary resources to meet these challenges.

PG&E's ES forecast includes the funding necessary for Nuclear, Power Generation, Energy Procurement and Energy Supply Business Technology to deliver safe, reliable, and affordable service to customers. PG&E's expense forecast for the Energy Supply function in 2017 is $746.8 million. PG&E's capital expenditure forecasts for the Energy Supply function are $577.2 million in 2015, $549.8 million in 2016, $480.2 million in 2017, $455.8 million in 2018, and $458.4 million in 2019.

---

5 Exhibit (PG&E-5) does not address:

- The cost of fuel for PG&E's generation facilities, purchased power from PG&E's Qualifying Facility (QF) and Power Purchase Agreement (PPA) resources or power procured from the market to serve PG&E's residual net open position. These costs are recovered through the Energy Resources Recovery Account (ERRA).
- The cost of power for the CDWR contracts. The CDWR revenue requirement is addressed in a separate proceeding.
- Forecasts for electric resource supply and demand planning. This is addressed in the Long-Term Procurement Plan Proceeding.
- The costs of nuclear decommissioning or Safe Storage Operations and Maintenance (O&M) costs, which are reviewed and authorized in the Nuclear Decommissioning Cost Triennial Proceeding.

a. Expense

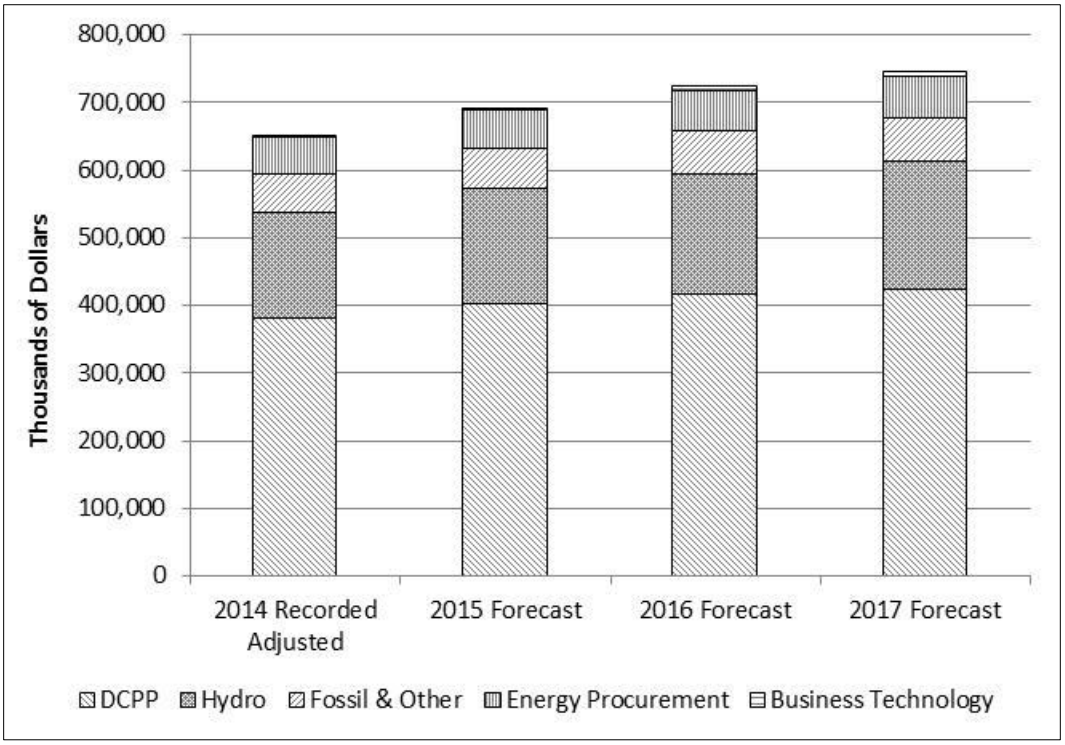
PG&E's O&M expense request for the Energy Supply function in 2017 is $746.8 million, including balancing account expenses. The 2017 forecasts for DCPP, Hydro, Fossil, Energy Procurement and Business Technology expenses are $425.7 million, $187.7 million, $65.0 million, $61.0 million and $7.4 million, respectively.

PG&E's 2014 recorded and forecast expense for the Energy Supply function is shown in Table 1-1 and Figure 1-1.

TABLE 1-1
ENERGY SUPPLY EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

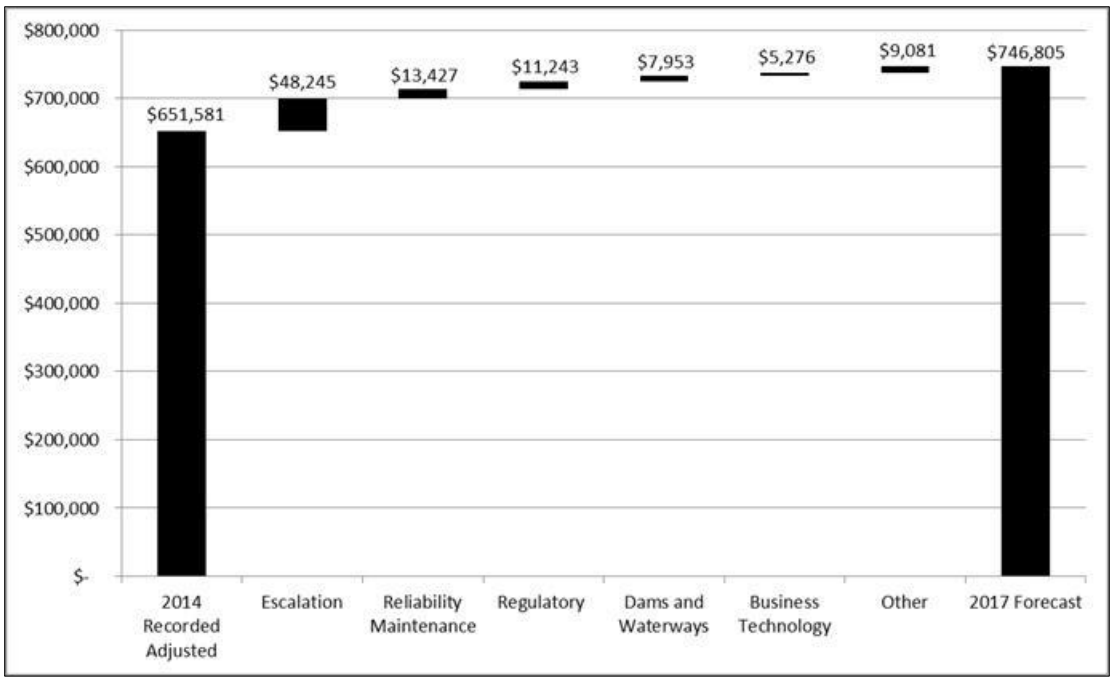
Line No.	Line of Business	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	Workpaper Reference
1	**DCPP Total**	$382,116	$404,444	$417,211	$425,650	WP 3-1, Line13
2	DCPP Non Bal Account	$365,223	$387,844	$398,344	$412,080	WP 3-1, Lines 1-11
3	DCPP Bal Account	$16,893	$16,600	$18,867	$13,570	WP 3-1, Line12
4	**Hydro Total**	$155,480	$170,348	$178,281	$187,746	WP 4-1, Line 14
5	Hydro Non Bal Account	$155,194	$169,894	$177,723	$183,804	WP 4-1, Lines 1-7, 9-12
6	Hydro Bal Account	$286	$454	$558	$3,942	WP 4-1, Line 8
7	**Fossil and Other**	$57,210	$58,389	$63,118	$65,036	WP 5-1, Line 9
8	**Energy Procurement**	$54,651	$56,550	$58,700	$60,975	WP 6-1, Line 5
9	**Business Technology**	$2,124	$1,575	$8,180	$7,400	WP 7-1, Line 6
10	**Energy Supply Total**	$651,581	$691,306	$725,490	$746,806	

FIGURE 1-1
ENERGY SUPPLY O&M
2014-2017
(THOUSANDS OF NOMINAL DOLLARS)



This Energy Supply 2017 forecast expense is an increase of $95.2 million over the 2014 recorded expense. The key drivers of the expense are presented in Figure 1-2 and discussed below.

FIGURE 1-2
ENERGY SUPPLY O&M EXPENSE WALK
2014-2017
(THOUSANDS OF NOMINAL DOLLARS)



1) Labor and Non-Labor Escalation is the biggest driver of the 2017 forecasted increase, representing $48.2 million, or 51 percent of the increase. This includes the higher employee costs attributed to market labor rate increases and union contract negotiations, as well as the expected general inflation for contracts, materials, and other services or fees. Escalation rates used in the preparation of the forecast are described in Exhibit (PG&E-12), Chapter 3.
2) Reliability Maintenance, representing $13.4 million or 14 percent of the 2017 increase over 2014, includes increased costs of large maintenance efforts for DCPP and Fossil, including main generator maintenance and the Dual Refueling outage at DCPP, and the major Fossil outages which are contracted under Long Term Service Agreements (LTSA). The Dual Refueling Outage and LTSA outages are costs which are periodic in nature, but are levelized in the GRC for ratemaking purposes.[6]

[6] As described in Exhibit (PG&E-5), Chapter 8, Section F.

3) Regulatory costs, representing $11.2 million or 12 percent of the 2017 increase over 2014, are primarily costs associated with renewing Hydro licenses or implementing new license conditions and costs associated with implementing regulatory mandates, such as the RPS and GHG emissions reductions. The Hydro relicensing and license condition implementation costs are in the Hydro Licensing and License Implementation Balancing account described further in this chapter, as well as in Chapter 4, Hydro Operations, in this exhibit.

4) Dams and Waterways, representing $8.0 million or 8 percent of the 2017 increase over 2014, are specific risk reduction expense projects and exclude routine dam and waterway maintenance. The facility safety reviews and asset management condition risk assessments described in Chapter 4, Hydro Operations, have identified needed repairs in parts of PG&E's water storage and conveyance systems. PG&E has included funding for specific programs and risk reduction expense projects to address these issues in its forecasts.

5) Business Technology expense, representing $5.3 million or 5.6 percent of the 2017 increase over 2014, are increasing primarily due to additional cybersecurity[7] expense which represents one-third of the increase. The remainder of the increase is due to increased support and implementation costs on projects, particularly at DCPP, where additional capital technology projects are planned over the GRC period for the consolidation and upgrades to several key systems. Additional detail on this expense driver is provided in Chapter 7 of this exhibit, where Business Technology costs are discussed.

6) Other costs, representing $9.1 million or 10 percent of the 2017 increase over 2014, represent a variety of smaller increases that are

---

[7] The cybersecurity program addresses risk evaluation and mitigation strategies at the Company level. These strategies are composed of capital and expense investments designed to reduce operational risks and improve the safety and reliability of the Company's cyber assets. For further discussion on the cybersecurity program and justification of the requested forecast, see Exhibit (PG&E-7), Chapter 10.

less easily grouped thematically and are also net of any cost decreases identified in individual chapters that follow. Examples include DCPP support allocations, Hydro infrastructure projects, weed abatement at photovoltaic sites, and resources to support the increasing complexity of the Energy Procurement portfolio.

b. Capital

PG&E's capital expenditure forecasts for the Energy Supply function are $577.2 million in 2015, $549.8 million in 2016, $480.2 million in 2017, $455.8 million in 2018, and $458.4 million in 2019. The 2017 forecasts for DCPP, Hydro, Fossil, Energy Procurement and Business Technology capital are $159.7 million, $253.7 million, $14.5 million, $0 million and $52.3 million, respectively.

PG&E's 2014 recorded and forecast capital expenditures for the Energy Supply functions are shown in Table 1-2. As shown in Table 1-2 and Figure 1-3, there is a substantial reduction in capital spending over the 2017-2019 GRC period compared to the period 2014-2016. The key driver for the decrease is PG&E's multi-year plan to reduce capital spending at DCPP as many large projects have been completed or are nearing completion.

TABLE 1-2
ENERGY SUPPLY CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Line of Business	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Workpaper Reference
1	**DCPP Total**	$217,275	$238,411	$213,929	$159,700	$137,700	$150,121	WP 3-103, Line 6
2	DCPP Non Bal Account	$173,176	$178,711	$177,861	$146,396	$132,543	$150,121	WP 3-103, Lines 1-4
3	DCPP Bal Account	$44,099	$59,700	$36,068	$13,304	$5,157	–	WP 3-103, Line 5
4	**Hydro Total**	$226,818	$287,698	$259,769	$253,667	$270,083	$260,184	WP 4-74, Line 12
5	Hydro Non Bal Account	$210,648	$265,304	$238,183	$226,681	$229,112	$213,042	WP 4-74, Lines 1-10
6	Hydro Bal Account	$16,169	$22,394	$21,586	$26,986	$40,971	$47,143	WP 4-74, Line 11
7	**Fossil and Other**	$9,923	$12,153	$21,645	$14,493	$2,960	$4,683	WP 5-57, Line 12
8	**Energy Procurement**	$7	–	–	–	–	–	WP 6-10, Line 2
9	**Business Technology**	$39,168	$38,954	$54,450	$52,300	$45,050	$43,450	WP 7-47, Line 3
10	**Energy Supply Total**	$493,191	$577,215	$549,794	$480,160	$455,793	$458,438	

The Energy Supply 2017 capital expenditure forecast is a decrease of $13.0 million over the 2014 recorded capital. The key drivers of this capital decrease are presented in Figure 1-3 and discussed below.

FIGURE 1-3
ENERGY SUPPLY CAPITAL SPENDING PROFILE
(THOUSANDS OF NOMINAL DOLLARS)

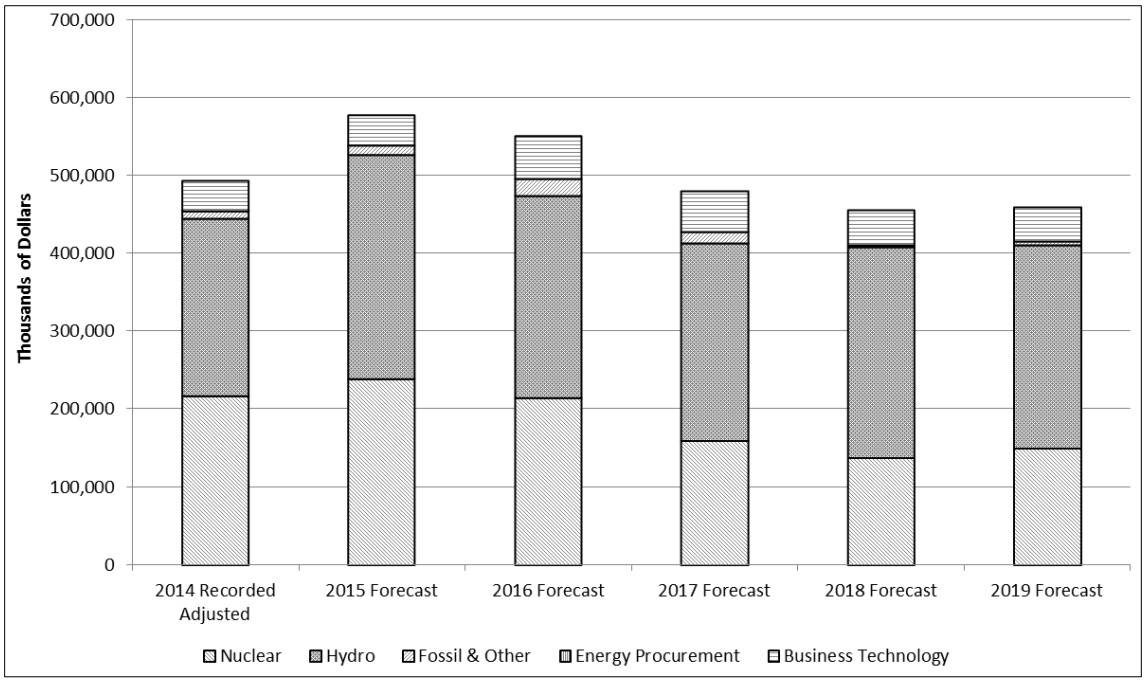
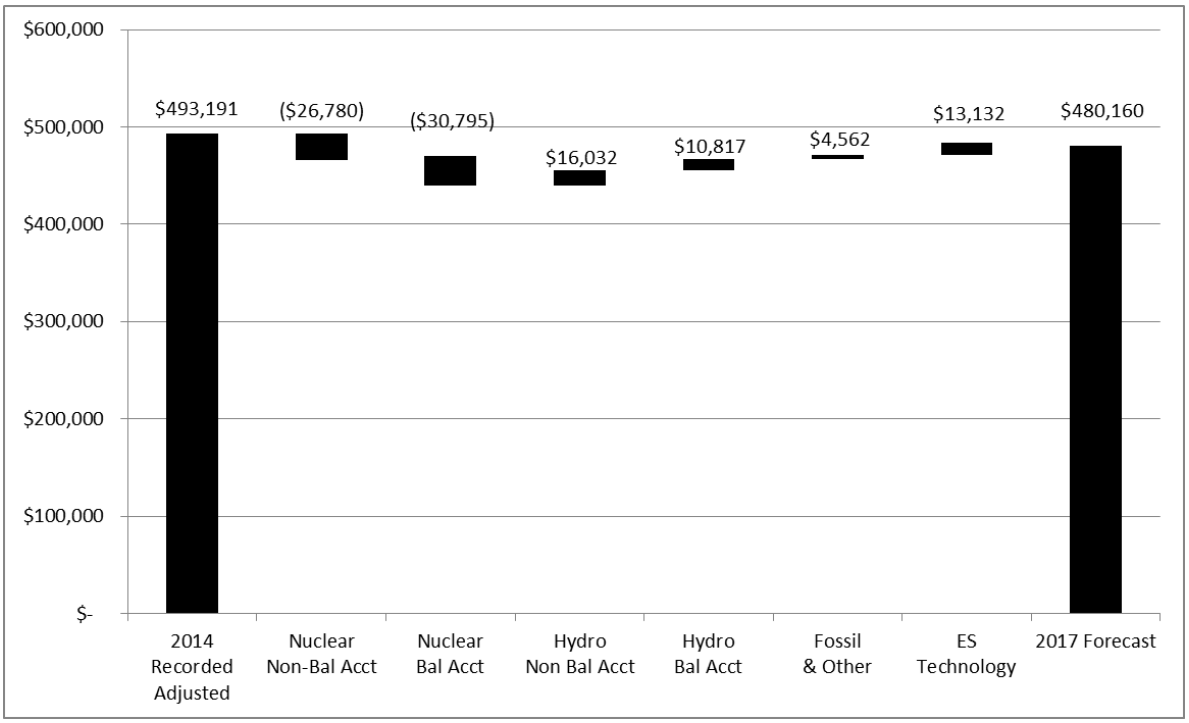


FIGURE 1-4
ENERGY SUPPLY CAPITAL WALK (2014-2017)
(THOUSANDS OF NOMINAL DOLLARS)



1) Nuclear Generation accounts for the major capital expenditure cost reductions across the Energy Supply function. Nuclear is forecasting a $27 million reduction in capital expenditures in non-balancing account capital work due to the completion of several large capital projects over the 2017 GRC period. This includes projects driven by regulatory requirements including dry cask storage facilities for spent fuel, various security readiness projects, and verification of DCPP's license basis. Partially offsetting this large decrease are increases in reliability investments, which are primarily comprised of the following key projects: Main Generator Stator replacement, Main Generator Output Breaker, Instrumentation and Controls projects, and Low Pressure Turbine Rotor.[8] Nuclear is forecasting a $31 million reduction in capital expenditures within the NRC Regulatory Balancing Account due to the timing of completion of various Fukushima response projects addressing the core damage frequency enterprise risk,[9] various Emergency Rulemaking projects, Reactor Cooling Pump Thermal Seal installations, and progress on various fire protection modifications. Additional detail on the capital expenditures for both balancing account and non-balancing account is discussed in Chapter 3, Nuclear Operations Costs.

2) The Hydro non-balancing account cost increase of $16.0 million is necessary for continued improvements to Hydro facilities to enhance safe and reliable operations of dams and waterway facilities and powerhouse generation equipment. Key projects discussed in Chapter 4, Hydro Operations, of this exhibit. An increase of $10.8 million is forecasted in the Hydro Licensing and License Condition Implementation Balancing Account for costs associated with relicensing PG&E hydro facilities and implementing new or amended FERC license conditions.

---

8 See WP 3-105 – 106, Lines 5-6, 16, 19, 23, 49, 66, Exhibit (PG&E-5).

9 See Exhibit (PG&E-5), Chapter 2, Part II: Diablo Canyon Safety and Risk Management.

3) The total increase in capital expenditures for Fossil and Other from 2014-2017 is $4.5 million. This increase is primarily attributable to projects to install and replace generating equipment to improve safety and operational reliability and flexibility.

4) For Energy Supply Business Technology, the increase from 2014-2017 is $13.1 million. This increase in largely driven by cybersecurity[10] investments across the Energy Supply function ($9.3 million). The remaining increase ($3.8 million) is primarily comprised of improvements to technology infrastructure and Asset and Work Management systems across the Energy Supply function. Among the key projects are the replacement of the radio and telephone systems at DCPP and continued strengthening and extension of the telecommunications infrastructure supporting Hydro operations along with continued focus on asset reliability assessment systems.

c. Balancing Accounts

1) NRC Regulatory Balancing Account

As approved in the 2014 GRC, PG&E implemented a two-way balancing account for cost recovery related to new safety and security measures. PG&E proposes to continue the NRC Regulatory Balancing Account (NRCRBA) to recover the costs of implementing new NRC rulemakings, proceedings and orders, such as the Fukushima, Fire Protection, EP Rulemaking, and Cyber Security proceedings.

The NRCRBA benefits customers by: (1) ensuring full funding of and compliance with new difficult to predict but critically important regulatory conditions associated with new NRC Rulemaking proceedings; (2) creating a mechanism to refund costs to customers to the extent NRC rulemaking costs are delayed or less than

---

10 The cybersecurity program addresses risk evaluation and mitigation strategies at the Company level. These strategies are composed of capital and expense investments designed to reduce operational risks and improve the safety and reliability of the Company's cyber assets. For further discussion on the cybersecurity program and justification of the requested forecast, see Exhibit (PG&E-7), Chapter 10.

expected; and (3) creating a mechanism to recover costs from customers to the extent the NRC Rulemaking costs are greater than expected, without requiring reprioritization of funding away from necessary reliability enhancements or maintenance work. Forecasts and further detail on the NRCRBA is discussed in Chapter 3, Section B, of this exhibit.

2) Hydro Licensing and License Implementation Balancing Account

As approved in the 2014 GRC, PG&E implemented a two-way balancing account to record the expense and capital costs of FERC Hydro licensing and license implementation costs. The time required for issuance of FERC licenses is uncertain and therefore the cost and timing of the implementation expenditures are uncertain. Historically, the FERC licensing process has exceeded the targeted dates for completion by several years. This trend has continued since the issuance of the 2014 GRC decision and PG&E proposes to credit back to rates the over-collection in the hydro balancing accounts for the costs of licensing activities that have been delayed.

PG&E proposes to continue this balancing account for the 2017 GRC period. The proposed continuation of this two-way balancing account addresses the uncertainties in the cost and timing of license renewal, amendments, and new license condition implementation measures by providing recovery in rates only of actual costs that are incurred.

Details regarding the cost forecast for this balancing account are discussed in Chapter 4, Section D.3.

B. Energy Supply Operations and Key Initiatives

1. Energy Supply Operations and Assets

a. Management Structure

In August 2015, the Energy Supply functions were reorganized into the current organization structure. Nuclear Generation, Power

Generation and Energy Procurement are part of the Electric Operations organization, reporting to the President of Electric Operations.

- Nuclear Generation (including Humboldt Bay Power Plant Decommissioning) has a Chief Nuclear Officer (CNO) and two Vice Presidents (VP) with eight directors providing functional area oversight.
- Power Generation has one VP with seven directors providing functional area oversight and reporting to the VP. The management of the utility-owned Hydro, Fossil and Renewable Generation resides within Power Generation.
- Energy Procurement has one Senior Vice President (SVP), one VP and five directors providing functional area oversight and reporting to the SVP.
- The Nuclear Generation CNO, the VP of Power Generation and the SVP of Energy Procurement report to PG&E's President of Electric Operations.

b. Nuclear Generation Operations

Diablo Canyon's exemplary record of reliability and safety has been established over its 30 years of operation. Diablo Canyon consists of two nuclear power reactor units, which began commercial operation in May 1985 and March 1986. Diablo Canyon provides 2,240 MW of operating capacity for PG&E customers and is capable of generating 52 million kilowatt-hours (kWh) of electricity per day. Each year Diablo Canyon safely and reliably generates about 18,000 gigawatt-hours (GWh) of clean electricity per year. DCPP provides more than 20 percent of the energy generated in PG&E's service territory and 10 percent of the energy generated in California annually—enough to meet the energy needs of more than 3 million northern and central Californians. For years, DCPP has continuously and safely produced clean and reliable energy without GHG emissions, avoiding six to seven million metric tons per year[11] of GHG emissions

[11] See WP 3-295, Exhibit (PG&E-5).

that would otherwise be emitted to the atmosphere if the DCPP production was replaced by conventional generation resources.

The first responsibility of a nuclear facility operator is to generate power safely. The second responsibility is to operate reliably through cost-efficient management of plant and related assets. PG&E accomplishes these objectives by maintaining high safety standards, achieving excellent reliability, continuously improving its operations, and managing costs.

c. Hydroelectric Operations

PG&E operates the largest privately owned hydroelectric system in the United States. PG&E has a long history of safely and reliably operating these flexible, cost-effective, and GHG-free energy resources for the benefit of PG&E's customers. PG&E's hydroelectric generation assets consist of 107 units at 67 powerhouses with a combined maximum normal operating capacity of 3,888.7 MW. PG&E hydroelectric units produce an average of about 11,000 gigawatt-hours of energy in a normal precipitation year. This is a unique portfolio of facilities that were built between 1898 and 1986. Many of the dams and powerhouses have been in service for well over 50 years, and some of the water collection and transport systems were used for gold mining and consumptive water prior to the development of these hydro generating facilities.

Despite the ongoing and challenging drought conditions in California, PG&E's hydro powerhouses continue to produce low-cost, clean energy, high-value ancillary services, and peaking capacity to meet customers' needs. PG&E's hydro system also supports the integration of intermittent RPS-eligible energy by providing a high level of operational flexibility. In addition, PG&E's customers and the citizens of California benefit from the Company's land conservation, recreation and environmental commitments. The FERC relicensing process and associated license conditions and commitments validate that Hydro Operations optimizes energy production from these facilities with the efficient use of water resources, recreational uses and continuing environmental stewardship.

d. Fossil and Other Generation

PG&E's fossil generation facilities provide customers with the benefit of state-of-the-art technology. PG&E's fossil fleet consists of two combined cycle plants, the Gateway Generation Station (GGS) and Colusa Generation Station (CGS), and the Humboldt Bay Generating Station (HBGS), which uses reciprocating engine technology. These three generating facilities have a combined maximum normal operating capacity of 1,400 MW. GGS was placed in service in January 2009, and HBGS and CGS were placed in service in September 2010 and December 2010, respectively. The two combined cycle facilities are among the most efficient gas-fired plants in the state, allowing for displacement of energy from older, less efficient plants. HBGS is designed to meet the generation needs of the remote Humboldt area, which has limited capacity to receive electricity from outside the area. PG&E's fossil plants support RPS goals by being operationally flexible and capable of providing a number of CAISO ancillary services to help integrate intermittent renewable resources, like solar and wind power, into the grid.

In addition to the fossil facilities, PG&E's generation fleet includes thirteen PV generation facilities, most of which range from 15 to 20 MW. PG&E also has two fuel cell facilities.

e. Energy Procurement

The EP organization administers PG&E's existing electric and gas portfolio, and is responsible for procuring new energy and capacity products. EP designs and implements a comprehensive, long-term energy resource strategy to meet PG&E's customers' needs in a safe, reliable, affordable, and environmentally responsible manner.

The electric and gas supply procurement and administration activities conducted by the EP organization are necessary to ensure that PG&E plans for and acquires resources so that supply is available when it is demanded by customers. In addition, EP is responsible for the long-term planning, policy development, strategy, and compliance functions associated with PG&E's energy portfolios.

The costs for EP include expenses associated with planning for, procuring, managing, and administering electric and gas supply resources and contracts to meet customer needs. Other activities performed by EP include: resource planning; scheduling loads and resources with the CAISO; providing billing and settlement services for PG&E's portfolio; selling surplus energy and capacity into the market; compliance and reporting activities and coordination of outage scheduling across PG&E's utility-owned and contracted resources portfolio.

f. Energy Supply Business Technology

Information Technology (IT) plays a critical enabling role for Energy Supply to provide safe and reliable gas and electric supply. Business Technology, which is a function in the IT organization and provides services to DCPP, Power Generation and Energy Procurement meets the business' needs and objectives through designing, building, deploying, and maintaining the IT systems necessary for safe, compliant, reliable, and cost-effective operational performance and procurement.

The Energy Supply technology portfolio and plan is based upon improvements and activities in the following areas: (1) Infrastructure; (2) Asset Management; (3) Work Management; (4) Application Simplification; (5) Compliance Management; (6) Foundational Platforms; (7) CAISO Market Initiatives Implementation; and (8) Resource Integration. The programs and costs for these areas are discussed in Chapter 7 of this exhibit.

2. Key Initiatives

a. Public and Workforce Safety

Protecting the safety of the public and PG&E's workforce is at the core of the ES function, and is a particular focus for the DCPP and Power Generation organizations, which are the custodians of PG&E's generating assets. This section touches on some of the key safety initiatives underway which are further discussed in the subsequent chapters of this exhibit.

- Nuclear Safety Regulations – PG&E is responding to increasing NRC safety regulations resulting from the Fukushima Daiichi accident and other NRC rulemaking proceedings, which are described in detail in Chapter 3 of this exhibit.
- Dam Safety Work – Upgrades and modifications to PG&E's dams are required because of: (1) changing FERC and DSOD guidelines; (2) findings resulting from FERC's and DSOD's regular facility inspections; and (3) the FERC Part 12 independent analysis, under both normal and emergency conditions, required every five years. These modifications will improve the dams' stability and operability, and, when necessary, strengthen the low-level outlet structures and spill gates.
- Water Conveyance and Storage Condition Assessment – In addition to Dam Safety Work, Power Generation, through its asset management program, has expanded the assessments of its dams to include the smaller, non-FERC Part 12 dams, PG&E's water conveyance systems (canals, flumes, tunnels, and natural waterways), and its penstocks that deliver pressurized water to the powerhouses.
- Public Safety Initiative – In order to enhance public safety associated with ES hydro and fossil generation assets, PG&E has implemented a comprehensive public safety program that includes: (1) public education, outreach and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.
- Prudent Electrical Practice is the contractual standard for safe and reliable operation of electric power resources. EP will assess certain types of physical electric transaction offers through structured, consistent Process Hazard Analysis (PHA) or functionally equivalent processes to evaluate offers for energy, capacity, and other electricity products.

b. Risk and Compliance Management

Managing risk and complying with applicable rules and regulations are a fundamental part of the Energy Supply function. DCPP, Power Generation and EP will continue to fortify the Enterprise and Operational Risk Management (EORM) program discussed in the 2014 GRC. PG&E's Safety Model Assessment Proceeding (S-MAP) testimony contains the details regarding how Electric Operations, including Power Generation, EP, and Nuclear Generation, is implementing the EORM Program.[12] Much of the S-MAP information is also included in Chapter 2, Safety and Risk Management, of this exhibit. PG&E's risk and compliance process helps PG&E proactively monitor and address Company risks and potential compliance issues.

The risk management processes for PG&E's generating assets will continue to be developed throughout this GRC period to address emergent risks, and provide controls and mitigations around existing ones. Detailed activities of the risk management process are provided in Chapter 2, Risk Management. Forecasts in support of these efforts are identified in the chapters for Nuclear, Hydro, Fossil and EP.

1) Risk Management Processes and Investment Frameworks

Since the 2014 GRC, the Energy Supply functions have continued to develop the risk-informed assessment/investment framework by, among other things:

- Standardizing to a cycle of continuous risk review that aligns with the EORM program through the annual Session D[13] risk and compliance process. The Session D process is leveraged to proactively monitor and address potential compliance issues.
- Developing a full risk register from which detailed risk assessments are conducted, reviewed and approved at the

---

12 At the time of filing the S-MAP, Nuclear Generation reported directly to the President of PG&E. This is why S-MAP testimony was filed with Electric Operations and Nuclear Generation as separate business units.

13 Session D, and other parts of the Integrated Planning Process are described in Exhibit (PG&E-2), Chapter 4.

Electric Operations Compliance and Risk Management Committee.

- Standardizing along with other PG&E lines of business, the Risk Informed Budget Allocation (RIBA)[14] process by which the annual portfolio of projects is risk scored and prioritized. In the 2014 GRC, Energy Supply addressed its model for assessing and prioritizing the portfolio of project work. The RIBA tool is now an added component to that process. Safety is a core part of PG&E's risk management processes, and one of the three drivers of PG&E's RIBA process. Therefore, improvements in PG&E's risk management processes directly result in improvements in PG&E's ability to address safety issues.

2) Management of Key Safety Risks

Energy Supply has continued to progress in managing its risks since the 2014 GRC, and risk management continues to be a focus in the 2017 GRC, as described in Chapter 2 of this exhibit. In the 2014 GRC, Energy Supply addressed three key safety risks managed through its EORM process. Key items of progress on the management of these Enterprise risks, is described below.

1) Hydroelectric Operations Risk – In 2015, Power Generation completed a 4-year Enterprise Risk Management effort for improving its mitigations and controls. This effort encompassed improved mitigations and controls related to dams and water conveyance. It included:
   - Physical inspections;
   - Capital improvements;
   - Refinements to asset management programs, operations procedures and guidance documents; and
   - Improvements to records, training, and other knowledge management.

[14] RIBA and other parts of the Integrated Planning Process are described in Exhibit (PG&E-2), Chapter 4.

2) DCPP Safety and Operational Risk – Since 2007, DCPP has been developing plans and addressing numerous actions to address the risk of a core damage event. Actions completed include:

- Examination of the susceptibility of the plant to external events using current NRC requirements to identify vulnerabilities.
- Developing plans to implement new NRC regulations regarding equipment to use for mitigating beyond design basis events (including non-permanent equipment, communication and staffing plans, and support programs and processes).
- Acquiring equipment for backup cooling for the spent fuel pools for both units including procedures to implement the use of the equipment in the event of a failure of the permanent design basis equipment.

3) Diablo Canyon Physical Security Risk – Since 2009, DCPP has implemented numerous projects to improve security equipment and security capabilities designed to address the risk of shut-down of DCPP due to a terrorist attack. Improved protected area lighting, strengthened security defensive positions, upgraded security detection capabilities, rebuilt personnel access facilities, and strengthened protections against cybersecurity have all led to the reassessment of security as an operational risk. Physical Security Risk at DCPP is no longer deemed an enterprise risk.

c. Reliability and Resource Integration

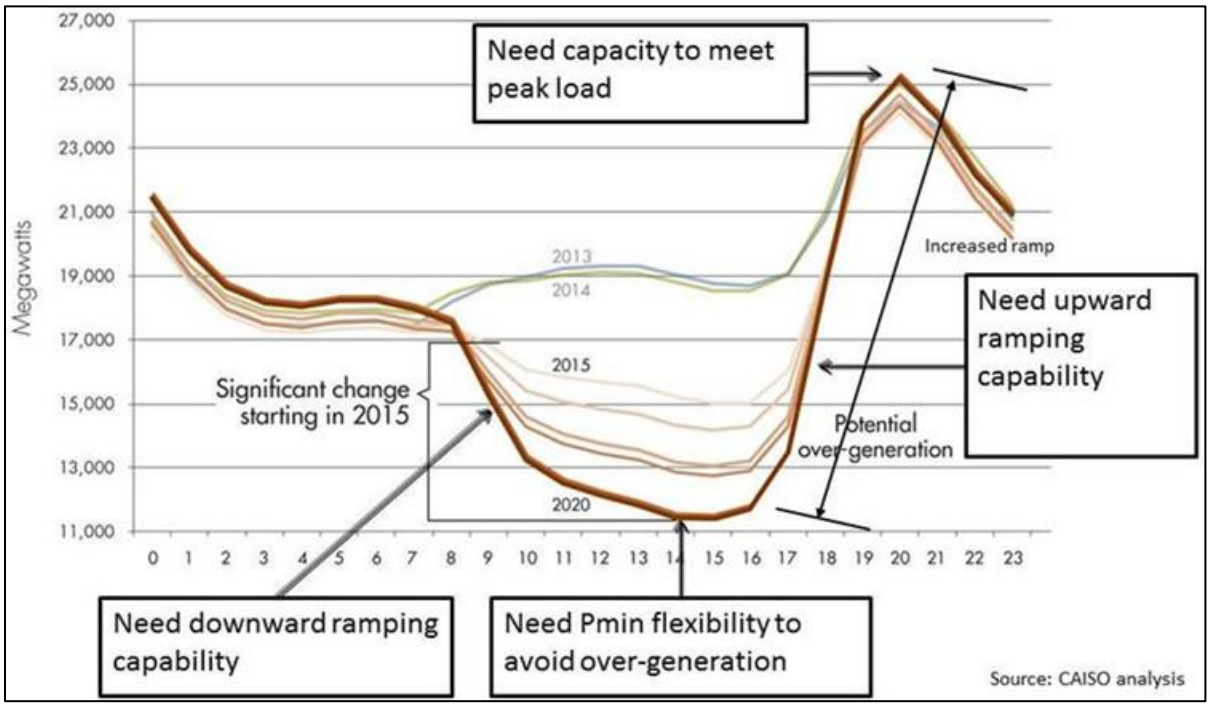
The power plants in PG&E's generation portfolio produce low cost, clean energy, high value ancillary services and peaking capacity to meet customers' needs. Ensuring the reliability of the generation portfolio is in our customers' best interest since the cost to produce electricity at PG&E's generation facilities is generally less than purchasing electricity from third-party generators. PG&E delivers some of the nation's

cleanest energy to its customers and many of PG&E's generation assets help PG&E to achieve the state's RPS goal and are GHG free.

In the *2014 Integrated Energy Policy Report* (IEPR), the California Energy Commission (CEC) stated that "the state's growth in renewable electricity is expected to be dominated by solar energy sources…."[15] The intermittent availability of solar and wind generation in California create a unique resource integration challenge that is growing in complexity each year as more renewable resources come on-line.

Figure 1-5, below, is illustrative of the challenge and demonstrates a future that will require increasingly flexible ramping capacity in the electric resource portfolio.

FIGURE 1-5
CALIFORNIA ISO "DUCK" CURVE – NET LOAD CHART(a)



(a) California ISO Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources December 2013: http://www.caiso.com/documents/dr-eeroadmap.pdf.

15 2014 IEPR, Chapter 6: Transportation Integration Trend with Electricity and Natural Gas Systems, page 103 (http://www.energy.ca.gov/2014publications/CEC-100-2015-001/CEC-100-2015-001-CMF-small.pdf).

Figure 1-5 is a pictorial representation created by the CAISO, to demonstrate the impact that increasing amounts of renewable generation will have on the grid and the need for resource flexibility.

As stated in the CAISO Publication: "Shaping a Renewed Future:"[16]

> The electric grid and the requirements to manage it are changing. Renewable resources increasingly satisfy the state's electricity demand. Existing and emerging technology enables consumer control of electricity consumption. These factors lead to different operating conditions that require flexible resource capabilities to ensure green grid reliability. The ISO created future scenarios of net load curves to illustrate these changing conditions. Net load is the difference between forecasted load and expected electricity production from variable generation resources. In certain times of the year, these curves produce a "belly" appearance in the mid-afternoon that quickly ramps up to produce an "arch" similar to the neck of a duck—hence the industry moniker of "The Duck Chart".

To that end, many of PG&E's generation assets can be operated in a flexible manner to allow for the integration of higher levels of wind and solar generation. Investments in reliability and technology support PG&E's ability to be flexible in its operations, and in the case of Fossil, generation specific capital investments have been identified to further enhance flexible operations as discussed in Chapter 5. Resource integration also presents an EP challenge because the increase in intermittent resources creates greater portfolio complexity that in turn requires an increased need for analytics, tools and other resources in order to arrive at cost-effective supply decisions for customers, as is described in Chapter 6. While DCPP provides base load power to customers, as an additional means of addressing the resource integration challenge, PG&E filed an operational curtailment protocol in its most recent 2014 Bundled Procurement Plan update to facilitate back-down of DCPP during CAISO-declared over-generation events.[17]

d. Performance Improvement and Benchmarking

The functions of Energy Supply each have their own performance management processes with a focus on improving performance in

---

16 California ISO: Shaping a Renewed Future, https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

17 Pacific Gas and Electric Company's Proposed 2014 Bundled Procurement Plan, filed October 3, 2014 in R.13-12-010, Sheet No. 190.

safety, reliability and providing affordable service to customers. These processes are also integrated with the Electric Operations performance management and continuous improvement efforts as described in the Electric Distribution testimony in Exhibit (PG&E-4), Chapter 1, as well as through PG&E's Integrated Planning processes as described in Exhibit (PG&E-2), Chapter 4.

In addition, Energy Supply participates in benchmarking through involvement with the Electric Utility Cost Group (EUCG), the NERC Generating Availability Data System (GADS), the National Hydropower Association, the NRC and the Institute of Nuclear Power Operations. Metrics and benchmarking data are discussed in Chapters 3, 4 and 5, Fossil of this exhibit.

C. Energy Supply Ratemaking Proposals

1. Balancing Accounts

As discussed in the Overview of Request section of this chapter, and further discussed in the Ratemaking Chapter in this exhibit, PG&E intends to continue the NRC Regulatory Balancing Account and the Hydro Licensing and License Implementation Balancing Account.

2. Credits to Electric Generation Revenue Requirement

In this application, PG&E is proposing to credit the Electric Generation Revenue Requirement with funds received as a result of Department of Energy (DOE) litigation and cost savings associated with PG&E's UOG PV Program. The DOE Litigation is described in detail in Chapter 3 of this exhibit, and PG&E's proposal to credit the litigation proceeds to customers is described in Chapter 8 of this exhibit. The PV Program cost savings credit and the inclusion of on-going program costs for the PV facilities is described in Chapter 8 of this exhibit.

3. Recovery of DCPP Seismic Studies

As further described in Chapter 8 of this exhibit, PG&E is including within this 2017 GRC the labor and consultant costs in PG&E's Geosciences Department associated with PG&E's on-going NRC commitment to continuously study and update the state of knowledge regarding seismic hazards affecting DCPP. Following the completion of California Energy

Commission and NRC mandated seismic work there is no longer a need to continue cost recovery coordination of on-going seismic efforts between ERRA and the GRC.[18]

4. Recovery of Smart Grid Pilot Projects

As discussed in Chapter 8 of this exhibit, Energy Supply Technology capital includes Smart Grid pilot projects to be completed within the 2014-2016 timeframe. This is in accordance with the Smart Grid Deployment Plan filed with the Commission in Application 11-11-017, that proposed that the Smart Grid pilot project capital-related revenue requirement be consolidated in the 2017 GRC. No new Energy Supply costs are forecasted at this time for the program within the 2017-2019 GRC period.

D. Conclusion

PG&E's forecast of expense and capital costs for Energy Supply activities is reasonable and necessary to fund: (1) the provision of continued safe, reliable and cost-effective energy when it is demanded by customers; (2) responses to new and increasing regulatory requirements and energy policy mandates as they pertain to safety and operational risks; (3) implementation of new and increasing energy policy mandates in the areas of renewable energy, GHG regulation, energy storage; (4) integration of a growing portfolio of intermittent renewable resources and make investments to enhance the reliability and flexibility of PG&E's UOG assets; (5) the cost of obtaining new licenses for PG&E's Hydro facilities and implementing new license conditions; and (6) technology to support the continued delivery of a safe, reliable, and affordable supply of energy to PG&E customers.

---

18 See Exhibit (PG&E-5), Chapter 8, Ratemaking, Section E.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ENERGY SUPPLY RISK MANAGEMENT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ENERGY SUPPLY RISK MANAGEMENT

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ENERGY SUPPLY RISK MANAGEMENT

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ENERGY SUPPLY RISK MANAGEMENT

This chapter describes how Pacific Gas and Electric Company (PG&E or the Company or the Utility) manages risks associated with its Energy Supply (ES) function, which consists of its: nuclear; hydro; fossil; photovoltaic (PV) and fuel cell generating facilities; and Energy Procurement (EP) activities. Due to a re-organization in July 2015, all the ES functions are now part of Electric Operations (EO).[1] However, from a risk management perspective, Nuclear Operations manages risk and safety items for Diablo Canyon Power Plant (Diablo Canyon or DCPP) separately from other Power Generation facilities (hydro, fossil, PV and fuel cell). For this reason, this exhibit is organized in two separate sub-parts, sponsored by two different witnesses. Part I (Sections A-G) addresses safety and risk management for the Power Generation facilities. Part II (Sections H-N) addresses safety and risk management for DCPP. The risks managed by EP are primarily financial, not safety-related, and are therefore not addressed in this chapter.[2]

Part I: Power Generation Safety and Risk Management

A. Introduction

Part I includes the following sections:

- Section B – Electric System Risk Management – Overview of the EO risk organization, risk register, risk evaluation activities and risk management software applications.
- Section C – Electric Operations Enterprise Risks – Provides information for enterprise risks that are the responsibility of EO and relate to Power Generation.

---

1 At the time of filing the Safety Model Assessment Proceeding (S-MAP) (A.15-05-003), Nuclear Generation reported directly to the President of PG&E. This is why S-MAP testimony was filed with Electric Operations and Nuclear Generation as separate business units.

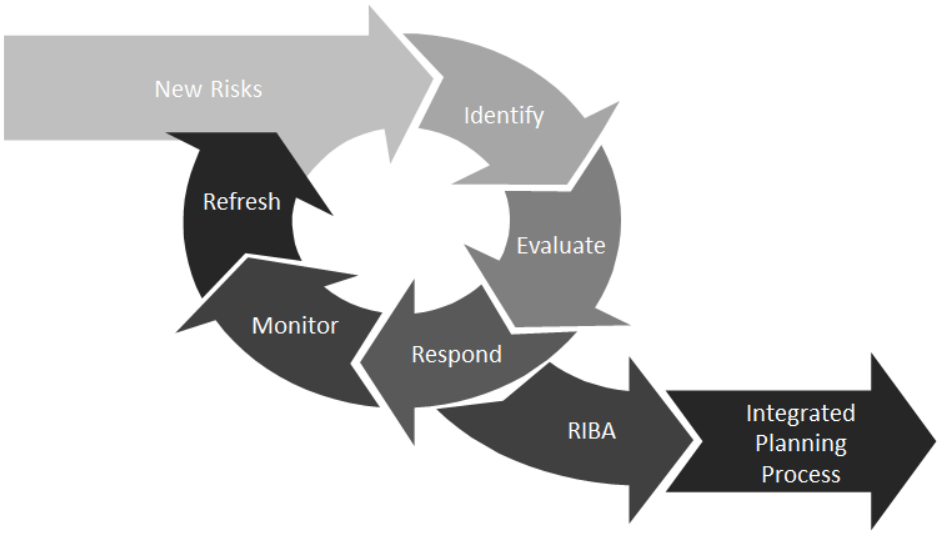
2 See Exhibit (PG&E-5), Chapter 6 for a description of EP Programs to mitigate financial risks and manage customer costs.

- Section D – Electric Operations' Asset and Process Risks – Identifies and provides information for non-enterprise risks that are safety and reliability related and relevant to the 2017 General Rate Case (GRC).
- Section E – 2017 GRC Expenditure Forecast to Risk Register Mapping – Describes the process and presents the results of PG&E's estimate of the relationship of 2017 GRC forecasts to the EO Risk Register.
- Section F – Risk Informed Budget Allocation Prioritization – Presents the RIBA process as it relates to the 2017 expense and capital expenditure forecasts.
- Section G – Power Generation – Conclusion – Discusses planned improvements to risk management in EO.

B. Electric System Risk Management

EO implements the Enterprise and Operational Risk Management (EORM) Program as described in Exhibit (PG&E-2), Chapter 3, to manage Power Generation risks. This program requires EO to identify, evaluate, respond, and monitor risks. The program provides a repeatable and consistent method of managing risks and is an important element of PG&E's Integrated Planning Process. Figure 2-1 is a high-level illustration of the risk management framework.

FIGURE 2-1
RISK MANAGEMENT FRAMEWORK



The remainder of this section is organized as follows:

- Organizational Structure – Describes EO risk management personnel and committees
- Risk Register – Describes the codification of identified risks
- Risk Evaluation – Describes the tools EO uses to score items on the Risk Register

1. Organizational Structure

The Risk Management organization within EO is the System Safety and Risk team and consists of a senior manager and several full-time risk analysts. This team reports to the director for Compliance and Risk Management, who reports to the Vice President for Electric Operations Asset Management.

The System Safety and Risk team is responsible for implementing the EORM Program for the following areas:

- Power Generation Facilities
- Energy Procurement
- Electric Transmission Lines
- Electric Transmission and Distribution Substations
- Electric Distribution Lines

Each item in the Risk Register (described in the next section) is assigned to a risk owner (typically a director) who is responsible for ensuring the accuracy of a risk's evaluation and implementing risk response plans and mitigations. Subject matter experts (SME) working within EO assist the risk owners and the EO System Safety and Risk team when evaluating risks and creating risk response plans.

Also, EO has a Risk and Compliance Committee (RCC). The RCC is chaired by EO's President and is composed of her executive leadership team. This committee meets monthly to review current risk-related topics and approve various items such as risk assessments, risk mitigation measures, and changes to the Risk Register.

2. Electric Operations (EO) Risk Register

PG&E uses risk registers to log and classify risks. The EO Risk Register currently includes 73 risks.[3] The risks are categorized as enterprise risks, asset risks, process risks, EP or corporate security risks. These different types of risk are defined below.

Enterprise Risks (5): Enterprise risks are risks that could have a catastrophic impact on PG&E if they were to occur.

Asset Risks (43): Risks that have consequences associated with component failure or malfunction. These are further divided into:

- Power Generation Risks
- Substation/Switchyard Risks
- Transmission Overhead Risks
- Distribution Overhead Risks
- Transmission and Distribution Underground Risks

Process Risks (12): Process-based risks are generally associated with business processes and operations, not assets. While not asset specific, some process risks can have safety and reliability related consequences.

Energy Procurement Risks (9): These risks are generally financial risks related to bulk power operations, energy markets, portfolio management, etc.

Corporate Security Risks (4): These are risks associated with the security of PG&E facilities, critical data, and employees.

Figure 2-2 shows the complete EO Risk Register.

---

[3] See Workpaper Table 2-2 for a complete list of all risks, their definitions and their risk scores.

FIGURE 2-2
ELECTRIC OPERATIONS RISK REGISTER

EO Risk Register – Grouped (73 Total Risks)

As of 7/21/15

ENTERPRISE RISKS

- ENT1 Wildfire
- ENT2 Emergency Preparedness and Response to Catastrophic Events
- ENT3 Failure of Substation (Catastrophic)
- ENT4 Hydro System Safety – Dams
- ENT5 Electric Grid Restoration

PROCESS RISKS

- PROC2 Critical Equipment Procurement
- PROC4 Encroachment on EO Assets
- PROC5 Lack of Transmission Project Delivery
- PROC6 Workforce Planning
- PROC7 Lack of Real-time Operational Workaround for Loss of Critical Systems
- PROC8 Control Room Operational Awareness
- PROC9 Cover-up/ Fraud
- PROC10 Risk of Non-Compliance
- PROC12 Distributed Generation
- PROC13 Seismic Resiliency
- PROC14 Voltage Planning and Operation
- PROC15 Contact Voltage

ENERGY PROCUREMENT RISKS

- EP1 AB 32/ Cap-and-Trade
- EP2 Market Flaws/ Manipulation
- EP3 New Policy and Market Design
- EP4 Bulk Power Operations
- EP5 Portfolio Mix
- EP6 Above-Market Stranded Costs
- EP7 Changing GHG Regulations
- EP9 Safety Standards for PPAs
- EP10 Significant Natural Gas Price Increase

CORPORATE SECURITY RISKS

- CSEC1 Asset Security
- CSEC2 Fairfield Security Control
- CSEC3 Insider Threat
- CSEC4 Workplace Violence

TRANSMISSION OVERHEAD RISKS

- ETOH1 Transmission Overhead Conductors
- ETOH2 Transmission Overhead Steel Support Structures
- ETOH3 Transmission Overhead Wood Support Structures
- ETOH4 System Integrity Protection Schemes (SIPS)
- ETOH5 Transmission Overhead Switches
- ETOH6 Loss of Transmission Corridor

DISTRIBUTION OVERHEAD RISKS

- EDOH1 Distribution Overhead Conductor Primary
- EDOH2 Distribution Overhead Support Structures
- EDOH3 Distribution Overhead Line Equipment – Voltage Regulators, Boosters, and Cap.
- EDOH4 Distribution Overhead Streetlight Struc.
- EDOH5 Distribution Overhead Conductor Secondary
- EDOH6 Distribution Overhead Transformers
- EDOH7 Distribution Overhead Line Equipment – Protective

T&D UNDERGROUND RISKS

- EDUG1 Distribution Underground Line Equipment
- EDUG2 Distribution Underground Cables
- EDUG3 Distribution Underground Subsurface and Pad-Mount Transformers
- EDUG4 Network Components (In Urban/ High Density Areas)
- ETUG1 Transmission Underground Cables and Equipment

SUBSTATION/SWITCHYARD RISKS

- SS2 Substation Transformers & Voltage Regulators
- SS3 Substation Protective Relays, Instrument Transformers & Station Batteries
- SS4 Substation Voltage & Flow Control Equipment
- SS5 Substation Circuit Breakers and Switchgear
- SS6 Substation Grounding Systems
- SS7 Substation Switches
- SS8 Unit Substations
- SS9 Substation Bus Structures

POWER GENERATION RISKS

- PG1 Hydro Public Access
- PG2 Hydro Material Release Into Water
- PG3 Failure of Generation Facility (Catastrophic)
- PG4 Fossil High Energy Systems
- PG5 Fossil Turbine – Generation Systems
- PG6 Fossil Protection and Control Systems
- PG7 Fossil Balance of Plant
- PG8 Fossil Chemical Systems
- PG9 Fossil Fuel Systems
- PG10 Hydro Pressure Integrity Systems
- PG11 Hydro Turbine – Generation Systems
- PG12 Hydro Protection and Control Systems
- PG13 Hydro Balance of Plant
- PG14 Hydro Support Infrastructure
- PG15 Hydro In-Stream Flow Release (IFR) Valve and Bypass
- PG16 Fuel Cell Systems
- PG17 Photovoltaic Systems

Examples of public safety risks from the EO Risk Register include hydro system safety[4] and asset-related risks associated with Power Generation facilities. The majority of process and EP risks are not considered public safety risks as they primarily relate to PG&E's efforts to manage and moderate customer costs.

Later in this testimony, Section C provides an overview of the Enterprise risks that relate to Power Generation while Section D identifies and provides the Risk Register scores for the non-enterprise risks relevant to this exhibit (a modified version of Figure 2-2, which highlights the relevant risks for this exhibit, appears later in Section D).

3. Risk Evaluation

EO uses two tools to evaluate items on the Risk Register:

- The Risk Evaluation Tool[5] (RET)
- Risk Assessments

a. Application of Risk Evaluation Tool for Electric Operations

EO uses RET, described in Exhibit (PG&E-2), Chapter 3, to establish a risk score for each risk in the Risk Register. While EO does not modify the RET model, a variety of data and judgment are inherent when applying the frequency and impact scales of the model and in the formulation of the scoring scenarios. How the RET is used in EO's risk assessment process is described more fully in the next section.

b. Risk Assessments

The purpose of a risk assessment is to identify potential hazards and analyze what might happen if a hazard event occurs. Within EO, risk assessments are used to provide a systematic understanding of the items on the Risk Register.

EO uses a common framework to perform risk assessments and upon completion, the assessments are presented to the EO RCC for

---

4 The official Risk Register title is "Hydro System Safety – Dams." The scope of this risk includes dams, conveyances and penstocks. For this reason the titles "Hydro System Safety – Dams" and "Hydro System Safety" are synonymous.

5 Detailed information on the RET was provided in PG&E's submission in the S-MAP (A.15-05-003).

review and approval of the Risk Register scores and recommended mitigations.

The components of a risk assessment include:

- Risk definition and scope
- A scoring scenario (the "P95" scenario)[6] and the application of the RET to determine a Risk Register score
- Identification of risk drivers and consequences
- Identification and assessment of existing controls
- Identification of current gaps in controls and consideration of alternative mitigations

Assessments typically take 60-90 days to complete, and are performed by a team of SMEs led by a risk analyst from the System Safety and Risk Management team. The team compiles and analyzes information such as asset condition data, event reports, reliability data, etc., to perform the assessment.

The team also identifies and assesses existing controls and identifies potential new mitigations (or strengthening of existing controls) during the assessment. Periodic reviews with the risk owner are conducted during the assessment. During these reviews there are discussions regarding alternative mitigations and which mitigations to recommend to the RCC. After the RCC approves a risk assessment, the approved mitigations are tracked to ensure completion.

EO is currently working to complete a formal risk assessment for all items on the Risk Register. When all the risk assessments are completed, EO will have established a common basis for relative risk scores for assets, processes, and events that rely on a common framework, particularly with respect to the application of the RET for scoring.

---

6 The P95 scenario is based on the concept of plotting a range of outcomes along a distribution and choosing the 95th percentile event for the purposes of the risk discussion. In practice, for many risks—in absence of quantitative support—PG&E identifies a reasonably probable worst case scenario, rather than a range of outcomes.

c. Risk Management Software Applications

PG&E is developing a software application for managing fossil, hydro, and other non-nuclear generating facilities. The application is called the Generation Risk Information Tool (GRIT). GRIT is an integrated asset management application which provides data centralization, standardization of asset management scoring, asset risk trending, improved reporting, and analytics. GRIT interfaces with SAP Work Management and is designed for logging, planning, and reporting on assessments (e.g., tests, inspections, reviews, and calculations), asset condition indicators, and asset health and consequence scores. Consequence scores are in line with the RET.[7] Lastly, GRIT also tracks risk mitigation activities, including projects, maintenance, and operational changes.

The GRIT application organizes and displays condition and consequence data on equipment within major hydro areas. These equipment records are categorized by program and geography. The GRIT program became operational in 2014, and has 15 hydro asset types in the tool today. By early 2016 new asset types and a new management dashboard report will be added to the tool. GRIT will also be piloting integration with OSI PI, which is a process data historian, to store all real-time data and events related to equipment and its operations in early 2016.

C. Electric Operations Enterprise Risks

This section identifies and discusses the Company's enterprise risks that are the responsibility of EO and relate to Power Generation facilities.

---

[7] PG&E notes that the current version of GRIT uses RET frequency and impact scores and guidance as directed by the EORM Program. However, GRIT still uses the linear RET1 Model algorithm (see PG&E's S-MAP submission, Chapter 3, Section C (A.15-05-003)).

PG&E has a total of 17 enterprise risks.[8] Of these, five are the responsibility of EO and the following two relate to Power Generation:[9]

- Hydro System Safety
- Electric Grid Restoration

The following sections provide additional information regarding the enterprise risks of Hydro System Safety and Electric Grid Restoration.

1. Hydro System Safety

a. Hydro System Safety – Risk Definition, Scenario and Score

Hydroelectric Operations System Safety was first identified as an enterprise risk in 2007 and is defined as the risk of failure of a PG&E dam or other hydro facility that may result in injuries, fatalities and/or significant property damage to the environment, and facilities owned by third parties or the Company. Failures of dams and water conveyance systems are more likely to arise during an abnormal event like a flood or earthquake, but they can also occur during normal conditions and operations as a result of deterioration or structural failures.

Hydro System Safety has a RET score of 349. The RET scenario used to score this risk is a low-probability, high-consequence event defined as:

> A dam develops a major breach causing significant uncontrolled water spillage resulting in multiple lives lost, and major facility, road, and environmental damage with outages lasting more than 6 months.

b. Hydro System Safety – Major Controls

Hydro Operations considers ways to both reduce the probability of an in-service failure, as well as how to limit the consequences of a failure. These assessments are incorporated into PG&E's facility and

---

8 See Exhibit (PG&E-2), Chapter 3 for an explanation of enterprise-level risks.

9 See Exhibit (PG&E-4), Chapter 2 for information relating to the other three EO Enterprise Risks which are Wildfire, Catastrophic Failure of Substation and Emergency Preparedness and Response to Catastrophic Events. In addition to the five that are owned and managed by EO, there are four enterprise risks owned and managed by other LOBs that relate to EO. These are: (1) Records Management, see Exhibit (PG&E-7), Chapter 8B; (2) Cybersecurity, see Exhibit (PG&E-7), Chapter 10; and (3) Employee Safety and Contractor Safety (two separate risks), see Exhibit (PG&E-7), Chapter 2.

equipment designs, operations and maintenance (O&M) procedures, and PG&E's spending decisions.

The likelihood of an in-service failure is influenced by several factors including asset condition. Methods used to assess the condition of dams and potential likelihood of dam failure are prescribed by the Federal Energy Regulatory Commission (FERC) and the California Department of Water Resources Division of Safety of Dams and include: engineering guidelines; surveillance and monitoring programs; seismic risk evaluations; and probable maximum flood standards.

PG&E works continuously to inspect, monitor, maintain, repair, and replace these assets. PG&E's Power Generation Department has a Dam Safety Program and an Asset Management team. These teams coordinate their work across the department to ensure the safe and reliable operation of PG&E's dams, water conveyance systems and penstocks. With respect to its water conveyance systems, PG&E is proactively relining its canals, improving drainage, removing hazardous trees, replacing flumes and installing Supervisory Control and Data Acquisition (SCADA) capability in order to detect leaks and breaks within required timeframes. Importantly, PG&E is prioritizing its work to address high consequence sections first.

c. Hydro System Safety Risk Assessment and Expenditures

Power Generation has substantially strengthened its controls for managing this enterprise risk over the last four years. Power Generation has completed this work to mitigate the risk of this low-probability, high-consequence event and has implemented new controls in its asset management and facilities safety programs. This risk will continue to be monitored and evaluated as part of the enterprise risk management program.[10]

---

10 See Exhibit (PG&E-5), Chapter 4 for the costs to address the risks associated with dams, water conveyance systems, and penstocks.

2. Electric Grid Restoration

a. Electric Grid Restoration – Risk Definition, Scenario, and Score

Electric Grid Restoration is a newly identified enterprise risk and considers PG&E's ability to restore power in a timely fashion in the event of a systemwide black-out requiring the deployment of black-start[11] resources within PG&E's service territory. The scenario used to score this risk in RET is, "following a system-wide black-out requiring black-start resources, extended customer restoration results in trust issues, negative financial impacts and potential public safety issues." This risk has a RET score of 283.

PG&E is including a discussion of this enterprise risk in the 2017 GRC because the CPUC is a key stakeholder when considering the reliability implications and public safety considerations of a systemwide black-out event. The Company is including the discussion in this exhibit as the risk aligns more with Power Generation facilities and the transmission system than the electric distribution system. If, in the future, PG&E determines that expenditures are necessary to mitigate this risk the Company will include those forecast expenditures in the appropriate filing, whether that is a GRC and/or a Transmission Owner filing with FERC.

b. Electric Grid Restoration – Controls

In compliance with North American Electric Reliability Corporation (NERC) EOP 005-2,[12] PG&E has created Electric System Restoration Guidelines to use black-start resources to execute restoration for the transmission grid based on the following priorities: (1) off-site power to

---

11 Black-start capable generation is defined as a generating unit and its associated equipment that has the ability to be started without support from the system and is designed to remain energized without connection to the remainder of the system. A formal "black-start resource" is a generating unit that has entered into a three-party Black-start Resource Agreement with the California Independent System Operator, generator owner, and Transmission Owner (TO) to adhere to black-start testing requirements and to maintain the black-start capability of a unit.

12 The purpose of this standard is to "ensure plans, Facilities, and personnel are prepared to enable System restoration from Black-start Resources to assure reliability is maintained during restoration and priority is placed on restoring the Interconnection." (NERC Standard EOP-005-2.)

Diablo Canyon Power Plant; (2) major generating stations; (3) the transmission system backbone; (4) peaking plants; (5) control centers; (6) local transmission; (7) interconnected operations; and (8) customer load.

Additional controls can be divided into two categories: (1) infrastructure; and (2) procedural. Infrastructure controls relate to having the proper assets in place to appropriately respond to black-start events. These controls include, but are not limited to: (1) black-start resources at a variety of strategic locations across the service territory; (2) assurance of the availability of multiple transmission paths to allow several options for energizing the transmission system; (3) substation battery tests; and (4) expediting transmission voltage planning and operations projects as needed to mitigate voltage concerns.

Procedural controls relate to having plans in place to respond in the instance of a black-start event. Procedural controls include, but are not limited to: (1) the existence of an Emergency Operations Center to aid in coordination during large emergency events; (2) annual training exercises for outage response; and (3) the establishment of multiple methods of communication to the field (e.g., cell phones, citizens band or CB radios, satellite phones, priority calling cards) to alleviate the risk of loss of communication in the case of an outage event.

c. Grid Restoration Risk Assessment and Expenditures

As mentioned above, this risk is new to the EO Risk Register and a formal risk assessment was completed in June 2015. Due to the timing of this assessment process, there is no expenditure forecast for this risk in this GRC. Although no forecasts are included in this GRC, there are a number of potential additional mitigations being considered that may require additional work in the future. These include: (1) the addition of new black-start resources in certain locations to address restoration needs; and (2) a re-evaluation of capital project prioritization with a focus on infrastructure supporting grid restoration (e.g., voltage control).

D. Electric Operations' Asset and Process Risks

The EO Risk Register includes numerous risks associated with power generation, transmission, substation, and distribution assets and processes. This section identifies: (1) which risks relate to the Power Generation facilities;[13] (2) how the hydro and fossil facility risks map to the other chapters in this exhibit; and (3) how PG&E's 2017 capital and expense forecast for hydro and fossil power generation operations align with all the relevant risks from the EO Risk Register.

Figure 2-3 modifies the EO Risk Register from earlier in this chapter (Figure 2-2) to highlight the relevant Power Generation safety and reliability risks for this exhibit. Risks that are not relevant to this exhibit, or are not a significant safety or reliability risk are shaded in gray.

---

13 See Exhibit (PG&E-4) for electric system risks.

FIGURE 2-3
RISKS RELEVANT TO EXHIBIT (PG&E-5)

EO Risk Register – Grouped (73 Total Risks)

As of 7/21/15

ENTERPRISE RISKS
- ENT1 Wildfire
- ENT2 Emergency Preparedness and Response to Catastrophic Events
- ENT3 Failure of Substation (Catastrophic)
- ENT4 Hydro System Safety – Dams
- ENT5 Electric Grid Restoration

PROCESS RISKS
- PROC2 Critical Equipment Procurement
- PROC4 Encroachment on EO Assets
- PROC5 Lack of Transmission Project Delivery
- PROC6 Workforce Planning
- PROC7 Lack of Real-time Operational Workaround for Loss of Critical Systems
- PROC8 Control Room Operational Awareness
- PROC9 Cover-up/ Fraud
- PROC10 Risk of Non-Compliance
- PROC12 Distributed Generation
- PROC13 Seismic Resiliency
- PROC14 Voltage Planning and Operation
- PROC15 Contact Voltage

ENERGY PROCUREMENT RISKS
- EP1 AB 32/ Cap-and-Trade
- EP2 Market Flaws/ Manipulation
- EP3 New Policy and Market Design
- EP4 Bulk Power Operations
- EP5 Portfolio Mix
- EP6 Above-Market Stranded Costs
- EP7 Changing GHG Regulations
- EP9 Safety Standards for PPAs
- EP10 Significant Natural Gas Price Increase

CORPORATE SECURITY RISKS
- CSEC1 Asset Security
- CSEC2 Fairfield Security Control
- CSEC3 Insider Threat
- CSEC4 Workplace Violence

TRANSMISSION OVERHEAD RISKS
- ETOH1 Transmission Overhead Conductors
- ETOH2 Transmission Overhead Steel Support Structures
- ETOH3 Transmission Overhead Wood Support Structures
- ETOH4 System Integrity Protection Schemes (SIPS)
- ETOH5 Transmission Overhead Switches
- ETOH6 Loss of Transmission Corridor

DISTRIBUTION OVERHEAD RISKS
- EDOH1 Distribution Overhead Conductor Primary
- EDOH2 Distribution Overhead Support Structures
- EDOH3 Distribution Overhead Line Equipment – Voltage Regulators, Boosters, and Cap
- EDOH4 Distribution Overhead Streetlight Struc.
- EDOH5 Distribution Overhead Conductor Secondary
- EDOH6 Distribution Overhead Transformers
- EDOH7 Distribution Overhead Line Equipment – Protective

T&D UNDERGROUND RISKS
- EDUG1 Distribution Underground Line Equipment
- EDUG2 Distribution Underground Cables
- EDUG3 Distribution Underground Subsurface and Pad-Mount Transformers
- EDUG4 Network Components (In Urban/ High Density Areas)
- ETUG1 Transmission Underground Cables and Equipment

SUBSTATION/SWITCHYARD RISKS
- SS2 Substation Transformers & Voltage Regulators
- SS3 Substation Protective Relays, Instrument Transformers & Station Batteries
- SS4 Substation Voltage & Flow Control Equipment
- SS5 Substation Circuit Breakers and Switchgear
- SS6 Substation Grounding Systems
- SS7 Substation Switches
- SS8 Unit Substations
- SS9 Substation Bus Structures

POWER GENERATION RISKS
- PG1 Hydro Public Access
- PG2 Hydro Material Release Into Water
- PG3 Failure of Generation Facility (Catastrophic)
- PG4 Fossil High Energy Systems
- PG5 Fossil Turbine – Generation Systems
- PG6 Fossil Protection and Control Systems
- PG7 Fossil Balance of Plant
- PG8 Fossil Chemical Systems
- PG9 Fossil Fuel Systems
- PG10 Hydro Pressure Integrity Systems
- PG11 Hydro Turbine – Generation Systems
- PG12 Hydro Protection and Control Systems
- PG13 Hydro Balance of Plant
- PG14 Hydro Support Infrastructure
- PG15 Hydro In-Stream Flow Release (IFR) Valve and Bypass
- PG16 Fuel Cell Systems
- PG17 Photovoltaic Systems

Risks in white apply to Exhibit 5

Risks in gray do not apply to Exhibit 5

(PG&E-5)

Table 2-1 summarizes the risks relevant to this exhibit and provides the risk score for each.

TABLE 2-1
2017 GRC ENTERPRISE, HYDRO AND FOSSIL GENERATION ASSET AND PROCESS RISKS

Risk Group	Risk Name	EO Risk Designation	Risk Score
Enterprise	Hydro System Safety	ENT4	349
	Electric Grid Restoration	ENT5	283
Hydro	Public Access	PG1	174
	Material Release Into Water	PG2	13
	Pressure Integrity Systems	PG10	104
	Turbine – Generation Systems	PG11	174
	Protection and Control Systems	PG12	37
	Balance of Plant	PG13	23
	Support Infrastructure	PG14	174
	In-Stream Flow Release	PG15	42
	Asset Security	CSEC1	229
	Risk of Non-Compliance	PROC10	82
Fossil	Failure of Generation Facility (Catastrophic)	PG3	189
	High Energy Systems	PG4	33
	Turbine – Generation Systems	PG5	98
	Protection and Control Systems	PG6	27
	Balance of Plant	PG7	23
	Chemical Systems	PG8	98
	Fuel Systems	PG9	103
Switchyard(a)	Transformers & Voltage Regulators	SS2	175
	Protective Relays, Instrument Transformers & Station Batteries	SS3	159
	Circuit Breakers/Switchgear	SS5	53
	Grounding Systems	SS6	18
	Switches	SS7	215
	Bus Structures	SS9	69
Other PG&E-Owned Generation & Additional Risks	Fuel Cell Systems	PG16	18
	PV Systems	PG17	18
	Safety Standards for Power Purchase Agreements	EP9	308

(a) All generation facilities have switchyards that contain assets such as step-up transformers, circuit breakers, switchgear, switches, grounding systems, etc. Substation/switchyard risks apply to switchyards at hydro and fossil generation facilities. While substation and switchyard assets are often very similar, these risks have not yet been uniquely scored for power generation applications. The scores in Table 2-1 use the scores based on substation equipment assessments.

With the risks relating to Power Generation assets identified, Figure 2-4 shows the relationship between the chapters and Major Work Categories (MWC) in this exhibit and the risks from Table 2-1.

FIGURE 2-4
2017 EXPENDITURE FORECAST MAPPING TO RISK REGISTER BY CHAPTER AND MWC

		Enterprise						Hydro												Fossil								Switchyard								Other PG&E Owned Gen. & Addtl Risks		Other Work
Chapter	MWC	(ENT5) Electric Grid Restoration	(ENT4) Hydro System Safety - Dams	Cybersecurity	Records Management	Employee Safety	Contractor Safety	Hydro - General	(PG1) Public Access	(PG2) Material Release Into Water	(PG10) Pressure Integrity Systems	(PG11) Turbine Generation Systems	(PG12) Protection & Control Systems	(PG13) Balance of Plant	(PG14) Support Infrastructure	(PG15) In-Stream Flow Release Valve & Bypass	(CSEC1) Asset Security	(PROC10) Risk of Non-Compliance	Fossil - General	(PG3) Failure of Gen Facility (Catastrophic)	(PG4) High Energy Systems	(PG5) Turbine - Generation Systems	(PG6) Protection & Control Systems	(PG8) Chemical Systems	(PG7) Balance of Plant	(PG9) Fuel Systems	Switchyard - General	(SS2) Transformers & Voltage Regulators	(SS5) Circuit Breakers & Switchgear	(SS7) Switches	(SS6) Grounding Systems	(SS3) Pro Relays, Inst Transformers & Batteries	(SS9) Bus Structures	(PG16) Fuel Cell Systems	(PG17) Photovoltaic Systems	(EP9) Safety Standards for PPAs	Hydro Other - Relicensing	Hydro Other Not Assigned
4	AB																																					
	AX																																					
	AY																																					
	EP																																					
	ES																																					
	IG																																					
	KG																																					
	KH																																					
	KI																																					
	KJ																																					
	2L																																					
	2M																																					
	2N																																					
	2P																																					
	3H																																					
	11																																					
	12																																					
4 & 5	AK																																					
	5																																					
5	KK																																					
	KL																																					
	KM																																					
	KQ																																					
	KR																																					
	KS																																					
	2R																																					
	2S																																					
	2T																																					
	3																																					
	3A																																					
	3B																																					
6	CT																																					
7	JV																																					
	2F																																					

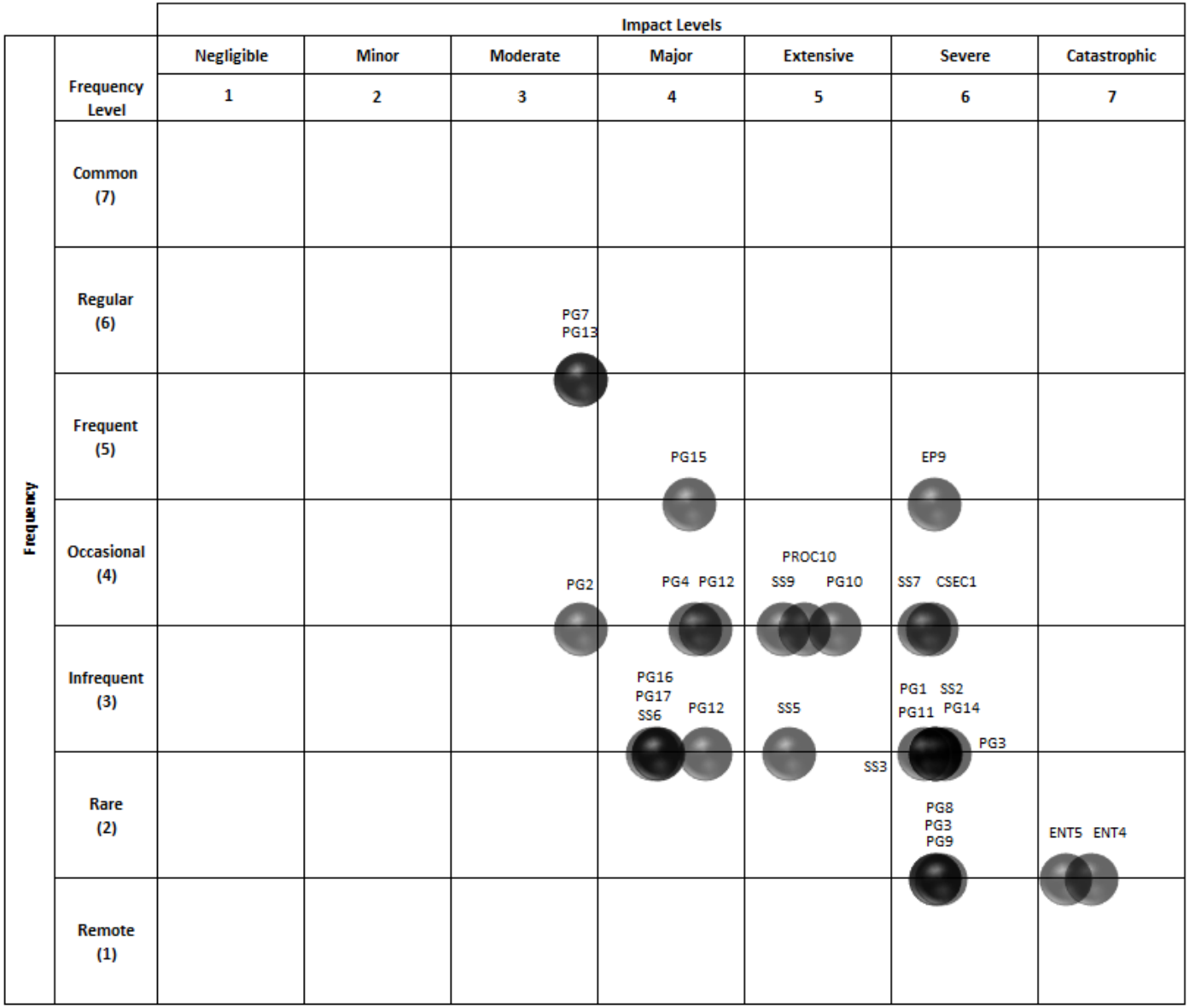
Figure 2-4 correlates the risks from Table 2-1, above, to the relevant chapters in this exhibit. If Figure 2-4 indicates a relationship between a risk and a chapter that means the work activities or forecasts in that chapter address a risk in some manner. For example, expenditures in MWC AX (to maintain reservoirs, dams, waterways) address risks associated with hydro system safety and other hydro facilities.

Two aspects of Figure 2-4 require further explanation. First, under the hydro and fossil categories there are column headings labeled "Hydro – General," and "Fossil – General." PG&E notes that the EO Risk Register does not include any "general risks." PG&E is including these categories in this GRC for the purpose of capturing relationships and expenditures for work activities that address several risks. Second, there is a section on the right hand side of Figure 2-4 titled "Other PG&E-Owned Generation & Additional Risks." The columns within this section identify work that is related to PG&E's fuel cell and PV facilities. It also includes the risk, Safety Standards for PPAs, which is related to administering safety-related terms and conditions in procurement contracts.[14]

Figure 2-5 displays the risks relevant to this exhibit in a "heat map." This visual representation provides insight into the impact and frequency components of each risk's overall risk score and displays the risk scores relative to one another.

[14] See Exhibit (PG&E-5), Chapter 6 for further information.

FIGURE 2-5
2017 GRC EXHIBIT (PG&E-5) RISK HEAT MAP



(PG&E-5)

See Chapters 4 and 5 of this exhibit for further information regarding how PG&E addresses hydro and fossil asset risks.

E. 2017 GRC Expenditure Forecast to Risk Register Mapping

This section describes the results of the mapping of expense and capital expenditure forecasts to the items tracked in the EO Risk Register that the forecasts help to mitigate. Figure 2-6 at the end of this section shows the product of mapping Hydro and Fossil Operations forecast expenditures to the relevant Risk Register items.[15]

Across the top of Figure 2-6 are five groupings:

1. Enterprise Risks
2. Hydro Risks
3. Fossil Risks
4. Switchyard Risks
5. Other PG&E Owned Generation & Additional Risks

The expense and capital expenditures in these categories represent the sum of the values in the boxes below each category. The boxes below each category come from Table 2-1 which, as described in the preceding section, are the items from the EO Risk Register that relate to Power Generation. Above the Risk Register items for the categories are the previously described hydro and fossil general risks. The sum of all the values in the five categories are shown at the bottom of the box labeled “Expenditures that Align with to Risk Register Items” located on the left side of the figure.

An additional category is shown in the lower section of the figure and is labeled as “Other Work.” The values in this section represent the sum of the values of the boxes to the right. Last, there is a box in the upper left corner. This box is the sum of the other two boxes on the left side of the figure and represents the total expense and capital forecast for this exhibit.[16]

For Hydro and Fossil Operations, expenditure mapping was done at the planning order level. When possible, a planning order was mapped to a

---

[15] Workpaper Tables 2-3 through 2-6 provide the details supporting Figure 2-6.

[16] Note that although risks related to DCPP are not discussed in Part I, they are included on this chart to best illustrate the comprehensive set of risks in Exhibit (PG&E-5).

single item on the Risk Register. When it was not possible, PG&E assigned the expenditures to either the Hydro or Fossil general risk categories.

Note that the expenditures in the general risk categories include projects and work activities that mitigate asset risks identified in Figure 2-6 but it is not possible to map the expenditures to the specific risks. For example, some switchyard risks show no expenditures. However, activities associated with these risks (e.g., inspections) are reflected in the expenditures for Hydro and Fossil Risks – General. This is also true for the fossil risk “Failure of Generation Risk (Catastrophic).”

FIGURE 2-6
2017 EXPENDITURE FORECAST TO RISK REGISTER MAPPING
(THOUSANDS OF NOMINAL DOLLARS)

Expenditures that Align to Risk Register Items

Ex. 5 Total Exp	Ex. 5 Total Cap	Total -- Enterprise Risks Exp	Total -- Enterprise Risks Cap	Total -- Hydro Risks Exp	Total -- Hydro Risks Cap	Total -- Fossil Risks Exp	Total -- Fossil Risks Cap	Total -- Switchyard Risks Exp	Total -- Switchyard Risks Cap	Total -- Other PG&E Owned Generation & Additional Risks Exp	Total -- Other PG&E Owned Generation & Additional Risks Cap
$746,806	$480,160	$42,902	$94,441	$140,743	$137,983	$60,000	$14,160	$1,312	$8,808	$5,536	$332

Risk	Exp	Cap
Enterprise Risks		
Electric Grid Resoration	$0	$0
Hydro System Safety - Dams	$38,871	$85,141
Cybersecurity	$1,800	$9,300
Records Management	$1,660	$0
Employee Safety	$570	$0
Contractor Safety	$0	$0
Nuclear Operations & Safety - Core Damaging Event	$0	$0
Hydro Risks		
Hydro Risks - General	$57,951	$1,247
Public Access	$503	$262
Material Release Into Water	$265	$3,691
Pressure Integrity Systems	$1,980	$7,304
Turbine - Generation Systems	$21,569	$74,821
Protection & Control Systems	$3,704	$13,751
Balance of Plant	$1,305	$8,776
Support Infrastructure	$20,902	$21,345
In-Stream Flow Release Valve & Bypass	$50	$0
Asset Security	$25	$550
Risk of Non-Compliance	$32,489	$6,235
Fossil Risks		
Fossil Risks - General	$37,309	$309
Failure of Generation Facilitity (Catastrophic)	$0	$0
High Energy Systems	$839	$0
Turbine - Generator Systems	$18,192	$6,951
Protection & Control Systems	$0	$6,350
Chemical Systems	$200	$150
Balance of Plant	$3,460	$300
Fuel Systems	$0	$100
Switchyard Risks		
Switchyard Risks - General	$0	$0
Transformers and Voltage Regulators	$106	$6,208
Circuit Breakers and Switchgear	$345	$2,400
Switches	$0	$200
Grounding Systems	$861	$0
Protective Relays, Instrument Transformers & Station Batteries	$0	$0
Bus Structures	$0	$0
Other PG&E Owned Generation & Additional Risks		
Fuel Cells	$1,393	$8
Photovoltaic Systems	$3,643	$324
Safety Standards for PPAs	$500	$0
Expenditures that Align to Risk Register Items		
Exp	$250,492	
Cap		$255,725

Other Work

	Exp	Cap	
Nuclear Operations	$425,650	$159,700	Values from Exhibit (PG&E-5), Ch 3, Tables 3-19 and 3-20
Hydro Other - Relicensing	$0	$16,485	Value from Workpaper Table 2-6, lines 269 thru 278
Hydro Other	$4,589	$5,250	Values from Workpaper Table 2-5, lines 349 thru 354; and Workpaper Table 2-6, lines 267 anb 268
Energy Procurement	$60,475	$0	Values from Ex (PG&E-5), Ch 6, Tables 6-11 and 6-12 less amounts mapped to Safety Standards PPAs
Information Technology	$5,600	$43,000	Values from Exhibit (PG&E-5), Ch 7, Tables 7-1 and 7-2, less amounts mapped to Cybersecurity
Other Work Exp	$496,314		
Other Work Cap		$224,435	

Notes:
(1) Hydro, Fossil, and Switchyard "General" risks represent expenditures that address multiple risks within those systems but a direct allocation is not possible.
(2) Numbers listed in each risk box represent total costs to mitigate the risk, not just the incremental portion.
(3) Gray highlighting denotes risks owned and managed by other lines-of-business that are included in the forecast for Exhibit 5.
(4) Black highlighting denotes risks associated with Diablo Canyon Power Plant (DCPP).
(5) DCPP projects mitigating enterprise risks completed before 2017. An estimated $54.4M was spent before 2017 to mitigate the Nuclear Operations & Safety risk of a Core Damaging Event.

Figure 2-6 results in an estimate of how the 2017 GRC forecast relates to the items on the Risk Register. This is an initial step in an evolving process. However, at this time, PG&E considers Figure 2-6 to be a reasonable representation of how the 2017 GRC forecast relates to the Risk Register.[17]

F. Risk Informed Budget Allocation (RIBA) Process

EO uses the RIBA[18] process to inform the prioritization of work for risk mitigation measures and other work in the Power Generation portfolio. The process is used for capital and expense work as part of PG&E's Integrated Planning Process and is also used throughout the year when budget trade-off decisions are necessary due to changing circumstances. RIBA is one of several factors used in prioritizing spending.

EO uses RIBA as directed by PG&E's Finance organization. The output of the RIBA process is a risk-scored portfolio that can be sorted in multiple ways (by flag, risk score, etc.). The results are presented to management as part of the Integrated Planning Process.

There is a distinction in purpose between a risk score from the Risk Register and a program or project score from the RIBA process. The purpose of the Risk Register risk score, a product of likelihood of failure and consequence of failure, is to rank risks from an asset, event or process level. The purpose of a RIBA score is to capture on a relative basis the safety, environment, and reliability risks that each project or program in EO aims to prevent, based on the worst-case credible event that the work activity mitigates.

Figures 2-7 and 2-8 summarize the outcome of the RIBA process for the 2017 GRC expense and capital expenditure forecasts for Hydro and Fossil facilities for this exhibit (i.e., the total expenditures for these figures equal the 2017 expense and capital forecasts for Chapters 4 and 5 of this exhibit).[19] In both figures, forecast expenditures are shown on the x-axis and the RIBA score is shown on the y-axis. The width of the bar represents the forecast and the

---

17 See Exhibit (PG&E-7), Chapters 2, 8B, and 10 for additional information regarding the enterprise risks—Employee Safety, Contractor Safety, Records Management, Cybersecurity—that are owned and managed by other lines of business (LOBs).

18 See PG&E's submission in the Safety Model Assessment Proceeding (A.15-05-003) for detailed information on the RIBA process.

19 Workpaper Tables 2-7 and 2-8 provide the details that support Figures 2-7 and 2-8.

height of the bar represents the RIBA score. The shading of each bar is used to show whether the work is hydro or fossil. The mandatory, compliance, and commitment flags are mutually exclusive and designed to capture all required work. Other flags are not mutually exclusive and multiple flags may be assigned to that work.

FIGURE 2-7
RIBA – 2017 POWER GENERATION EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

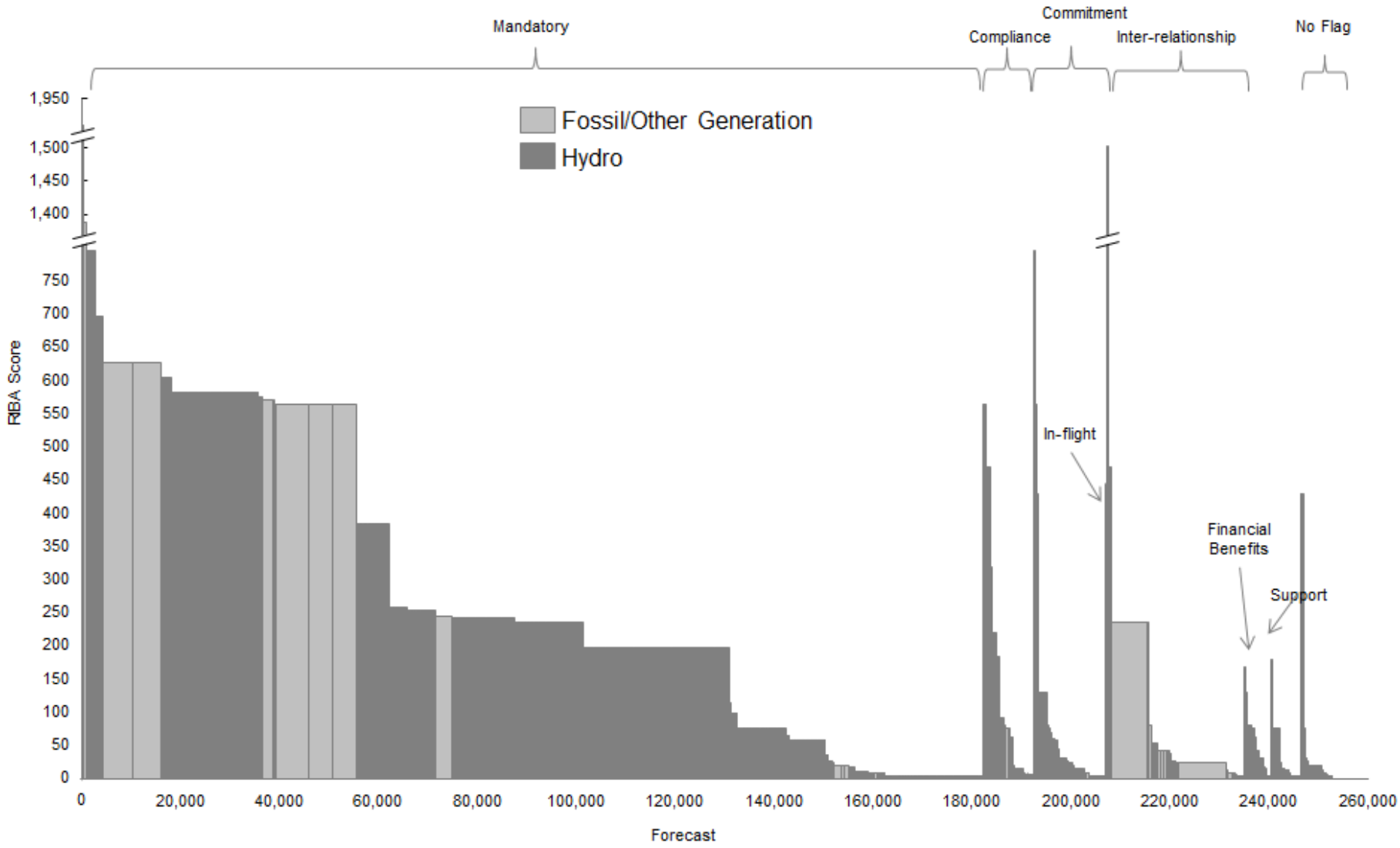
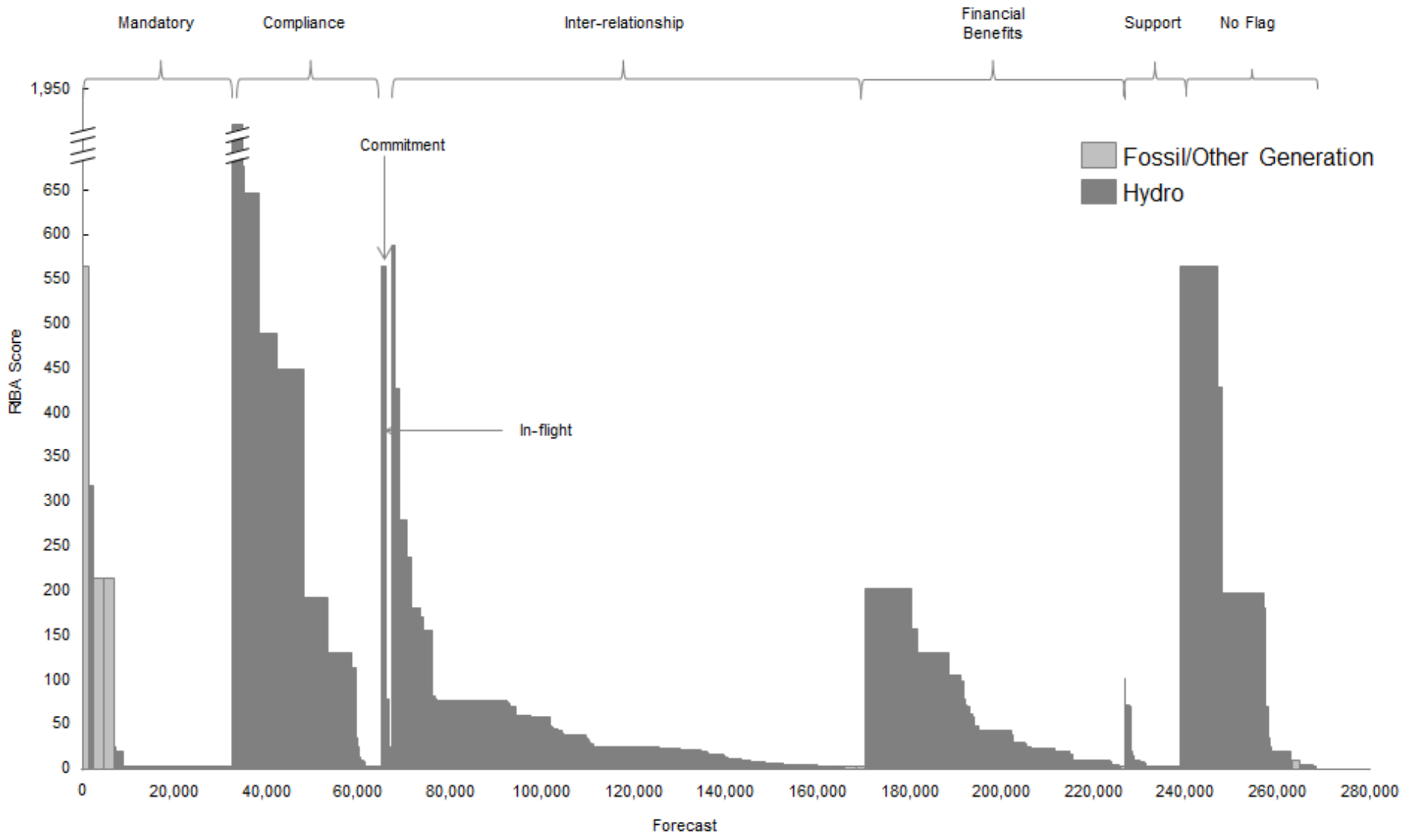


FIGURE 2-8
RIBA – 2017 POWER GENERATION CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)



(PG&E-5)

RIBA scores alone do not determine work prioritization. For example, due to system and/or resource constraints it is sometimes more efficient to coordinate and perform lower scoring RIBA work during a single facility outage in order to avoid multiple outages or waiting an excessive period of time to perform the work.

G. Power Generation – Conclusion

EO's use of the EORM Program provides a repeatable and consistent method of managing risks through identification, evaluation, response, and monitoring. The RIBA process provides a means of making expenditure decisions that are risk informed while considering other important factors. Lastly, both the EORM Program and RIBA process involve personnel that are most familiar with the condition of assets so that all levels of management are engaged. PG&E believes these approaches, over time, will reduce the overall risk profile of its Power Generation assets.

While the processes have matured considerably over the last several years, further improvement and evolution is necessary. PG&E is exploring methodologies to evolve its risk management framework from one focused on relative risk to a more quantitative methodology including pilots in both Gas and Electric Operations in probabilistic risk assessment methods. The Company is also exploring methods of quantifying risk reduction.[20] Potential areas of future focus for EO also include:

- Improving the quantitative rigor associated with the likelihood of asset failure.
- Enhancing GRIT to better aid Power Generation users in making informed decision about equipment replacement.
- Further developing and refining the EO Risk Register to address interactive threats.[21]
- Improving the relationship between risks and expenditures.

---

20 See Exhibit (PG&E-2), Chapter 3 for a description of PG&E's exploration of methodologies to evolve the Company's risk management framework from one focused on relative risk to a more quantitative methodology.

21 Interactive threats are the coincidence of two or more threats to an asset or process, the result of which is more damaging than either of the individual threats themselves.

Part II: Diablo Canyon Safety and Risk Management

H. Introduction

1. Scope and Purpose

The purpose of Part II of this chapter is to describe PG&E's Risk Management Program for Diablo Canyon. Part II includes the following sections:

- Section I – Nuclear Operations Risk Management Program – Overview of the Nuclear Operations Risk Register, risk evaluation activities and the RIBA process.
- Section J – Nuclear Operations Enterprise Risks – Identifies and provides information on the top nuclear Enterprise and Operational risks.
- Section K – Operational Risks Assessments – Presents the results of:
  - The RIBA process as it relates to the 2017 expense and capital expenditure forecasts.
  - Mapping of the forecast expenditures to items in the Risk Register.
- Section L – Other Risk Assessment, Controls and Mitigation.
- Section M – Risk Informed Budget Allocation.
- Section N – Nuclear Operations – Conclusion – Discusses future plans.

I. Nuclear Operations Risk Management Program

Nuclear Operations uses the EORM Program to manage nuclear operations risks. This program requires Nuclear Operations to identify, evaluate, respond, and monitor risks. The process provides a repeatable and consistent method to manage risks and is an important element of PG&E's Integrated Planning Process. Figure 2-1 above, illustrates the process.

From an organizational perspective, the EORM Program requires that each line of business (LOB) have a risk management organization to coordinate risk management activities within the LOB. The risk management organization within Nuclear Operations is the Compliance, Alliance and Risk (CAR) Department. CAR is responsible for ensuring that risks are identified and evaluated and that risk response plans are developed. The team consists of a director, manager, and two full-time employees from the Project Management Office, Project Services, and the Project Review Sub-committee comprised of

managers from Operations, Engineering, Maintenance, and Project Services. All risk assessments are reviewed and approved by the Project Review Committee (PRC) comprised of directors from Operations, Engineering, Work Management, Project Services, and CAR.

The remainder of this section addresses the Nuclear Operations Risk Register, risk assessments, and the RIBA process.

1. Risk Register

PG&E uses risk registers to consistently log and classify risks. Nuclear Operations' risks are categorized as follows: enterprise risks, operational risks, equipment issue risks, or process risks.

Enterprise Risks: Enterprise risks are risks that could have a catastrophic impact on the Company if they were to occur.

Operational Risks: Operational risks are risks that could have a catastrophic impact on DCPP if they were to occur. Additionally, projects that have been approved to resolve equipment issue risks can also introduce operational risk during implementation. These are documented in the Project Risk Register.

Process Risks: Process-based risks have consequences associated with business processes, programs, company personnel, etc. All of the processes at Diablo Canyon have been risk scored using the RIBA methodology.

Equipment Issue Risks: System health issues that have been documented as issues with potential or actual component failure or malfunction. These are documented in Plant Health Issue Plans. These issues are risk scored utilizing the Plant Priority Matrix and the RIBA methodology.

Section J of this chapter identifies key safety and reliability enterprise risks associated with operations and DCPP. Evaluations and projects being implemented to mitigate these risks are briefly discussed. Each of the risk-mitigating projects identified in Tables 2-2 and 2-3 has a corresponding priority score that reflects the consequence and likelihood of component failure or malfunction. This score is used to provide a relative ranking of risks. The following sections provide an overview of the tools Nuclear Operations uses to evaluate and score risks.

2. Risk Evaluation

Nuclear Operations uses three tools to evaluate enterprise, operational, and equipment issue/process risks:

- The Risk Evaluation Tool 2.1 (RET)
- Plant Priority Matrix
- RIBA

a. Application of RET for Nuclear Operations

PG&E's EORM organization has created the RET which is used to establish a risk score for each item on the Risk Register. The risk score reflects a product of the consequence and likelihood of failure and is used to rank and prioritize risks. To foster consistency, risk scores are reviewed by SMEs and risk owners with support from the risk management team. The RET is used for enterprise risks and for operational risks introduced by implementation of projects.

b. Plant Priority Matrix/RIBA

It is important to note that there is a distinction between scoring enterprise and operational risks and scoring equipment issue/process risks. Equipment issues are evaluated using the Plant Priority Matrix and RIBA scoring tools. Processes are evaluated using the RIBA scoring tool. These evaluations focus on the risk incurred if the issue or process is not resolved or performed.

J. Nuclear Operations Enterprise Risks

This section identifies and discusses the Company's enterprise risks that are the responsibility of Nuclear Operations.

PG&E has a total of 17 enterprise risks. Of these, one is the responsibility of Nuclear Operations. Additionally, Nuclear Operations has one key operational risk that is managed and monitored similar to an enterprise risk. These risks are as follows:

- Nuclear Operations and Safety – Core Damaging (enterprise risk)
- Nuclear Operations and Safety – Extended Shutdown (operational risk)

The following sections provide additional information regarding these risks of Nuclear Operations and Safety.

1. Core Damaging (Enterprise Risk)

a. Risk Definition, Scenario, and Score

Nuclear Operations and Safety Core Damaging was first identified as an enterprise risk in 2007 and is defined as a nuclear reactor core-damaging event with the potential for radiological release. A core-damaging event is most likely to arise from a natural disaster, equipment failure, or some other significant event.

Nuclear Operations and Safety Core Damaging risk has a RET score of 110. The RET scenario (or P95 scenario) used to score this risk is defined as, “Extreme external event (seismic) results in a station blackout (no onsite or offsite power available) and subsequent equipment failures and recovery actions fail. This results in the inability to remove decay heat leading to a core damaging event.”

b. Major Controls

Nuclear Operations develops and monitors controls relative to potential core damaging events by identifying risk drivers and developing mitigation plans. Table 2-2 below summarizes those assessments.

TABLE 2-2
NUCLEAR OPERATIONS AND SAFETY – CORE DAMAGING

Risk Driver	Mitigation	Status
Natural Events (Beyond Design Basis (BDB))	Reexamine the susceptibility to external events using current Nuclear Regulatory Commission (NRC) requirements to identify any vulnerabilities that are not mitigated by current strategies.	DUE: 3/12/15 for external hazards such as seismic, flooding, and tsunami events Submittal to NRC sent 3/10/15
Core Cooling (Beyond Design Basis)	Implement new NRC regulations regarding BDB non-permanent plant equipment that may be relied upon for mitigating such events.	Plan submitted to NRC 2/28/13 DUE: 5/26/16 to implement the plan to the NRC, with final completion within two refueling cycles (consistent with NRC FLEX implementation timeline)
Core Cooling (Beyond Design Basis)	Perform on-shift staffing and communication studies to assure that sufficient staff is available with acceptable communication systems to support existing and emergent BDB strategies.	Phase 1 submitted 4/24/13 to NRC DUE: 5/27/15 Implementation from submittal is final action. Staffing Study Table Top 4/1/15 Submitted to NRC in May – Complete
Core Cooling (Beyond Design Basis)	Evaluate and upgrade the spent-fuel pool level instrumentation to ensure it is capable of determining accurate level during a BDB scenario.	Plan submitted to NRC 2/28/13 DUE: 12/31/16 to implement the plan to the NRC with, final completion within two refueling cycles
Natural Events (Beyond Design Basis)	Evaluate the need for additional equipment onsite to clear debris generated by natural events in order to permit unfettered movement of equipment and materials around the station.	COMPLETE
Core Cooling (Beyond Design Basis)	Improve Reactor Cooling Pump seal design to extend the duration of the time that the seals will endure a station blackout without becoming a significant reactor coolant leak source.	DUE: 5/30/16 Westinghouse issued 10 Code of Federal Regulations (CFR) Part 21. Outage Management and Projects schedule 1R19 (10/30/15) and 2R19 (5/30/16).
Core Cooling (Beyond Design Basis)	Evaluate and modify plant support programs/processes to adequately include critical non-permanent plant equipment that is relied upon to mitigate BDB events.	Plan submitted to NRC 2/28/13 DUE: 5/26/16 to implement the plan to the NRC, with final completion within two refueling cycles
Core Cooling (Beyond Design Basis)	Add a requirement for Quality Verification, Nuclear Safety Oversight Committee (NSOC), and the self-assessment program to periodically assess BDB activities/ capabilities.	COMPLETE QV – Complete NSOC – Complete SA – Complete
Operational Response	Complete all actions associated with Significant Operating Experience Report (SOER) 10-02. "Engaged Thinking Organization" to enhance response to operational events.	COMPLETE
Safety Culture	Complete actions to improve work environment (per existing action plans).	COMPLETE Completion of action plan documented in notification.
Safety Culture (Beyond Design Basis)	Institute for Nuclear Power Operations (INPO) has issued a series of Industry Event Reports to collect information on existing and needed BDB capabilities. Lessons learned and recommendations were issued in IER LI-13-10 (March 2013).	DUE: 01/15/17

c. Cost of Major Controls

Certain projects and equipment purchases were identified as part of the EORM process to implement mitigation measures and address "gap"

issues that were identified as part of the process. The EORM projects that have been completed for DCPP include: (1) the acquisition of equipment for backup cooling for the spent fuel pools for both units; and (2) the creation of procedures to implement the use of the equipment in the event of a failure of the permanent design basis equipment.

Table 2-3 identifies specific projects that address risk of BDB events that are in progress and are included for planning and forecasting purposes in the 5 years ending 2019. These projects have been included in DCPP's GRC forecast. The equipment and work scope planned for these projects include:

- Evaluate and upgrade the spent-fuel pool level instrumentation to ensure it is capable of determining accurate level during a BDB scenario.
- Perform on-shift staffing and communication studies to assure that sufficient staff is available with acceptable communication systems to support existing and emergent BDB strategies.
- Adopt the NRC-endorsed guidelines for the industry-developed FLEX strategy for BDB event mitigation. The FLEX strategy includes procurement of equipment that can quickly be connected to nuclear safety equipment if needed.
- Improve RCP seal design to extend the duration of time that the seals will endure a postulated event without becoming a reactor coolant leak source.

TABLE 2-3
NUCLEAR OPERATIONS COSTS
RISK MANAGEMENT INVESTMENTS – TOTAL PROJECT ESTIMATES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	ERM Projects	Capital
1	Spent Fuel Pool Instrumentation	$4,314
2	Fukushima Communication Equipment	$2,532
3	Fukushima FLEX Equipment	$33,706
4	Reactor Cooling Pump Thermal Seals	$13,823

2. Extended Shutdown (Operational Risk)

a. Risk Definition, Scenario, and Score

Nuclear Operations and Safety Extended Shutdown was first identified as an enterprise level risk in 2007 and is defined as an extended shutdown of Diablo Canyon (for longer than three months or with a financial impact greater than $100 million) due to equipment failure, natural disaster, regulatory action or some other significant event.

Nuclear Operations and Safety Extended Shutdown risk has a RET score of 126. The RET scenario (or P95 scenario) used to score this risk is defined as, “A major component failure or project risk occurs that is characterized by long lead time (> 90 days) to replace (e.g., turbine-generator, steam generator, reactor pressure vessel), or financial impact would exceed relief provided by business interruption provisions PG&E has invested in through NEIL, or vital structural component is damaged or failed (e.g., containment building).”

b. Major Controls

Nuclear Operations develops and monitors controls relative to potential extended shutdown events by identifying risk drivers and developing mitigation plans. Table 2-4 below summarizes those assessments.

TABLE 2-4
NUCLEAR OPERATIONS AND SAFETY – EXTENDED SHUTDOWN

Risk Driver	Mitigation	Status
Operational Response	Complete all actions associated with SOER 10-02. "Engaged Thinking Organization" to enhance response to operational events.	COMPLETE
Equipment Failure (Assessment)	Evaluate failure mechanisms for diesel generators to determine if any would result in extended shutdown.	COMPLETE
Equipment Failure (Assessment)	Conduct a thrust bearing capacity evaluation.	Complete. No additional actions required.
Asset Protection (Damage Prevention)	Install separation walls on Unit 2 transformers (to be scheduled in concert with planned outage).	Complete with alternative methods
Asset Protection (Damage Prevention)	Install separation walls on Unit 1 transformers (to be scheduled in concert with planned outage).	See above. Same status as Unit 2.
Equipment Failure (Spare Equipment)	Procure additional low-pressure blading.	COMPLETE Blading was received in December 2010.
Equipment Failure (Spare Equipment)	Pursue access to a spare Unit 1 generator rotor.	COMPLETE: Spare generator rotor is onsite. No additional action required.
Equipment Failure (Spare Equipment)	Evaluate feasibility of a spare 230-kilovolt (kV) to 12-kV start-up transformer.	COMPLETE: Transformer is now in stock
Equipment Failure (Spare Equipment)	Have spare low-pressure rotor on hand.	COMPLETE: Spare turbine LP rotor is onsite. No additional action required.
Enhanced Project Oversight (Inadequate Modification)	Enhanced management oversight for implementation of key modifications that could result in achieving a long duration outage or > $100 million of impact if performed incorrectly. Program and process enhancements.	COMPLETE INPO AFI CO.2-2 Action Plan completed 08/06/14 INPO IER L1 14-20 risk related actions completed
Key Project (Inadequate Modification)	U2 Main Generator Stator Project (Project – P.03044).	DUE: 2019 2R20
Key Project (Inadequate Modification)	U1/U2 Main Generator Output Circuit Breaker Project (back-feed 500 kV rapidly) (Project – P.03667).	DUE: Unit 2 – 19th refueling/Unit 1 – 20th refueling
Key Project (Inadequate Modification)	Replace the station's First Level Under-Voltage Relays and Second Level Under-Voltage Relays (Project – P.03519).	
Key Project (Inadequate Modification)	Replace the Main Generator Protection (Project - P.05244).	
Procurement (Single Source Fuel Supplier)	Westinghouse business continuity planning. Fuel Contract warranties, remedies, and insurance coverage.	DUE: 12/31/18 Nuclear Fuel Procurement Plan approved by the CPUC in January 2012, as part of the Utility's Bundled Procurement Plan (2010 LTPP II). PG&E policy is to design and build fuel such that all fuel is received onsite at least 30 days prior to any outage start.

TABLE 2-4
NUCLEAR OPERATIONS AND SAFETY – EXTENDED SHUTDOWN
(CONTINUED)

Risk Driver	Mitigation	Status
Regulatory Confidence (Licensing Basis)	Complete base-scope of licensing basis validation project	DUE: 12/31/2015
Regulatory Confidence (Planning and Policy)	Develop process to address regulatory issues that may arise following an earthquake with magnitude above operating basis earthquake.	COMPLETE Enercon Corporation (engineering contractor) has prepared a seismic compliance review of the Diablo Canyon pre- and post-earthquake planning, inspection, and restart procedures. The final review is with the Diablo Canyon engineering staff for consideration of implementation.
Safety Culture	Complete actions to improve work environment (per existing action plans).	COMPLETE
Safety Culture	Complete Actions to establish a leadership/ engagement model of behaviors, with the objective of enhancing workforce involvement in assuring DCPP safe operation.	COMPLETE Facilitative leadership training completed.

c. Cost of Major Controls

Certain projects and equipment purchases were identified as part of the EORM process to implement mitigation measures and address “gap” issues that were identified as part of the process.

Table 2-5 identifies specific projects included in the five years ending 2019 which address risk of equipment failure that could cause an extended shutdown event. These projects have been included in DCPP’s GRC forecast. The equipment and work scope planned for these projects include:

- Main Generator Stator: This project replaces the DCPP Main Generator Stator in place with timing consistent with the vendor-recommended rotor out inspections interval. Scope will include core iron replacement as well as copper winding replacement and include a new frame to allow for less refueling outage time.
- Main Generator Output Breaker: Replace motor-operated disconnect with a generator output breaker and make the necessary logic changes such that following a unit trip, the breaker opens automatically and plant loads remain on auxiliary transformer. This modification would make the station’s sole source of offsite power,

the 230 kV start-up power system to become a backup to the 500 kV system.

- Main Generator Under-Voltage Relays: This project implements the following actions:
  1. Westinghouse to re-perform DCPP Accident Analysis calculations to validate the existing 20 Second Level Under-Voltage Relay (SLUR) TS 3.3.5 limits.
  2. Submit License Amendment Request to resolve degraded 230 kV voltage/First Level Under-Voltage Relay (FLUR)/SLUR non-conforming interaction Prompt Operability Assessment.
  3. Implement a new design change to upgrade the FLURs:
     a) New relays will permit set points that meet licensing and design requirements.
     b) New relays capable of several voltage and time-step changes to protect safety systems and components from failure during low/degraded voltage conditions.
     c) System maximum time delay ensures full Emergency Core Cooling System flow to the core within Westinghouse revised Final Safety Analysis Report Accident Analysis Limits.
     d) Account for the known effects of short duration disturbances from reducing the availability of offsite power. Addresses sustained non-mechanistic failure modes.
     e) Ensure adequate equipment protection for a sustained degraded voltage while minimizing impact to offsite power availability.
- Main Generator Protection: Replace outdated existing discrete electro-mechanical devices with integrated microprocessor relays. This project will include the 100 percent stator ground injection relay.

TABLE 2-5
NUCLEAR OPERATIONS COSTS
RISK MANAGEMENT INVESTMENTS – TOTAL PROJECT ESTIMATES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	ERM Projects	Capital
1	U2 Main Generator Stator	$76,465
2	U1/U2 Main Generator Output Breaker	$24,437
3	Main Generator Under-voltage Relays	$8,739
4	Main Generator Protection	$4,550

K. Operational Risk Assessments

Within Nuclear Operations, risk assessments are used to provide a systematic understanding of the risks associated with implementation of all approved project work. The purpose of a risk assessment is to identify potential hazards and analyze what might happen if a hazard occurs while manipulating the plant or performing projects or maintenance work.

Nuclear Operations is using a common framework for risk assessments. Completed assessments are presented to the PRC for review and determination of whether an equipment issue and its associated mitigation plan constitutes an operational risk or not.

The components of a risk assessment include:

- Risk event identification that could create operational challenges
- Risk event triggers
- Application of the RET to determine a Risk Register score
- Identification of appropriate risk responses and controls
- Identification of planned mitigations

Assessments are performed by a team of SMEs that is led by a project manager. The team compiles and analyzes data from a variety of sources (e.g., asset condition data, event reports, reliability data) to perform the assessment.

The team identifies and assesses existing controls and identifies potential new mitigations (or strengthening of existing controls) during the assessment. After the PRC approves a project, risk mitigation plans are tracked to ensure completion.

Nuclear Operations is currently working to complete a formal risk assessment for all Plant Health issues and associated mitigation projects approved to resolve those issues.[22]

L. Other Risk Assessment, Controls and Mitigation

Some of the other key existing assessments, controls and mitigations at DCPP include:

- Probabilistic Risk Assessment (PRA) – all nuclear power plants in the US have a plant-specific PRA that is based on NRC endorsed regulatory guidelines. These quantified plant-specific operational risk management models are used to obtain insights and trends based on actual plant performance taking into account plant-specific design features. Quantified risk analyses provide a more accurate assessment and identification of risks.
- A robust risk-informed work management program – manages risk to plant operations during the execution of maintenance and monitors implementation of the risk management program.
- Accredited and non-accredited training programs based on a Systematic Approach to Training – staffing, training and qualification are the most important variables which can be controlled to achieve Nuclear Operations' goals of maximizing plant safety, efficiency and reliability. Therefore, it is the policy of Nuclear Operations that personnel at all levels shall be qualified for the positions they fill and receive the necessary training and retraining to enable them to perform at the highest level of efficiency. The accredited training programs are performance-based programs that are expected to produce and maintain competent employees. The programs are highly integrated processes involving the participation and support of line management, training leaders, instructors and students. Operations and emergency response personnel are trained on the implementation of procedures for mitigating natural phenomena and external events within the current design basis.

---

22 See WP 2-39, Exhibit (PG&E-5) for projects with the highest implementation risks.

- Extensive independent oversight, assessment and audit by the NRC, INPO, NSOC, Diablo Canyon Independent Safety Committee, and Quality Verification.
- DCPP maintains a robust Corrective Action Program as required by NRC regulation 10 CFR 50 Appendix B. The Corrective Action Program is the main process that DCPP uses to identify, analyze, and resolve plant problems. Elements of the program include issue identification, issue significance reviews, various levels of cause analysis up to root cause analysis, corrective action development and implementation, and performance trending and monitoring. The program is used to develop corrective actions to prevent recurrence of problems.
- DCPP maintains an Operating Experience Program – systematic means of sharing operating experience information among nuclear power plants. The purpose of the Operating Experience Program is to evaluate event precursors so actions can be identified and implemented to eliminate vulnerabilities and prevent similar events at DCPP, as well as share internal events with the industry.
- DCPP has extensive design control processes – nuclear generation design activities are controlled per NRC regulations to assure that design, technical, and quality requirements are correctly translated into design documents and that changes to design are properly controlled.
- Guidance exists for using temporary equipment to monitor certain plant parameters needed to manage response to some BDB events.
- The Long-Term Seismic Program is ongoing and has been in place since early in plant life.
- DCPP implements a robust security program based on NRC regulatory requirements.
- DCPP has in place Emergency Operating Procedures and Severe Accident Mitigation Guidelines based on industry-endorsed guidelines. Extreme Damage Mitigating Guidelines for BDB events are in place based on NRC-mandated content.

M. Risk Informed Budget Allocation

RIBA is a process by which risk scoring of projects and programs is used to inform budgeting decisions with the LOBs. RIBA is an integral part of the

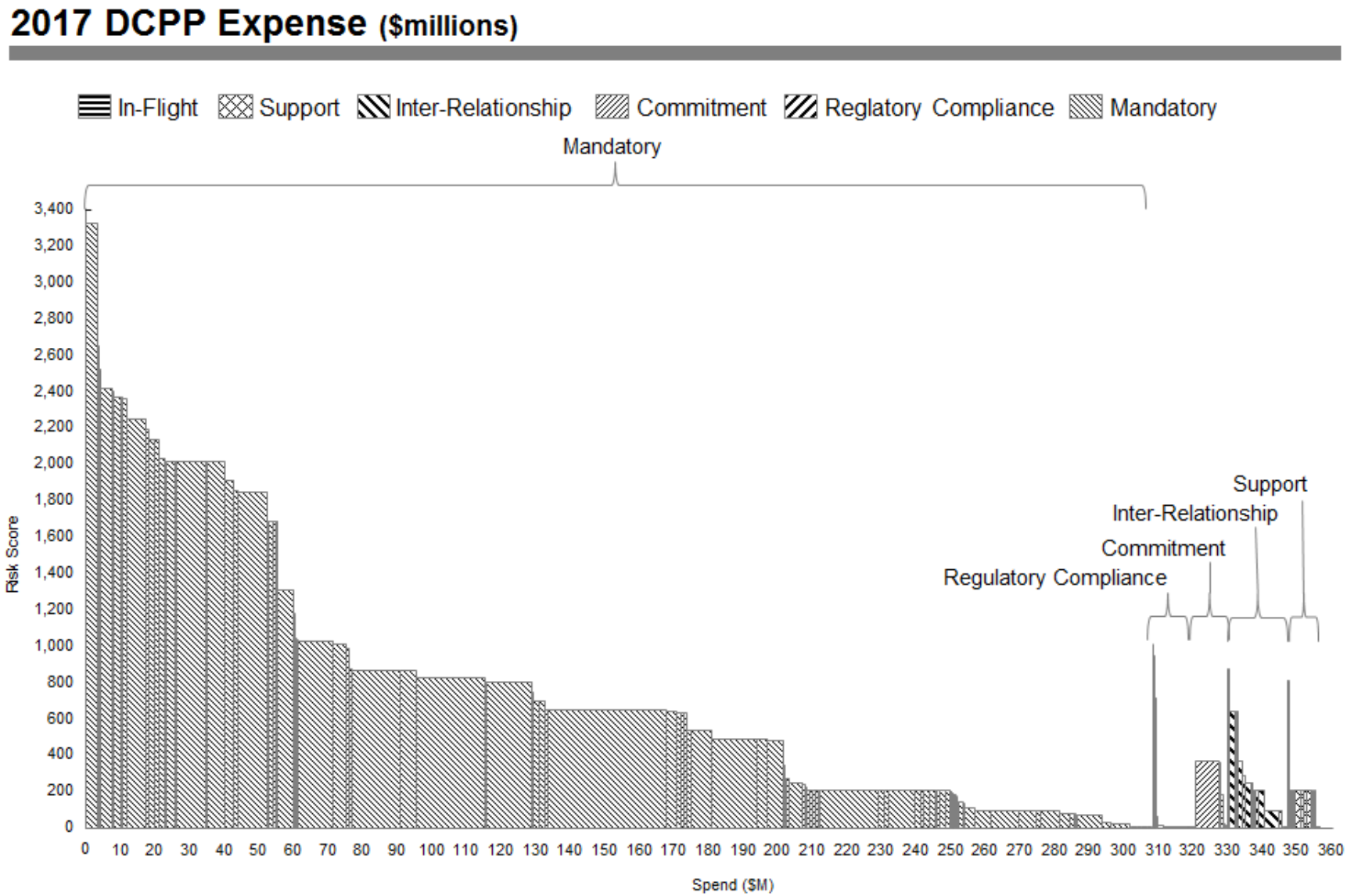
Company's Integrated Planning Process. This section provides information on how Nuclear Operations uses RIBA in the Integrated Planning Process and a summary of the Nuclear Operations spending portfolio using the RIBA process.

Nuclear Operations uses RIBA as directed by the Company's Finance organization. This information provides the basis for project prioritization. While the data is used in the Integrated Planning Process in the spring of each year, for Nuclear Operations, the data is continuously updated as new information and new issues/projects are identified. As a result, the portfolio of projects may change from time to time and adjustments made, as necessary, to meet annual planning targets and to ensure that the highest priority work is always accommodated.

1. Risks and the 2017 GRC Capital and Expense Forecast

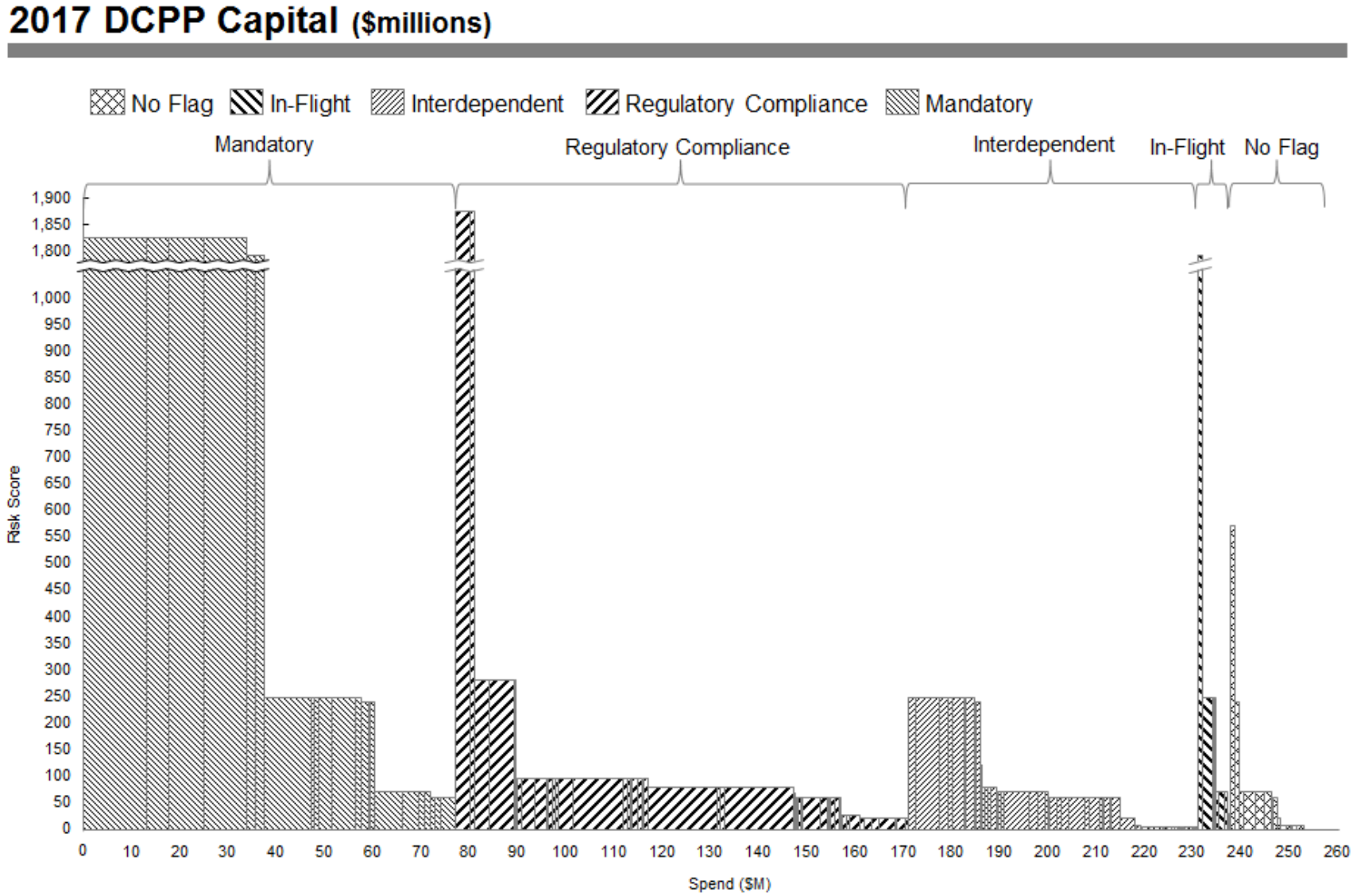
This section describes the RIBA Prioritization results. The output of the RIBA process is a risk scored portfolio that can be sorted in multiple ways (by flag, risk score, etc.). The results are also presented to management graphically. Figures 2-9 and 2-10 summarize the outcome of the RIBA process for the 2017 GRC expense and capital forecast, respectively.

FIGURE 2-9
RIBA RESULTS – 2017 NUCLEAR OPERATIONS EXPENSE



Flags represent categorization not prioritization

FIGURE 2-10
RIBA RESULTS – 2017 NUCLEAR OPERATIONS CAPITAL EXPENDITURES



Flags represent categorization not prioritization

The graphs show the RIBA risk scores on the Y-axis and the cumulative dollars of expense spend on the X-axis. Individual processes that were risk-scored are also categorized by various flags including:

- Mandatory – must be conducted in the budget or forecast year to comply with a regulation.
- Regulatory Compliance – work that is required to comply with a regulation, but that does not meet the definition of "Mandatory."
- Commitment – the Company has made a specific commitment to completing the proposed work in a public forum or to regulators.
- Inter-Relationship – used to indicate that the proposed work either must, or should, be done in conjunction with other work. For Diablo Canyon, this flag has been used exclusively for work to be completed during a planned refueling outage.
- Support – Information Technology Apps and Infrastructure; Tools and Equipment; Fleet; Buildings, Roads and Physical Infrastructure; and Training.
- In-Flight – Under construction or 50 percent of total expected cost committed as of the beginning of the budget year—applies to project work that has a defined scope.

The expense RIBA graph shown in Figure 2-9 indicates that while the RIBA risk scores for process related work at DCPP range from 2,344 down to 40, the vast majority of expense costs are mandatory; i.e., required by various regulatory agencies or by the Diablo Canyon license basis documents to be completed in the current budget year. Other commitments and outage work (as indicated by the Interdependent flag) comprise the bulk of the remainder of the DCPP expense budget.

The capital RIBA graph shown in Figure 2-10 indicates that the vast majority of the work planned for 2017 is mandatory, required for regulatory compliance, or refueling outage related (as indicated by the Interdependent flag).

The reliability risk matrix provides an indication of Diablo Canyon's multi-year project spending to address enterprise risks and other key risks relative to their impact potential as well as the expected time to impact.[23]

N. Nuclear Operations – Conclusion

Nuclear Operations has a robust, multifacted risk analysis and management process that is applied to its nuclear operations, maintenance, and plant modification process via a variety of tools and is overseen by the highest levels of station leadership.

Nuclear Operations continues to refine its risk management process to ensure that the highest priority work is planned and completed in our planning horizon and to ensure that the enterprise and operational risks are mitigated to the fullest extent possible.

---

23 See WP 2-47 (PG&E-5).

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

NUCLEAR OPERATIONS COSTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
NUCLEAR OPERATIONS COSTS

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
NUCLEAR OPERATIONS COSTS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
NUCLEAR OPERATIONS COSTS

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to describe Pacific Gas and Electric Company's (PG&E or the Company) capital expenditure and Operations and Maintenance (O&M) expense forecasts for the management of its Diablo Canyon Power Plant (Diablo Canyon or DCPP) Nuclear Generation Program and to demonstrate these forecasts are reasonable and should be adopted by the California Public Utilities Commission (CPUC or the Commission).

Diablo Canyon Units 1 and 2 have a combined capacity of 2,240 megawatts[1] and each year Diablo Canyon safely and reliably generates approximately 18,000 gigawatt-hours (Figure 3-12) of clean electricity. DCPP provides more than 20 percent of the energy generated in PG&E's service territory annually[2] and 10 percent of the energy generated in California annually—enough to meet the energy needs of more than three million northern and central Californians. For years, DCPP has continuously and safely produced clean and reliable energy without greenhouse gas (GHG) emissions, avoiding six to seven million metric tons per year of GHGs that would otherwise be emitted to the atmosphere by conventional generation resources.[3] DCPP Units 1 and 2 began commercial operation in May 1985 and March 1986, respectively, and are licensed by the Nuclear Regulatory Commission (NRC) for operation until September 2024 and April 2025, respectively.

The first responsibility of a nuclear facility operator is to generate power safely. The second responsibility is to operate reliably through cost-efficient management of plant-related costs. PG&E accomplishes these goals by

---

1 See WP 3-184, Exhibit (PG&E-5).

2 See WP 6-14, Exhibit (PG&E-5).

3 See WP 3-295, Exhibit (PG&E-5).

maintaining high safety standards, continuously improving its operations and effectively managing costs. Diablo Canyon has had an exemplary record of safety and reliability during the course of its 31 years of operation. DCPP is a valuable, environmentally beneficial resource for PG&E's customers and is a significant contributor to California's state-wide policy to reduce GHG emissions under Assembly Bill (AB) 32 (2011) to 1990 levels by 2020.

Diablo Canyon has an excellent operating record in its 31 years of operation. As nuclear industry experience has shown, however, investment will be needed to continue reliable plant operations. No other industrial facility has the requirements that a nuclear power plant does to run in as "perfect condition" on the last day of operation as it did on the first day. Commission adoption of PG&E's expense and capital forecasts for operating and maintaining Diablo Canyon is necessary to enable PG&E to continue providing safe, reliable, affordable and environmentally beneficial source of electricity to its customers from this resource.

This chapter provides PG&E's expense and capital forecasts for its nuclear operations in the 2017 GRC period. In addition, this chapter also describes PG&E's proposal to continue the Nuclear Regulatory Commission Regulatory Balancing Account (NRCRBA) to capture capital and expenses related to new and evolving nuclear safety and security regulatory requirements for Diablo Canyon mandated by the NRC.

Finally, in Section V of this chapter, PG&E provides updates required by the 2014 General Rate Case (GRC) in Decision 14-08-032.

2. Summary of Request

a. Expense

PG&E requests that the Commission adopt its 2017 expense forecast of $425.7 million for O&M,[4] including the NRCRBA expense amount of $13.6 million. See Table 3-1 below.

[4] See WP 3-1, Exhibit (PG&E-5).

TABLE 3-1
OPERATIONS AND MAINTENANCE EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	NRCRBA – Expense	$8,339	$11,200	$14,817	$9,400
2	Long-Term Seismic Balancing Account (BA)	8,554	5,400	4,050	4,170
3	Other Expense	373,777	393,244	402,394	416,250
4	Total O&M Expense	$382,116	$404,444	$417,211	$425,650

b. Capital

PG&E also requests that the Commission adopt its capital expenditure forecast of $238.4 million for 2015 (including NRCRBA capital of $59.7 million), $213.9 million for 2016 (including NRCRBA capital of $36.1 million), $159.7 million for 2017 (including NRCRBA capital of $13.3 million), $137.7 million for 2018 (including NRCRBA capital of $5.2 million), and $150.1 million for 2019 which has no projected NRCRBA capital expenditures.[5] See Table 3-2 below.

TABLE 3-2
CAPITAL EXPENDITURES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	NRCRBA – Capital	$44,099	$59,700	$36,068	$13,304	$5,157	–
2	Other Capital	173,173	178,711	177,861	146,396	132,543	$150,121
3	Total Capital Expenditures	$217,272	$238,411	$213,929	$159,700	$137,700	$150,121

c. Nuclear Regulatory Commission Regulatory Balancing Account

PG&E proposes to continue the NRCRBA as a two-way balancing account for new nuclear safety and security regulatory-mandated projects. The balancing account was originally approved in PG&E's 2014 GRC decision.[6] For the period 2017 to 2019, PG&E forecasts approximately $18.5 million in capital projects and approximately

[5] See WP 3-103, Exhibit (PG&E-5).

[6] D.14-08-032, p. 420; Ordering Paragraph 24.

$9.4 million in expense associated with NRC regulatory requirements that would be tracked and recovered through the NRCRBA.

d. Other Issues

PG&E has included the following additional proposals in this exhibit:

- Second Refueling Outage: There will be two refueling outages in 2019. PG&E proposes to spread the costs of the second refueling outage over the 3-year GRC period, such that one-third of the costs would be recovered in 2017, 2018 and 2019. This is the same treatment of the second refueling outage that was adopted in the 2014 GRC. The amortization amount included in 2017 is $20.2 million.[7]
- License Renewal: This exhibit does not include any costs associated with the License Renewal application process and does not assume operations of DCPP beyond the current license life for DCPP. The exhibit only includes costs that are forecast to occur for the period 2017-2019. PG&E has not included any costs in this forecast associated with operations following the expiration of operating licenses in 2024 and 2025. The issue of whether PG&E should operate DCPP beyond 2024 and 2025 is not addressed in this exhibit and is outside the scope of the 2017 GRC. Additionally, project justifications for projects included in this filing are bounded by the existing license period.

B. Activities and Costs

1. Overview of Recorded and Forecast Costs

a. Expense

The Nuclear Generation expense amounts for 2014 were $382.1 million including the amortization of the second refueling outage in 2014 over three years and including the NRCRBA expense amounts. For 2015 through 2017, the expense amounts are forecast to be $404.4 million, $417.2 million, and $425.7 million, respectively.

---

7 See WP 3-67, Exhibit (PG&E-5).

FIGURE 3-1
EXPENSE
NUCLEAR GENERATION
(THOUSANDS OF NOMINAL DOLLARS)

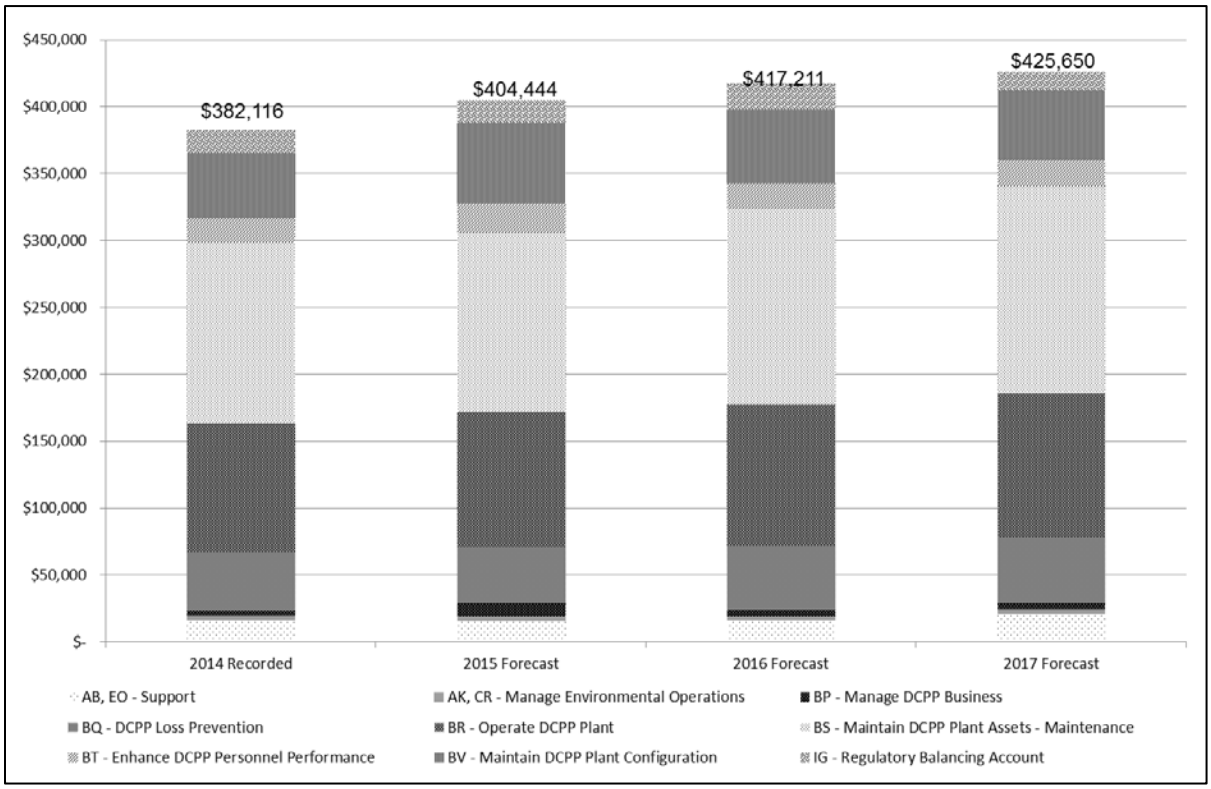
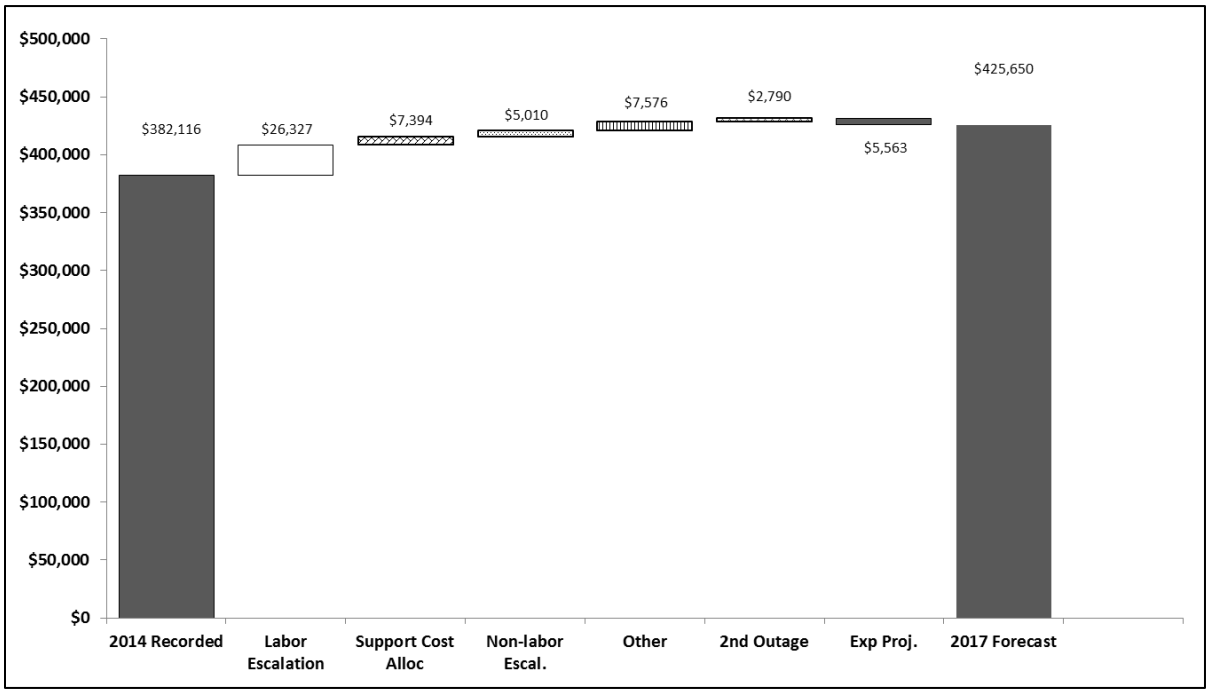


Figure 3-2 depicts the primary drivers of the changes in expense from 2014 to 2017. The primary drivers are (1) labor escalation; (2) non-labor escalation; (3) support cost allocations; (4) changes in work scope; and (5) second refueling outage scope.

FIGURE 3-2
EXPENSE WALK (2014-2017)
NUCLEAR OPERATIONS
(THOUSANDS OF NOMINAL DOLLARS)



Of the total $48.1 million increase in expense from 2014-2017, labor escalation accounts for approximately $26.3 million of higher expense labor costs in 2017 compared to 2014 actual expense labor costs. This includes the higher employee labor rates attributed to market labor rate increases and union contract negotiations. The average annual labor escalation rate used for this calculation is 2.90 percent. Escalation rates are discussed in detail in Exhibit (PG&E-12), Chapter 3. The labor escalation impact is shown in each of the Major Work Category (MWC) walks.[8]

Non-labor escalation accounts for approximately $5.0 million of higher expense non-labor costs in 2017 compared to 2014 actual expense non-labor costs. This estimate reflects the expected general inflation for contracts, materials, and other services or fees. The average annual non-labor escalation rate used for this calculation is 1.8 percent. Escalation rates are discussed in detail in

---

8 See WP 3-12 – 3-23, Exhibit (PG&E-5); See also WP 3-11, Exhibit (PG&E-5) for summary.

Exhibit (PG&E-12), Chapter 3. The non-labor escalation impact is shown in each of the MWC walks.[9]

Support cost allocations represent the shift in overhead costs driven by a relatively higher expense labor cost compared to capital labor cost for 2017. Many of the support cost functions at Diablo Canyon are allocated to expense or capital on the basis of labor. As the capital spending plans are reducing due to completion of several significant strategic projects, these support costs are shifting to expense. The impact is a $7.4 million increase in expense.[10]

The expanded scope of the 2019 outage accounts for approximately $2.8 million in higher expense costs in 2017. Under PG&E's proposal to levelize the costs of the second outage, one-third of the costs will be recovered in 2017, 2018 and 2019. The principal issues are:

- Extended outage duration to 70 days to accommodate implementation of the Main Generator Stator project – $1.3 million (one-third of 2019 impact).
- Telecom support transferred from other lines of business – $0.3 million (one-third of 2019 impact).
- Main Generator turbine and maintenance scope and Steam Generator Eddy Current scope greater than average 2014 base year – $0.2 million (one-third of 2019 impact).
- Higher project and non-labor costs compared to the second refueling outage in 2014 – $0.9 million.

Changes in work scope (summarized as "Other" in the expense walk) represent numerous items – $7.6 million. There are both increases and decreases in this category. The most significant of the increases include:

- Main Generator Maintenance scope for the 2017 outage is significantly higher than work done in 2014 (after the second outage is excluded). This scope includes maintenance on both the

---

9 See WP 3-12 – 3-23, Exhibit (PG&E-5); See also WP 3-11, Exhibit (PG&E-5) for summary.

10 See WP 3-77, Exhibit (PG&E-5).

low-pressure turbine as well as the high-pressure turbine. This increase is approximately $6.3 million.

- Some regulatory fees are expected to increase significantly more than the general non-labor escalation rate of 1.8 percent. In particular, the Office of Emergency Services (OES) and Federal Emergency Management Agency (FEMA) fees are expected to increase by $0.9 million compared to actual 2014 costs of $2.9 million. This increase is the result of lower than normal 2014 OES fees caused by a surplus in the OES budget and reallocation of the OES billings from Southern California Edison (SCE) to PG&E due to closure of SCE's nuclear facility. Additionally, FEMA fees are increasing due to the post-Fukushima and Emergency Planning (EP) Rulemaking regulatory requirements and actions being implemented and evaluated by the federal government.
- Telecom support for outage transferred from other line of business (LOB) – increase of $0.8 million.
- Various Engineering programs, permitting and industry fee increases, quality assessment costs, and miscellaneous cost increases – $2.0 million.

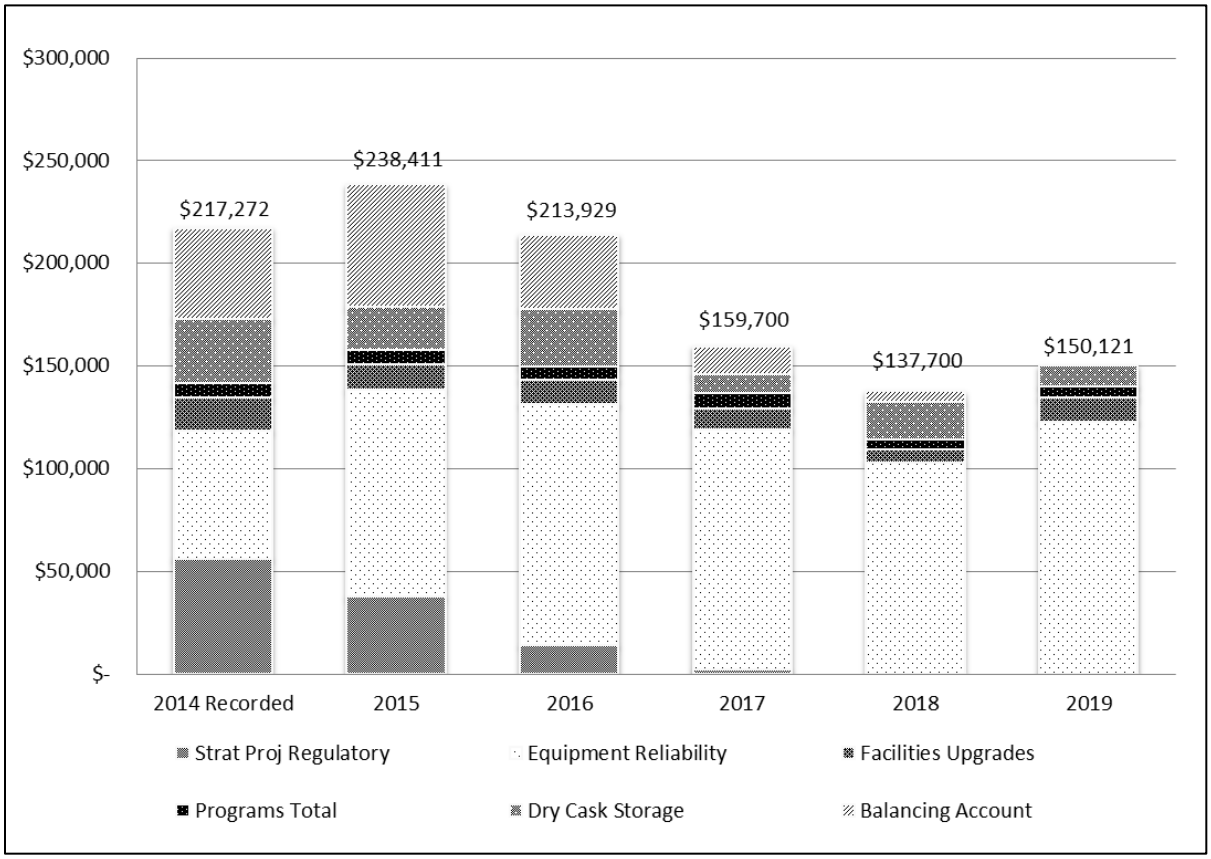
There are several reductions which partially offset the increases discussed above. The most significant decreases in scope include:

- Reduction of one-time 2014 expenses as follows:
  - Unit 1 10-year Reactor In-Service Inspection – $1.8 million
  - Once-through Cooling Study – $0.6 million
- Expense Project reductions – $5.6 million:
  - License Basis Verification expense project cost reductions due to project completion in 2017 – $1.4 million.
  - 3-Dimensional (3D) Seismic Testing and Analysis expense project cost reductions due to project completion in 2015 – $4.6 million.
  - Miscellaenous expense project changes – increase of $0.4 million.

b. Capital

The Nuclear Generation capital expenditures for 2014 were $217.3 million including the NRCRBA capital amounts. For 2015 through 2019, the capital expenditures are forecast to be $238.4 million, $213.9 million, $159.7 million, $137.7 million and $150.1 million, respectively. 2017 through 2019 capital expenditures drop significantly and are expected to level out by 2018 with accommodation for escalation and years with two outages (as in 2019).

FIGURE 3-3
CAPITAL EXPENDITURES
NUCLEAR OPERATIONS
(THOUSANDS OF NOMINAL DOLLARS)



Figures 3-4A and 3-4B below shows a comparison of 2014 capital expenditures by category to 2017 capital expenditures by category. This depiction shows the principal reasons for the decrease from 2014-2017 is the completion or reduction of most of the Strategic Projects driven by regulatory issues. With the completion of this work,

DCPP has prioritized even more capital expenditures to be focused on equipment reliability issues. These changes from 2014-2017 are summarized as follows:

- **Strategic Projects and Dry Cask Storage Included in MWC 20**
  - The License Basis Verification project will be completed in 2017, resulting in a reduction of 2017 capital expenditures of $30.4 million.[11]
  - Security infrastructure work is $18.6 million less in 2017 than in 2014 with the most significant work completing in 2015.[12]
  - Dry Cask Storage work in 2017 is approximately $22.2 million less than in 2014. The most significant change is that the work on the expansion of the Dry Cask Storage Pad completes in 2015.[13]
- **Strategic Projects Included in NRCRBA**

  Much of the NRC regulatory work that is being tracked in the NRCRBA will be completed by 2017, resulting in a number of decreases in capital expenditures in 2017 as compared to 2014:
  - EP Rulemaking capital expenditures will be largely complete by 2017. 2017 expenditures are $9.4 million less than in 2014. WP 3-137 details out the scope and total costs associated with this project – Public Address system.
  - Fukushima capital expenditures will be complete in 2016. 2017 expenditures are $16.7 million less than in 2014.[14]
  - NFPA 805 modifications (Reactor Cooling Pump Thermal Seals, Hot Shut Down Panels, Electrical Raceway Fire Barrier System, and Fire Detection System) implementation progress reduces

---

11 See WP 3-132, Exhibit (PG&E-5).

12 See WP 3-168, Exhibit (PG&E-5).

13 See WP 3-115, Exhibit (PG&E-5) and WP 3-128, Exhibit (PG&E-5) for 2014 through 2017 capital project estimates for the Independent Spent Fuel Storage Installation (ISFSI) related work.

14 See WP 3-113, Exhibit (PG&E-5).

these expenditures in 2017 by $4.3 million compared to 2014 expenditures.[15]

- **Equipment Reliability Projects**

  In addition, there are some increases in capital project scope that result in increases as compared to 2014:

  – Main Generator Stator replacement. There is an approximate $22.5 million increase from 2014-2017.[16]

  – Main Generator Output Breaker is $9.5 million more in 2017 compared to 2014.[17]

  – Upgrade of Diesel Equipment and Controls. This is an approximate $19.3 million increase from 2014-2017.[18]

FIGURE 3-4A
2014 CAPITAL EXPENDITURES
NUCLEAR OPERATIONS
(THOUSANDS OF NOMINAL DOLLARS)

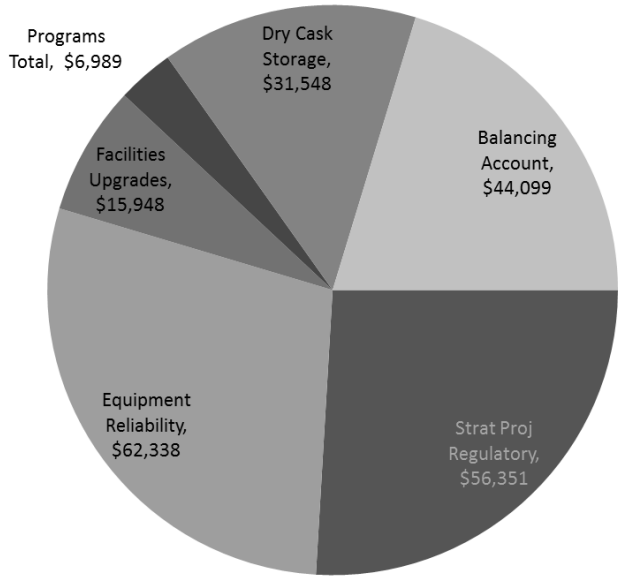
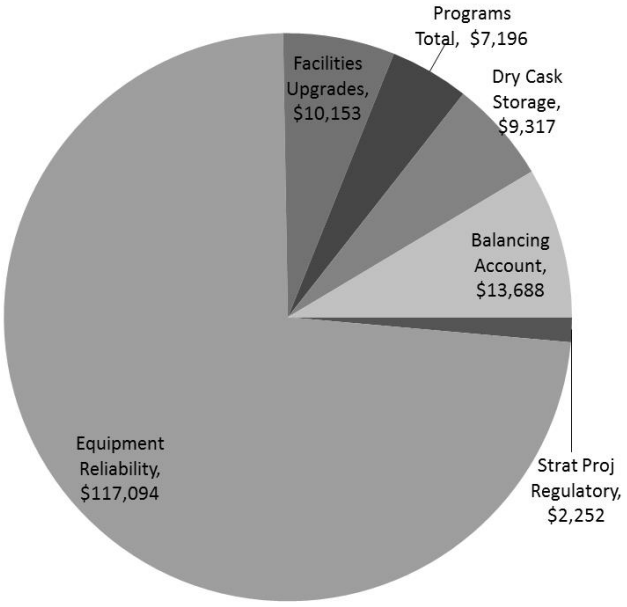


FIGURE 3-4B
2017 CAPITAL EXPENDITURES
NUCLEAR OPERATIONS
(THOUSANDS OF NOMINAL DOLLARS)



---

15 See WP 3-148 – 3-154, Exhibit (PG&E-5).

16 See WP 3-125, Exhibit (PG&E-5).

17 See WP 3-144, Exhibit (PG&E-5).

18 See WP 3-117, Exhibit (PG&E-5) and WP 3-112, Exhibit (PG&E-5) for details of the principal projects being implemented over the next three years.

c. Nuclear Regulatory Commission Regulatory Balancing Account

While the expense and capital orders comprising the balancing account request are included in the Expense and Capital summaries in Tables 3-6 and 3-7, PG&E requests continuation of the two-way balancing account cost recovery treatment for these orders. The NRC rulemakings, proceedings and orders and associated implementation efforts are continuing in the areas related to Fukushima, Fire Protection, EP Rulemaking, and Cyber Security. The policy objectives that warranted approval of the NRCRBA in the 2014 GRC decision remain. The NRCRBA benefits customers for the following reasons: (1) the proposal will help assure full funding of and compliance with new difficult to predict but critically important regulatory conditions associated with new NRC Rulemaking proceedings; (2) to the extent NRC rulemaking costs are delayed or less than expected, unspent funds will be returned to customers; and (3) to the extent that NRC Rulemaking costs are greater than expected, the mechanism will provide a vehicle for cost recovery in the next GRC and will not require reprioritization of funding for reliability enhancements or important maintenance work. The balancing account amounts by issue are shown in Table 3-9.

Table 3-3 shows a comparison of expenditures for NRCRBA capital and expense—2014 GRC forecast versus 2017 GRC Actuals/Forecast.

TABLE 3-3
NUCLEAR REGULATORY COMMISSION REGULATORY BALANCING ACCOUNT
COMPARISON OF 2014 GRC AND 2017 GENERAL RATE CASE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	Prior Recorded	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	Capital Expenditures						
2	2014 GRC Forecasts	$47,514	$45,210	$60,903	$62,639	–	
3	2017 GRC Act/Forecast	39,711	44,099	59,700	36,068	$13,304	$5,157
4	Difference	$7,803	$1,111	$1,203	$26,571	$(13,304)	$(5,157)
5	Expense						
6	2014 GRC Forecasts		$14,560	$11,409	$10,000	–	
7	2017 GRC Act/Forecast		8,339	11,200	14,817	$9,400	
8	Difference		$6,221	$209	$(4,817)	$(9,400)	

2. Program Description

a. Assets

1) Description and Condition

PG&E's Diablo Canyon Power Plant is a 2,240 MW[19] facility located 7.5 miles north of Avila Beach in San Luis Obispo County, California. The site consists of approximately 12,000 acres of PG&E-owned land and the assets related to two nuclear units, including a power block and related facilities. See Figure 3-5 below.

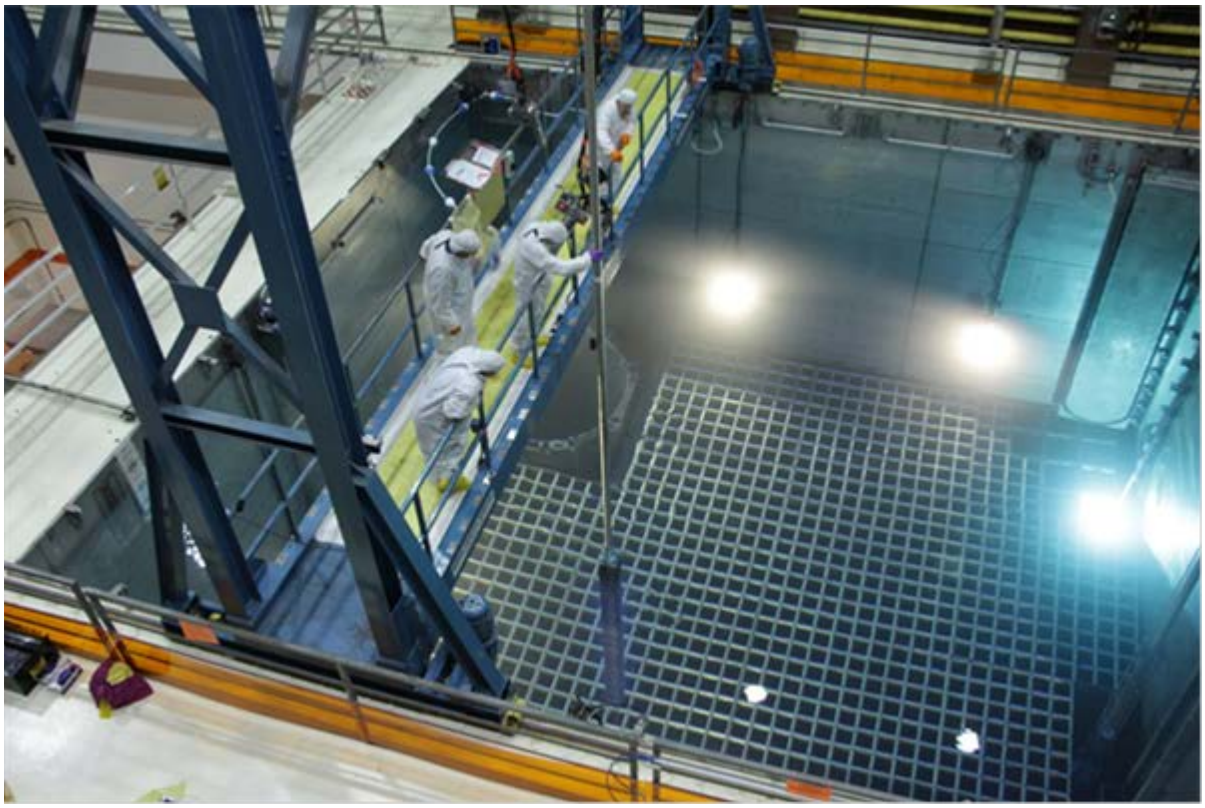
FIGURE 3-5
DIABLO CANYON POWER PLANT – AERIAL VIEW

The power block includes two nuclear units, each consisting of a Westinghouse four-loop, pressurized water reactor coupled with a steam-electric turbine generator, feed water systems and cooling water systems. In addition to the unit-specific facilities, the common facilities include a fuel handling building, a radioactive waste storage

19 See WP 3-184, Exhibit (PG&E-5).

building, an auxiliary building containing emergency safety systems and various support systems. See Figure 3-6 for a picture showing fuel offload at the spent fuel pool in the fuel handling building.

FIGURE 3-6
FUEL OFFLOAD AT THE SPENT FUEL POOL IN THE FUEL HANDLING BUILDING



In addition to the power-block described above, Diablo Canyon facilities include an administrative building, a training building, maintenance shop buildings, Independent Spent Fuel Storage Installation (ISFSI), Removed Steam Generator and Removed Reactor Vessel Head Storage Facility, and a warehouse. The warehouse holds consumables, spare parts and complete spare replacements for key components, such as a reactor coolant pump motor, main turbine rotors and various safety system pumps. The site has multiple communications systems, a vehicle fleet, an aircraft operation, office equipment, and a high voltage

switchyard.[20] See Figure 3-7 for a picture showing the 500 kilovolt (kV) switchyard.

FIGURE 3-7
500 KV SWITCHYARD

PG&E's primary responsibility as the owner and operator of DCPP is to generate power safely and reliably through cost-efficient management of plant and related assets. PG&E's safety responsibility extends to the general public, as well as to its employees. Plant safety is essential to the successful operation of a nuclear power station. PG&E has been careful to maintain plant safety and equipment reliability by pursuing critical projects while also pursuing cost control efforts. Due to PG&E's effective balancing of plant safety, reliability and cost control, the plant has performed very well.

---

20 The 500-kV switchyard, into which the two electrical generators feed, is physically located on the Diablo Canyon site; however, the associated costs for this facility are included in electric transmission, which is not forecasted in this chapter.

An important element of maintaining high safety standards while continuously improving operations and managing costs is employee culture. DCPP employees maintain a questioning attitude when developing, reviewing, or making changes to plant Systems, Structures and Components (SSC), programs and procedures. In addition to expecting employees to affirmatively participate in the process of developing, reviewing, implementing and making changes to plant procedures and processes, all employees are expected to continuously assess and improve their performance. Employees critique their performance, compare their work to relevant industry best practices, participate in industry groups and conferences, share operational information with others, and implement changes when appropriate. Additionally, when necessary, employees solicit vendor expertise to help assure unexpected conditions are investigated and important technical questions are answered.

2) Risk

PG&E's Enterprise and Operational Risk Management (EORM) effort is designed to minimize various risks, including risks associated with the ongoing operation of DCPP. The Diablo Canyon Nuclear Operations and Safety is one of PG&E's key enterprise risks. This risk is defined as a Core Damaging Event, which is the potential for radiological release at Diablo Canyon due to natural disaster, equipment failure, or some other significant event. Additionally, Nuclear Operations has one key operational risk, Extended Shutdown, which is defined as an extended shutdown of Diablo Canyon for longer than three months or with a financial impact greater than $100 million. Diablo Canyon leadership performed an updated risk analysis in 2015 to identify the key risk drivers and evaluate their potential impact, evaluate the effectiveness of existing mitigating activities, and develop additional planned mitigating activities to maintain the overall level of risk at low. The result of this analysis is that PG&E believes that current and planned mitigation activities will be effective in managing the

identified risks. Mitigation of these risks were taken into account as part of the Integrated Planning Process and PG&E has included capital and expense projects associated with implementation of the mitigations in the DCPP request.

a) Existing Risk Mitigations

An extensive listing of all of the existing mitigations that address the risk of core damage or extended shutdown at DCPP is provided in Chapter 2; however, some of the key existing mitigations that address the risk of core damage or extended shutdown at DCPP include:

- Probabilistic Risk Assessment (PRA) – All nuclear power plants in the U.S. have a plant-specific PRA that is based on NR-endorsed regulatory guides. These quantified plant-specific operational risk management models are used to obtain insights and trends based on actual plant performance taking into account plant specific design features. Quantified risk analyses provide a more accurate assessment and identification of risks.
- A robust risk-informed work management program – Program to manage risk to plant operations during the execution of maintenance and to monitor implementation of the risk management program.
- Accredited and non-accredited training programs based on a Systematic Approach to Training – Staffing, training and qualification are the most important variables which can be controlled to achieve the nuclear generation goals of maximizing plant safety, efficiency and reliability. Therefore, it is the policy of nuclear generation that personnel at all levels shall be qualified for the positions they fill and receive the necessary training and retraining to enable them to perform at the highest level of effectiveness. The accredited training programs are performance-based programs that are expected to produce and maintain competent employees. The programs are highly integrated

processes involving the participation and support of line management, training leaders, instructors and students. Operations and emergency response personnel are trained on the implementation of procedures for mitigating natural phenomena and external events within the current design basis.

- Extensive independent oversight, assessment and audit by the NRC, Institute for Nuclear Power Operations (INPO), the Nuclear Safety Oversight Committee, Diablo Canyon Independent Safety Committee (DCISC), and Quality Verification.
- DCPP maintains a robust corrective action program as required by NRC regulation 10 CFR 50 Appendix B. The Corrective Action Program is the main process that DCPP uses to identify, analyze, and resolve plant problems. Elements of the program include issue identification, issue significance reviews, various levels of cause analysis up to root cause analysis, corrective action development and implementation, and performance trending and monitoring. The program is used to develop corrective actions to prevent recurrence of problems.
- DCPP maintains an operating experience program – Systematic means of sharing operating experience information among nuclear power plants. The purpose of the operating experience program is to evaluate event precursors so actions can be identified and implemented to eliminate vulnerabilities and prevent similar events at DCPP, as well as share internal events with the industry.
- DCPP has extensive design control processes – Nuclear generation design activities are controlled per NRC regulations to assure that design, technical, and quality requirements are correctly translated into design documents and that changes to design are properly controlled.

- DCPP has acquired diesel driven pumps and piping to be used in the event the intake structure is rendered unavailable.
- DCPP has acquired equipment for backup cooling for the spent fuel pools for both units and created procedures to implement the use of the equipment in the event of a failure of the permanent design basis equipment.
- Guidance exists for using temporary equipment to monitor certain plant parameters needed to manage response to some Beyond Design Basis (BDB) events.
- The Long-Term Seismic Program is ongoing and has been in place since early in plant life.
- DCPP implements a robust security program based on NRC regulatory requirements.
- DCPP has in place Emergency Operating Procedures and Severe Accident Mitigation Guidelines based on industry endorsed guidelines. Extreme Damage Mitigating Guidelines for BDB events are in place based on NRC-mandated content.

b) Completed Mitigation Measures

Certain projects and equipment purchases were identified as part of the EORM process to implement mitigation measures and address “gap” issues that were identified as part of the process. The EORM projects that have been completed are:

- Low-pressure turbine blading (completed 2008)
- Low-pressure turbine rotor (completed 2005 and 2006)
- 230-kV to 12-kV start-up transformer (completed 2012)
- Two Spare Main Bank Transformers (completed 2011)
- Two main generator rotor spares: (completed 2009 and 2012)

The mitigation efforts in progress are:

- Licensing Basis Verification Project (base scope complete December 2015)

c) Additional Risk Mitigation Measures in the GRC

Table 3-4 identifies specific projects included in the five years ending 2019 which mitigate the risk of BDB events. The equipment and work scope planned for these projects include:

- Spent Fuel Pool Instrumentation: Evaluate and upgrade the spent fuel pool level instrumentation to ensure it is capable of determining accurate level during a BDB scenario.
- Fukushima Communication Equipment: Perform on-shift staffing and communication studies to assure that sufficient staff is available with acceptable communication systems to support existing and emergent BDB strategies.
- Fukushima FLEX Equipment: Obtain equipment, implement plant modifications, use of equipment, develop mitigating strategies, and train personnel. Adopt the NRC-endorsed guidelines for the industry-developed FLEX strategy for BDB event mitigation. Modify existing design and configuration control program and process for BDB events.
- Reactor Cooling Pump Thermal Seals (RCP): Improve RCP seal design to extend the duration of the time that the seals will endure a station black out event without becoming a significant reactor coolant leak source.

TABLE 3-4
RISK MANAGEMENT INVESTMENTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	ERM Projects	Capital
1	Spent Fuel Pool Instrumentation	$4,314
2	Fukushima Communication Equipment	$2,532
3	Fukushima FLEX Equipment	$33,706
4	Reactor Cooling Pump Thermal Seals	$13,823

b. Management Structure

1) Organization and Staffing

PG&E's Nuclear Generation organization, led by the Chief Nuclear Officer (CNO), is responsible for the overall safe and efficient operation of DCPP. Following a reorganization of the Energy Supply Organization in 2015, the CNO reports directly to the President of PG&E Electric Operations. The Site Vice President (VP), VP of Nuclear Services, Director of Compliance, Alliance and Risk, and Director of Quality Verification report to the CNO.

The Site VP is responsible for the overall safe operation of the station and has control over onsite activities necessary for safe operation of the station. The Station Director reports to the Site VP and is responsible for operations, maintenance, nuclear work management, and safety. The Directors of Operations Services, Maintenance Services, and Nuclear Work Management report to the Station Director.

The VP of Nuclear Services is responsible for providing Engineering services, Technical Services, Emergency Services, Strategic Projects and Equipment Reliability. The Director of each of these groups reports to the VP of Nuclear Services.

The Director, Quality Verification is responsible for management of the Quality Assurance (QA) Program and for assuring that the QA Program is implemented and complied with by all involved organizations, both internal and external to PG&E. The Director, Quality Verification is responsible for independent review and oversight of operations, corrective action, plant support, engineering, procurement, and maintenance activities performed by or for DCPP.

2) Key Metrics and Other Performance Measures

DCPP uses the following key measures and metrics to monitor safety and reliability.

a) Safety

The safe operation of Diablo Canyon is PG&E's number one priority for the facility. The NRC's Reactor Oversight Process (ROP) is the process through which the NRC measures nuclear safety, regulatory compliance, and recognition for compliance with safety requirements. The NRC initiated this process in April 2000 to: (1) evaluate the overall safety performance of the operating commercial nuclear reactors based on objective performance data and NRC inspections; and (2) communicate those results to plant management, the public and other government agencies. The process includes one strategic performance area, Reactor Safety; with seven cornerstone areas. These seven cornerstone areas consist of one or more Performance Indicators as shown in Table 3-5. In addition, the NRC conducts periodic inspections of the seven cornerstone areas. DCPP has generally performed well in each of these seven areas.

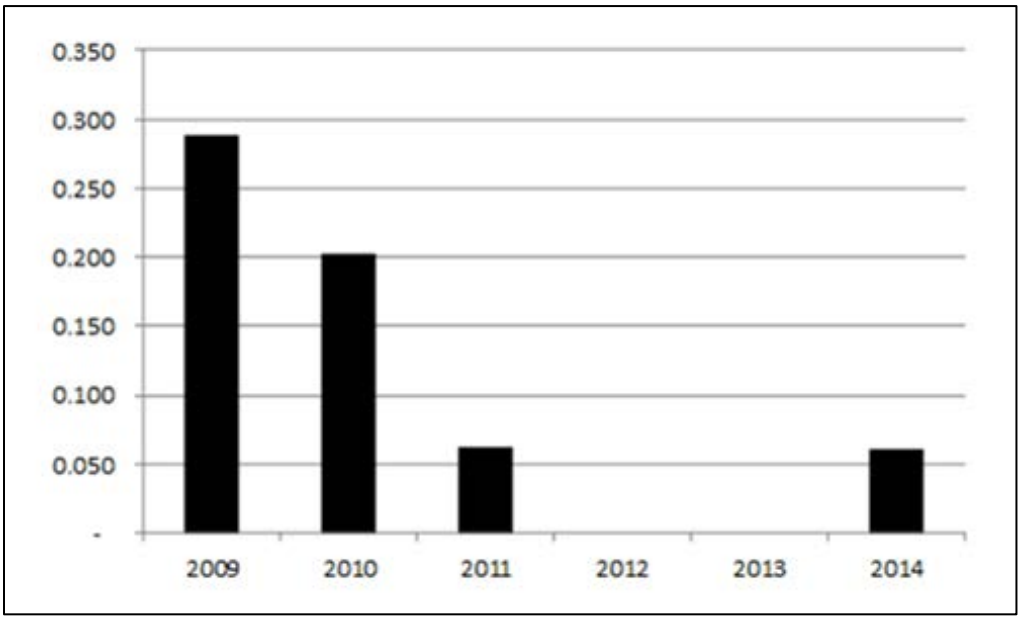
Table 3-5 below, shows PG&E's level of performance in the ROP Strategic Performance Area. Green, "Licensee Response Band," is the highest level of performance and indicates licensee performance is acceptable and the cornerstone objectives are being met. PG&E reports Diablo Canyon Unit 1 and 2 performance for each of the 19 Performance Indicators to the NRC on a quarterly basis. Diablo Canyon has the highest measure, a rating of "green," for each of the ROP Performance Indicators.

TABLE 3-5
NRC REACTOR OVERSIGHT PROCESS
(AS OF 4TH QUARTER 2014)

Line No.	Strategic Performance Areas	Seven Cornerstones	Performance Indicators	Current PG&E Performance
1	Reactor Safety	Initiating Events	Unplanned Rector Trips	Green
2			Unplanned Power Changes	Green
3			Unplanned Reactor Trips with Complications	Green
4		Mitigating Systems	Safety System Functional Failures	Green
5			Emergency Alternating Current Power System	Green
6			High Pressure Injection System	Green
7			Heat Removal System	Green
8			Residual Heat Removal System	Green
9			Cooling Water System	Green
10		Barrier Integrity	Reactor Coolant System Activity	Green
11			Reactor Coolant System Leakage	Green
12		Emergency Preparedness	Drill/Exercise Participation	Green
13			Emergency Response Organization Drill Participation	Green
14			Alert and Notification System	Green
15		Occupational Radiation Safety	Occupational Exposure Control Effectiveness	Green
16		Public Radiation Safety	Radiation Effluent Technical Specifications/Offsite Dose Calculation Manual Radiological Effluent	Green
17		Security	Protected Area Equipment	Green

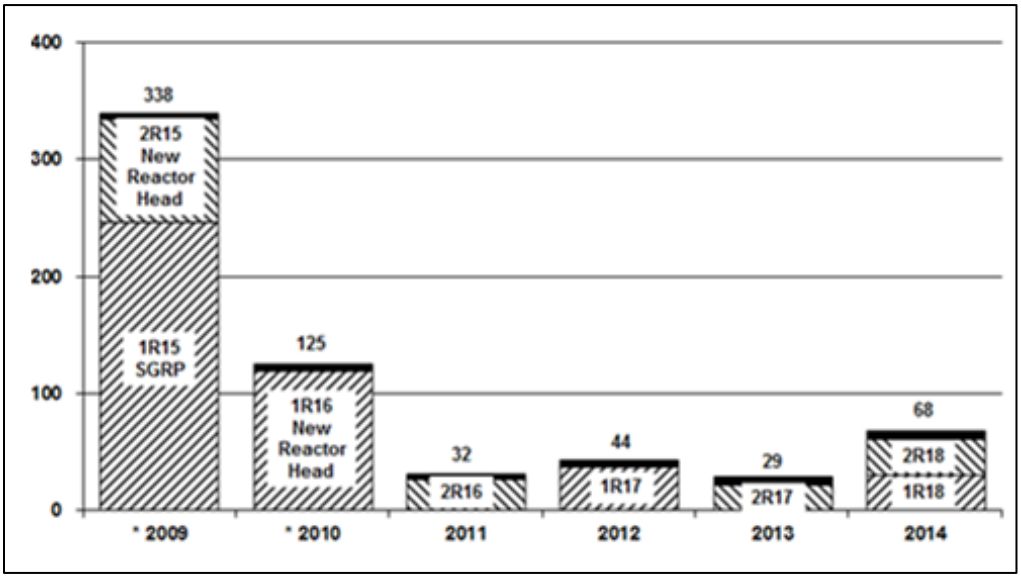
In addition to public safety, PG&E is also strongly focused on the safety of the PG&E employees and contractors working at Diablo Canyon. PG&E measures personal safety at DCPP by the Occupational Safety and Health Administration lost work day rate. As shown in Figure 3-8 below, DCPP personal safety performance has improved dramatically during the 2009-2014 period. The very low lost work day rate achieved in 2011 has been sustained through 2014.

FIGURE 3-8
DIABLO CANYON POWER PLANT
OSHA LOST WORK DAY RATE
LOS WORK DAYS PER 200,000 HOURS WORKED



PG&E measures collective radiation exposure at DCPP by Person-REM (Roentgen Equivalent Man), a unit of absorbed doses of radiation, or the collective radiation exposure when summed across all site personnel. Figure 3-9 below shows DCPP's steady performance since completing the large steam generator and reactor head replacement projects in 2009 and 2010. Note that 2014 had two outages.

FIGURE 3-9
DIABLO CANYON POWER PLANT
COLLECTIVE RADIATION EXPOSURE (PERSON-REM)



DCPP is intensely dedicated to fulfilling the federal requirements of all nuclear power facilities by maintaining a security program committed to preventing radiological sabotage and the theft of special nuclear material.

b) Reliability

PG&E strives to achieve maximum output from DCPP consistent with the safety priorities described above. DCPP is a significant supplier of electricity to PG&E's customers and tracks various reliability-based metrics including capacity factor and net generation. The net capacity factor of a power plant is the ratio of the actual output of a power plant over a period of time and its potential output if it had operated at full nameplate capacity the entire time. Figures 3-10 and 3-11 below provide the capacity factors for DCPP Units 1 and 2 between 2009 and 2014.

Net generation is the amount of electricity generated by a power plant that is transmitted and distributed for consumer use. Net generation is less than the total gross power generation as some power produced is consumed within the plant itself to

power auxiliary equipment such as pumps and motors. Figure 3-12 shows the net generation of DCPP.

FIGURE 3-10
DIABLO CANYON POWER PLANT
CAPACITY FACTOR (%) – UNIT 1

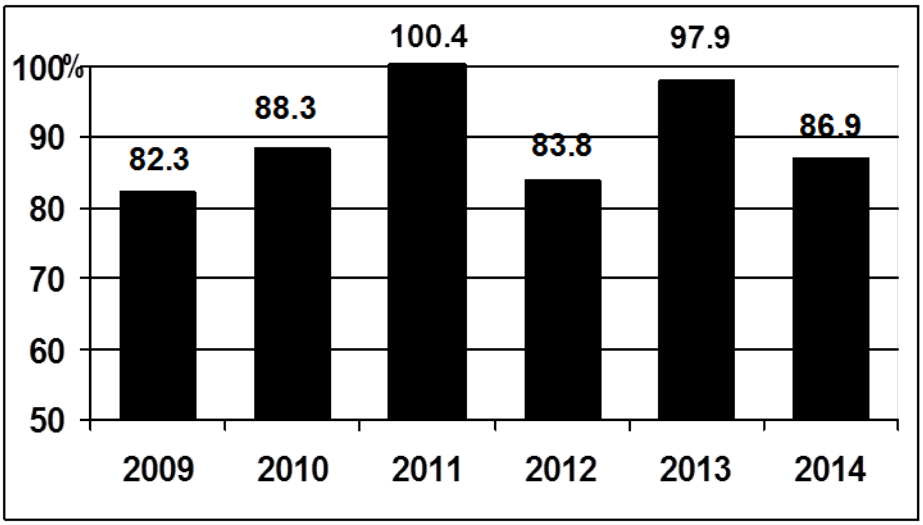


FIGURE 3-11
DIABLO CANYON POWER PLANT
CAPACITY FACTOR (%) – UNIT 2

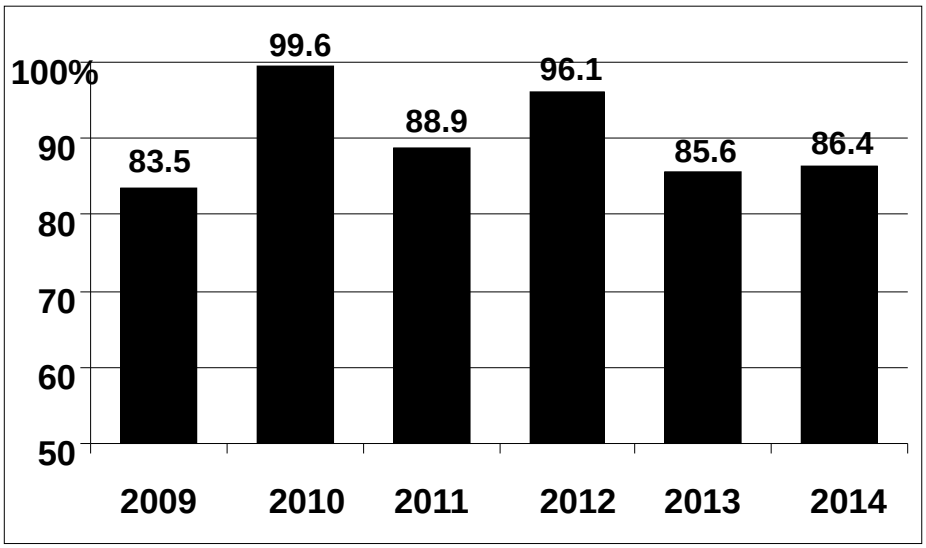
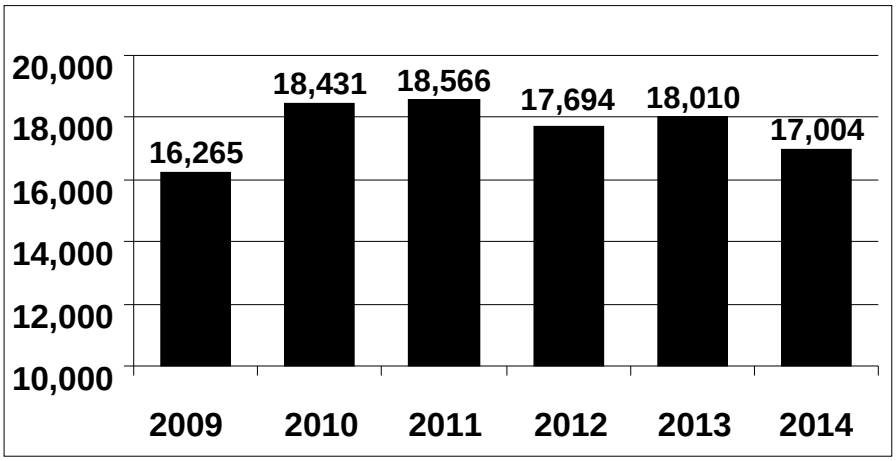


FIGURE 3-12
DIABLO CANYON POWER PLANT
NET GENERATION (GWH)(a)



(a) 2009 and 2014 were two-outage years. Additionally, both outages in 2009 were longer duration due to installation of the Unit 1 Steam Generator equipment and the Unit 2 Reactor Vessel Head equipment.

3. Key Initiatives

a. Expense

PG&E's O&M expense forecast for 2015-2017 for Diablo Canyon is shown below in Table 3-6:

TABLE 3-6
OPERATIONS AND MAINTENANCE EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	NRCRBA – Expense	$8,339	$11,200	$14,817	$9,400
2	Long Term Seismic BA	8,554	5,400	4,050	4,170
3	Other Expense	365,223	387,844	398,344	412,080
4	Total O&M Expense	$382,116	$404,444	$417,211	$425,650

The principal initiatives reflected in Diablo Canyon's expense request are as follows:

1. Cyber Security costs are included in the 2014 through 2017 period. This regulatory requirement continues in response to the NRC-issued 10 CFR 73.54 which requires each nuclear licensee to

make the necessary modifications and implement a program that provides high assurance that digital computer and communication systems and networks are adequately protected against cyber-attacks, up to and including design basis threat as described in Section 73.1 of 10 CFR. In the summer of 2014, the NRC completed an audit of the progress that all nuclear facilities are making relative to implementation of this rulemaking. As a result, the scope of this project has increased; however, the full extent of the requirements remain uncertain. Diablo Canyon has requested an extension of time to complete the Cyber Security assessments and implement the program for continued monitoring. The new due date is expected to be December 31, 2017. These costs are included in the NRCRBA.

2. Fukushima expense scope was required by the NRC as part of Order EA-12-049. This requirement explicitly required information and reevaluation of seismic and flooding risks, required walk-downs of plant equipment to identify any need for plant upgrades, and required a staffing study to address the need to operate and maintain additional equipment to be installed as part of mitigating risks beyond the design basis. The scope of this order remains unchanged; however, the NRC continues to review materials and has asked for additional information to aid in their review and assessment of the adequacy of measures taken. By the beginning of 2017, the NRC is expected to release implementation guidance and schedules for implementation of the Tier 2 and 3 recommendations. This has the potential to extend the work into 2020. These costs are included in the NRCRBA.
3. The main turbine generator maintenance for 2015 through 2017 includes requirements to inspect both the low-pressure turbine and high-pressure turbine rotors in addition to recurring valve maintenance. This low-pressure turbine inspection work is the first to be done since the installation of upgraded low-pressure turbines (six in total) in 2005-2006. Diablo Canyon's plan is to inspect one or two turbine rotors per outage for the next several years starting in

2015. The high-pressure turbine rotor requires an 8-year interval inspection. This will be completed in 2017 and 2018 for Unit 1 and Unit 2, respectively. The 2017 contract amount for the main turbine generator expense is $9.3 million.

b. Capital

PG&E's Capital expenditure forecast for 2015-2019 for Diablo Canyon is shown below in Table 3-7:

TABLE 3-7
CAPITAL EXPENDITURES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	NRCRBA – Capital	$44,099	$59,700	$36,068	$13,304	$5,157	–
2	Other Capital	173,173	178,711	177,861	146,396	132,543	$150,121
3	Total Capital Expenditures	$217,272	$238,411	$213,929	$159,700	$137,700	$150,121

The principal initiatives reflected in Diablo Canyon's request are as follows:

1) Equipment Reliability

In response to an uptick experienced in the forced loss rate in 2014, DCPP initiated an Equipment Reliability Initiative (ERI). This multi-faceted initiative is headed by the Director of Equipment Reliability.

The ERI strives to improve performance through a set of 23 action plans that address station evaluation and prioritization practices as well as maintenance plans and frequencies, and equipment replacement schedules and inventoried spares.

Implementation and completion of approved ERI projects is tracked by a project-specific ERI metric to monitor and assure timely completion.

Future and long range ERI projects have been identified and included in the stations 5-year financial plan. Projects such as Replacing the U-2 Main Generator Stator, Reactor Coolant Pump motor replacements, purchase of spare Rod Control Cluster Assemblies (RCCA), and upgrades to all the major fuel handling

components are planned to minimize outage durations and avoid forced generation losses. See Table 3-8 below.

TABLE 3-8
EQUIPMENT RELIABILITY CAPITAL EXPENDITURES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	20	U2: Repl. Main Generator Stator	$270	$4,678	$16,438	$22,775	$23,240	$11,240
2	20	Reactor Coolant Pump Motor Replacements	4,294	9,980	4,577	4,555	4,151	6,163
3	20	Spare RCCA						9,264
4	20	Fuel Handling Cranes and Controls	1,616	5,590	9,192	4,192	6,063	5,565
5		Total	$6,180	$20,248	$30,207	$31,522	$33,454	$32,232

2) Regulatory Balancing Account – Capital

As a result of the 2014 GRC decision PG&E established a two-way balancing account for managing the capital and expense forecasts associated with new nuclear energy safety and security regulatory required projects. The Fukushima Daiichi Response project is anticipated to be complete by 2017, and capital balancing account spending overall is forecast for $0 in 2019.

Table 3-9 depicts capital expenditures for the NRCRBA for 2014 through 2019. These capital expenditures are included in the capital expenditures shown in Table 3-2 and Table 3-20.

TABLE 3-9
NUCLEAR REGULATORY COMMISSION REGULATORY BALANCING ACCOUNT
CAPITAL EXPENDITURES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	EP Rule Total	$10,443	$8,667	$6,712	$1,008	$3,135	–
2	Fukushima Total	17,058	22,900	7,243	–	–	–
3	NFPA 805 Total	16,598	28,132	22,113	12,296	2,022	–
4	Total	$44,099	$59,700	$36,068	$13,304	$5,157	–

3) License Basis Verification Project

In 2010, PG&E, with NRC support, initiated the Licensing Basis Verification Project in order to perform a rigorous and methodical review of the entirety of the licensing documentation for

Diablo Canyon and to proactively identify and address any ambiguity or inconsistency in the licensing documentation, which at that point reflected nearly 30 years' worth of updates and revisions.

As of June 2015, the project has spent approximately $110 million and is approximately 70 percent complete, being more than 80 percent complete with the review and update of the Final Safety Analysis Report (FSAR). The FSAR is a summary document which details DCPP's compliance with and operation within the applicable NRC requirements and DCPP specific design basis. The original FSAR was submitted to the NRC as part of the initial application request for the DCPP operating licenses. The current FSAR is updated as needed by DCPP, and changes are required to be submitted annually to the NRC. Any changes to the DCPP facility are reviewed by PG&E against the FSAR and the Current Licensing Basis (CLB) to help assure that DCPP maintains regulatory compliance. The CLB is the information that the NRC used to grant the original license to operate DCPP Units 1 and 2. It also includes all the subsequent license amendments, information requested by the NRC, PG&E written responses to those requests, and any other correspondence with the NRC that includes commitments that PG&E has made with respect to operating the units. The licensing basis is implemented in the design and operation of Diablo Canyon, including drawings, calculations, analyses, and plant procedures, which are being reviewed to help assure consistency.

C. Activities and Costs by MWC

1. Support – MWC AB

TABLE 3-10
OPERATIONS AND MAINTENANCE EXPENSE BY MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2nd Outage Reclass	2014 Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
1	AB	Misc Expense	(30,007)	46,032	16,025	15,344	16,015	20,871

MWC AB has been used primarily for reclassification of the 2014 and 2019 second refueling outage costs. As authorized in the 2014 GRC decision, the costs of the 2014 second refueling outage are being amortized over three years from 2014 through 2016. 2019 also has a second refueling outage. PG&E proposes to use the same method approved in the 2014 GRC to amortize the costs of the 2019 second refueling outage over the 3-year period beginning in 2017.[21] Higher outage costs for the 2019 second refueling outage not attributed to escalation are due to:

a) Extended outage duration to 70 days to accommodate implementation of the Main Generator Stator project – $1.3 million (one-third of 2019 impact).
b) Telecom support transferred from other lines of business – $0.3 million (one-third of 2019 impact).
c) Main Generator turbine and maintenance scope and Steam Generator Eddy Current scope greater than average 2014 base year – $0.2 million (one-third of 2019 impact).
d) Higher project and non-labor costs compared to 2R18 outage – $0.9 million.

[21] See WP 3-67, Exhibit (PG&E-5) for the development of the 2019 second refueling outage estimate; See also WP 3-12, Exhibit (PG&E-5) for MWC AB Expense Walk.

2. Environmental Operations – MWC AK, CR, and EO

TABLE 3-11
OPERATIONS AND MAINTENANCE EXPENSE BY MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2nd Outage Reclass	2014 Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
1	AK	Manage Environmental Operations	$3,133	–	$3,133	$3,334	$2,999	$3,131
2	CR	Manage Waste Disposal and Transp	46	–	46	–	102	105
3	EO	Provide Nuclear Support	$245	–	$245	$335	$208	$214

The Environmental group manages the DCPP Environmental Protection Programs mandated by federal, state and local regulations. These programs include air quality, pollution prevention, water quality, offshore monitoring, radiological environmental monitoring and storage tank integrity. In 2014, this group incurred a one-time cost of $560,000 for once-through cooling studies. These costs will not be incurred in 2017 and have been removed from the forecast.[22] These MWCs include labor of $1.3 million in 2017 as compared to 2014 labor of $1.1 million. This is attributed primarily to labor escalation. In addition to labor, these MWCs include non-labor costs for the Receiving Water Monitoring Program as a requirement of our water use permit, Operations support at the Intake facility, and waste treatment and disposal for hazardous, industrial, and mixed waste products. These MWCs also include various fees and permit costs to oversight groups including the Department of Fish and Game, National Pollution Discharge Elimination System (NPDES), San Luis Obispo County and the state of California. The non-labor costs are $1.9 million in 2017 compared to $2.1 million in 2014.

[22] See WP 3-13 – 3-15, Exhibit (PG&E-5) for the expense walk from 2014-2017 for MWCs AK, CR and EO.

3. Manage DCPP Business – MWC BP

TABLE 3-12
OPERATIONS AND MAINTENANCE EXPENSE BY MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2nd Outage Reclass	2014 Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
1	BP	Manage DCPP Business	4,154	–	4,154	9,713	4,489	4,479

MWC BP includes non-labor costs for Strategic Teaming and Resource Sharing (STARS) fees, INPO fees, and 50 percent of Nuclear Energy Institute (NEI) fees totaling $2.8 million, compared to adjusted 2014 costs of $2.9 million. STARS is an alliance of southwestern nuclear facilities. INPO is a private nuclear oversight organization. NEI is a private nuclear education and policy organization. This MWC also includes charges for the Land Management Program and property leasing totaling $1.4 million compared to 2014 of $1.3 million. Changes in this MWC are principally attributed to escalation.[23] DCPP is requesting only 50 percent of the NEI fees consistent with the treatment of these costs in previous GRC decisions.[24]

4. Loss Prevention – MWC BQ

TABLE 3-13
OPERATIONS AND MAINTENANCE EXPENSE BY MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2nd Outage Reclass	2014 Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
1	BQ	Loss Prevention	44,053	(1,099)	42,954	42,020	48,573	48,699

The Loss Prevention MWC BQ is comprised principally of Security departments and the Emergency Planning department. The Security Operations group: (1) implements NRC requirements; (2) formulates tactical responses; (3) implements searches; (4) assesses barriers; and

---

23 See WP 3-16, Exhibit (PG&E-5).

24 See WP 3-70 – 3-76, Exhibit (PG&E-5) for the invoices for NEI fees for 2010 through 2014.

(5) evaluates alarm monitoring to make certain that safeguards are effective on a continuous basis.

The Emergency Planning Department administers the Emergency Plan, which is a part of the plant license. As such, Emergency Planning is a heavily regulated program, with the basis for our emergency plan found in the 16 planning standards in 10 CFR 50.47(b), and NUREG-0654, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans. This includes such things as plans, processes, procedures, facilities, equipment, training and drills, all in support of protecting the health and safety of the public in the event of a radiological emergency. MWC BQ includes labor of $44.3 million in 2017 as compared to adjusted 2014 labor of $39.8 million.[25] This is attributed completely to labor escalation and changes in the allocation of support costs (from capital to expense). In addition to labor, this MWC includes non-labor costs for weather forecasting and modeling, emergency plan public education, and emergency plan drill preparation and simulation. MWC BQ also includes various fees to the OES and FEMA. The non-labor costs are $4.3 million in 2017 compared to $3.2 million in 2014. Changes in the non-labor costs are attributable to non-labor escalation and state and county Emergency Service fee increases.[26] In particular, the OES and FEMA fees are expected to increase by $0.9 million compared to actual 2014 costs of $2.9 million. This increase is the result of lower than normal 2014 OES fees caused by a surplus in the OES budget and reallocation of the OES billings from SCE to PG&E due to closure of SCE's nuclear facility. Additionally, FEMA fees are increasing due to the post-Fukushima and EP Rulemaking regulatory requirements and actions being implemented and evaluated by the federal government.

---

25 See WP 3-17, Exhibit (PG&E-5).

26 See WP 3-17, Exhibit (PG&E-5).

5. Manage Production – MWC BR

TABLE 3-14
OPERATIONS AND MAINTENANCE EXPENSE BY MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2nd Outage Reclass	2014 Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
1	BR	Operate DCPP Plant	104,713	(7,861)	96,852	101,057	104,918	107,979

The Manage Production MWC BR consists of the following groups: Operations Services, Chemistry Department, and Radiation Protection. Each of these groups and the work that they perform are described below.

Operations Services includes the operation of the plant, radiation control, monitoring of plant chemistry, managing radioactive waste and hazardous waste generation, nuclear fuel movement, environmental engineering and reactor physics testing.

The Chemistry Program includes plant chemistry control for Diablo Canyon Units 1 and 2, as well as radiological effluent monitoring and control for the DCPP site. Chemical control is the process of establishing and maintaining a prescribed set of chemical parameters to prevent or minimize corrosion and/or deposition on system components.

Radiation Protection provides oversight for control of radioactive material and support to plant workers on radiation safety. The main focus of this section is to maintain radiation dose received by workers as low as reasonably achievable. This is accomplished by minimizing radiation levels in the plant through engineering controls, radiation shielding and controlling plant chemistry. Radiation Protection also provides oversight and guidance to plant workers to help assure work practices minimize radiation dose.

Changes in MWC BR are attributable to labor and non-labor escalation, changes in the allocation of support costs (from capital to expense) and other minor cost increases.[27]

MWC BR includes labor of $98.7 million in 2017 as compared to adjusted 2014 labor of $87.5 million.[28] This is attributed primarily to labor

[27] See WP 3-18, Exhibit (PG&E-5).

[28] See WP 3-18, Exhibit (PG&E-5).

escalation and changes in the allocation of support costs (from capital to expense). In addition to labor, this MWC includes non-labor costs for materials of $5.9 million compared to 2014 material costs of $4.9 million. This increase is partially attributed to non-labor escalation ($0.3 million) but also to the effects of an early 2014 outage for Unit 1 which caused the Radiation Protection materials to be procured in the prior year ($0.7 million). DCPP maintains chemical parameters through the use of chemical additives or by minimizing the ingress of impurities into the systems. PG&E maintains chemical control of the Diablo Canyon Units 1 and 2 reactor coolant systems (which includes the fuel assemblies), the secondary systems including Steam Generators, and auxiliary systems such as the service cooling water and component cooling water systems. In addition, PG&E generates all necessary water with an on-site reverse osmosis system for use in all plant systems. In addition, this MWC includes contract costs for radioactive waste monitoring and disposal, dosimetry analysis, and chemical analysis and disposal.

6. Manage Diablo Canyon Power Plant Assets – MWC BS

TABLE 3-15
OPERATIONS AND MAINTENANCE EXPENSE BY MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2nd Outage Reclass	2014 Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
1	BS	Maintain DCPP Plant Assets	$157,275	$(29,553)	$127,722	$123,982	$137,233	$148,156
2	BS	Expense Projects	$8,112	$(451)	$7,661	$10,182	$8,514	$7,112

The Manage DCPP Assets MWC BS includes groups and sections within the Maintenance Department, Outage Management Department, Facilities Maintenance Department and Project Services group.

The Maintenance Department plans and performs preventive maintenance, corrective maintenance and maintenance surveillance testing of DCPP mechanical, electrical, and Instrument and Control equipment.

The Outage Management group consists of two sections: Outage Services section and Work Control section. The Outage Management group develops and plans on-line maintenance and outage activities at DCPP.

The Facilities Maintenance Department provides repair and maintenance services for all non-power block buildings and facilities and does minor project work. Because of new security and environmental demands, the group increasingly addresses land maintenance issues. It also maintains all Diablo Canyon vehicles and heavy equipment as part of fleet services. In addition, this section manages a significant number of support service contracts for such areas as janitorial services, rental needs, trash collection for all offices and work areas, restrooms, cafeterias, sewer maintenance, and infrastructure maintenance.

The Project Services section provides consistent application of Project Management methodology for DCPP projects. Project Services assigns project managers that play a key role to proactively replace and/or maintain the original equipment of the plant. Additional considerations for assigning project management are made if the project has implementation or financial risk, requires significant coordination, or involves regulatory commitments. Only expense projects are charged in MWC BS. Capital projects are charged into MWC 20. The expense projects included in 2014 through 2017 are summarized in WP 3-24.

Changes in MWC BS are attributable to labor and non-labor escalation, changes in the allocation of support costs (from capital to expense), lower expense project work, telecom costs incurred during the refueling outage that were previously charged to another line of business, and increased Turbine Generator maintenance.[29] Main Generator Maintenance scope for the 2017 outage is significantly higher than work done in 2014 (after the second outage is excluded). This scope includes maintenance on both the low-pressure turbine as well as the high-pressure turbine. This increase is approximately $6.3 million.

Telecom support for outage has been transferred from another line of business and is now included in MWC BS. The impact is $0.8 million.

MWC BS includes labor of $111.7 million in 2017 (excluding expense project work) as compared to adjusted 2014 labor of $101.7 million.[30]

---

29 See WP 3-19, Exhibit (PG&E-5).

30 See WP 3-19, Exhibit (PG&E-5).

This is attributed primarily to labor escalation and changes in the allocation of support costs (from capital to expense). In addition to labor, MWC BS includes non-labor costs for materials of $14.4 million compared to 2014 material costs of $13.9 million used in the maintenance of all plant equipment. In addition, MWC BS includes contract and other costs of $22.1 million compared to 2014 costs of $12.4 million. These costs include security camera system maintenance, plant intake maintenance, reactor equipment specialty maintenance, and secondary equipment specialty maintenance (including the main generator turbine). Costs for charges from other PG&E lines of business are also included in this MWC for transmission line and substation equipment maintenance and plant painting needs.

The lower expense project work is primarily attributable to completion of all expense related License Basis Verification project work although the mix of projects has changed as well. The principal change in the mix of projects is that the 2014 expense projects included a rewedge of the main generator stator core while 2017 will include work to restore the feedwater heater pipe integrity.[31]

7. People Performance – MWC BT

TABLE 3-16
OPERATIONS AND MAINTENANCE EXPENSE BY MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2nd Outage Reclass	2014 Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
1	BT	Nuclear Generation Fees	18,191	(85)	18,106	21,280	19,311	19,497

The People Performance MWC BT consists of the following departments: Training Department, Quality Verification, and Site Services. The Site Services Department has two principal sections that charge to MWC BT. These are the Regulatory Services section and the Performance Improvement section.

The Training Department manages the preparation and delivery of employee training specific to the nuclear industry and manages training

31 See WP 3-24, Exhibit (PG&E-5).

facilities. These training programs result in industry certification recognition for the operators, maintenance workers, technicians and engineers.

The Quality Verification Department has overall responsibility for independent quality oversight of DCPP plant operations, maintenance, radiation protection, chemistry, EP, environmental protection plan, fitness for duty, engineering, design, procurement, outage management, work control, and Strategic Projects. This includes independent QA audits, assessments, reviews, quality control inspections, welding nondestructive examinations, source assessments, and supplier audits.

The Regulatory Services section manages the process for maintaining the DCPP NRC facility operating licenses, including the preparation of all correspondence related to maintaining those licenses. This section also manages PG&E's participation in NRC inspection activities. They provide NRC inspectors with unfettered access to PG&E personnel and plant operation and design information, and address any issues that may arise.

The Performance Improvement section has overall programmatic responsibility for performance improvement at DCPP. Performance improvement elements include problem identification and resolution via the Corrective Action Program, station improvement via operating experience, human performance, self-assessment, benchmarking, and the Employee Concerns Program.

MWC BT includes labor of $4.0 million in 2017 as compared to adjusted 2014 labor of $3.7 million. This is attributed completely to labor escalation. In addition to labor, MWC BT includes non-labor costs for NRC fees—$12.7 million in 2017 compared to $13.4 million in 2014—and DCISC fees. Changes in the non-labor costs are attributable to non-labor escalation offset by one-time NRC fees in 2014 for Fukushima related issues.[32]

[32] See WP 3-20, Exhibit (PG&E-5).

8. Maintain Plant Configuration – MWC BV

TABLE 3-17
OPERATIONS AND MAINTENANCE EXPENSE BY MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2nd Outage Reclass	2014 Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
1	BV	Maintain DCPP Plant Configuration	55,634	(7,309)	48,325	60,597	55,982	51,837

The Maintain Plant Configuration MWC BV consists of Engineering and Strategic Projects.

The Engineering Department's fundamental responsibility is to maintain the configuration of the plant. Configuration management is essential to continuing the health and regulatory compliance of the plant SSCs. Safe operations and NRC regulations require nuclear plants to examine all potential changes to plant SSCs. This ensures that plant operations will not be compromised and complete, accurate, up-to-date records will be maintained which exactly reflect the current configuration of plant facilities.

The Strategic Projects Department has only minor expense amounts with its primary focus on implementation of major capital projects.

Changes in MWC BV are attributed to labor and non-labor escalation, changes in the allocation of support costs (from capital to expense), and lower expense contract work. MWC BV includes labor of $40.2 million in 2017 as compared to adjusted 2014 labor of $35.9 million. In addition to labor, MWC BV includes non-labor costs for Electric Power Research Institute dues, Pressurized Water Reactor Owners Group dues, Triennial Decommissioning Study costs, and various reactor equipment inspection contract costs—$11.7 million in 2017 compared to $12.9 million in 2014. Changes in the non-labor costs are attributable to non-labor escalation and a large 10-year frequency inspection performed in 2014 that will not be repeated in 2017.[33]

[33] See WP 3-22, Exhibit (PG&E-5).

9. Nuclear Regulatory Commission Regulatory Balancing Account – MWC IG

TABLE 3-18
OPERATIONS AND MAINTENANCE EXPENSE BY MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2nd Outage Reclass	2014 Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
1	IG	Manage Var Bal Acct Processes	16,893	–	16,893	16,600	18,867	13,570

The Nuclear Regulatory Commission Regulatory Balancing Account expense MWC IG consists of three expense projects—Cyber Security, Fukushima, and EP Rulemaking. These projects were implemented to respond to the NRC's orders. In addition, the Long-Term Seismic Program (LTSP) costs are also included in this MWC.

The Cyber Security project responds to the NRC-issued 10 CFR 73.54, (protection of digital computer and communication systems and networks) which requires each nuclear licensee to make all necessary modifications and implement a program to provide high assurance that digital computer and communication systems and networks are adequately protected against cyberattacks.

Fukushima expense project responds to the NRC Order EA-12-049 issued on March 3, 2012, which requires completing seismic and flooding reevaluations and walk-downs to identify any need for plant upgrades. Additionally, an update and upgrade of the DCPP Seismic Probabilistic Risk Analysis models to new standards as well to fragilities and seismic hazards documents is required to comply with this NRC order.

The EP Rulemaking responds to 10 CFR 50.54(q), which describes the process for making changes to the emergency plan.

The changes in these project costs are attributed to the expected completion of the EP Rulemaking project, winding down of the Fukushima expense project, and increased scope on the Cyber Security project.

Changes in the LTSP costs are attributed to labor escalation, non-labor escalation, and work scope changes. This component of MWC IG includes labor of $1.2 million in 2017 as compared to adjusted 2014 labor of $0.9 million. In addition to labor, this portion of MWC IG includes non-labor

costs for seismic analysis consultants. 2017 non-labor costs are $2.9 million compared to $3.1 million in 2014. The principal non-labor work scope for 2017 are additional ground motion studies and on-shore and off-shore geologic survey and mapping work.[34]

D. Estimating Method

PG&E's expense and capital estimating methods are based on a combination of trends from recent historical information and specifically identified non-recurring work scope.

1. Provider Cost Center Standard Labor Rates

PG&E developed its expense forecast for Test Year (TY) 2017 by starting with 2014 actual staffing and straight-time labor costs by Provider Cost Center (PCC). The staffing is based on supporting an appropriate work force management plan as well as an understanding of changing roles and responsibilities and work scope. We then adjusted this starting point for changes in staffing and labor escalation rates.[35] The non-labor costs for each PCC consist of department materials, employee expenses, staff augmentation, employee benefits and payroll taxes, and interdepartmental chargebacks. These costs are generally averaged for recent history and escalation rates are applied to account for inflation. The overtime labor is modeled by comparing total work hours planned to total resource available hours without overtime.[36] The total work planned encompasses all base expense, expense projects, capital projects, and miscellaneous work charged to other LOBs. Support organization costs are then allocated to the core operating cost centers (Operations, Maintenance, Engineering, Strategic Projects and Security). The summation of the straight time labor, overtime labor, non-labor PCC costs, and allocated support costs are then divided by total productive (billable) hours to determine a standard rate for each PCC.[37]

---

[34] See WP 3-23, Exhibit (PG&E-5).

[35] See WP 3-185 – 3-187, Exhibit (PG&E-5) for the staffing plan.

[36] See WP 3-239 – 3-290, Exhibit (PG&E-5) for hours available and hours required for all planned work.

[37] See WP 3-239 – 3-290, Exhibit (PG&E-5) for the derivation of the standard rate for each PCC.

2. Expense Labor Costs

Expense labor costs are determined by multiplying expense hours (base and project expense orders) by the PCC standard rate to determine expense labor charges. Hours for base expense orders are determined by examining baseline history separately from outage incremental hours. The baseline hours are generally averaged from recent history but will consider the impacts of changing work scope. For expense project orders, the PG&E labor hours are estimated for each project based on the specific work scope. Comparable historical projects and vendor inputs form the basis for the labor hour estimates. The outage incremental hours are determined for each PCC based on planned maintenance and support work for the upcoming outages.

The scheduling of DCPP's refueling outages is driven by the rate at which fuel is used. These refueling outages are normally 18 to 20 months apart in each of Diablo's two units. Additionally Diablo Canyon seeks to avoid the scheduling of an outage during the summer months when electric demand is the highest, so these refueling outages are typically planned to occur in the spring or fall of a given year.

The duration of future refueling outages is determined by balancing the desire to keep outage durations to a minimum with the need to perform the work necessary to assure safe reliable operations in the long run. The starting point in achieving this balance is the calculation of the minimum time it takes to perform the refueling functions as well as all the required routine maintenance and inspection activities that must be performed in a given outage and adding in any additional time required to complete approved non-recurring upgrades and replacements. Efforts are made to assure outage durations are minimized, and that planning of the non-recurring work is optimized while maintaining equipment reliability.

3. Expense Non-Labor Costs

The non-labor costs are charged directly to orders and are estimated based on a combination of trending and specifically identified non-recurring costs. For expense project orders, we removed one-time projects from 2014 that had been completed, updated our cost estimates of continuing expense

programs and used our planning and budget process to identify new or continuing projects that will occur in 2017.[38]

4. Total Expense Costs

The result of this estimating process was PG&E's expense forecast for Nuclear Operations of $405.2 million. PG&E then normalized the second refueling outage costs for 2019 by spreading the second refueling outage costs over three years beginning in 2017 to establish the expense forecast of $425.4 million.[39]

5. Capital Labor and Non-Labor Costs

For capital project orders, we removed one-time projects from 2014 that had been completed, updated our costs estimates of continuing capital programs and used our planning and budget process to identify new or continuing projects that will occur from 2015 through 2019.[40] Project cost estimates are developed using vendor inputs, subject matter expert input, standard PG&E labor hour estimates for various project classifications, and analogous historical projects.

E. Compliance With 2014 General Rate Case Reporting Requirements

1. California Energy Commission – Transfer of Spent Fuel to Dry Casks

In the 2014 GRC, PG&E's forecast of $26.1 million to construct the remaining five pads at the ISFSI in 2014 was approved, subject to the requirement that PG&E "file with its next GRC a satisfactory plan to comply with CEC recommendations regarding the transfer of spent fuel to dry cask storage in its AB 1632 Report." D.14-08-032, p. 413.

PG&E is committed to transferring used fuel from the spent fuel pools to the ISFSI as soon as possible. The lower limit constraint is the NRC compensatory measure b.5.b, which requires four cold assemblies available to surround one hot assembly. With a 193 element core, PG&E needs to

---

38 See WP 3-24, Exhibit (PG&E-5) for a detailed listing of each expense project planned for 2015 through 2017.

39 See WP 3-67, Exhibit (PG&E-5) for the derivation of the 2019 second refueling outage costs.

40 See WP 3-188 – 3-238, Exhibit (PG&E-5) for procedures documenting the capital project approval and prioritization process.

keep 772 cold assemblies in the pool. With the planned eight casks in 2015 and 12 casks in 2016, this approaches the b.5.b limit (within the constraint of 32 assemblies per cask) by the end of 2016. Future fuel movements are planned every two years at a rate that keeps the pools at the b.5.b limit.[41]

2. Department of Energy Litigation Refund

As discussed in Exhibit (PG&E-5), Chapter 8, in the 2014 GRC, PG&E reached a joint proposal with The Utility Reform Network and Marin Energy Authority (now Marin Clean Energy) for crediting the proceeds of the Department of Energy (DOE) litigation settlement to generation rates (for reimbursement of spent fuel related storage costs for DCPP) and to nuclear decommissioning rates (for reimbursement of spent fuel related storage costs for Humboldt Bay Nuclear Power Plant (HBPP). D.14-08-032, Appendix F-5. For the period 2017-2019, PG&E will continue to use the allocation method for "future claims proceeds" in the joint proposal. As a general matter, the settling parties agreed that 72 percent of the proceeds under the DOE claims process should be attributed to Diablo Canyon and 28 percent if the proceeds should be attributed to HBPP. The implementation of these ratemaking concepts is discussed in Exhibit (PG&E-5), Chapter 8.

In September 2012, PG&E entered into a settlement agreement with the DOE to resolve litigation surrounding DOE's failure to perform under spent fuel disposal agreements for DCPP and HBPP. PG&E provided a full status report on the settlement in its 2014 GRC filing. Under the terms of the settlement agreement, PG&E recovered a lump sum amount reimbursing PG&E for the costs of spent fuel storage at DCPP and HBPP through 2010. In addition, the settlement approved an annual administrative claims process that requires PG&E to document its costs of spent fuel storage in defined recoverable categories and submit an annual claim to be reviewed by DOE staff and approved by the Department of Justice. The annual claims process has been successful and PG&E agreed to extend the administrative claims process through the end of 2016 in an amendment to

---

41 See WP 291, Exhibit (PG&E-5) for the complete report on compliance with this directive.

the settlement agreement that was reached in 2013. PG&E anticipates that DOE will agree to continue the annual administrative claims process beyond 2016. PG&E's forecast for the period 2017-2019 is based on the assumption that the annual claims process will continue.

For the period 2017-2019, PG&E forecasts that it will continue to collect approximately $20 million per year from DOE under the administrative claims procedure in the settlement to compensate PG&E for the costs of storing spent nuclear fuel at DCPP and HBPP. This forecast is consistent with the recent results. For the period June 1, 2012, to May 31, 2013, PG&E received approximately $20.8 million from DOE. For the period June 1, 2013, to May 31, 2014, PG&E received approximately $20.9 million from DOE.

Although the current settlement agreement with DOE is set to expire and future recovery of the costs of storing spent fuel in dry casks at DCPP is uncertain, PG&E has included a forecast of continued revenues from DOE and proposes to continue the crediting process for DCPP in the joint recommendation, subject to true-up when actual proceeds are received. If the DOE settlement is not extended, PG&E will be required to file new lawsuits against DOE to recover the costs of spent fuel storage starting in 2017 and this could significantly delay recovery of spent fuel costs at DCPP and HBPP.

3. Review of LTSP Costs

As discussed in Exhibit (PG&E-5), Chapter 8, PG&E has included in its 2017 forecast the costs of PG&E's ongoing seismic program for DCPP. In the 2014 GRC decision, the costs of PG&E's Long Term Seismic Program (LTSP) costs were transferred to the Diablo Canyon Seismic Studies Balancing Account (DCSSBA) for review on an annual basis in the Energy Resource Recovery Account (ERRA) compliance proceeding. Review of the costs of the LTSP were transferred to ERRA in order to help assure the proper integration of the AB 1632 advanced seismic studies (already under review in the ERRA) with the NRC-directed Senior Seismic Hazards Analysis Committee (SSHAC) process (the costs of which were included in the 2014 GRC application as part of the LTSP). Because the AB 1632 advanced seismic studies have been completed and the SSHAC

process had been completed, PG&E proposes to return the review of LTSP costs to the GRC. See Exhibit (PG&E-12), Chapter 9, regarding PG&E's proposal to close the account upon final disposition by the Commission on the December 31, 2016 balance in the account as part of the ERRA compliance proceeding.

The LTSP costs for 2017-2019 included in PG&E's DCPP exhibit include the labor and consultant costs in PG&E's Geosciences Department associated with PG&E's on-going NRC commitment to continuously study and update the state of knowledge regarding seismic hazards affecting DCPP. The 2017 forecast for the LTSP is $4.2 million. These costs are included in MWC IG and are described in Section C.9, Nuclear Regulatory Commission Regulatory Balancing Account – MWC IG.

AB 1632 (codified as Public Resources Code Section 25303) directed the California Energy Commission (CEC) to assess the potential vulnerability of large base load plants, including DCPP, to a major seismic disruption. In response, the CEC issued the AB 1632 Report as part of its 2008 Integrated Energy Policy Report, which recommended, among other things, that PG&E undertake advanced seismic studies at DCPP. PG&E filed an application with the Commission for funding of the recommended studies, which was approved in Decision 12-09-008. The Commission authorized PG&E to track the costs of the AB 1632 seismic studies in the DCSSBA and to recover the costs on an annual basis through the ERRA compliance proceeding. PG&E issued the final report on the advanced seismic studies recommended in the CEC's AB 1632 Report on September 10, 2014.

In March 2013, following the Fukushima earthquake, the NRC directed all licensed nuclear plants to reevaluate the seismic hazards at their sites using present day NRC requirements. As part of this review, the NRC directed PG&E and other Western area licensees to perform the seismic hazard re-evaluation using a Level 3 SSHAC process. The results of the advanced seismic studies presented in the September 10, 2014 AB 1632 report were reflected in the SSHAC process. On March 12, 2015, PG&E submitted the seismic hazard re-evaluation for Diablo Canyon, which was

the end result and product of the SSHAC Level 3 process, to the NRC. The SSHAC process was completed on that date.

The AB 1632 advanced seismic studies and the NRC SSHAC process are, therefore, now complete. PG&E will not incur any additional costs associated with these activities in 2017 or beyond.

F. Cost Tables

Table 3-19[42] shows recorded and forecasted costs by MWC for expense and Table 3-20[43] shows recorded and forecasted capital expenditures by MWC. For 2014, each of the expense MWC has been adjusted to reclassify the second refueling outage to MWC AB. This was done for consistency with the 2015 through 2017 amounts.

---

42 See WP 3-1, Exhibit (PG&E-5).

43 See WP 3-103, Exhibit (PG&E-5).

TABLE 3-19
OPERATIONS AND MAINTENANCE EXPENSE BY MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2nd Outage Reclass	2014 Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
1	AB	Misc Expense	$(30,007)	$46,032	$16,025	$15,344	$16,015	$20,871
2	AK	Manage Environmental Oper	3,133	–	3,133	3,334	2,999	3,131
3	BP	Manage DCPP Business	4,154	–	4,154	9,713	4,489	4,479
4	BQ	DCPP Support Services	44,053	(1,099)	42,954	42,020	48,573	48,699
5	BR	Operate DCPP Plant	104,713	(7,861)	96,852	101,057	104,918	107,979
6	BS	Maintain DCPP Plant Assets	165,387	(29,678)	135,709	134,164	145,747	155,268
7	BT	Nuclear Generation Fees	18,191	(85)	18,106	21,280	19,311	19,497
8	BU	Procure DCPP Materials & Svcs	(326)	–	(326)	–	–	–
9	BV	Maintain DCPP Plant Configuration	55,634	(7,309)	48,325	60,597	55,982	51,837
10	CR	Manage Waste Disposal & Transp	46	–	46	–	102	105
11	EO	Provide Nuclear Support	245	–	245	335	208	214
12	IG	Manage Var Bal Acct Processes	16,893	–	16,893	16,600	18,867	13,570
13		Grand Total	$382,116	–	$382,116	$404,444	$417,211	$425,650

TABLE 3-20
CAPITAL EXPENDITURES BY MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	03	Office Furniture & Equipment	$199	$232	$232	$232	$232	$232
2	04	Fleet/Auto Equip	865	963	917	817	817	817
3	05	Tools & Equipment	980	782	1,158	1,158	1,158	1,158
4	20	DCPP Capital	171,129	176,735	175,554	144,189	130,336	147,914
5	3I	Nuclear Safety and Security	44,099	59,700	36,068	13,304	5,157	–
6		Total	$217,272	$238,411	$213,929	$159,700	$137,700	$150,121

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

HYDRO OPERATIONS COSTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
HYDRO OPERATIONS COSTS

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
HYDRO OPERATIONS COSTS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
HYDRO OPERATIONS COSTS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
HYDRO OPERATIONS COSTS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
HYDRO OPERATIONS COSTS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
HYDRO OPERATIONS COSTS

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to demonstrate that Pacific Gas and Electric Company's (PG&E or the Company) forecasts of expense and capital expenditures to operate and maintain its Hydroelectric Generation (Hydro) facilities are reasonable and should be adopted by the California Public Utilities Commission (CPUC or Commission).

PG&E operates the largest investor-owned hydroelectric system in the United States for the benefit of its electric customers and the citizens of California. PG&E's customers benefit from the continued safe and reliable operation of the hydro system because it provides high-value, low-cost, dispatchable electricity products (energy, capacity, and ancillary services) to meet their demands, and supports integration of intermittent renewable energy. In addition, PG&E's customers and the public benefit from this air-emission-free source of electricity and the Company's associated land conservation, recreation, and environmental commitments.

In this exhibit PG&E requests that the Commission adopt the expense and capital forecasts for operating and maintaining PG&E's hydro generation facilities in order to ensure safe, reliable, cost-effective, and environmentally-responsible generation from these assets in 2017 and beyond. PG&E also requests that the Commission approve the continuation of a two-way balancing account for costs associated with relicensing its hydro facilities and implementing new and/or amended Federal Energy Regulatory Commission (FERC) license requirements.

2. Summary of Request

a. Expense

PG&E requests that the Commission adopt its 2017 forecast of $187.7 million for hydro operations and maintenance (O&M) expenses.[1] An overview of the expense forecast is provided in Section B.1.a, and the major cost drivers are discussed in Section C.1.

b. Capital

PG&E requests that the Commission adopt its capital expenditure forecast of $287.7 million for 2015, $259.8 million for 2016, $253.7 million for 2017, $270.1 million for 2018, and $260.2 million for 2019.[2] An overview of the capital forecast is provided in Section B.1.b, and the major areas of capital work are discussed in Section C.2.

c. Balancing Account

PG&E requests that the Commission approve the continuation of the two-way balancing account (hydro balancing account) that was adopted in the 2014 General Rate Case (GRC). The hydro balancing account is forecast to include expense costs of $0.5 million for 2015, $0.6 million for 2016, and $3.9 million for 2017 as well as capital costs of $22.4 million for 2015, $21.6 million for 2016, $27.0 million for 2017, $41.0 million for 2018, and $47.1 million for 2019.[3] These costs are associated with relicensing its hydro facilities and implementing new/amended FERC license conditions. The hydro balancing account is discussed in Section D.3.[4]

3. Support for Request

Despite the ongoing and challenging drought conditions in California, PG&E's hydro powerhouses provide low-cost, clean energy, high-value ancillary services, and peaking capacity to meet customers' needs. PG&E

---

1 See WP 4-1, Line 14, Exhibit (PG&E-5).

2 See WP 4-74, Line 12, Exhibit (PG&E-5).

3 See WP 4-1, Line 8 and WP 4-74, Line 11, Exhibit (PG&E-5).

4 The hydro balancing account mechanism and PG&E's proposed process for truing up the account balance is discussed in Exhibit (PG&E-5), Chapter 8.

has demonstrated its ability to optimize these generation facilities through efficient use of water resources and continuing environmental stewardship. The request in this exhibit, which generally seeks continuation of existing funding levels adjusted for inflation, is necessary and appropriate in order to maintain and improve the reliability and performance of these generation assets.

Because it offers flexible storage and generation capabilities, PG&E's hydro portfolio will play a critically important role in integrating additional intermittent renewable resources that are expected to be added to PG&E's portfolio in the 2017 GRC period.[5] A large and increasing portion of California's electric generating fleet consists of non-dispatchable energy sources such as wind, solar, nuclear, and regulatory "must take" generation. To successfully integrate these non-flexible resources onto the grid, the California Independent System Operator (CAISO) relies on PG&E's hydro resources to satisfy a large portion of its operating reserve requirements. PG&E's hydro system represents about 28 percent of California's installed hydro capacity,[6] and over 43 percent of the dependable hydro capacity in the CAISO balancing authority area.[7]

PG&E's hydroelectric generating units typically start up quickly, have fast ramp rates, and can easily, quickly, and economically vary output in response to changing customer loads and system conditions. In addition, PG&E's hydro generating units can operate at no load or low load with much higher efficiency than the alternative fossil-fueled peaking plants. For example, PG&E's Helms pumped storage facility, which is described more fully in Section B.2.a, below, is a cornerstone of grid stability and may be called upon by CAISO multiple times in a day to meet grid requirements.

PG&E's system of dams, reservoirs, and water collection facilities enable PG&E to store runoff and aquifer flows and then subsequently to use the water to generate power when customers need it most. This "shaping"

---

5 See Exhibit (PG&E-5), Chapter 6, Energy Procurement Administration Costs.

6 See California Energy Commission's Hydroelectric Statistics & Data http://www.energyalmanac.ca.gov/renewables/hydro/.

7 See CAISO 2015 Summer Loads and Resources Assessment https://www.caiso.com/Documents/2015SummerAssessment.pdf.

of the available generation is performed both seasonally (for example, by storing more water in the spring and releasing water from the reservoirs during high value hot summer days) and day to day (for example, generating more during hours of peak system demand—typically weekday afternoons and evenings—and less at night and on weekends). In general, the highest value of PG&E-owned generation is likely to be when PG&E's demand is greatest, and hydro generation can contribute significantly toward reducing the amount of power that PG&E has to purchase during these higher-priced hours.

In sum, PG&E's hydro assets provide significant value to PG&E's customers, and PG&E only expects this value to increase as the need for clean, flexible generation and storage increases. While flexible operation of these assets provides high value, it also can increase the operating and capital costs of these facilities through more frequent ramping events. In addition to the routine upkeep of PG&E's hydro facilities, this exhibit describes the cost-effective work that PG&E proposes to undertake to preserve and enhance the value of these facilities for customers.

B. Activities and Costs

1. Overview of Recorded and Forecast Costs

a. Expense

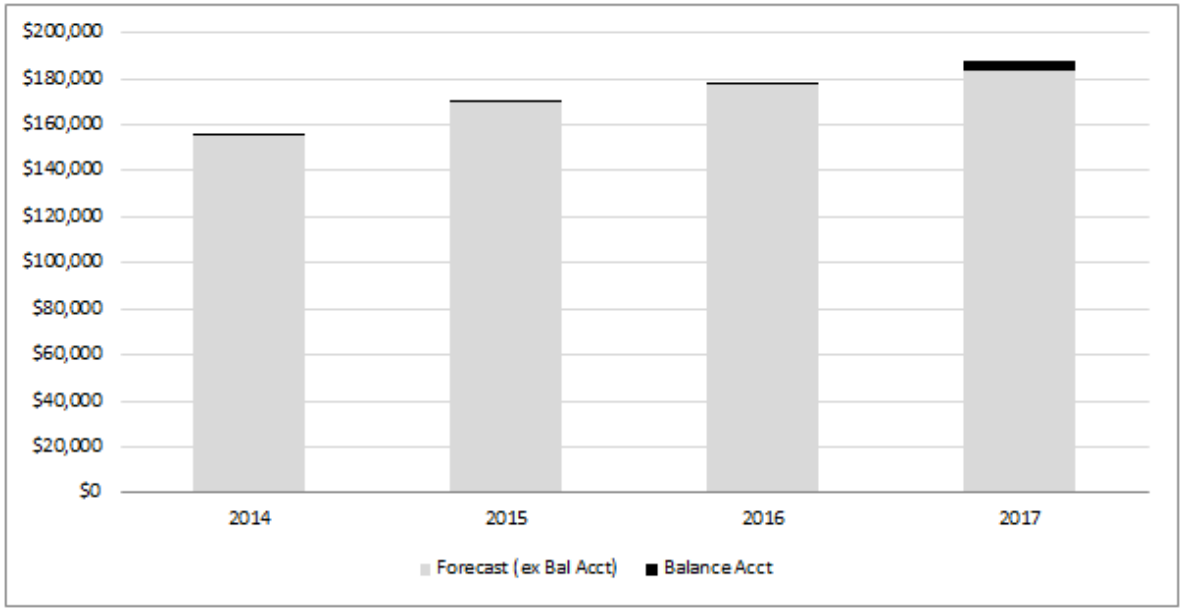
Table 4-1 summarizes 2014 recorded hydro O&M expenses and PG&E's forecast for 2015-2017. Figure 4-1 provides this same information in a bar chart format. The forecast for expenses associated with the hydro balancing account is shown separately.

TABLE 4-1(a)
HYDRO GENERATION O&M EXPENSE 2015-2017
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	Hydro O&M Expense	$155,194	$169,894	$177,723	$183,804
2	Hydro Balancing Account	286	454	558	3,942
3	Total	$155,480	$170,348	$178,281	$187,746

(a) See WP 4-1, Exhibit (PG&E-5).

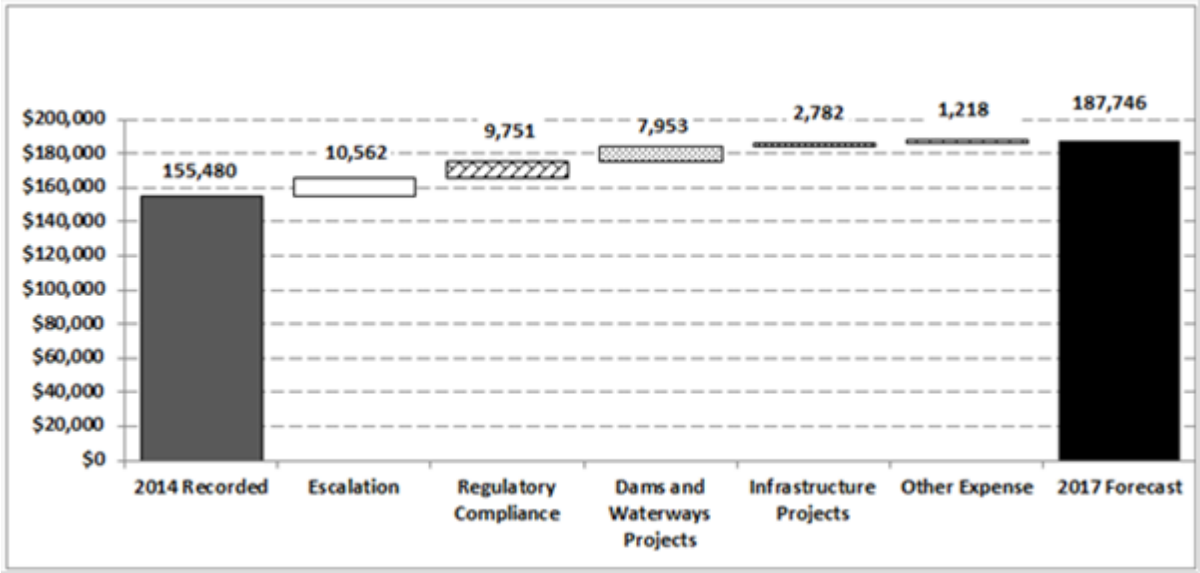
FIGURE 4-1
HYDRO GENERATION O&M EXPENSE 2014-2017
(THOUSANDS OF NOMINAL DOLLARS)



PG&E's forecast for 2017 hydro expense is $187.7 million, which is $32.2 million or 21 percent more than the recorded 2014 expense amount of $155.5 million. Figure 4-2 provides an expense walk depicting the key drivers for the difference between the 2014 recorded costs and the 2017 forecast.[8] Additional information on each driver has been provided in Section C.1.

[8] See WP 4-73, Exhibit (PG&E-5).

FIGURE 4-2
HYDRO GENERATION O&M EXPENSE WALK 2014-2017
(THOUSANDS OF NOMINAL DOLLARS)



b. Capital

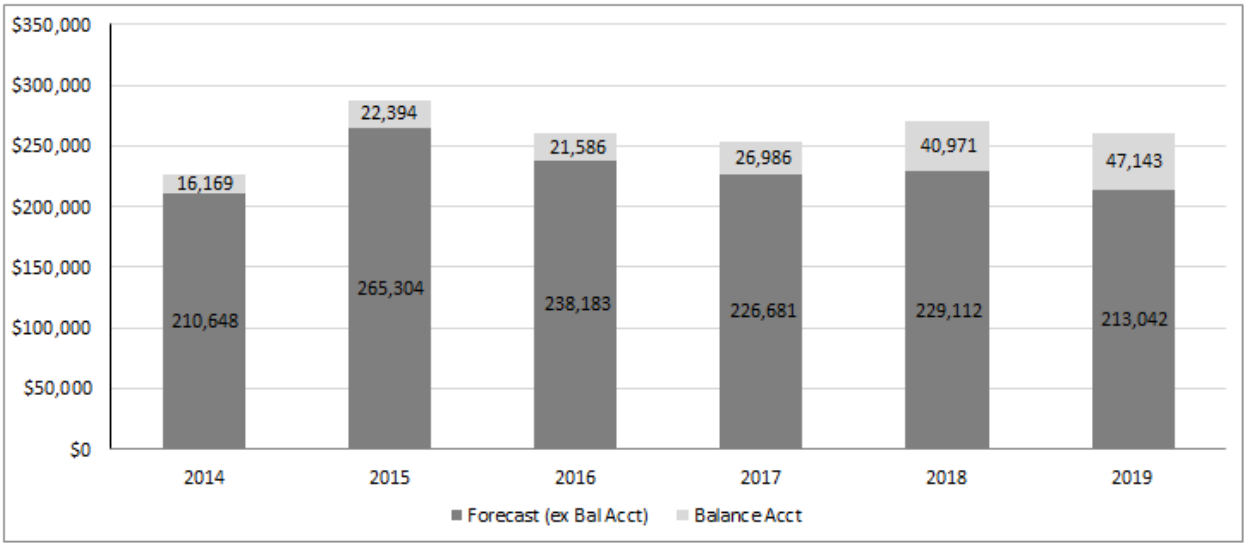
Table 4-2 summarizes the 2014 recorded hydro capital expenditures and PG&E's forecasts for 2015-2019. Figure 4-3 provides this same information in a bar chart format. The forecast for capital expenditures associated with the hydro balancing account is shown separately.

TABLE 4-2(a)
HYDRO GENERATION CAPITAL EXPENDITURES 2014-2019
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	Hydro Gen Cap Expenditures	$210,648	$265,304	$238,183	$226,681	$229,112	$213,042
2	Hydro Balancing Account	16,169	22,394	21,586	26,986	40,971	47,143
3	Total	$226,818	$287,698	$259,769	$253,667	$270,083	$260,184

(a) See WP 4-74, Exhibit (PG&E-5).

FIGURE 4-3
HYDRO GENERATION CAPITAL EXPENDITURES 2014-2019(a)
(THOUSANDS OF NOMINAL DOLLARS)

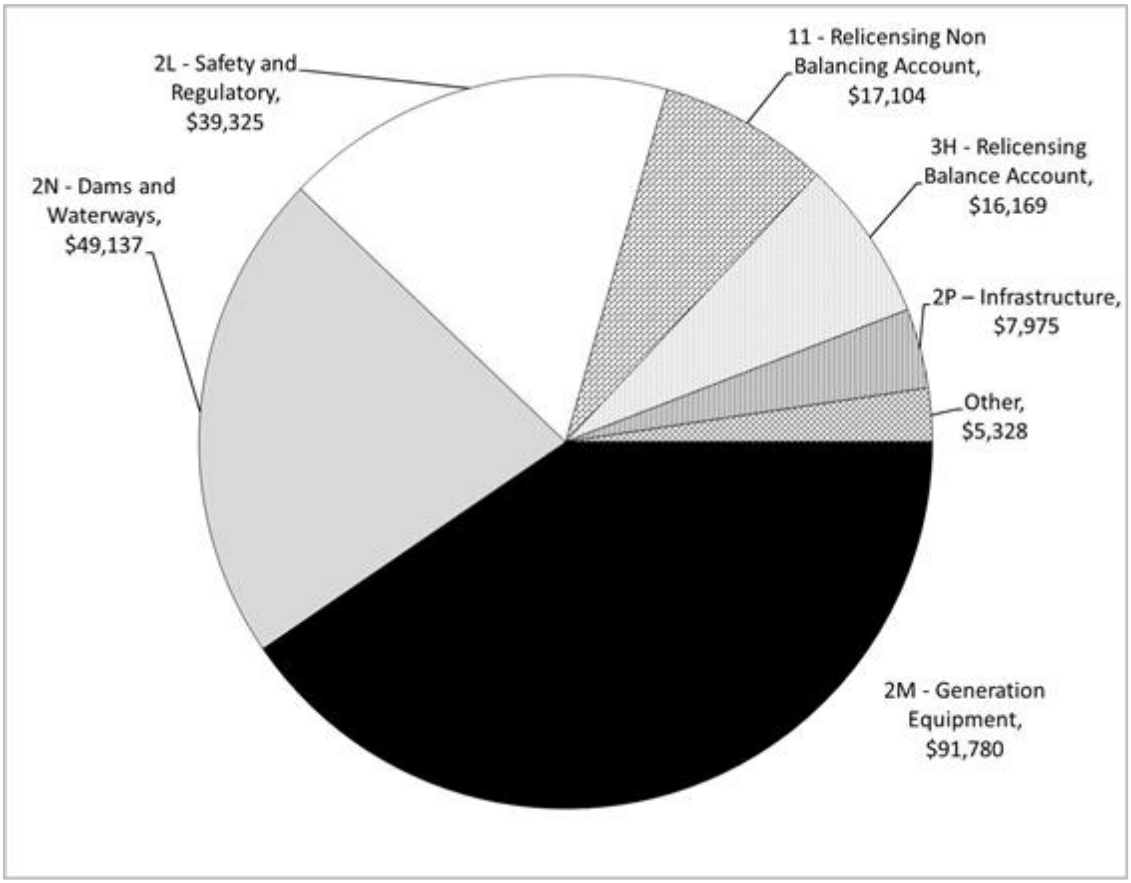


PG&E's forecast for 2017 hydro capital expenditures is $253.7 million, which is 11.8 percent more than the recorded 2014 capital expenditure amount of $226.8 million.

The increase shown between 2014 recorded and 2015 forecast is primarily the result of two factors: (1) one-time credits received in 2014 for Pit 5, Unit 1 treasury grants; and (2) the rescheduling of projects from 2014-2015.

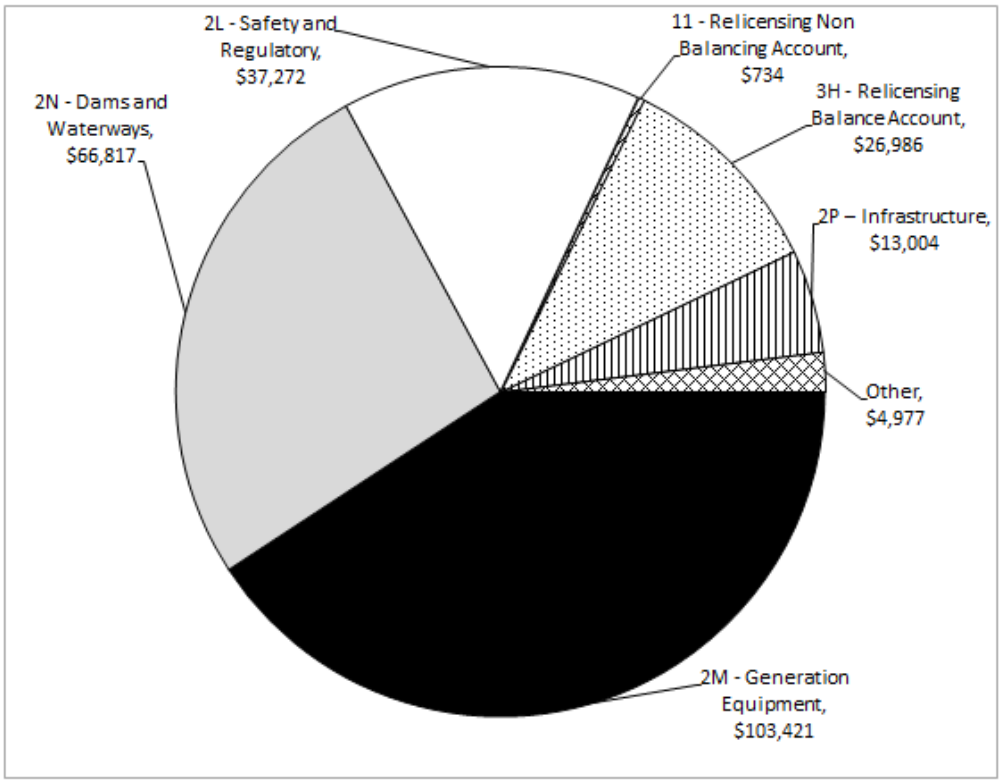
Figures 4-4 and 4-5 show the composition of the hydro capital expenditures for 2014 and 2017 by Major Work Category (MWC): Generation Equipment (2M); Dams and Waterways (2N); Safety and Regulatory (2L); Relicensing – Non-Balancing Account (11); Relicensing – Balancing Account (3H); Infrastructure (2P); and Other. Descriptions of each of these MWCs are provided in Section D.2 of this chapter.

FIGURE 4-4
HYDRO GENERATION CAPITAL EXPENDITURES 2014(a)
(THOUSANDS OF NOMINAL DOLLARS)



(a) See WP 4-74, Exhibit (PG&E-5).

FIGURE 4-5
HYDRO GENERATION CAPITAL EXPENDITURES 2017(a)
(THOUSANDS OF NOMINAL DOLLARS)



(a) See WP 4-74, Exhibit (PG&E-5).

As the figures show, the proportionate share of capital by MWC remains roughly the same between 2014 and 2017. However, by 2017, the work associated with implementing licenses received prior to 2012 (MWC 11) will be essentially complete, so the majority of the license-related work in 2017 is in the balancing account forecast (MWC 3H). A discussion of the specific capital projects driving the 2017 forecast are provided in Section C.2.

2. Hydro Program Description

This section describes PG&E's hydro portfolio. Additionally, this section provides an overview of the hydro organization's management structure and presents key measures and metrics that are used to manage the hydro function.

a. Assets

1) Hydro System Overview

PG&E's Hydro system stretches nearly 500 miles in northern and central California from Burney in the north to Bakersfield in the south.[9] PG&E's hydro generating portfolio consists of 67 powerhouses with 107 generating units with an aggregate nameplate capacity of 3,888.7 megawatts (MW) and produces an average of about 11 terawatt-hours of energy in a normal precipitation year.[10]

The size of PG&E's hydro powerhouses ranges from under 1 MW to over 1,200 MW. The powerhouses are uniquely designed to match the water flows and elevations of each site. Each powerhouse consists of one to four turbine-generators. The hydro turbine types are either Pelton-Impulse or Francis-Reaction turbines with varying physical designs ranging from vertical to double over-hung horizontal unit configurations.

The average age of the 107 units in PG&E's hydro portfolio is 75 years, and 85 of the 107 units have been in operation for over 50 years. Maintenance and capital investments are critical to ensure safe and reliable continued operation of these units for the benefit of PG&E's electric customers.

2) Hydro Categories

PG&E's hydro system can be segregated into three categories based on the characteristics of the water supply to the powerhouse.

a) Run-of-the-River Powerhouses

These powerhouses generally have little or no water storage facilities and rely on stream/river diversions, with small impoundments, to direct the water into the water conveyance system. The powerhouses are operated based on the flow available to be diverted from the river. Once diverted, the water

---

9 Attachment A shows the locations of PG&E's hydro and other generation facilities.

10 A full listing of powerhouses and individual units is included in WP 4-105 to WP 4-107, Exhibit (PG&E-5).

travels through various water conveyance facilities, such as canals, flumes, tunnels, natural waterways, and conduits to the penstock.

b) Reservoir Storage Powerhouses

Powerhouses that have significant water storage facilities are not limited to run based on the available river flow, but can store runoff and aquifer flows and then subsequently use the water to generate power when customers need it most. Generally, these powerhouses have forebays and afterbays, or are located immediately downstream of a large storage reservoir. Because of their impoundments and hydro's ability to quickly come online and ramp up to full capacity, these powerhouses can be used to meet peak demand.

c) Pumped Storage Powerhouse

Pumped storage plants operate by moving water between two reservoirs, an upper and a lower. When energy demand is high, water is released from the upper reservoir to the plant where electricity is generated before the water is discharged into the lower reservoir. When demand is low at times, such as the middle of the night, water is then pumped back up to the upper reservoir to be used as stored energy for a later time. This is accomplished by pump-generators which serve a dual role as both pumps which can reverse into generators.

3) Hydro Operating Areas

PG&E's powerhouses are organized into five operating areas and operated under 26 FERC licenses.[11] Table 4-3 below provides a breakdown of the hydro system assets by the five areas and 26 licenses.

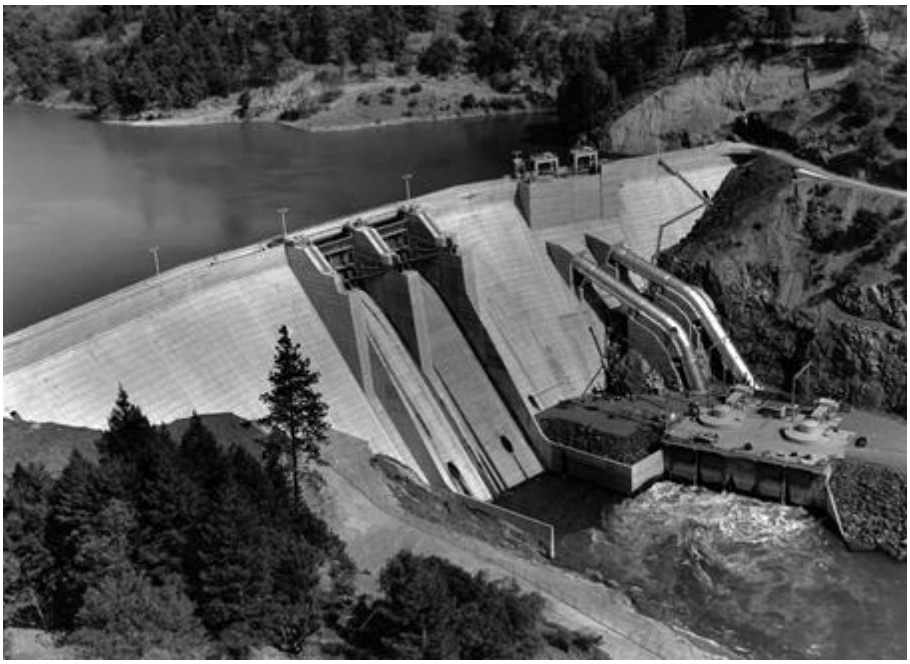
[11] See WP 4-105 to 4-107, Exhibit (PG&E-5). There are four generating units at two non-FERC jurisdictional powerhouses.

TABLE 4-3
HYDRO GENERATION AREA DETAILS

Line No.	Area	No. of Powerhouses	No. of Units	MW	No. of FERC Licenses
1	Shasta	16	28	809.9	6
2	DeSabla	15	27	778.7	6
3	Central	22	29	526.1	7
4	Kings Crane Valley	13	20	562.0	6
5	Helms	1	3	1,212.0	1
6	Total	67	107	3,888.7	26

a) Shasta Area

FIGURE 4-6
SHASTA: PIT 7 POWERHOUSE

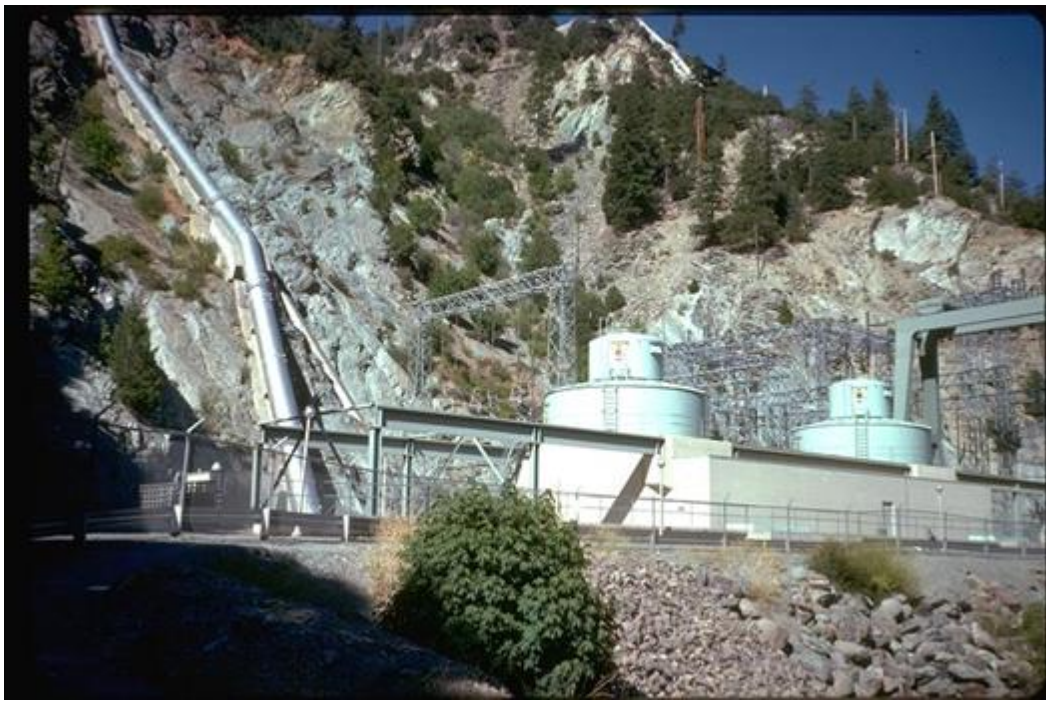


The Shasta Area consists of 16 powerhouses with 28 generating units and has an installed capacity of 809.9 MW. The powerhouses have in-service dates spanning from 1903 to 1981. The largest powerhouses in Shasta area are Pit 5 and James B. Black with normal operating capacities of 160 MW and 172 MW, respectively.

The facilities are situated on six different watersheds in Shasta and Tehama counties. There are two switching centers in Shasta, located at the Pit 3 and Pit 5 Powerhouses.

b) DeSabla Area

FIGURE 4-7
DESABLA: CARIBOU 2 POWERHOUSE



The DeSabla Area consists of 15 powerhouses with 27 generating units and has an installed capacity of 778.7 MW. The powerhouses have in-service dates spanning from 1900 to 1986. The largest powerhouses in this area are Belden, Caribou 2, and Poe and Rock Creek with normal operating capacities of 125 MW, 120 MW, 120 MW, and 119 MW, respectively.

The facilities are situated on five different watersheds in Plumas and Butte counties, and on one watershed located in Mendocino County. There are two switching centers in DeSabla located at Caribou Powerhouse and Rock Creek Powerhouse.

c) Central Area

FIGURE 4-8
CENTRAL: TIGER CREEK POWERHOUSE

The Central Area consists of 22 powerhouses with 29 generating units and has an installed capacity of 526.1 MW. The powerhouses have in-service dates spanning from 1902 to 1986. The largest powerhouses in this area are Electra and Stanislaus with normal operating capacities of 98 MW and 91 MW, respectively.

The facilities are situated on eight different watersheds in Nevada, Placer, El Dorado, Amador, Tuolumne and Merced counties. There are three switching centers in the Central Area located at Drum Powerhouse, Wise Powerhouse and Tiger Creek Powerhouse.

d) Kings-Crane Valley Area

FIGURE 4-9
KINGS-CRANE: HAAS POWERHOUSE

The Kings-Crane Valley Area consists of 13 powerhouses with 20 generating units and has an installed capacity of 562 MW. The powerhouses have in-service dates spanning from 1910 to 1983. The largest powerhouses in this area are Kerckhoff 2, Haas, and Balch 2 with normal operating capacities of 155 MW, 144 MW, and 105 MW, respectively.

The facilities are situated on six different watersheds in Madera, Fresno, Tulare and Kern counties. The Kings-Crane Valley switching center is located at the Fresno Operating Center.

e) Helms Pumped Storage Facility

FIGURE 4-10
HELMS PUMPED STORAGE FACILITY

Helms consists of three pump-generator units and an installed capacity of 1,212 MW. It was placed in service in 1984. The powerhouse is operated around-the-clock from a control room in the powerhouse and is not under the control of a separate switching center.

Helms is situated between an upper reservoir, Courtright Lake, and lower reservoir, Lake Wishon, with three generators that can be reversed to act as pumps. During off peak hours, when energy prices are lower, pumping mode is used to pump water back up to Courtright Lake to be reused during the next generating cycle. The ability to pump the water back up to storage allows the water resource to be reused during peak demand periods.

Additionally, Helms has 2,100 MW of flexibility spanning from 1,200 MW in the generation mode to 900 MW of pumping demand. This flexibility provides renewable integration benefits

such as regulation up and down, load following, operating reserves (backup), shaping, and management of system over-generation conditions that result from excess renewables generation during off-peak and partial-peak periods.

f) Water Conveyance and Water Storage

FIGURE 4-11
ROCK CREEK DAM: FEATHER RIVER

PG&E's water storage and conveyance systems consist of dams, reservoirs, tunnels, canals, flumes, siphons and penstocks and enable PG&E to transport and store runoff and aquifer flows to the hydro powerhouses to allow for flexible generation. Additionally, the conveyance and storage systems meet critical water storage and delivery requirements, for purposes of water conservation, fish and wildlife habitat protection and enhancement, domestic water usage, recreational water requirements, irrigation district and agricultural water needs, and natural resource protection.

PG&E's authority to divert and store water for power generation is based on 89 water right licenses or interim permits, and 160 Statements of Water Diversion and Use.

The system collectively includes the following approximate number of, or miles of, support infrastructure: 98 reservoirs, 73 diversions, 170 dams (68 large dams and 103 small dams), 173 miles of canals, 43 miles of flumes, 132 miles of tunnels, 65 miles of pipe (penstocks, siphons, and low head pipes), four miles of natural waterways, and approximately 140,000 acres of fee-owned land.[12] Water storage and conveyance details of the system are shown in Table 4-4.

TABLE 4-4
HYDRO GENERATION WATER STORAGE AND CONVEYANCE DETAILS

Line No.	Area	Usable Storage (acre-feet)	Tunnels (Miles)	Canals (Miles)	Flumes (Miles)
1	Shasta	200,714	27.9	44.5	4.6
2	DeSabla	1,427,239	34.2	48.4	7.4
3	Central	423,732	37.3	71.3	29.4
4	Kings Crane Valley	51,866	28.6	8.8	2.0
5	Helms	252,404	3.9	N/A	N/A
6	Total	2,355,955	131.9	173.0	43.4

These systems continue to age and require repairs and modifications to meet current dam and waterway standards. Examples of PG&E's water conveyance and storage systems are shown below in Figures 4-12, 4-13 and 4-14.

[12] The FERC classifies large dams as those dams with a height of greater than 33 feet. Dams less than 33 feet high but that are classified by FERC as high or significant hazard are treated as large dams and must comply with the Part 12 regulations.

FIGURE 4-12
EXAMPLES OF DAMS, FLUMES, AND CANALS

Example of small dam:

Hendricks Head Dam located on the West Branch of Feather River, less than 6-ft high & 50 acre-feet of storage

Example of a large dam:

Crane Valley Dam located in Madera County, 145-ft high & 45,410 acre-feet of storage

Example of one of 43 miles of flumes located on relatively low sloping terrain

Example of one of 173 miles of canals located on moderately sloping terrain

FIGURE 4-13
EXAMPLES OF PENSTOCKS: DRUM POWERHOUSE 1, 2, & 3 PENSTOCKS

Drum Penstocks No. 1, 2 & 3

FIGURE 4-14
EXAMPLE OF A TUNNEL: HELMS PUMPED STORAGE TUNNEL

Helms Tunnel - Example of one of 132 miles of tunnels

g) Support Facilities and Infrastructure

The hydro system also includes service centers, administrative buildings, employee housing, roads and bridges owned and/or maintained by PG&E, PG&E fleet (vehicles and construction equipment), communication infrastructure and equipment (telephone, radio, internet), materials and supplies inventories, and office equipment.

b. Management Structure

PG&E's Power Generation organization, which became part of the Electric Operations organization in 2014, is responsible for managing the hydro generating portfolio. The Power Generation organization has six main functions: Hydro O&M, Fossil & Solar O&M, Project Execution, Safety, Quality & Standards, Hydro Licensing, and Planning, and is led by the Vice President of Power Generation. Power Generation had a staff of 770 employees as of the end of 2014.[13]

1) Hydro O&M

The Hydro O&M Department within Power Generation is responsible for operating and maintaining PG&E's hydro facilities works side by side with the other Power Generation departments to provide safe, reliable, cost-effective, and environmentally-responsible generation.

The Hydro O&M Department is overseen by a director and is organized geographically into five areas to enable efficient oversight, control and management of hydro O&M activities. Since a majority of the powerhouses are in "river chains" where the water is most optimally used sequentially through the powerhouses as it moves downriver, this organizational structure allows for closely coordinated operations to assure each powerhouse is on line to use the water flow as it arrives, without spilling past the powerhouse. The powerhouses are operated from eight switching centers located

---

[13] There were 10 vacant positions as of December 31, 2014, not included in the 770. Numbers shown for each department are as of December 31, 2014. Actual and forecasted employee headcount levels and organization charts are provided in WP 4-127 to WP 4-129, Exhibit (PG&E-5).

throughout the system. Seven of the switching centers are located at powerhouses and one is located in Fresno.

a) Shasta Area

The Shasta Area staffing includes a total of 69 employees located at a principal headquarters in Burney and a satellite headquarters in Manton.

b) DeSabla Area

The DeSabla Area staffing includes a total of 75 employees with a principal headquarters located at Rodgers Flat (between Oroville and Quincy) and two satellite headquarters at Camp One (near Paradise) and Potter Valley (near Ukiah).

c) Central Area

The Central Area staffing includes a total of 106 employees with a principal headquarters in Auburn and satellite headquarters at Alta, Angels Camp, Tiger Creek (near Jackson) and Sonora.

d) Kings-Crane Valley Area

The Kings-Crane Valley Area staffing includes 59 employees with a principal headquarters in Auberry and a satellite headquarters at Balch Camp (east of Clovis).

e) Helms Pumped Storage Facility

Helms pumped storage facility staffing includes 32 employees and is located in Fresno County with a headquarters facility at the project site.

2) Support Organizations

The Hydro O&M support organizations provide critical resources and technical information and advice to support Hydro O&M.

a) Hydro Licensing and Compliance

Hydro Licensing and Compliance manages PG&E's 26 FERC hydropower licenses and related water rights, permits, and agreements. It has the primary responsibility for FERC relicensing and for managing license compliance in partnership

with Hydro O&M. The Hydro Licensing and Compliance has a staff of 41 employees. Water Management, within the Hydro Licensing Department, supports the Hydro O&M operations through flow measurement and reporting, the utilization of sophisticated computer models to schedule the hydroelectric resources based on the latest hydro-meteorological data, forecasts of stream flow runoff, and pricing forecasts. Water Management produces a calendar year hydro generation forecast. Water Management has a staff of 19 employees, including hydrographers located in the Hydro areas but not counted in the area staffing numbers.

b) Safety, Quality and Standards

The Safety, Quality and Standards (SQS) organization ensures that Power Generation is focused on public and employee safety, smart and simple processes, high quality work, and compliance with all standards and procedures that govern the Power Generation business. In addition, SQS manages the Facility Safety Program for dams and water conveyance facilities to assure compliance with FERC and California Department of Water Resources (CDWR) Division of Safety of Dams (DSOD) regulations. The SQS organization has a staff of 51 employees.

c) Project Execution

Project Execution combines engineering, project management, outage management, inspection services, contract services, and construction services into an integrated department that manages project work in addition to supporting routine O&M operations. The Project execution organization has 233 employees. Project Execution uses a number of contractors to augment its workforce, particularly in the Project Engineering and Construction functions, in order to execute on planned work. The organizations within Project Execution are:

Programs and Designs

Programs and Designs provide civil, electrical, and mechanical engineering and design services for projects at all powerhouses, switchyards, dams, water conveyance systems and appurtenant facilities throughout the PG&E hydro system.

Outage Management

Outage Management coordinates outage work scope and schedules among various groups performing project and routine maintenance work.

Inspection Services

Inspection Services inspects contract construction and equipment installation associated with Power Generation projects.

Contract Services

Contract Services provides various procurement services including specification development, requests for proposal, bid evaluation and contract administration support for hydro maintenance and project work.

Project Engineering

Project Engineering provides project management and engineering services to Power Generation projects. Project work includes both capital and expense safety, reliability, regulatory, and efficiency improvement projects. Project Engineering also provides engineering services in support of routine hydro operations and maintenance work.

Construction

Construction is a mobile construction organization that handles major maintenance and construction projects throughout the hydro system. With both a civil construction group and an electrical-mechanical group, this organization constructs and/or makes major repairs on a wide variety of hydro facilities.

d) Planning

The Planning Department is responsible for identifying, prioritizing, and planning Power Generation's work. Planning combines several functions into an integrated department that provides strategic, tactical (operational and financial), and project and outage planning services. The Planning organization has a staff of 24 employees. Like Project Execution, Planning uses contractors, particularly in Asset Management and Project Planning, to supplement its staff.

Asset Management

Power Generation's Asset Management Program provides a systemwide look into the condition of the hydro system equipment and proposes projects and/or changes to operations and/or maintenance practices to ensure that Power Generation's long-term investment plan reduces risk and improves the safety and reliability of the hydro portfolio.

Planning and Regulatory Strategy

Planning and Regulatory Strategy (PRS) supports Hydro Operations by prioritizing and scheduling work across the hydro portfolio. The resulting 5-year long-term plan is the basis of this GRC forecast. The PRS group is also responsible for tracking and reporting operational performance relative to benchmarks.

Project and Resource Planning

Project and Resource Planning (PRP) develops the initial scope, schedule, resources, and cost estimate for all the major projects included in the Hydro Operations long-term plan. PRP ensures that resources are balanced to improve the implementation of the portfolio of projects in the plan. PRP also develops the multi-year hydro outage schedule.

Business Operations and Planning

Business Operations and Planning provides planning and operational support to the various departments within Power Generation.

e) Land Stewardship Council

This group is responsible for administering PG&E's Land Conservation Commitment (LCC). PG&E staff dedicated to the LCC includes 2 employees. Additional information on PG&E's LCC is included in Sections C.1.e2 and D.1 of this chapter under the MWC AB description.

The Power Generation organization is forecasted to be 813 employees by December 31, 2017 to support the work forecasted in the 2015 through 2019 period. The increase in headcount is needed to support the implementation of, and compliance with, new Hydro FERC licenses as described in Section C, safety specialists to support work in the field, maintenance planners, and replacing contractors in Project Execution and Planning.[14]

c. Key Measures and Metrics

PG&E uses many metrics to assess its progress towards achieving its business priorities. The key safety, reliability, cost-effectiveness, and environmental metrics used by the Power Generation organization are presented below.

1) Safety

Public and workforce safety is the number one priority of PG&E and the Power Generation organization.

Beginning in 2015, Power Generation is using a composite measure to track performance of its Hydro public safety programs. The measure tracks milestones achieved on hydro public safety initiatives, including public outreach and education, reducing access to facilities through controls such as fencing and barriers, and improving emergency response through joint safety exercises with our communities and other PG&E organizations.

Three key employee safety metrics are tracked in Power Generation: Recordable Incidents; Lost Work Day (LWD) Cases; Motor Vehicle Incidents (MVI). The results are tracked by counting individual incidents and also expressed as a rate based on hours

---

14 See WP 4-127 for detailed forecast.

worked or miles driven. Table 4-5 is a summary of PG&E's safety performance over the past five years.

TABLE 4-5
POWER GEN RECORDABLE INJURY, LWD CASES, MVIS RESULTS 2010-2014

		Recordable Injury		Lost Work Day Cases Motor Vehicle Incidents			Motor Vehicle Incidents			
Line No.	Year	Incidents	Rate	Incidents	Days Off	Rate	Incidents	Rate	Serious Incidents	Serious Rate
1	2014	22	2.909	4	443	0.529	15	2.091	0	0.000
2	2013	14	1.912	5	1032	0.683	10	1.412	1	0.141
3	2012	19	2.652	7	371	0.977	13	1.952	NA	NA
4	2011	24	3.569	11	334	1.636	19	2.885	NA	NA
5	2010	16	2.457	3	9	0.461	18	2.910	NA	NA

Note 1: Recordable Injury and Lost Work Day Case Rate are based on 200,000 man-hours worked.
Note 2: Motor Vehicle Incident Rates are based on 1,000,000 miles driven.

2) Reliability

PG&E's goal is to responsibly operate and maintain all generation facilities so these facilities can reliably generate electricity whenever needed to meet customer needs.

PG&E's reliability metrics for the hydro facilities include the equivalent availability factor (EAF) and forced outage factor (FOF). Both FOF and EAF are annual, MW-weighted factors that reflect the relative capacity of the units in the hydro portfolio. PG&E uses data from North American Electric Reliability Corporation Generating Availability Data System (NERC-GADS) as a benchmark for performance.[15]

FOF is a ratio of the hours a unit is forced out of operation to the total hours in the operation period (i.e., month, year). Forced outages causes can vary widely from unanticipated equipment malfunctions to external events such as lightning strikes, storm-induced transmission line interruptions, debris in the water, or even vandalism.

[15] The hydro portfolio industry benchmarks are from the NERC-GADS brochure titled "2009-2013 Generating Unit Statistical Brochure – All Units Reporting."

Table 4-6 presents the Hydro FOF for the last five years. Despite facilities that are approximately 75 years old on average, the hydro portfolio FOF has exceeded industry average benchmark in four of the past five years. Most notably, the hydro portfolio FOF in 2014 was 1.44 percent which is significantly better than the industry average of 2.92 percent, and the lowest it has been in the last 10 years.

TABLE 4-6
HYDRO PORTFOLIO FORCED OUTAGE FACTOR

Line No.	Asset	2010 FOF (%)	2011 FOF (%)	2012 FOF (%)	2013 FOF (%)	2014 FOF (%)	Average FOF (%)
1	Hydro Portfolio	2.08	2.83	9.76(b)	2.80	1.44	3.78
2	Benchmark						2.92

(a) WP 4-135, Line 115.
(b) 2012 Hydro Portfolio FOF is 3.31 percent excluding one-time breaker failure event at Helms.

EAF is a ratio of the total amount of hours a unit is in operation less the planned and unplanned outage and curtailment hours to the total amount of hours in a given year. Table 4-7 presents the conventional Hydro EAF (excluding Helms) for the last five years. The hydro portfolio average EAF over the 2010-2014 period was 85.9 percent. This EAF is better than the industry average benchmark of 84.3 percent.

TABLE 4-7
HYDRO PORTFOLIO EQUIVALENT AVAILABILITY FACTOR

Line No.	Asset	2010 EAF (%)	2011 EAF (%)	2012 EAF (%)	2013 EAF (%)	2014 EAF (%)	Average EAF (%)
1	Conventional Hydro	89.4	86.5	81.8	86.1	85.5	85.9
2	Benchmark						84.3

(a) WP 4-138, Line 108.

3) Cost-Effectiveness

PG&E also compares the costs to operate and maintain its hydro system with industry benchmarks. Table 4-8 compares the 2012-2014 O&M $/kilowatt (kW) of PG&E's system with other hydro systems in North America. PG&E's cost is about average when compared to the benchmarks.[16]

TABLE 4-8
HYDRO PORTFOLIO O&M $ PER KW

Line No.	Asset	2012 O&M ($/kW)	2013 O&M ($/kW)	2014 O&M ($/kW)	Average O&M ($/kW)
1	Power Gen	38.00	43.27	40.02	40.43
2	Benchmark				42.27

(a) WP 4-139.

Another way that PG&E assesses the cost-effectiveness of its hydro system is through the value it provides for customers. The electricity products PG&E's Hydro system provides for our customers include base-load energy, peaking energy, dependable capacity, ancillary services, and RPS-eligible renewable energy. Ancillary services provided by PG&E Hydro facilities include load following, reserves, black start, voltage control, and regulation capabilities. The market values of these electricity products, in aggregate, far exceed the costs of the system.

4) Environmental

PG&E uses two key metrics to track environmental compliance. First, the FERC Compliance Index tracks incidents which resulted in a deviation from a license required flow, and were subsequently reported to a jurisdictional agency for further consideration. Second, an Enforcement Actions count tracks written notifications of non-compliance by a regulatory agency and is issued for failure to comply with environmental laws, regulations, permits, certifications,

16 Benchmark is based on EUCG data.

licenses, or registrations. This includes judicial sanctions to address non-compliance. A Level 1 Environmental Citation is having an actual or potential impact on the environment and/or having a negative impact to the company's regulatory status. Table 4-9 shows PG&E's performance on these metrics for the last five years.

TABLE 4-9
HYDRO FERC COMPLIANCE AND LEVEL 1 ENVIRONMENTAL CITATION 2010-2014

		2010		2011		2012		2013		2014	
		FERC Index	Level 1 Citation	FERC Index	Level 1 Citation	FERC Index	Level 1 Citation	FERC Index	Level 1 Citation	FERC Index	Level 1 Citation
Line No.	Asset	Rate	no.	Rate	no.	Rate	no.	Rate	no.	Rate	no.
1	Hydro	93.7%	2	97.9%	2	97.9%	1	100%	4	97.9%	1

3. Risk Management

Exhibit (PG&E-5), Chapter 2, describes how Electric Operations uses the Enterprise and Operational Risk Management (EORM) Program to manage electric system risks.[17] A foundational element of the EORM Program is the EO Risk Register, which includes enterprise risks, asset risks, and process risks (risk families). Table 4-10 includes the subset of risks from the EO Risk Register that are associated with Hydro Operations.

[17] See Exhibit (PG&E-2), Chapter 3 for a detailed discussion of the EORM Program.

TABLE 4-10
HYDRO RISKS ON EO RISK REGISTER

Risk Group	Risk Name	EO Risk Designation	Risk Score
EO Enterprise	Hydro System Safety	ENT4	349
	Electric Grid Restoration	ENT5	283
Other LOB Enterprise	Cybersecurity	NA	
	Records Management	NA	
	Employee Safety	NA	
Hydro Asset	Public Access	PG1	174
	Material Release Into Water	PG2	13
	Pressure Integrity Systems	PG10	104
	Turbine – Generator Systems	PG11	174
	Protection and Control Systems	PG12	37
	Balance of Plant	PG13	23
	Support Infrastructure	PG14	174
	Instream Flow Release Valve & Bypass	PG15	42
Switchyard(a)	Transformers & Voltage Regulators	SS2	175
	Circuit Breakers & Switchgear	SS5	53
	Switches	SS7	215
	Grounding Systems	SS6	18
Additional	Asset Security	CSEC1	229
	Risk of Non-Compliance	PROC10	82

(a) All generation facilities have switchyards that contain assets such as step-up transformers, circuit breakers, switchgear, switches, grounding systems, etc. Substation/switchyard risks apply to switchyards at hydro and fossil generation facilities. While substation and switchyard assets are often very similar, these risks have not yet been uniquely scored for power generation applications. The scores in Table 4-10 use the scores based on substation equipment assessments.

The following section provides an overview of hydro-related risk management activities.

a. Hydro Risk Management Overview

Power Generation identifies and manages/mitigates its hydro-related risks through a number of key programs and processes, including its Dam Safety Program, its Process, Standards, and Quality functions, its Asset Management programs and its Work Management process.

1) Dam Safety

PG&E's Dam Safety Program, which is managed by Power Generation's Safety, Quality, and Standards (SQS) Department, is responsible for ensuring the long-term safe and reliable operation of

PG&E's dams by all company personnel, and for ensuring that power production or other business objectives do not take precedence over dam safety or regulatory compliance. PG&E's dams are regulated by both the FERC and the California DSOD. PG&E's Dam Safety Program was developed in line with FERC requirements. The Dam Safety Program's objectives include the following:

- Maintaining a well-trained and resourced organization, with a primary focus on public and employee safety as well as compliance with FERC and DSOD requirements for dam safety.
- Communicating policies and expectations regarding dam safety and regulatory compliance to all Dam Safety Program team members, O&M personnel, and other stakeholders.
- Defining protocols for communicating and reporting dam safety issues.
- Defining the responsibilities and authority of the Chief Dam Safety Engineer.
- Providing and implementing a comprehensive training plan for dam safety, formal dam safety quality assurance and quality control programs and a dam safety inspection program.
- Requiring internal and external audits and assessments to verify and document compliance and maintain an ongoing focus on dam safety and regulatory compliance.

To carry out these objectives, the Dam Safety Program provides engineering and other construction support and analysis, inspection services, dam surveillance and monitoring services, maintenance procedures and emergency action plans, dam security, and the development of other safety-related standards and procedures. The Dam Safety Program also convenes and seeks the input of a Dam Safety Advisory Board.

2) Process, Standards, and Quality

The Process, Standards and Quality functions within Power Generation's SQS organization work to improve operational performance through guidance documents, training, certifications,

event reporting, root cause analyses, and corrective actions, all of which help PG&E's hydro employees learn from past incidents and work with a higher level of safety and quality.

3) Asset Management

Power Generation's Asset Management team, which is part of the Planning department, employs the following process to identify and ultimately mitigate the risks associated with PG&E's hydroelectric assets:

a) Asset Registry

PG&E uses equipment records in SAP Work Management to track all of the key characteristics and nameplate data for each hydro asset. These records provide the foundation for maintenance planning, asset management and engineering.

b) Design and Performance Criteria

For each hydro asset type, PG&E develops technical documents which contain design and performance criteria. While design criteria are used primarily for new equipment, performance criteria are used to assess existing equipment, providing a technical threshold against which to measure assessment results.

c) Assessment Standards

For each hydro asset type, PG&E develops technical documents which contain assessment standards and procedures. Such standards and procedures (often based on industry best-practices and/or regulations) explain how and when each asset type should be assessed.

d) Assessments

In line with its assessment standards and procedures, PG&E conducts tests and inspections across its fleet of hydro assets. For each asset type, there are often numerous types of tests and inspections, each with its own required frequency, as outlined by the assessment standard/procedure. Assessment results are analyzed and interpreted, and corresponding

condition indicators are logged in the Generation Risk Information Tool (GRIT) that is linked directly to each equipment record.

e) Quantification of Asset Risk

Based on its assessment results and condition indicators, PG&E's Asset Management team calculates risk scores for each key piece of hydro equipment. Risk scores consist of health scores (which are a proxy for the probability of failure) and consequence scores (which are a proxy for the consequence of failure). Taken together, PG&E is able to quantify the risk its hydro assets pose. Risk scores are logged in GRIT. The GRIT tool is discussed in more detail in Exhibit (PG&E-5), Chapter 2.

f) Asset Risk Mitigation/Control

PG&E mitigates and/or controls identified risks through the following methods:

- Operational changes and restrictions. For example, PG&E might temporarily lower the flow in a leaking canal or institute a no-run-zone on a hydro unit with vibration problems.
- Increased or modified maintenance, monitoring and surveillance. For example, PG&E might install instrumentation near a penstock to monitor ground movement.
- Repair, refurbishment or replacement projects. For example, PG&E might replace a highly deteriorated (due to cavitation or corrosion) turbine runner, or it might re-line a degraded section of canal.

4) Work Management

The equipment records contained in SAP Work Management described above also provide the foundation for managing PG&E's hydro maintenance activities. PG&E's hydro maintenance activities are a critical part of its overall risk management approach, and work

management allows PG&E to plan, prioritize, schedule, and document maintenance work. More specifically, PG&E's work management program provides:

- A common platform and methodology for managing maintenance across geographically-separated hydro watersheds.
- The creation of recurring maintenance plans with frequencies that can be adjusted based on industry best practices, and as conditions changes.
- A record of work history, which is important not only for compliance but also for remote monitoring of asset conditions. For example, Asset Management employees rely on the work history as a source of information for understanding equipment condition.
- A consistent framework for equipment types throughout the system, including standardized characteristics, making it much easier to take fleet-wide equipment-related corrective actions.

b. Hydro Risks and Controls

This section provides additional details regarding the controls Power Generation uses to manage hydro-related risks from the EO Risk Register.

1) Enterprise Risks

Enterprise risks and mitigations are discussed in detail in Exhibit (PG&E-5), Chapter 2, but an overview of Key Hydro-related enterprise risks is presented below.

a) Hydro System Safety

Definition: The risk of failure of a PG&E dam or other water storage or conveyance facility that may result in significant damage to third parties, the environment, and/or the Company.

Risk Controls: PG&E works continuously to inspect, monitor, maintain repair and replace these assets. As described above, PG&E's Power Generation department has a Dam Safety Program and an Asset Management team. These teams

coordinate their work across the department to ensure the safe and reliable operation of PG&E's dams, water conveyance systems and penstocks. With respect to its water conveyance systems, PG&E is proactively relining its canals, improving drainage, removing hazardous trees, replacing flumes and installing Supervisory Control and Data Acquisition (SCADA) capability in order to ensure that leaks and breaks can be detected within required timeframes. Importantly, PG&E is prioritizing its work to ensure that high consequence sections are addressed first. The costs associated with these activities are generally included in MWCs AX, KJ, 2L and 2N.

b) Records Management

Definition: The risk of not having an effective records management program may result in the failure to construct, operate, and maintain a utility system safely and prudently. Risk Controls: PG&E has implemented a new document management system, Documentum, and the inclusion of key documents into the system will continue over the next several years. Records associated with high-risk EORM assets (dams, water conveyance, and penstocks) have been added to Documentum and Documentum has been configured for going forward use by O&M, Engineering, Project Execution, Asset Management, and Licensing for EORM and Powerhouse Assets. The next set of hydro records that will be added to the system are engineering drawings. The hydro operations expense forecast includes funding for scanning, attribute capture, and ingestion of engineering drawings into Documentum in MWC KG. Additionally, the IT forecast in Exhibit (PG&E-5), Chapter 7, includes costs to build-out the Documentum system to accommodate these records.

c) Cybersecurity

Cybersecurity risks are discussed in Exhibit (PG&E-7), Chapter 10. The work and associated costs to mitigate the

Power Generation-specific cyber security risks are included in MWC 05 and are discussed in Exhibit (PG&E-5), Chapter 7.

2) Hydro Asset Risks

The following section describes the hydro-specific asset risks and the controls that Power Generation has in place to manage the risks.

a) Hydro Public Access

Definition: The risk that members of the public participating in activities on PG&E, USFS, BLM, and third-party lands, facilities and waterways are potentially injured or killed as a direct result of an unplanned hydroelectric operating event or PG&E's failure to reasonably guard or warn consistent with the California recreational use statute against a known dangerous condition, use, structure, or activity.

Risk Controls: PG&E proactively works with public agencies and communities near its water storage and water conveyance facilities. For example, PG&E develops public safety plans, conducts annual phone drills, conducts joint emergency response exercises, educates communities on the dangers associated with canals, posts warning signs, and builds fences in certain areas to deter the public from accessing dangerous areas. The costs associated with these activities are generally included in MWCs AX and 2N.

b) Hydro Material Release Into Water

Definition: The risk that hydro operational activities involving storage or moving of petroleum products near bodies of water could result in an accidental release, resulting in adverse environmental conditions, financial impacts, and/or reputational damage.

Risk Controls: PG&E works to minimize oil-spill risks associated with its hydroelectric assets. More specifically, PG&E has 62 Spill Prevention, Control, and Countermeasure (SPCC) Plans for its hydro facilities, as required by the U.S. Environmental Protection Agency (EPA) and the California

State Fire Marshall's office. These plans are recertified at least every five years or whenever there is a change to the oil spill risk potential for the facility. These plans identify the measures required to minimize oil spill risks and identify failing containers and equipment.

Beyond complying with the U.S. EPA's requirements, PG&E works proactively to be a good environmental steward, and so the company monitors the environmental risks of all of its hydroelectric facilities, not just those facilities that have enough oil to meet the SPCC criteria. For example, hydraulic actuation equipment for valves and gates located over waterways has been outfitted with double-walled piping, leak detection, and oil/water separators.

Finally, PG&E tries to find new methods and/or products to reduce its environmental footprint. For example, PG&E is investigating the feasibility of using environmentally-friendly oils in its hydroelectric equipment and replacing oil-operated components with motorized or water-operated types. The costs associated with these activities are generally included in MWCs 12, AK and ES.

c) Hydro Pressure Integrity Systems

Definition: The risk of failure of systems or components subject to penstock pressure and inside the powerhouse. Such failure may result in public or employee safety issues, environmental damage, reliability issues, and cascading infrastructure impacts.

Risk Controls: PG&E's Power Generation department proactively assesses its hydro pressure boundaries through maintenance, inspections, finite element analyses and vibration testing. The department also maintains, inspects, refurbishes and replaces its penstock shut-off valves and turbine shut-off valves, which are critical for providing clearances during planned outages and emergency closure capability in certain low probability scenarios. Shut-off valve assessments include visual inspections, annual trip tests and stroke/timing tests. The

costs associated with these activities are generally included in MWCs KH and 2M.

d) Hydro Turbine-Generator Systems

Definition: The risk that failure of or interaction with turbine and generator systems may result in employee safety issues and reliability issues.

Risk Controls: PG&E proactively maintains tests, inspects, refurbishes and replaces its turbine-generator systems, which include the core mechanical and electrical equipment at the heart of power generation. From governors to turbines to bearings to exciters to generators to generator breakers, PG&E works to ensure that this equipment is in good working condition. For example, PG&E conducts oil sampling, temperature monitoring, index and load rejection tests, vibration tests, clearance readings, and Western Electricity Coordinating Council tests. The costs associated with these activities are generally included in MWCs KH and 2M.

e) Hydro Protection and Control Systems

Definition: The risk that unintended operation or non-operation of powerhouse, dam, and water conveyance protection schemes, distributed control system (DCS), and SCADA systems may result in public and employee safety and reliability issues.

Risk Controls: PG&E is upgrading its SCADA systems across the hydro fleet, upgrading protection schemes, and validating that its protection schemes are robust. The costs associated with these activities are generally included in MWCs KH and 2M.

f) Hydro Balance of Plant

Definition: The risk that failure of or interaction with plant systems may result in employee safety issues, environmental damage, and reliability issues.

Risk Controls: PG&E proactively assesses arc flash hazards and overstressed equipment associated with its 67 hydro powerhouses and switchyards. When hazards are identified, PG&E moves forward with both short-term and long term mitigations. The costs associated with these activities are generally included in MWCs KG, KH and 2M.

g) Hydro Support Infrastructure

Definition: The risk that failure of support infrastructure, such as roads, bridges, cableways, and building structures, may result in public and employee safety issues and compliance impacts.

Risk Controls: PG&E maintains, inspects and repairs its roads, bridges, and other support infrastructure. With respect to its cableways, PG&E is actively replacing many of its manned cableways with bank-operated systems, reducing the safety risk for PG&E's hydrographers and United States Geological Survey inspectors. The costs associated with these activities are generally included in MWCs EP, KI and 2P.

h) Hydro Instream Flow Release Valve and Bypass

Definition: The risk that failure of or interaction with instream flow release (IFR) valve or bypass systems may result in environmental damage and failure to meet compliance requirements.

Risk Controls: In the short-term, PG&E continues practice of slightly over-releasing to ensure IFR compliance and has a heighten awareness by Operations anytime changes need to be made, using both SCADA and additional manual operations to meet all requirements. PG&E's Power Generation Asset Management team launched a new program in 2015 to programmatically assess IFR and powerhouse bypass valves. The costs associated with these activities are generally included in MWC KJ.

3) Hydro Switchyard Risks

Generation facilities have switchyards that contain assets such as step-up transformers, circuit breakers, Station Service transformers, switches, grounding systems, etc. While the risk associated with these assets is similar to the risks associated with transmission and distribution substations, these risks have not yet been uniquely scored for Power Generation switchyards.

a) Switchyard Transformers and Voltage Regulators

Definition: The risk that failure of or contact with energized electric substation/switchyard transformers may result in public or employee safety issues, significant environmental damage, prolonged outages, or significant property damage.

Risk Controls: For its GSU transformers, PG&E conducts dissolved gas analyses, installs remote monitoring capability (in certain cases), builds fire barriers, and refurbishes or replaces those transformers that have reach the end of life. For its larger units, PG&E uses single phase transformer banks with a spare transformer to reduce the reliability risk associated with a planned or forced outage. The costs associated with these activities are generally included in MWCs KH and 2M

b) Switchyard Circuit Breakers

Definition: The risk that failure of, or contact with, energized substation circuit breakers may result in public or employee safety issues, significant environmental damage, prolonged outages, or significant property damage.

Risk Controls: For its high-voltage breakers that are used by Hydro Generation, PG&E conducts dielectric tests, contact resistance tests, and dissolved gas analyses (for oil circuit breakers). PG&E monitors changing conditions on the grid and how such changes might cause certain breakers to become overstressed. Ultimately, when needed PG&E installs and/or replaces breakers. The costs associated with these activities are generally included in MWCs KG, KH and 2M.

c) Switchyard Switches

Definition: The risk that failure of, or contact with, substation/switchyard switch assets (which includes non-protection related devices such as disconnect, bypass, and grounding air switches) may result in public or employee injuries, prolonged outages, or significant `property damage.

Risk Controls: PG&E tracks the number of operations and inspects its switchyard switches. Ultimately, when needed, PG&E repairs and/or replaces switchyard switches. The costs associated with these activities are generally included in MWC KG, KH, and 2M.

d) Switchyard Grounding Systems

Definition: The risk that ineffective substation/switchyard grounding system design, construction, or maintenance may result in employee or public injury.

Risk Controls: With respect to its hydro powerhouse grounding systems, PG&E conducts grounding studies (consistent with IEEE Standard 80) to determine if touch and step voltage levels are within allowable limits. If not, PG&E takes action to mitigate the risk and is currently executing a number of ground grid mitigation projects. The costs associated with these activities are generally included in MWC KG.

4) Additional Risks

In addition to the asset-related risks discussed above, there are additional risks for hydro operations that are included in the EO risk register.

a) Risk of Non-Compliance

Definition: The risk of not using an effective system of internal controls and processes, as part of the compliance program/framework, may result in cease and desist orders and/or the forced shutdown of critical assets and facilities.

Risk Controls: PG&E's operation of its hydro system is substantially governed by 26 Operating Licenses issued by

FERC, which contain nearly 600 discrete operating conditions. PG&E safely and reliably operates the system in compliance with all FERC license conditions and all federal, state, and local regulations. In addition, operations are constrained by many conditions imposed by agreements with other regulatory agencies (e.g., U.S. Forest Service (USFS), California Department of Fish and Wildlife, etc.), contractual obligations, water diversion rights, and other regulations. PG&E's hydro projects deliver water at 54 locations for consumption by 39 different user groups under water delivery agreements that contain additional constraints on how the projects are operated. There are defined minimum and maximum flow requirements in most river reaches below PG&E's reservoirs and powerhouses. Any changes in the flows have to be performed in compliance with prescribed ramp rates. Reservoirs have both minimum and maximum storage requirements that often vary depending upon the time of year. The expense costs associated with managing license compliance are included in MWC KJ and the costs of implementing specific license requirements are included in MWC KJ and IG (expense) and MWC 11 and 3H (capital).

b) Asset Security Risks

Definition: The risk that an individual or group commits acts which result in fatalities or inflicts damage making critical facilities inoperable.

Risk Controls: Many of PG&E's hydro facilities are remote. PG&E has fencing and gating to keep the public away from its assets. Additionally PG&E has installed security cameras and card readers at several of its hydro facilities. The costs associated with managing asset security are included in MWC 2L and 2P.

c. Hydro Risk Register to MWC Mapping

As presented in Exhibit (PG&E-5), Chapter 2, PG&E has mapped its hydro expense and capital forecasts for 2017 to the relevant risks from

the EO Risk Register. Attachment B summarizes the mapping of the 2017 Hydro expense and capital forecasts to the EO Risk Register by MWC.[18]

d. Risk Informed Budget Allocation

All of the proposed work included in PG&E's hydro expense and capital forecasts were evaluated using the Risk Informed Budget Allocation (RIBA) risk-scoring methodology described in Exhibit (PG&E-2), Chapter 4. Each project is scored to assess the risks to safety, the environment, and reliability that would be mitigated by the project. These scores are then used by management (along with other key data) to prioritize proposed work.

C. Key Expense Drivers and Capital Major Areas of Work

This section describes the key drivers of the 2017 expense forecast for hydro and the major capital areas of work in 2015-2019.

1. Expense

There are five key drivers of the increase in the 2017 expense forecast above the 2014 recorded amount.

a. Escalation

Escalation accounts for $10.6 million, or 32.7 percent, of the total hydro expense increase from 2014 recorded to 2017 forecast.[19] This includes escalation of labor and non-labor costs for ongoing routine operations, maintenance, and compliance costs in MWCs AB, AK, AX, EP, IG, KG, KH, KI and KJ. The escalation factors used in this chapter are consistent with standard escalation guidance discussed in Exhibit (PG&E-12), Chapter 4.

b. Regulatory Compliance

Regulatory compliance activities and projects account for $9.8 million, or 30.2 percent, of the total hydro expense increase from

---

18 See WP 4-108 to WP 4-118, Exhibit (PG&E-5) for expense and WP 4-119 to WP 4-126, Exhibit (PG&E-5) for capital.

19 See WP 4-64, Line 324, Exhibit (PG&E-5).

2014 recorded to 2017 forecast.[20] The regulatory compliance driver includes current ongoing compliance costs in MWC KJ as well as balancing account costs in MWC IG for anticipated new expense license implementation costs associated with new FERC licenses. The increases in MWC IG are primarily driven by expected new license implementation expense for the Upper North Fork Feather River (UNFFR) and DeSabla-Centerville. The increases in MWC KJ are primarily driven by the Crane Valley Recreation Settlement Agreement, Pit 3 Britton Concrete Bridge Repair, and increases in FERC fees. These work activities and expense projects are required to comply with FERC and USFS requirements to allow for continued operation of the associated hydro facilities.

1) New License Implementation Expense

The forecast new license implementation costs associated with the anticipated new FERC licenses are for UNFFR and DeSabla-Centerville, both of which licenses were also included in PG&E's 2014 GRC forecast. As described in more detail in Section D.3., below, PG&E has proposed the continuation of a two-way balancing account for all new license condition costs. Because these costs are subject to the two-way balancing account, the revenue requirements associated with the 2014 GRC forecast that were not needed because of delays in the regulatory process will be returned to customers, as further described in Exhibit (PG&E-5), Chapter 8.[21]

UNFFR new license implementation expense costs are forecasted to total $3.0 million in 2017.[22] The largest of these is a $2.8 million payment to the USFS associated with recreation land use around Lake Almanor.

---

20 See WP 4-57, Line 123, Exhibit (PG&E-5).

21 See WP 4-130, Exhibit (PG&E-5) for a complete listing of the FERC license statuses for all 26 of PG&E's hydro projects.

22 See WP 4-31, Lines 236, 239-242, Exhibit (PG&E-5).

DeSabla-Centerville new license implementation expense costs are forecasted to total $0.6 million in 2017.[23] The largest of these is $0.4 million for preparation and implementation of various land management plans in consultation with various parties including USFS, U.S. Bureau of Land Management, and Butte County.

2) Crane Valley Recreation Settlement Agreement

This item is to provide funding for installation, rehabilitation, and repair of various recreation facilities as required by Crane Valley Recreation Settlement Agreement between PG&E and the USFS. The settlement agreement between PG&E and the USFS was a requirement of the FERC license for the Crane Valley Project, FERC License 1354. The planned expenditure for this item in 2017 is $2.5 million. PG&E's forecast total cost for implementation of the settlement agreement is $17.0 million.[24]

3) Pit 3 Britton Dam Concrete Bridge Repair

This item is to provide funding for repair of the bridge on top of the Pit 3 Dam as required by the DSOD and the FERC. The concrete road surface has deteriorated and reinforcing steel exposed due to age, wear, and environmental elements including seasonal weather cycles. The planned scope of work includes these major elements: concrete testing; repair design; permitting; construction to extend roadway to original width; and installation of guardrails. The planned expenditure for this item in 2017 is $0.7 million. PG&E's forecast total cost for this project is $2.3 million.[25]

4) FERC Fees

Payment of annual FERC fees is required to comply with FERC license conditions. Fees are calculated based on two factors: (1) land (federal land occupied by the licensed hydroelectric

---

[23] See WP 4-17, Lines 88 and 89, and WP 4-31, Lines 237 and 238, Exhibit (PG&E-5).

[24] See WP 4-23, Line 542, Exhibit (PG&E-5).

[25] See WP 4-40, Line 564, Exhibit (PG&E-5).

facilities); and (2) administrative (approved installed capacity of each licensed hydroelectric facility and the actual annual generation produced by the hydroelectric facility during the year). Planning for future FERC fees is based on a generation forecast which assumes a normal water year.

c. Dams and Waterways Projects

Dams and waterways projects represent $8.0 million, or 24.6 percent, of the total hydro expense increase from 2014 recorded to 2017 forecast.[26] The dam and waterway projects include specific risk reduction expense projects in MWC AX and exclude routine dam and waterway maintenance. The facility safety reviews and asset management condition risk assessments described in Section B.3.a, above, have identified needed repairs in parts of PG&E's water storage and conveyance systems. PG&E has included funding for specific programs and risk reduction expense projects to address these repairs in its forecasts. Three specific expense projects account for $4.9 million of the $8.0 million increase in this driver category: Weather/Seismic/ Wildfire Emergent work; Fordyce Dam leakage reduction; and grouting repair in the Drum Tunnel.[27] There are forty other small water conveyance projects that account for $9.2 million of the total 2017 forecast of $14.1 million for this work.[28]

1) Weather/Seismic/Wildfire Emergent Work

PG&E forecasts $2.9 million for emergent expense work that is expected to result from storms or other force majeure events in 2017.[29] PG&E's hydro water conveyance facilities are susceptible to damage during severe weather, seismic events, and wildfires. Historically, such events have occurred annually, but no specific funding was set aside for this purpose. As a result, this emergent work has displaced other planned and needed work.

---

26 See WP 4-61, Line 250, Exhibit (PG&E-5).

27 See WP 4-29, Lines 179 and 180 and WP 4-30 Line 216, Exhibit (PG&E-5).

28 See WP 4-31, Line 217, Exhibit (PG&E-5).

29 See WP 4-30, Line 216, Exhibit (PG&E-5).

This forecast is not duplicative of work covered by the Catastrophic Event Memorandum Account (CEMA). Due to the dispersed nature of the hydro water conveyance facilities, they often do not correspond with state-designated disaster areas. CEMA funding is limited to work undertaken to repair structures within such disaster areas.[30]

2) Fordyce Dam Leakage Reduction

Lake Fordyce Dam is a composite, concrete-faced earth-fill and rock-fill dam constructed in stages between 1873 and 1926. PG&E has been closely monitoring leakage in this dam and has been testing to determine the leakage mechanism and path. The dam has a long history of seepage, ranging from 23-60 cubic feet per second at full reservoir (about 10,000-27,000 gallons per minute). This level of seepage would not generally be concerning for a rock fill only embankment, but Lake Fordyce dam contains, as a remnant of its earliest construction phase, about 10,000 cubic yards of erodible soil in the upstream toe. Erosion of this material could result in cracking and damage of the concrete liner that holds water in the reservoir, resulting in an uncontrolled release of water. PG&E is continuing to evaluate the best alternative for mitigating the leakage. The scope of work covered in this expense item includes engineering, potholing, and grouting. The planned expenditure for this item in 2017 is $1.0 million.[31] There is also a capital project associated with this leakage which is discussed in Section C.2.b below.

3) Drum Tunnel Grouting

This item is to provide funding for grouting work on the Drum Tunnel. The planned expenditure for this item in 2017 is $1.0 million.[32]

---

30 Electric Preliminary Statement Part G, Catastrophic Event Memorandum Account (CEMA), http://www.pge.com/tariffs/tm2/pdf/ELEC_PRELIM_G.pdf.

31 See WP 4-29, Line 180, Exhibit (PG&E-5).

32 See WP 4-29, Line 179, Exhibit (PG&E-5).

d. Infrastructure Projects

Infrastructure projects represent $2.8 million, or 8.6 percent, of the total hydro expense increase from 2014 recorded to 2017 forecast.[33] This driver includes numerous building repair, painting, and road and bridge repair projects throughout the hydro system in MWC KI.

e. Other Expense

Other activities not included in the above expense drivers account for $1.2 million,[34] or 3.8 percent, of the total hydro expense increase from 2014 recorded to 2017 forecast. This driver category includes increased 2017 forecasts for the Records Management Initiative and PG&E's LCC. These increases are partially offset by reductions in forecasts for several other items.

1) Records Management Initiative

As discussed above in Section B.3 above, Power Generation is continuing its records management initiative to put its critical documents into the Documentum system. PG&E's 2017 forecast of MWC KG includes the costs to convert its paper engineering drawings to digitized/searchable format. This work will take several years to complete. $1.0 million of the expense increase in 2017 above 2014 recorded is associated with this work.[35]

2) Land Conservation Commitment

In accordance with the Bankruptcy Settlement Agreement and related Stipulation adopted by the Commission in Decision 03-12-035 ("Settlement"), PG&E committed to protect and preserve the beneficial public values on approximately 140,000 acres of its watershed lands in the Sierra Nevada, Cascades, and North Coast Range mountains, for the benefit of current and future generations of Californians. Currently, the company estimates it will retain approximately 100,000 acres, all of

---

33 See WP 4-63, Line 306, Exhibit (PG&E-5.

34 See WP 4-73, Line 596, Exhibit (PG&E-5).

35 See WP 4-32, Line 272, Exhibit (PG&E-5).

which will be encumbered by conservation easement, including the lands with hydroelectric facilities. The company further estimates that these 100,000 acres will be encumbered by approximately 60 individual conservation easement agreements. PG&E is actively negotiating the real estate transactions necessary to fulfill the Settlement requirements.

The 2017 forecast of LCC support and implementation costs is primarily comprised of internal: (1) project management costs; (2) Stewardship Council Support costs; (3) real estate transaction and related implementation support; and (4) regulatory application preparation. These initial transaction costs are included under MWC AB. These costs are incremental internal costs associated with PG&E's support of the LCC, or are chargeback costs from PG&E departments that provide support services, such as Environmental Services, Land and Environmental Management, and Law. Other internal support costs, such as legal, regulatory, and accounting costs are not presented here. Those costs are captured in the forecasts of the appropriate administrative and general support departments in Exhibit (PG&E-9), and may or may not be incremental to each department.

The forecast is based on an expected level of transactions over the GRC period. There are about 1,100 parcels of land covered by the LCC, and, although full information is not yet available to develop an accurate estimate of the number of transactions required to implement the LCC, PG&E expects that approximately 60 transactions will be executed in the period between 2017 through 2019. The transactions will consist of granting conservation easements, ownership transfers, or a combination of the two. $0.9 million[36] of the increase in 2017 expense above 2014 recorded is associated with LCC support and transactional implementation work.

---

36 See WP 4-15, Line 2, (Exhibit PG&E-5).

As each conservation easement encumbering PG&E land is recorded, the company must be prepared to comply with the requirements of that agreement in perpetuity. The land trusts holding these conservation easements have the right to enforce PG&E's compliance with the agreements. Conservation easement compliance is a specialized field, and PG&E needs the in-house expertise required to interpret and fulfill its obligations under the terms of the conservation easements. Staying in compliance with the conservation easements make sure that PG&E fulfills its obligations under the Settlement while maintaining operational efficiency.

To that end, Land Management and Power Generation agreed to have the company establish, within the Land Management organization, a core team responsible for ensuring the company establishes and maintains a robust LCC Program. This Key Initiative establishes the LCC Program. The LCC Program staff will be accountable for all aspects of conservation easement compliance, including maintaining constructive internal and external communications, developing and maintain policies and procedures for compliance, and managing the annual disclosures and monitoring visits required by the conservation easements. Costs associated with establishing and staffing this LCC program are included in Exhibit (PG&E-7), Chapter 7, under MWC JE.

2. Capital

This section describes the major areas of capital work as illustrated within the pie charts in Section B.1.b. above. Summary information on the types of work represented in each area is included here. Additional detail regarding the type of work included in each MWC is provided in Section C, below.

a. Generating Equipment

This area of work includes installation or replacement of hydro generating equipment in MWC 2M. The largest items for this area of

work account for 49 percent of the $103.4 million[37] forecast in 2017 for MWC 2M: Generator rewinds ($28.0 million); asset management capital programs ($15.0 million); and turbine runner replacements ($9.6 million).[38] Work in this capital area is necessary to ensure the reliable operation of the hydro generation facilities.

1) Generator Rewinds

The generator windings at Belden, Bucks Creek, Pit 1, Tiger Creek, Pit 3, and Caribou 1, Caribou 2, AG Wishon, Pit 7 and Kerckhoff 2 are approaching the end of their useful lives and must be refurbished to ensure continued reliable operation into the future. The projects include disassembly of the generator unit, installation of new stator windings, fabrication and restacking of core steel, installation of generator management relay and vibration monitoring systems, and reassembly. Table 4-11 shows the 2017 capital forecast associated with each rewind and the forecast total capital cost of each project.

TABLE 4-11
HYDRO GENERATOR REWINDS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Unit	Capacity (MW)	Forecast Operative Year	2017 Forecast	Total Project Forecast
1	Belden	125	2017	$6,296	$11,262
2	Bucks Creek U1	33	2017	5,675	$9,000
3	Pit 1 U1	30	2018	5,175	$6,475
4	Tiger Cr U1	29	2017	3,875	$6,550
5	Pit 3 U3	23	2018	3,375	$6,375
6	Caribou 1 U1	25	2018	2,700	$6,275
7	Caribou 2-5	60	2020	500	$5,200
8	AGWishon U3	5	2018	250	$1,750
9	Pit 7 U2	56	2019	250	$6,150
10	Kerckhoff 2	155	2018	150	$8,000
11				$28,246	

37 See WP 4-74, Line 7, Exhibit (PG&E-5).

38 See WP 4-76 to WP 4-78, Exhibit (PG&E-5).

2) Turbine Runner Replacements

Turbine runner replacements are planned for Caribou 1, Pit 4, Salt Springs, Potter Valley, Crane Valley and Narrows powerhouses. The current runners have required extensive welding repairs to keep the units in acceptable operating condition. After decades of performing welding repairs, the runners' profiles have degraded resulting in reduced performance of the turbines. It is no longer feasible to make temporary repairs to these components, and they have reached the end of their useful lives. Table 4-12 shows the 2017 capital forecast associated with each runner project and the forecast total capital cost of each project.

TABLE 4-12
HYDRO TURBINE RUNNER REPLACEMENTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Unit	Capacity (MW)	Forecast Operative Year	2017 Forecast	Total Project Forecast
1	Caribou 1 Replace U2 Runner	47.0	2017	$3,375	$4,725
2	Pit 4 Unit 2 Replace Runner & Wickets	33.0	2017	2,069	$7,907
3	Salt Springs 2 Replace Runner	25.0	2017	1,500	$3,045
4	Caribou 1 Replace U1 Runner	2.5	2017	850	$4,975
5	Potter Valley U3 Runner	5.5	2019	450	$2,000
6	Potter Valley U1 Runner	25.0	2020	200	$1,750
7	Caribou 1 Replace U3 Runner	0.9	2019	150	$4,375
8	Crane Valley - Runner Replacement	12.0	2018	150	$950
9	Narrows Replace Runner	47.0	2016	100	$4,586
10				$8,844	

3) Asset Management Capital Programs

These programs provide funding for replacements of bearings, high voltage transformers, generator rotors, turbine shut-off valves, and high voltage breakers. Funding will be allocated to specific projects prior to implementation based on condition assessments and prioritization within the fleet of hydro units.

b. Safety and Regulatory

This area of work includes installation or replacement of equipment or facilities to address safety and/or regulatory requirements other than

re-licensing and new license implementation. This area of work is classified under MWC 2L. The largest projects for this area of work account for 79 percent of the $37.7 million[39] forecast 2017 MWC 2L cost: Helms Access Tunnel Structural Reinforcements ($8.2 million), Fordyce Dam Leakage Reduction ($5.2 million), Dam Mitigation projects ($5.7 million), Poe Dam Gate Trunnions ($4.0 million), and Lower Bucks Dam Resurface ($3.3 million).[40] Work in this capital area is necessary to ensure the safe operation of PG&E's hydro generation facilities in compliance with FERC licenses and other federal and state agency regulatory requirements.

1) Helms Access Tunnel Structural Reinforcements

This project is necessary to protect workers from rocks falling from the tunnel walls and ceiling. The project scope is expected to include installation of shotcrete over rock bolted mesh to reinforce the tunnel structure. The 2017 forecast for this item is $8.2 million. PG&E's total cost forecast for this project is $8.8 million.[41]

2) Fordyce Dam Leakage Reduction (Capital)

As described in Section C.1.c.2, above improvements to Fordyce dam are needed to reduce leakage and to comply with DSOD requirements. In addition to the expense repairs described in the section referenced above, the project scope is expected to include making capital improvements to the lower part of the dam (the dam's upstream "toe"), where it is estimated that currently about two thirds of the seepage occurs. The lower part of the dam includes a thin, unreinforced concrete seepage barrier (cutoff wall) built in 1911 that will likely need to be replaced. The 2017 forecast for this item is $5.2 million. PG&E's forecast total cost for this project is $15.9 million.[42]

---

39 See WP 4-74, Line 6, Exhibit (PG&E-5).

40 See WP 4-76, Exhibit (PG&E-5).

41 See WP 4-76, Line 25, Exhibit (PG&E-5).

42 See WP 4-76, Line 16, Exhibit (PG&E-5).

3) Dam Mitigation Projects

The Dam Safety Program includes capital work that implements repairs and replacements to hydro dams and associated equipment as a result of issues identified and prioritized through ongoing analysis and inspections within the Facility Safety Program. This Program includes dam modifications to alleviate unacceptable levels of leakage through a dam, to restore the functionality of existing radial gates, drum gates, and low level outlets, and to rebuild damaged spillways, dam faces, and outlets. The type of capital work in this program includes: replacing sections of concrete dam face; replacing worn and leaking water seals; grouting dam structures to reduce leakage; and replacing drum gate seals, low level outlet valve operators, and radial gates. As dam modifications are identified, they will be budgeted as specific projects and removed from the program.

This program additionally addresses findings and mandates from FERC and DSOD. FERC and DSOD require formal dam safety reviews and studies to determine the condition of our dams and to assess the long-term suitability for continued safe and reliable operation. In compliance with these requirements, PG&E prepares action plans, designs, and implements the necessary physical dam remediation to mitigate the risk of failure. These programs are needed to systematically identify dam safety and reliability risks and remedies before failure. As more fully described in Section B.3 above, an in-service failure of a dam can jeopardize public and employee safety, in addition to causing third-party property damage, collateral damage to hydro facilities, and environmental damage. This program is intended to minimize the risk and consequences associated with such dam failures. The 2017 forecast for this item is $5.9 million.[43]

[43] See WP 4-78, Line 87, Exhibit (PG&E-5).

4) Poe Dam Gate Trunnions

DSOD has required refurbishment of the Poe Dam Gates. Friction testing has shown the design to capacity ratio for the Poe Dam Gates is above one, indicating the design load is greater than the capacity of the structural member, which could result in the members yielding (bending) when the gate is opened. PG&E is required to have operators on the dam during spill conditions to monitor gate operations. Failure of the gates could result in flooding downstream, preventing PG&E from impounding water to operate the Poe Powerhouse. The scope of this work is to replace the gate trunnion bearings, seals, and arms, as well as improve the hoist system for all four gates at Poe Dam. There are separate projects for replacement of each pair of the Poe Dam gate trunnions. The first gate trunnion replacement is forecast to be complete prior to 2017. The trunnion replacements for the other three gates are expected to continue into and beyond 2017. The 2017 forecast for these three projects is $4.0 million. The total forecast for these three projects is $10.9 million.[44]

5) Lower Bucks Dam Resurface

This project is in response to a July 2014 FERC inspection which noted significant concrete spalling on the downstream face and deterioration of the concrete abutment thrust blocks. The project scope is expected to include resurfacing of the downstream face of the dam and reinforcement of the abutment thrust blocks. The 2017 forecast for this item is $3.3 million. The total forecast for this project is $3.9 million.[45]

c. Dams and Waterways

This area of work includes installation or replacement of capital components associated with dams and waterways in MWC 2N. The five largest items for this area of work account for 62 percent of the $66.8 million 2017 forecast MWC 2N cost: Drum Canal water

---

[44] See WP 4-76, Lines 21-23, Exhibit (PG&E-5).

[45] See WP 4-76, Line 27, Exhibit (PG&E-5).

conveyance improvements ($15.4 million), Helms Plug and By-Pass Tunnel Lining ($9.2 million), Asset Management Penstock Program ($6.7 million), Dam Remediation ($5.9 million), and Tiger Creek Canal Liner ($4.4 million).[46] Work in this capital area is necessary ensure reliable operations of the dams and waterways needed for operation of the hydro generation facilities.

1) Drum Canal Water Conveyance Improvements

The Drum Canal water conveyance improvements item represents a group of similar projects planned over several years for several canal sections within the Drum watershed. These projects are expected to include replacing deteriorated linings with new linings, strengthening canal berms, installing new controllers for gates and valves, and replacing flumes and/or flume substructures. This work is necessary to reduce the risk of water conveyance failure by restoring and maintaining the integrity of the canals and flumes in the Drum watershed. The 2017 forecast for this item is $15.4 million. PG&E's forecast total cost for this program in the 2017-2019 timeframe is $47.3 million.[47]

2) Asset Management Penstock Program

The Asset Management Penstock Program allocates funds for capital penstock component replacements, including penstock couplings or joints, sections of penstock pipe, anchor blocks, and instrumentation. The 2017 forecast for this item is $6.7 million. PG&E's forecast total cost for this project in the 2017-2019 timeframe is $23.3 million.[48]

3) DeSabla and Motherlode Water Conveyance Improvements

This item includes funding for water conveyance improvements within the DeSabla Hydro Area and the Motherlode watershed. Similar to the Drum water conveyance items discussed above, these

---

46 See WP 4-78, Exhibit (PG&E-5).

47 See WP 4-78, Lines 106 and 108, Exhibit (PG&E-5).

48 See WP 4-78, Line 86, Exhibit (PG&E-5).

projects are expected to include replacing deteriorated linings with new linings, strengthening canal berms, installing new controllers for gates and valves, and replacing flumes and/or flume substructures. The 2017 forecast for these improvements is $4.8 million. PG&E's forecast total cost for these improvements in the 2017-2019 timeframe is $14.8 million.[49]

4) Tiger Creek Canal Liner

The 17.3-mile Tiger Creek Canal has many deteriorated components, including, for example walls, the invert (bottom), and expansion joints. The scope of work included in this project includes replacement of joints, removal of existing coal tar lining, and installation of new lining in the canal. The 2017 forecast for this item is $4.4 million. PG&E's forecast total cost for this project is $18.5 million.[50]

5) Weather/Seismic/Wildfire Emergent Work

PG&E expects emergent capital work to result from storms or other force majeure events in 2017.[51] As noted in the expense drivers section above, PG&E's hydro water conveyance facilities are susceptible to damage during severe weather, seismic events, and wildfires. Historically, such events have occurred annually but no specific funding was set aside to repair or replace damaged facilities. As a result, this emergent work has displaced other planned and needed work. PG&E is proposing to establish a budget for emergent work going forward so that other work can proceed as planned.

This forecast is not duplicative of work covered by CEMA. Due to the dispersed nature of the hydro water conveyance facilities, they often do not correspond with state-designated disaster areas. CEMA funding is limited to work undertaken to repair structures

---

49 See WP 4-78, Lines 105 and 107, Exhibit (PG&E-5).

50 See WP 4-78, Line 104, Exhibit (PG&E-5).

51 See WP 4-78, Line 110, Exhibit (PG&E-5).

within such disaster areas.[52] The 2017 forecast for this item is $4.2 million.[53] This forecast is based on the amount of such emergent work experienced in recent years.

d. Relicensing and New License Implementation

This area of work includes obtaining new FERC licenses and implementing new capital license requirements. Costs for licenses and capital license implementation projects for licenses received prior to 2014 are classified under MWC 11. Costs and forecasts for obtaining new licenses and implementing capital license conditions beginning in 2014 are classified under MWC 3H and are included in the hydro balancing account described in Section D.3. The largest items for this area of work account for 86 percent of the $27.7 million 2017 forecast MWC 11 and MWC 3H cost: 10 relicensing projects ($16.5 million), Centerville Decommissioning ($5.0 million), and Kilarc-Cow Physical Decommissioning ($2.3 million).[54] Work in this capital area is necessary to ensure compliance with our FERC licenses and other federal and state agency regulatory requirements.

1) Relicensing Projects

The forecast includes the costs to relicense ten hydro projects representing 1,330 megawatts of hydro capacity. These projects are: Drum-Spaulding, McCloud-Pit, UNFFR, Poe, DeSabla-Centerville, Potter Valley, Bucks Creek, Narrows, Phoenix, and Kerckhoff. The 2017 forecast for these projects is $16.5 million. The total costs for the 2015-2019 period for these projects is $80.7 million.[55] Relicensing costs include the following activities: (1) performing environmental studies; (2) preparation of a relicensing Notice of Intent and an application for relicensing; (3) responding to FERC additional information requests (3)

---

52 Electric Preliminary Statement Part G, Catastrophic Event Memorandum Account (CEMA), http://www.pge.com/tariffs/tm2/pdf/ELEC_PRELIM_G.pdf.

53 See WP 4-78, Line 110, Exhibit (PG&E-5).

54 See WP 4-76, 4-78 and 4-79, Exhibit (PG&E-5)

55 See WP 4-78 and 4-79, Exhibit (PG&E-5).

acquisition of a Water Quality Certificate from the State Water Resources Control Board (SWRCB) including the SWRCB's California Environmental Quality Act analysis; (4) completing agency consultations through receipt of the new license; and (5) accepting and preparing an implementation plan for the new license when it is issued. Costs to implement new license conditions are typically incurred for several years following issuance of the new license.

2) Centerville Decommissioning

The Centerville Decommissioning project is to comply with FERC requirements to officially retire Centerville Powerhouse and have it removed from the DeSabla-Centerville FERC License 803.[56] The expected scope of the project includes: (1) preparation and filing of an application for Amendment of FERC license; (2) work to obtain Section 401 certification of water quality and other necessary permits; and (3) decommissioning of certain facilities as required by FERC order. The 2017 forecast for this item is $5.0 million. PG&E's total cost for this project is $25.7 million.[57]

3) Kilarc-Cow Physical Decommissioning

The Kilarc-Cow Physical decommissioning project is awaiting FERC action. Once a FERC Order is issued, the company will likely be required to decommission the hydroelectric facilities. The scope of work is expected to include removal of diversions, structures, forebay diversions, penstocks, powerhouse equipment, and the switchyard. The scope will likely also include grading of canals. FERC may also require additional follow-up maintenance/monitoring and other potential additional work, including: revegetation/erosion control; hazardous material remediation; permitting; cultural/historic documentation/mitigation; and recreational mitigation at the forebay. The 2017 forecast for this item is $2.3 million. The total cost for this project in the 2015 through 2019 period is $10.9 million.[58]

---

56 Federal Power Act Section 10(a)(3)(c).

57 See WP 4-79, Line 138, Exhibit (PG&E-5).

58 See WP 4-79, Line 132, Exhibit (PG&E-5).

e. Infrastructure

This area of work includes installation or replacement of capital components of buildings, roads, bridges, and other capital items within MWCs 03, 05, 12 and 2P. The largest items included in the 2017 forecast for this area of work account for 35 percent of the $18.0 million total 2017 forecast cost for infrastructure: DeSabla Consolidate Switching Center ($3.0 million), Asset Management sump systems ($2.0 million), and Caribou Road Improvements ($1.3 million).[59] Work in this capital area is necessary ensure PG&E's ability to continue reliable operation of the hydro generation facilities.

1) DeSabla Consolidate Switching Center

The DeSabla Consolidate Switching Center project includes remodeling of control room and reconfiguration of communication system to support DeSabla Switching Center Consolidation. Current operator workstations at Rock Creek Switching Center need to be reconfigured to include control of Caribou jurisdiction (Upper Feather River) system via SCADA. This will include revamping the existing workstations at Rock Creek and installing additional communications circuits, HMI screens, etc. The 2017 forecast for this item is $3.2 million. PG&E's total cost for this project is $4.2 million.[60]

2) Asset Management Sump Systems

The Asset Management sump systems program focuses on the Powerhouse Critical Sump Systems (PCSS); the last line of defense in case of oil spills. The PCSS consist of multiple sumps, pits or oily water separators. Capital work identified by the program includes system improvements or replacements such as: (1) pump system replacements (i.e., pipes, pump, filters); (2) installation of alarm systems; (3) heater installation to keep water from freezing so oil stays on top for skimming; (4) installation of new valves; and (5) installation of oil separation systems (i.e., skimmer belt, baffles

---

59 See WP 4-76, 4-80, and 4-96 to 4-98, Exhibit (PG&E-5).

60 See WP 4-78, Line 116, Exhibit (PG&E-5).

installation, independent oil separation systems). The 2017 forecast for this item is $2.0 million. PG&E's total cost for this project is $6.1 million.[61]

3) Caribou Road Improvements

Caribou Road is severely deteriorated. The pavement has failed in several locations and erosion of the steep road edge due to the heavy rain, heavy usage, and fluctuating forebay levels has resulted in a narrowing and risk of further failure. Further failure of the road could limit access to Caribou Powerhouse and related facilities. The anticipated scope of work is to improve and stabilize several sections of Caribou Road using a variety of methods including, but not limited to, installation of retaining walls, widening, patching, sealing, and installing erosion control measures such as drains, curbs, and swales. The 2017 forecast for this item is $1.3 million. PG&E's total cost for this project is $4.5 million.[62]

f. Other

In addition to the major capital work described above, PG&E's 2017 hydro forecast also includes a minor amount of capital for miscellaneous tools and equipment.

D. Activities and Costs by MWC

PG&E manages its hydro and other generation assets through a centralized program management process. PG&E allocates funds to address not only priority efforts and developing or emerging work, but also routine work and long-term needs. Program management assures consistency in budgeting and priorities across the generating assets. The expense and capital budgeting process requires each facility to develop annual plans to address labor, materials and contracts, using individual charge numbers or "Order Numbers"[63]

---

61 See WP 4-76, Line 7, Exhibit (PG&E-5).

62 See WP 4-78, Line 115, Exhibit (PG&E-5).

63 Order Numbers are internal identification numbers and include sub-identifiers like Specific Orders and Standing Orders to allow PG&E facilities and personnel to budget and subsequently charge time and materials to specific accounts for tracking and trending expenditures.

for each activity, project, or scope of work. These order numbers are then rolled under PG&E defined work type groupings called MWCs. The use of MWCs standardizes cost groups that allow an evaluation of the planned expenditures against historic spending levels for similar projects and similar activities. The MWCs are also grouped under various functions like operations, maintenance, environmental, or capital projects. Finally, PG&E uses MWCs to comply with FERC and CPUC accounting and/or reporting requirements.

PG&E's hydro organization currently uses 12 MWCs for expense costs and 9 MWCs for capital costs. Definitions and examples of the type of work, equipment and facilities covered under each MWC are provided below and in the workpapers supporting this chapter. Recorded costs by MWC for 2014 and forecasted costs for 2015, 2016, and 2017 for both expense and capital are provided in Cost Tables 4-36 and 4-37 in Section E of this chapter. Forecasts for capital also include forecasted costs for 2018 and 2019.

1. Expense

a. MWC AB – Miscellaneous Expense

This MWC includes the costs to support PG&E's LCC, which is described in more detail in Section C.1.e above.[64]

TABLE 4-13
MWC AB
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
AB	Misc Expense	2,116	(2,641)	2,022	3,000

b. MWC AK – Manage Environmental Operations

This MWC includes the labor costs to support PG&E's environmental stewardship programs in Hydro Operations. Increases in MWC AK are included in Section C.1 under the "Escalation" and "Other Expense" drivers.

---

64 The 2015 and 2016 amounts include adjustments to Power Generation's expense budgets for various one-time credits and expected benefits from sourcing and process improvement efforts.

TABLE 4-14
MWC AK
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
AK	Manage Environmental Oper	1,313	1,430	1,416	1,503

c. MWC AX – Maintain Reservoirs, Dams, Waterways

Cost to maintain reservoirs, dams and waterways for Hydro Generation. This MWC includes the following costs and activities:

- The cost to maintain reservoirs, dams, waterways and tunnels to support the operation of hydro power generating stations. This includes: water conveyance systems, weirs, tunnels, surge chambers, penstocks, intakes, tail races, and spill channels.
- The cost to maintain gauge stations and associated facilities (cableway, for example), which are necessary to support the operation of hydro power generating stations.
- The cost for inspections and studies required to meet general engineering best practices.

Increases in MWC AX are included in Section C.1 under the "Escalation" and "Dams and Waterways" drivers.

TABLE 4-15
MWC AX
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
AX	Maint Resv	24,002	29,595	30,673	33,150

d. MWC AY – Habitat and Species Protection

This MWC includes the costs to support habitat and species protection. The forecast for this MWC is essentially flat.

TABLE 4-16
MWC AY
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
AY	Habitat and Species Protection	209	170	199	203

e. MWC BC – Perform Reimbursable Work for Others

This MWC includes the costs to perform work for other parties who reimburse PG&E's costs to perform that work. No net costs are forecast for this MWC in 2017. Examples of costs in this MWC are those associated with specific work requests from water agencies/irrigation districts such as Placer County Water Agency (PCWA) for design reviews of new or modified facilities and operation and maintenance of Grizzly Powerhouse for the city of Santa Clara. These costs are reimbursed as incurred. Costs for routine work to administer water sales contracts are part of MWC KG. These costs are generally incidental to normal operating and maintenance costs for PG&E's hydro system and are not tracked or charged against the water sale revenue. An estimate of the annual costs of administering the PCWA water sale contract is provided in workpaper 4-328. Discussion of water sale revenue from this contract is included in Exhibit (PG&E-10), Chapter 17.

TABLE 4-17
MWC BC
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
BC	Perf Reimburs Wk for Oth	108			

f. MWC EP – Manage Property and Buildings

This MWC includes the cost to manage land rights as required in order to support the operation of hydro power generating stations. Increases in MWC AK are included in Section C.1 under the "Escalation" and "Other Expense" drivers.

TABLE 4-18
MWC EP
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
EP	Manage Property & Bldgs	1,259	1,492	2,016	2,068

g. MWC ES – Implement Environmental Projects

This MWC includes the costs to implement projects in support of environmental protection. The costs in this MWC are expected to decrease by 2017 as the mitigation work associated with the Crane Valley Dam Project is expected to be completed in 2016.

TABLE 4-19
MWC ES
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
ES	Implement Environment Projects	689	757	458	111

h. MWC IG – Manage Various Balancing Account Processes

This MWC includes the costs to implement new expense license conditions for FERC licenses issued after 2013. Note that costs for ongoing license management and implementation of conditions for FERC licenses issued prior to 2014 are included under MWC KJ. The increase in 2017 forecast compared to 2014 recorded is due to additional licenses expected to be received in the 2016 and 2017, as discussed in greater detail in Section C.1.b.

TABLE 4-20
MWC IG
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
IG	Manage Var Bal Acct Processes	286	454	558	3,942

i. MWC KG – Operate Hydro Generation

This MWC includes the following costs and activities related to the operation of hydro power generating stations and associated facilities:

- The cost to operate and monitor hydro power generating stations and switching centers, including auto testing.
- The cost to operate and control the flow of canals and waterways to support the operation of hydro power generating stations.
- The cost to provide hydro meteorological data and forecasts in order to optimally schedule water releases for hydro power generating stations.
- The cost to seed clouds in order to increase precipitation over watersheds.
- The cost for hazardous waste disposal and transportation in support of the operation of hydro power generating stations.
- The cost for routine inspections in support of the operation of hydro power generating stations.
- The cost for safety program in support of the operation of hydro power generating stations.

Costs within MWC KG are essentially growing at the rate of inflation. Increases in MWC KG are included in Section C.1 under the "Escalation" and "Other Expense" drivers.

TABLE 4-21
MWC KG
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
KG	Operate Hydro Generation	50,791	54,486	53,726	54,643

j. MWC KH – Maintain Hydro Generating Equipment

This MWC includes the following costs and activities related to the maintenance of generating equipment or components to support hydro generation activities:

- Repairs to runners, seal rings, governors, exciters, wicket gates, needle valves, turbine shut-off valves, pressure relief valves,

miscellaneous oil, water and air mechanical systems, stator reminds, field coils and poles, and associated turbine components.

- The cost to maintain accessory electrical equipment to support hydro operations. Examples include medium and low switchgear, motor control centers, transformers, direct current batteries, chargers and distribution systems, emergency backup generator, plan instrumentation and automation, annunciators, switchboards, station service, and station batteries.
- The cost to maintain switchyard equipment to support the operation of hydro power generating stations. This includes breakers, switches, step-up transformers, and bus work.
- The cost to maintain SCADA and other required technologies or software applications to support the operation of hydro power generating stations. This includes radio systems, master stations, Remote Terminal Units, operating consoles, telephones, communication batteries, and uninterruptable power supplies.
- The other costs to maintain hydro facilities that are not categorized in other MWCs.

Costs within MWC KH are essentially growing at the rate of inflation. Increases in MWC KH are included in Section C.1.a under the "Escalation" and the "Other Expense" drivers.

TABLE 4-22
MWC KH
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
KH	Maint Hydro Generating Equip	32,703	33,409	33,388	35,954

k. MWC KI – Maintain Hydro Buildings, Grounds, and Infrastructure

This MWC includes the following costs and activities related to the maintenance of buildings, grounds, and infrastructure to support hydro generation activities:

- The cost to maintain PG&E roads to support the operation of hydro power generating stations. This includes the costs for snow and dirt removal, repairs, signage, inspections, grading and repairs.
- The cost to maintain PG&E bridges to support the operation of hydro power generating stations. This includes the costs for inspections, repairs, and signage.
- The cost to maintain hydro generation buildings, grounds, and infrastructure to support the operation of hydro power generating stations. This includes capital replacement of buildings, roofing, parking lots, lighting, ventilation and air conditioning systems, oil/water separator, station air compression, and sump equipment.

Increases in MWC KI are included in Section C.1.a under the "Escalation" and "Infrastructure Projects" drivers.

TABLE 4-23
MWC KI
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
KI	Maint Hydro Bldg	10,859	13,289	13,185	14,781

I. MWC KJ – Regulatory Compliance Hydro Generation

This MWC includes the following costs and activities related to compliance with regulatory licenses:

- The cost of managing license compliance.
- The cost to monitor survey and study environmental conditions that are required to stay compliant with hydro licenses.
- Fees required for license compliance. Examples include fees for fish stocking and regulatory fees paid to FERC, DSOD, and U.S. Geological Survey.
- Projects required for license compliance.
- The cost to manage public recreational facilities to meet regulatory requirements.

Increases in MWC KJ are discussed in Section C.1.a under the "Escalation" and "Regulatory Compliance" drivers.

TABLE 4-24
MWC KJ
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast
KJ	License Compliance Hydro Gen	31,144	37,908	40,641	38,391

2. Capital

a. MWC 03 – Office Furniture and Equipment

This MWC includes capital costs to install/replace capital office furniture or other accessory equipment needed to support hydro generation operations. No costs are included in the 2017 forecast for this MWC.

TABLE 4-25
MWC 03
(THOUSANDS OF NOMINAL DOLLARS)

		Recorded Adjusted	Forecast				
MWC	Description	2014	2015	2016	2017	2018	2019
03	Office Furniture & Equipment	203					

b. MWC 05 – Tools and Equipment

This MWC includes capital costs of tools and equipment needed to support hydro generation operations. Costs in the MWC are forecast to remain essentially flat.

TABLE 4-26
MWC 05
(THOUSANDS OF NOMINAL DOLLARS)

		Recorded Adjusted	Forecast				
MWC	Description	2014	2015	2016	2017	2018	2019
05	Tools & Equipment	1,196	1,001	962	985	1,008	1,030

c. MWC 11 – Relicensing Hydro Generation – Non-Balancing Account

This MWC includes the following costs and activities related to renewals of hydro operating licenses or the installation of new equipment mandated by conditions of renewed or new operating licenses:

- The costs to obtain new licenses as the existing licenses expire in order to support the operation of hydro power generating stations. This includes, for example, preparing studies and drafting regulatory applications.
- The cost associated with capital projects needed in order to comply with the requirements in a license.

The major work included in this MWC is described in Section C.2.d above.

Note that MWC 11 is being phased out due to the implementation of balancing account treatment for hydro licensing costs as approved in the 2014 GRC decision. Projects resulting from licenses issued prior to 2014 will continue to be accounted for under MWC 11 until their completion. Ongoing relicensing projects and new license implementation capital projects for licenses issued beginning in 2014 will be accounted for under MWC 3H, which is described below.

TABLE 4-27
MWC 11
(THOUSANDS OF NOMINAL DOLLARS)

		Recorded Adjusted	Forecast				
MWC	Description	2014	2015	2016	2017	2018	2019
11	Relicensing Hydro Gen	17,104	6,006	3,593	734	626	

d. MWC 12 – Implement Environmental Projects

This MWC includes capital costs to install/replace environmental projects or related capital equipment needed to support Hydro Generation, including oil spill prevention systems and equipment. The forecast for this MWC is expected to remain relatively flat.

TABLE 4-28
MWC 12
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	Recorded Adjusted 2014	Forecast 2015	2016	2017	2018	2019
12	Implement Environment Projects	3,928	3,709	3,894	3,991	2,350	3,650

e. MWC 2L – Install/Replace Hydro Safety and Regulatory

This MWC includes capital costs to install/replace safety or regulatory required equipment, or other related accessory equipment needed to support hydro generation operations. Costs in this MWC are primarily related to employee or public safety, and regulatory requirements that are not connected with relicensing. The work identified in this category has a high priority and is typically addressed before competing reliability-related work. The major work included in this MWC is described in Section C.2.b above.

TABLE 4-29
MWC 2L
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	Recorded Adjusted 2014	Forecast 2015	2016	2017	2018	2019
2L	Instl/Rpl for Hydro Safety&Reg	39,325	53,987	47,519	37,727	25,037	6,999

f. MWC 2M – Install/Replace Hydro Generating Equipment

This MWC includes the capital costs to install/replace generating equipment, or other accessory equipment needed to support Hydro Generation operations. This includes, for example, the costs of replacements or upgrades of runners, seal rings, governors, exciters, wicket gates, valves, breakers, switchgear, transformers, and station batteries. The major work included in this MWC is described in Section C.2.a above. Some of the work in this category may be reclassified into MWC 2L if it is determined that there is a safety risk associated with the work.

TABLE 4-30
MWC 2M
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	Recorded Adjusted 2014	Forecast 2015	2016	2017	2018	2019
2M	Instal/Repl Hydro Gneratng Eqp	91,780	111,219	92,404	103,421	96,589	100,045

g. MWC 2N – Install/Replace Res, Dams and Waterways

This MWC includes capital costs to install/replace generating equipment, or other accessory equipment needed to support hydro generation operations. These costs include, for example, replacements or upgrades of penstocks, penstock couplings, penstock shut-off valves, spill gates, water conveyance monitoring systems, and improvements to canals, ditches, and tunnel linings. The major work included in this MWC is described in Section C.2.c above. Some of the work in this category may be reclassified into MWC 2L if it is determined that there is a safety risk associated with the work.

TABLE 4-31
MWC 2N
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	Recorded Adjusted 2014	Forecast 2015	2016	2017	2018	2019
2N	Instal/Repl Resv	49,137	75,361	71,515	66,817	93,416	89,932

h. MWC 2P – Install/Replace Hydro Infrastructure

This MWC includes capital costs to install/replace infrastructure and accessory equipment needed to support Hydro Generation operations. This includes, for example, the capital costs to install/replace buildings, roads, and bridges. The major work included in this MWC is described in Section C.2.a above.

TABLE 4-32
MWC 2P
(THOUSANDS OF NOMINAL DOLLARS)

MWC	Description	Recorded Adjusted 2014	Forecast 2015	2016	2017	2018	2019
2P	Instl/Repl Hydr BldgGrndInfrst	7,975	14,021	18,297	13,004	10,085	11,386

i. MWC 3H – Relicensing and New License Implementation – Balancing Account

This MWC includes the cost to renew hydro operating licenses or install new equipment mandated by conditions of renewed or new operating licenses beginning with licenses received after 2013. This MWC includes the following costs and activities:

- The costs to obtain new licenses as the existing licenses expire in order to support the operation of hydro power generating stations. This includes, for example, preparing studies and drafting regulatory applications.
- The costs to file for license surrender or modification including decommissioning.
- The cost associated with capital projects needed in order to comply with the requirements in a license.

The major work included in this MWC is described in Section C.2.d above.

Note that MWC 11 is being phased out due to the implementation of balancing account treatment for hydro licensing costs as approved in the 2014 GRC decision. Projects resulting from licenses issued prior to 2014 will continue to be accounted for under MWC 11 until their completion. Ongoing relicensing projects and new license implementation capital projects for licenses issued beginning in 2014 will be accounted for under MWC 3H. The following section provides the justification for continuation of the Hydro Licensing Balancing Account.

TABLE 4-33
MWC 3H
(THOUSANDS OF NOMINAL DOLLARS)

		Recorded Adjusted	Forecast				
MWC	Description	2014	2015	2016	2017	2018	2019
3H	Hydroelec Lic & Lic Conditions	16,169	22,394	21,586	26,986	40,971	47,143

3. Hydro Licensing and License Implementation Balancing Account

As approved in the 2014 GRC, PG&E implemented a two-way balancing to record the expense and capital costs of FERC Hydro licensing and license implementation costs. The duration and timing of issuance of the licenses is uncertain, and therefore the cost and timing of the implementation expenditures are uncertain. It is difficult to forecast when FERC will issue new licenses for hydro projects because the regulatory process includes a number of stakeholders and several separate state and federal reviews that run in parallel with the FERC process. For example, the California State Water Resources Control Board must issue a water quality certification under Section 401 of the Clean Water Act and related California Environmental Quality Act analysis as part of the relicensing process, and the USFS and certain other federal agencies also have mandatory conditioning authority to propose enhancements to or mitigation on federal lands to the extent a hydro project is on or establishes a nearby impact to federal lands. The FERC process includes a separate National Environmental Policy Act analysis. Historically, the FERC licensing process has exceeded the targeted dates for completion by several years.

A licensee cannot accurately forecast the scope and costs of license implementation because the measures that will be required are not known in advance and often take years of study of potential impacts before new operating conditions can be specified. For example, it is common to require that instream flows be increased as part of the licensing process, and this typically requires physical changes to the hydro facilities or dams to release more water into the river. Until the magnitude of the flow increase is known, it is difficult to determine the detailed scope and cost of modifications to the

water release facilities. Another common example is the issue of fish passage past diversions or dams. The full extent of changes to the hydro facility, such as adding a fish screen or fish ladder, or even potentially decommissioning or modifying a diversion cannot be known until the resource agencies complete their studies of the impacts of continued operations and of the effectiveness of potential enhancements. This process is not in PG&E's control, yet PG&E is required by law to implement all measures included in its new FERC licenses if PG&E accepts the new license.

PG&E proposes to continue this balancing account for the 2017 GRC period. The proposed continuation of this two-way balancing account addresses the uncertainties in the cost and timing of license renewal, amendments, and new license condition implementation measures by providing recovery in rates only of actual costs that are incurred.

In the 2014 GRC forecast, PG&E was expecting four new FERC licenses to be issued in late 2012. The first of those new licenses, Chili Bar, was issued in August 2014. The remaining three licenses continue to be delayed and are now forecast to be issued beginning in late 2016. These shifts in license issuance forecasts and the resulting shifts in expense and capital forecasts for hydro licensing balancing account forecasts are shown in Tables 4-34 and 4-35.

TABLE 4-34(a)
HYDROELECTRIC RELICENSING EXPECTED LICENSE ISSUANCE DATES
2017 GRC VS. 2014 GRC

		EXPECTED LICENSE ISSUANCE: ASSUMPTION USED FOR BUDGET PLANNING	
FERC LICENSE	PROJECT NAME	2014 GRC	2017 GRC
2155	Chili Bar	01-Nov-12	License received in Aug-14
803	DeSabla-Centerville	01-Dec-12	Oct-16
2105	Upper NF Feather River	01-Dec-12	Jun-17
2107	Poe	01-Dec-12	Jun-18
2106	McCloud - Pit	01-Jul-14	Apr-18
606	Kilarc-Cow Creek Surr.	01-Dec-14	Jun-16
2467	Merced Falls	01-Feb-16	Feb-16
2310	Drum-Spaulding	01-Apr-16	Feb-19
619	Bucks Creek	01-Dec-20	Dec-20

(a) See WP 4-130, Exhibit (PG&E-5).

TABLE 4-35(a)
HYDROELECTRIC LICENSING AND LICENSE IMPLEMENTATION FORECASTS
2017 GRC VS. 2014 GRC (THOUSANDS OF NOMINAL DOLLARS)

	2012	2013	2014	2015	2016	2017	2018	2019
2014 GRC Expense Forecast	$ 553	$ 6,371	$ 6,286					
2017 GRC Expense Actuals/Forecast	$ -	$ -	$ 305	$ 454	$ 635	$ 5,139		
2014 GRC Capital Forecast	$ 16,958	$ 13,303	$ 28,646	$ 38,572	$ 48,387			
2017 GRC Capital Actuals/Forecast	$ 16,935	$ 16,088	$ 17,227	$ 21,325	$ 20,314	$20,160	$45,039	$49,866

(a) See WP 4-131 and WP 4-132, Exhibit (PG&E-5).

As is demonstrated by the costs in Table 4-35 above, customers have benefited from the establishment of the Hydro balancing account. The difference between the revenue requirement associated with the costs adopted in the 2014 GRC and the actual/forecasts costs presented here in the 2017 GRC will be credited back to customers in 2017. This process is discussed further in Exhibit (PG&E-5), Chapter 8.

E. Estimating Method

Power Generation uses a number of different approaches to estimate the costs of the work included in its Hydro expense and capital expenditure forecasts.

1. Estimating Routine Operations, Maintenance, and Compliance

Costs for routine operations, maintenance, and compliance for PG&E's hydro generation facilities are primarily based upon labor and other recurring costs, and are typically consistent year over year. PG&E developed the 2017 forecast of O&M expenses needed to support the ongoing routine work using 2014 recorded expenses as a base. These recorded expenses were adjusted for labor and non-labor escalation, consistent with rates described in Exhibit (PG&E-12), Chapter 3. Further adjustments were made to reflect changes in program activity, as well as any changes in specific contract services and fees other than escalation.

2. Estimating Project Costs

The costs of the individual projects included in the Hydro forecast are estimated on a project-specific basis. PG&E's forecast is based on a bottom-up calculation of the expected costs for the projects and programs to be implemented in the forecast year. These cost estimates for these programs and projects were developed using a combination of the following: (1) actual costs for similar work, adjusted as appropriate; (2) the knowledge and experience of PG&E's program and project managers; (3) contractor and consultant experience with similar work; and (4) estimates from potential vendors. Typically Power Generation's Planning Department will develop initial project cost estimates by comparing the proposed scope of work with similar completed projects, adjusted to account for scale and/or differing site specific conditions. Once the project is handed off to Power Generation's Project Execution Department, the project estimates are then refined based on any unique permit compliance requirements, preliminary engineering, equipment, vendor proposals, and construction labor, contract, and materials forecasts. The work included in the 2017 GRC forecast is at various stages—some of the work is in the planning phase, some is in Project Execution in the design and engineering phase, and some is the

construction phase of Project Execution. Naturally, the further along the project is in its lifecycle, the better the cost estimate.

3. Hydro Planning and Prioritization

The portfolio of work included in Hydro's long-term plan is identified in a number of ways; through Power Generation's Asset Management process, by O&M personnel, and through regulatory requirements. The Planning Department works with the other departments in Power Generation to prioritize the work based on a number of factors, including the RIBA scores mentioned in Section B.3.d above and the executability of the work, and balances the plan to Power Generation's expense and capital budget targets. Power Generation updates its long-term plan three times a year to reflect newly identified work, updates to project costs and schedules, and/or changes in priorities or budgets.

Because Power Generation has not historically included a placeholder for contingency in its plan for unplanned work, planned work is rescheduled to accommodate emergent or carry-over work.[65] In order to ensure that the most important work is being executed, Power Generation has a monthly (and sometimes more frequent if needed) process to review project status and make necessary tradeoffs. The forecast included in this 2017 GRC is based on the most recent long term plan at the time of filing.

In addition to the internal Power Generation budget prioritization and planning efforts, PG&E executive management conducts a regular and ongoing strategic planning process that similarly assesses priorities and needed prioritization of funding across all PG&E organizations.[66]

These reviews and planning processes have resulted in the rescheduling or re-prioritization of some Hydro projects originally planned for the 2014 GRC period. Some of this work was rescheduled due to higher priority emergent work that was not originally planned as part of the 2014 GRC filing.

---

65 See Sections C.1.c.1 and C.2.c.5, *supra*.

66 See PG&E's Exhibit (PG&E-2), Chapter 4.

F. Cost Tables

TABLE 4-36
HYDRO OPERATIONS COSTS BY MWC
EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2010 Recorded Adjusted	2011 Recorded Adjusted	2012 Recorded Adjusted	2013 Recorded Adjusted	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	Workpaper Reference
1	AB	Misc Expense	1,228	3,862	2,022	1,797	2,116	(2,641)	2,022	3,000	WP 4-13, Line 4
2	AK	Manage Environmental Oper	1,356	1,434	1,397	1,303	1,313	1,430	1,416	1,503	WP 4-13, Line 8
3	AX	Maint Resv	18,224	23,456	23,916	29,343	24,002	29,595	30,673	33,150	WP 4-13, Line 12
4	AY	Habitat and Species Protection	119	101	114	175	209	170	199	203	WP 4-13, Line 16
5	BC	Perf Reimburs Wk for Oth	(305)	(508)	(492)	(159)	108	–	–	–	WP 4-13, Line 20
6	EP	Manage Property & Bldgs	965	992	1,402	1,648	1,259	1,492	2,016	2,068	WP 4-13, Line 24
7	ES	Implement Environment Project	490	338	409	192	689	757	458	111	WP 4-13, Line 28
8	IG	Manage Var Bal Acct Processe	–	269	306	231	286	454	558	3,942	WP 4-14, Line 32
9	KG	Operate Hydro Generation	33,738	36,444	42,386	54,705	50,791	54,486	53,726	54,643	WP 4-14, Line 36
10	KH	Maint Hydro Generating Equip	24,226	27,429	37,786	26,332	32,703	33,409	33,388	35,954	WP 4-14, Line 40
11	KI	Maint Hydro Bldg	10,060	10,923	9,281	15,235	10,859	13,289	13,185	14,781	WP 4-14, Line 44
12	KJ	License Compliance Hydro Ger	30,731	27,514	34,770	29,115	31,144	37,908	40,641	38,391	WP 4-14, Line 48
13											
14		**Total**	**120,831**	**132,253**	**153,297**	**159,917**	**155,480**	**170,348**	**178,281**	**187,746**	Sum of Lines 1-12

TABLE 4-37
HYDRO OPERATIONS COSTS BY MWC
CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2010 Recorded	2011 Recorded	2012 Recorded	2013 Recorded	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Workpaper Reference
1	01	IT - Desktop Computers	36	-	-	-	-	-	-	-	-	-	
2	03	Office Furniture & Equipment	-	-	1	489	203	-	-	-	-	-	
3	05	Tools & Equipment	568	898	455	1,412	1,196	1,001	962	985	1,008	1,030	WP 4-80, ln 10
4	11	Relicensing Hydro Gen	45,571	13,576	17,230	16,832	17,104	6,006	3,593	734	626	-	WP 4-80, ln 26 + WP 4-76, ln 4
5	12	Implement Environment Projects	7,134	8,045	11,385	4,802	3,928	3,709	3,894	3,991	2,350	3,650	WP 4-81, ln 47 + WP 4-76, ln 8
6	2L	Instl/Rpl for Hydro Safety&Reg	34,915	86,218	100,392	47,207	39,325	53,987	47,519	37,727	25,037	6,999	WP 4-84, ln 200 + WP 4-76, ln 31
7	2M	Instal/Repl Hydro Gneratng Eqp	45,827	68,509	83,133	83,132	91,780	111,219	92,404	103,421	96,589	100,045	WP 4-92, ln 532 + WP 4-78, ln 83
8	2N	Instal/Repl Resv	22,471	43,050	51,268	40,917	49,137	75,361	71,515	66,817	93,416	89,932	WP 4-96, ln 710 + WP 4-78, ln 111
9	2P	Instl/Repl Hydr BldgGrndInfrst	2,318	5,163	4,712	12,524	7,975	14,021	18,297	13,004	10,085	11,386	WP 4-98, ln 794 + WP 4-78, ln 119
10	2Q	Construct New Hydro Gen	(8)	-	-	-	-	-	-	-	-	-	
11	3H	Hydroelec Lic & Lic Conditions	16,100	17,094	16,713	16,077	16,169	22,394	21,586	26,986	40,971	47,143	WP 4-99, ln 810 + WP 4-79, ln 142
12	**Total**		**174,931**	**242,552**	**285,289**	**223,392**	**226,818**	**287,698**	**259,769**	**253,667**	**270,083**	**260,184**	Sum lns 1-11

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT A

PG&E'S GENERATION SYSTEM

PG&E's Generation System

PG&E GIS Group lxfr: G:\Projects\hydro_sys\ArcMap\poster_hydrofacil.mxd | 10/8/2013

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT B

HYDRO RISK MAPPING TO MWC

Chapter	MWC	Enterprise			Hydro												Switchyard				Other Work	
		(ENT4) Hydro System Safety – Dams	Records Management	Employee Safety	Hydro – General	(PG1) Public Access	(PG2) Material Release Into Water	(PG10) Pressure Integrity Systems	(PG11) Turbine Generation Systems	(PG12) Protection & Control Systems	(PG13) Balance of Plant	(PG14) Support Infrastructure	(PG15) In-Stream Flow Release Valve & Bypass	(CSEC1) Asset Security	(PROC10) Risk of Non-Compliance	(SS2) Transformers & Voltage Regulators	(SS5) Circuit Breakers & Switchgear	(SS7) Switches	(SS6) Grounding Systems	Hydro Other – Relicensing	Hydro Other Not Assigned
4	AB																					■
	AX	■				■		■		■		■										
	AY															■						■
	EP											■										
	ES						■															
	IG															■						
	KG		■	■	■	■			■		■	■		■		■		■		■		■
	KH				■			■	■	■	■	■	■			■	■					■
	KI	■			■							■										
	KJ	■								■	■	■				■						
	2L	■						■	■	■	■	■		■								
	2M				■			■	■	■	■	■					■	■	■			■
	2N	■				■		■		■		■										
	2P							■		■	■	■										
	3H															■					■	■
	11															■						
	12						■		■													
	AK				■		■									■						
	5				■																	

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

FOSSIL AND OTHER GENERATION OPERATIONS COSTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
FOSSIL AND OTHER GENERATION OPERATIONS COSTS

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
FOSSIL AND OTHER GENERATION OPERATIONS COSTS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
FOSSIL AND OTHER GENERATION OPERATIONS COSTS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
FOSSIL AND OTHER GENERATION OPERATIONS COSTS

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to demonstrate that Pacific Gas and Electric Company's (PG&E or the Company) forecast expense and capital expenditures to safely and reliably operate and maintain its Fossil, Photovoltaic (PV), and fuel cell generation facilities are reasonable and should be adopted by the California Public Utilities Commission (CPUC or Commission).

PG&E's fossil generation fleet consists of two combined cycle plants, the Gateway Generating Station (GGS or Gateway) and the Colusa Generating Station (CGS or Colusa), and the Humboldt Bay Generating Station (HBGS or Humboldt), which uses reciprocating engine technology. The two combined cycle facilities are among the most efficient gas-fired plants in the state, allowing for the displacement of older, less efficient plants and facilitating the integration of intermittent renewable resources. HBGS provides critical reliability support for the Eureka area. These three generating facilities have a combined maximum normal operating capacity of 1,400 megawatts (MW).

In addition, PG&E's generation fleet also includes 10 ground-mounted PV solar stations and two fuel cell generating facilities. The ground-mounted PV generating stations, which were approved as part of PG&E's Solar PV Program in Decision 10-05-052, have a combined operating capacity of 152 MW. In compliance with Ordering Paragraph (OP) 7 of Decision 10-05-052, PG&E has included in this exhibit a showing on the performance of the PV facilities. With output from these facilities exceeding 100 percent of expected output, PG&E has significantly exceeded the performance benchmark of 80 percent that was adopted by the Commission. PG&E's fuel cell facilities, which were approved in Decision 10-05-028, are the California State University (CSU) East Bay Fuel

Cell Facility and the San Francisco State University (SF State) Fuel Cell Facility. The fuel cell facilities have a combined capacity of 3 MW.

Finally, in this exhibit, PG&E requests that the Commission approve the decommissioning forecast described in Section C.5 of this chapter.

2. Summary of Request

a. Expense

PG&E requests that the Commission adopt its 2017 forecast of $65.0 million for operations and maintenance (O&M) expense.[1]

b. Capital

PG&E requests that the Commission adopt its capital expenditure forecast of $12.2 million for 2015, $21.7 million for 2016, $14.5 million for 2017, $3.0 million for 2018, and $4.7 million for 2019.[2]

c. Decommissioning

PG&E requests that the Commission authorize its updated decommissioning forecast of $75.0 million of remaining liability after January 1, 2017.[3]

3. Support for Request

PG&E's capital and expense forecasts for its fossil, PV and fuel cell generation operations are reasonable. These resources are an essential part of PG&E's resource portfolio and it is appropriate to adopt overall funding levels that are necessary to maintain and improve the reliability and performance of these generation assets.

These generation resources support California's aggressive environmental policy goals. In the *2014 Integrated Energy Policy Report* (IEPR), the California Energy Commission (CEC) stated that "the state's growth in renewable electricity is expected to be dominated by solar energy sources, which will result in surplus electricity for daytime consumption."[4]

---

1 See WP 5-1, Line 9, Exhibit (PG&E-5).

2 See WP 5-57, Line 12, Exhibit (PG&E-5).

3 See WP 5-83, Line 33, Exhibit (PG&E-5).

4 2014 IEPR, Chapter 6: Transportation Integration Trend with Electricity and Natural Gas Systems, Page 103 (http://www.energy.ca.gov/2014publications/CEC-100-2015-001/CEC-100-2015-001-CMF-small.pdf).

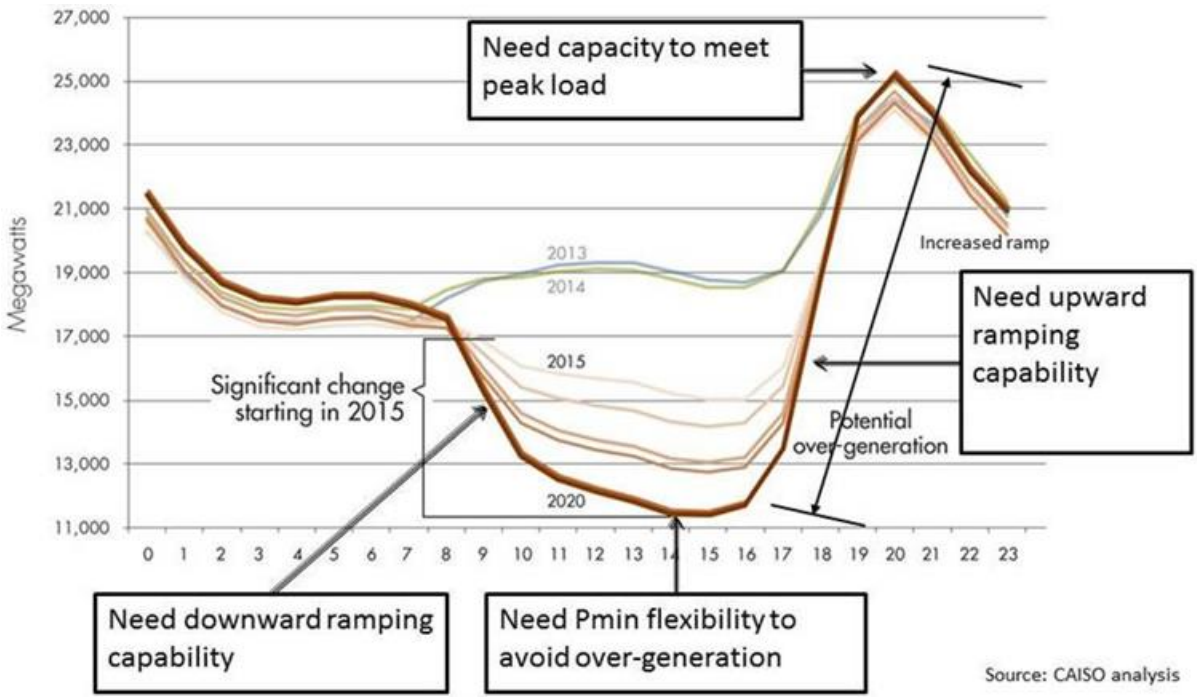
The 2014 IEPR also notes that "new natural gas power plants are increasingly deployed to fill gaps when intermittent renewable electricity is not available."[5] Intermittent and relatively flat demand coupled with these increases in solar and wind generation create a unique resource integration challenge that is growing in complexity each year as more and more renewable resources come on-line.

PG&E's fossil plants support the Renewables Portfolio Standard (RPS) goals by being operationally flexible and capable of providing a number of California Independent System Operator (CAISO) ancillary services to help integrate intermittent renewable resources, like solar and wind power, into the grid. With large amounts of solar and wind being added to the grid, PG&E has experienced greater operational demands on its highly-efficient combined cycle facilities and highly-flexible reciprocating engines. Colusa and Gateway have been called on more frequently to adjust schedules to ramp up and down to meet hourly fluctuations in electricity demand and off-set short-notice outages or curtailments at base load power plants. This is apparent in the below graph depicting the results of CAISO's analysis of the electric grid, which reflects the steep ramping needs, the overgeneration risk, and what ultimately is required to support the changing grid.

---

5 2014 IEPR, Chapter 6: Transportation Integration Trend with Electricity and Natural Gas Systems, Page 103 (http://www.energy.ca.gov/2014publications/CEC-100-2015-001/CEC-100-2015-001-CMF-small.pdf).

FIGURE 5-1
CAISO ELECTRIC GRID DUCK CURVE



The CAISO has stated that "to ensure reliability under changing grid conditions, the ISO needs resources with ramping flexibility and the ability to start and stop multiple times per day. To ensure supply and demand match at all times, controllable resources will need the flexibility to change output levels and start and stop as dictated by real-time grid conditions."[6]

The PV facilities are eligible renewable energy resources that help PG&E to achieve the state's RPS and are greenhouse gas (GHG) free sources of clean power. In order to improve the operational flexibility and responsiveness of its PV units, in 2014 PG&E added dispatch capability allowing for ramping capability on an hourly basis. This enabled PG&E to bid the PV units into the CAISO real-time and day ahead energy markets and respond when curtailed by the CAISO during periods of overgeneration or negative market prices. This flexible operation of the PV resources helps improve the efficiency and reliability of the energy markets, but it will also

6 http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

accelerate deterioration of the inverters, and may result in a lower capacity factor if market conditions require the units to be curtailed often.[7]

By investing prudently in the reliability and flexibility of PG&E's generation fleet, PG&E will continue to do its part to improve grid operating efficiencies and maintain system stability under changing market conditions.

The remaining sections in this chapter provide: (1) an overview of the recorded and forecast expense and capital costs for the 2017 General Rate Case (GRC); (2) an overview and the condition and management structure of the generation fleet; (3) key risks, risk mitigation and monitoring implemented by PG&E; and (4) key drivers and major areas of work that constitute the expense and capital forecast in the 2017 GRC.

B. Activities and Costs

1. Overview of Recorded and Forecast Costs

a. Expense

Table 5-1 summarizes the 2014 recorded O&M expenses and PG&E's forecasts for 2015-2017. Figure 5-2 provides this same information in a bar chart format.

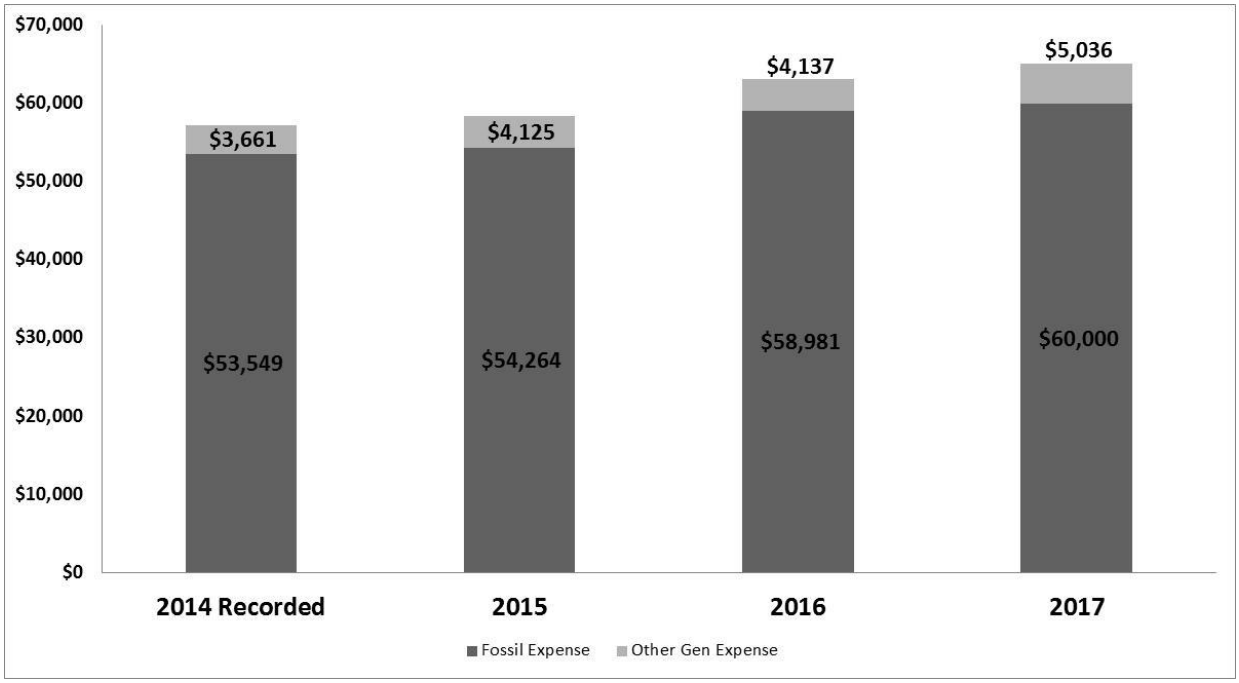
TABLE 5-1
FOSSIL AND OTHER GENERATION O&M EXPENSE 2015-2017
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	Fossil O&M Expense	$53,549	$54,264	$58,981	$60,000
2	Other Gen Expense	3,661	4,125	4,137	5,036
3	Total	$57,210	$58,389	$63,118	$65,036

Note: See WP 5-1, Line 9, Exhibit (PG&E-5). Includes separately funded PV maintenance costs.

[7] A lower capacity factor could preclude the PV units from achieving the expected output and performance threshold set forth in Decision 10-04-052, as further discussed in Section B.2.c.2., below.

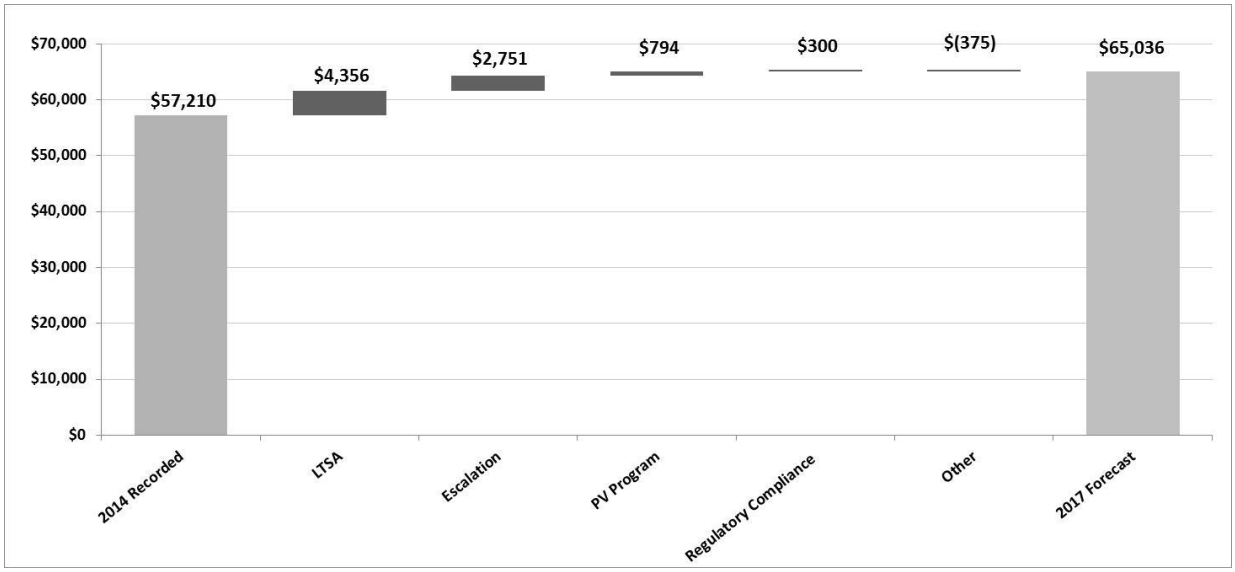
FIGURE 5-2
FOSSIL AND OTHER GENERATION O&M EXPENSE 2015-2017
(THOUSANDS OF NOMINAL DOLLARS)



Note: See WP 5-1, Lines 1-8, Exhibit (PG&E-5).

The forecast for 2017 expense is $65.0 million. As shown in Figure 5-2, PG&E is seeking an increase of $7.8 million as compared to 2014 recorded spending levels. Figure 5-3 provides an expense walk that depicts the key drivers for the difference in the 2017 forecast versus 2014 recorded. Each key driver is summarized below and additional information has been provided in Section C: Activities and Costs by Major Work Category (MWC).

FIGURE 5-3
FOSSIL AND OTHER GENERATION O&M EXPENSE WALK 2015-2017
(THOUSANDS OF NOMINAL DOLLARS)



Note: See WP 5-56, Lines 1-7, Exhibit (PG&E-5).

1) Long Term Service Agreements

In 2017, LTSA costs are forecast to increase by approximately $4.4 million due to: (1) contractually required annual escalation adjustments; (2) an increase in the applicable use tax; (3) an increase in the quarterly variable payment forecast; and (4) inclusion in the forecast of other LTSA-related obligations.

2) Escalation

Escalation of O&M costs accounted for $2.75 million of the $7.8 million increase from 2014 recorded to 2017 forecast. The base recorded labor and non-labor costs for 2014 were escalated consistent with the escalation rates specified in Exhibit (PG&E-12), Chapter 3.

3) PV Program Maintenance

The warranties that were in effect in 2014 will begin to expire in 2016 and will be fully expired in 2018, resulting in a forecast increase of about $0.8 million in PV program maintenance costs.

4) Regulatory Compliance Costs

Regulatory compliance costs are expected to increase by $0.3 million from 2014 recorded to 2017 forecast. GHG emission fees and waste treatment costs are expected to increase by about $0.22 million by 2017 largely due to a projected increase of approximately nine cents per Metric Ton for GGS, CGS and HBGS per year through the GRC period. An increase in environmental coordinator labor costs of $0.08 million is also required since 2014 recorded costs reflect an extended of leave of absence.

5) Other

One time reductions in expenditures that occurred in 2014 that will not re-occur in 2015 and expense project decreases. Additionally, there is a total increase in the cost for weed abatement and grounds keeping costs at the ten solar PV sites as a result of an increase in contracting costs.

b. Capital

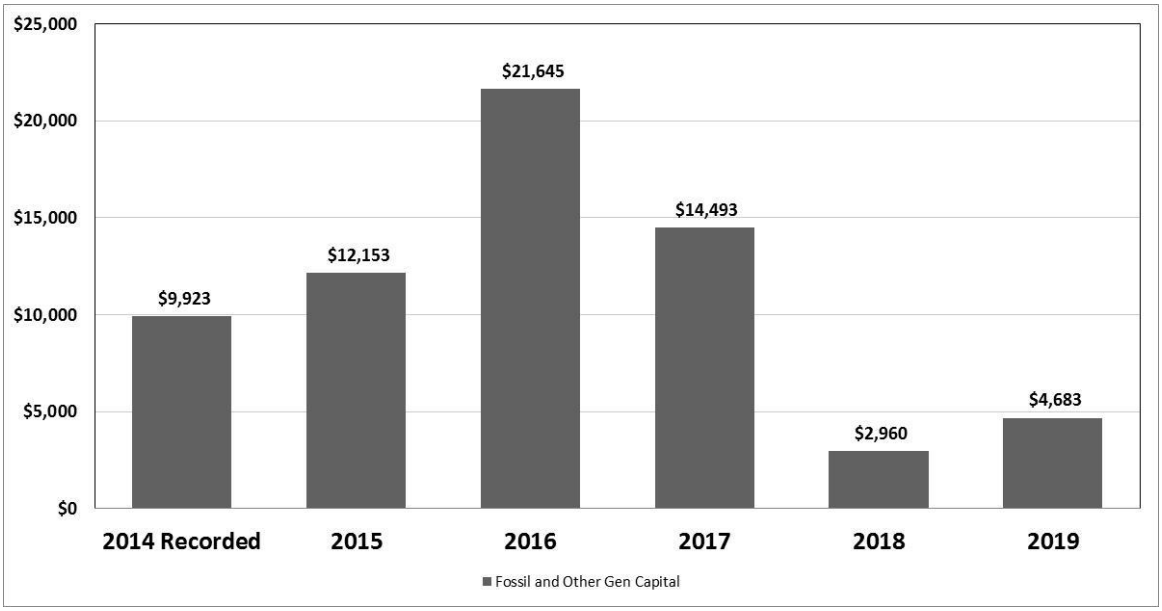
Table 5-2 below provides the 2014 recorded capital expenditures and PG&E's capital forecasts for 2015-2019. Figure 5-3 provides this same information in a bar chart format.

TABLE 5-2
FOSSIL AND OTHER GENERATION CAPITAL EXPENDITURES 2015-2019
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	Fossil and Other Gen Capital Expenditures	$9,923	$12,153	$21,645	$14,493	$2,960	$4,683

Note: See WP 5-57, Line 12, Exhibit (PG&E-5).

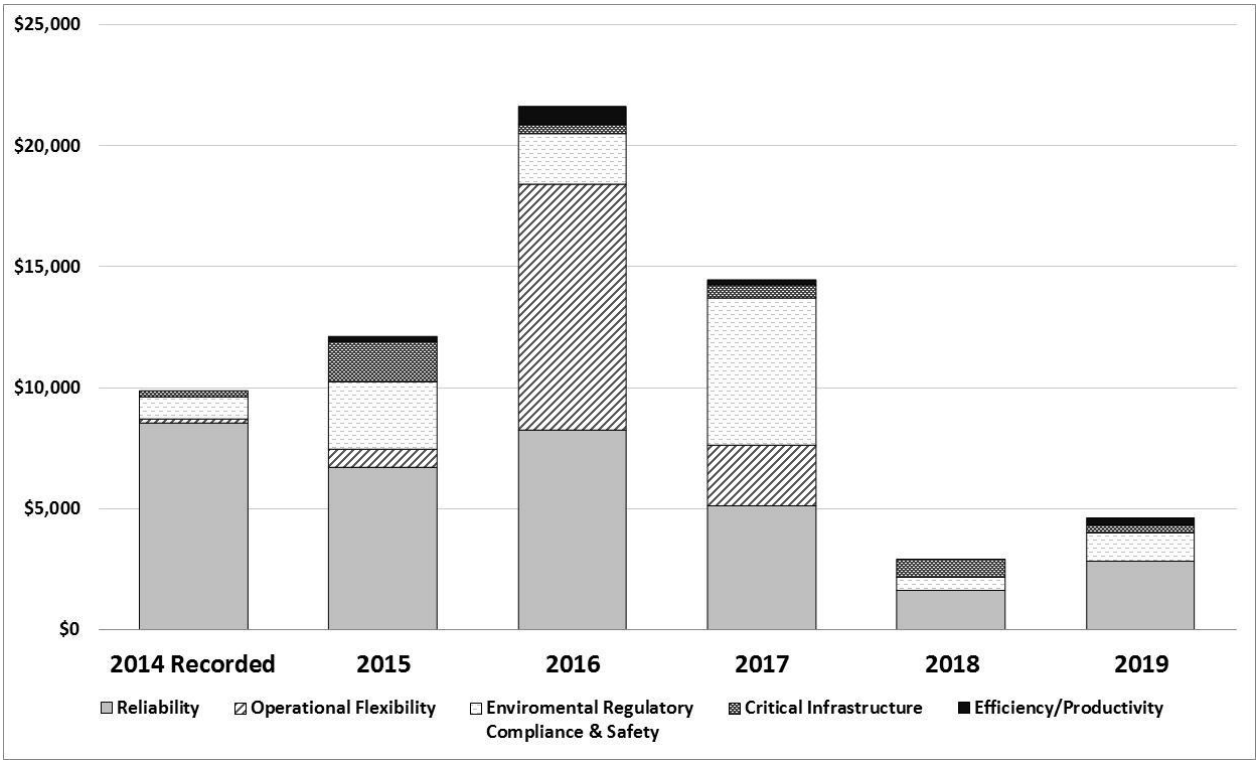
FIGURE 5-4
FOSSIL AND OTHER GENERATION CAPITAL EXPENDITURES 2015-2019
(THOUSANDS OF NOMINAL DOLLARS)



Note: See WP 5-57, Line 12, Exhibit (PG&E-5).

As shown in Figure 5-4 above, year to year capital expenditures vary widely primarily due to a number of large, one-time projects at PG&E's fossil facilities. These projects, which are discussed in more detail below, are prioritized and planned based on PG&E's risk and budget prioritization processes.

FIGURE 5-5
FOSSIL AND OTHER GENERATION CAPITAL EXPENDITURES – MAJOR PROJECTS
(THOUSANDS OF NOMINAL DOLLARS)



Note: See WP 5-77, Lines 1-7, Exhibit (PG&E-5).

As shown in Figure 5-5, PG&E's forecast consists of a number of capital projects that are necessary to maintain reliability, improve operational flexibility, environmental regulatory compliance and safety, and address critical infrastructure improvements at PG&E's fossil generating facilities. The key projects are listed below:

1) Reliability: Life Cycle Replacement/Single Point of Failure

PG&E has identified equipment replacements and upgrades that are required due to the age and run-time of the plants identified through periodic testing, condition assessments, operating and maintenance history, and/or equipment manufacturer issues. Examples of projects in this category include:

- GGS Steam Turbine-Generator (STG) Generator Rewind;
- CGS Generator Breakers; and
- GGS Rewind/Replace Combustion Turbine (CT)-A Generator

PG&E has also identified equipment that would cause extended forced outage time of the plant if the equipment were to fail. These projects aim to provide additional capacity, redundancy, or newer technology to remove these potential failure points from the various systems in the plant. Examples of projects in this category include:

- CGS Combustion Turbine (CT) Bushing Replacement;
- HBGS Spare Transformer; and
- CGS New Boiler Feed Pumps (BFP)

2) Operational Flexibility

PG&E has identified system technology and control enhancements to achieve new operating profiles desired by CAISO which will result in economic payback through reduction in start-up time, decreased fuel consumption, and/or decreased emissions. Examples of projects in this category include:

- CGS/GGS Op Flex Ready/Steam Turbine Blankets;
- CGS/GGS Op Flex Balance/Advantage;
- CGS/GGS Op Flex Reserve (Turndown);
- CGS Water Treatment Enhancements; and
- CGS Vacuum Pumps

3) Environmental Regulatory Compliance and Safety

These projects are necessary to address specific risks identified by the O&M staff and include:

- CGS/GGS NOx Catalyst Replacements;
- HBGS Engine 1 Selective Catalytic Reduction (SCR) Module Replacement; and
- CGS Air Cooled Condenser (ACC) Fan Blade Replacement

4) Critical Infrastructure

These projects are necessary to address critical infrastructure improvements identified by the O&M staff. An example of projects in this category includes the CGS Replace Canal Bridge Replacement.

2. Program Description

This section describes the Fossil and Other Generation Operations Program, including description and current condition on PG&E's Gateway, Colusa, Humboldt, and PV and fuel cell generating facilities. Additionally, this section includes the key areas of risks and risk monitoring and mitigation employed by PG&E.

a. Assets

1) Gateway Generating Station

FIGURE 5-6
GATEWAY GENERATING STATION

Gateway is a 530 MW combined cycle power plant that achieved commercial operational in January 2009. The plant consists of two General Electric (GE) Frame 7FA CT generators, each with its own Vogt-NEM heat recovery steam generator (HRSG), and a single GE steam turbine-generator (STG). In this standard 2 × 1 configuration, each CT generates power and exhausts directly into its own HRSG where the exhaust heat is captured and generates steam for use in the ST. The exhaust steam leaves the turbine and is condensed for reuse in an ACC. Air

emissions are controlled through the use of Dry Low NO_x combustion coupled with a selective catalytic reduction (SCR) system. For each HRSG, two catalyst systems are used to reduce NO_x, carbon monoxide (CO), and Volatile Organic Compound (VOC) production. Additionally, GGS is equipped with capacity enhancing technology to improve output during peak generation periods, this technology consists of duct burners to increase steam production in the HRSGs resulting in increased steam turbine (ST) output. The duct burners allow GGS to increase its output by approximately 50 MW.

PG&E entered into a LTSA with GE on December 12, 2008. The LTSA provides for the maintenance of the CTs and ST at GGS.

2) Colusa Generating Station

FIGURE 5-7
COLUSA GENERATING STATION

Colusa is a 530 MW combined cycle power plant that achieved commercial operational in December 2010. The plant consists of two GE Frame 7FA CTs, each with its own HRSG, and a single GE ST. In this standard 2 × 1 configuration, each CT generates power and exhausts directly into its own HRSG where the exhaust heat is captured and generates steam for use in the ST. The exhaust steam leaves the turbine and is condensed for reuse in an ACC. Air emissions are controlled through the use of Dry Low NO_x combustion coupled with a SCR system. For each HRSG, catalysts are used to reduce NO_x, and VOC production. Additionally, CGS is equipped with capacity enhancing technology to improve output during peak generation periods, this technology includes duct burners to increase steam production in the HRSGs resulting in increased ST output. The duct burners allow CGS to increase its output by approximately 127 MW.

PG&E entered into an LTSA with GE on December 16, 2008. The LTSA provides for the maintenance of the CTs and ST at CGS.

3) Humboldt Bay Generating Station

FIGURE 5-8
HUMBOLDT BAY GENERATING STATION

Humboldt replaced the old Humboldt Bay Power Plant (HBPP) that had been operating since 1956 and was retired in 2010. HBGS achieved commercial operations in September 2010.[8]

HBGS is a 163 MW reciprocating engine power plant consisting of 10 Wartsila 18V50 DF natural gas fired reciprocating engines. Each engine has 18 cylinders, each with a bore of 50 centimeters, and operates at 514 revolutions per minute. Each engine is designed to run on natural gas with 1 percent of total fuel input provided by low sulfur distillate as the pilot fuel. The engines are also designed with the capability to run on low sulfur distillate or biofuel. Each engine is equipped with a separate independent closed loop cooling system. Emission control is accomplished through the use of SCR.

---

8 Unit 3 achieved commercial operations in March 2011 due to a generator failure that was covered by the original equipment manufacturer's warranty.

HBGS generators are critical for Humboldt area reliability. During high customer natural gas demand or unavailability of the gas transmission line feeding the Humboldt area, HBGS natural gas use is curtailed requiring the facility to transfer to distillate fuel to generate electricity and support local reliability. Likewise, during high customer electrical demand or unavailability of electric transmission import capability feeding the Humboldt area, the highly flexible HBGS is available to support the Humboldt area electrical needs (electrical demand and voltage support).

4) PV Generating Facilities

PG&E's 10 ground-mounted PV solar stations consist of Vaca Dixon, Giffen, Westside, Five Points, Stroud, Huron, Cantua, Gates, West Gates, and Guernsey solar stations. PG&E also owns three small PV generation facilities in San Francisco.

a) Vaca Dixon Solar Station

FIGURE 5-9
VACA DIXON SOLAR STATION

Vaca Dixon Solar Station (VDSS) is a 2 MW PV solar station located in Vacaville, California, on a 16 acre site that entered commercial operations in December 2009. The solar station includes 9,672 solar modules that provide direct current (DC) energy; five inverters that convert the DC energy to alternating current (AC); one transformer that increases the voltage from 480 volts (V) to 12.47 kilovolts (kV); and other equipment such as a communications enclosure, two weather stations, and switchgear.

b) Five Points, Stroud, Westside, Huron, Cantua, Giffen, Gates, West Gate, and Guernsey Solar Stations

FIGURE 5-10
STROUD SOLAR STATION

Five Points Solar Station is a 15 MW PV solar station located near Five Points, California that entered commercial operations in September 2011. The solar station includes over 75,000 solar modules that provide DC energy; 24 inverters that convert the DC energy to AC; 12 transformers that increase the

voltage from 320 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and switchgear.

Stroud Solar Station is a 20 MW PV solar station located near Helm, California that entered commercial operations in September 2011. The solar station includes 88,000 solar modules that provide DC energy; 40 inverters that convert the DC energy to AC; 20 transformers that increase the voltage from 440 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and switchgear.

Westside Solar Station is a 15 MW PV solar station located near Five Points, California that entered commercial operations in August 2011. The solar station includes over 66,000 solar modules that provide DC energy; 30 inverters that convert the DC energy to AC; 15 transformers that increase the voltage from 440 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and switchgear.

Huron Solar Station is a 20 MW PV solar station located near Huron, California that entered commercial operations in August 2012. The solar station includes over 90,000 solar modules that provide DC energy; 40 inverters that convert the DC energy to AC; 10 transformers that increase the voltage from 420 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and switchgear.

Cantua Solar Station is a 20 MW PV solar station located near Cantua Creek, California that entered commercial operations in July 2012. The solar station includes approximately 110,000 solar modules that provide DC energy; 32 inverters that convert the DC energy to AC; 16 transformers that increase the voltage from 320 V to 12.47 kV; and other

equipment such as a communications enclosure, two weather stations, and switchgear.

Giffen Solar Station is a 10 MW PV solar station located near Cantua Creek, California that entered commercial operations in July 2012. The solar station includes close to 55,000 solar modules that provide DC energy; 16 inverters that convert the DC energy to AC; eight transformers that increase the voltage from 320 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and switchgear.

Gates Solar Station a 20 MW PV solar station located on a 120 acre site, adjacent to the Huron Solar Station near Huron, California that entered commercial operation in 2013. The solar station includes 91,490 solar modules that provide DC energy; 28 inverters that convert the DC energy to AC; 31 transformers that increase the voltage from 420 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and switchgear.

West Gate Solar Station. West Gates Solar Station is a 10 MW PV solar station located on a 60 acre site, near Huron, California that entered commercial operation in 2013. The solar station includes over 45,752 solar modules that provide DC energy; 14 inverters that convert the DC energy to AC; 14 transformers that increase the voltage from 420 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and switchgear.

Guernsey Solar Station is a 20 MW PV solar station located on a 120 acre site, near Hanford, California that entered commercial operation in 2013. The solar station includes 89,400 solar modules that provide DC energy; 20 inverters that convert the DC energy to AC; 27 transformers that increase the voltage from 420 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and switchgear.

In 2014, PG&E installed a centralized monitoring and control system for the nine solar generating stations. This system included the addition of a system control and data acquisition monitoring station at Caruthers. This system provides real-time voltage regulation, CAISO ability to curtail the output of the solar stations when required, ramp-rate controls, frequency control, and start-up and shut-down control. This system allows the PV sites to behave more like conventional generators but with increased dispatch and curtailment capabilities to meet the flexibility requirements of the grid.

c) San Francisco PV Generating Facilities

PG&E owns three small PV facilities that are located in San Francisco, at AT&T Park and near PG&E's San Francisco Service Center. They were put into service in 2007 and were approved as rate base additions in PG&E's 2014 GRC. PG&E's AT&T Park PV Facility is rated at 110 kilowatts (kW) AC. PG&E's Harrison Street PV Facility in San Francisco includes three roof-mounted PV generation systems which provide up to 70 kW AC. PG&E's Folsom Street PV Facility in San Francisco consists of 24 tracker arrays with 24 PV modules rated at 215 watts per array. This system is rated at 114 kW AC.

5) Fuel Cells

PG&E's fuel cell generating facilities consist of two fuel cell facilities located at SF State and CSU East Bay.

FIGURE 5-11
SF STATE FCE FUEL CELL

FIGURE 5-12
SF STATE BLOOM FUEL CELL

FIGURE 5-13
CSU EAST BAY FUEL CELL

The three fuel cell generating facilities have a total capacity of 3.0 MW and are located at two CSU campuses—CSU East Bay and SF State. Two of the fuel cells are located at SF State, namely a 1.4 MW molten carbonate fuel cell and a 200 kW solid oxide fuel cell. One molten carbonate fuel cell is also located at CSU East Bay. The molten carbonate fuel cells, manufactured by Fuel Cell Energy (FCE), provide electricity to PG&E's electrical grid and waste heat for the universities' use. The 200 kW solid oxide fuel cell, manufactured by Bloom Energy, also provides electricity to PG&E's electrical grid while utilizing any waste heat internally to improve fuel cell efficiency.

PG&E has entered into an O&M Agreement with the fuel cell manufacturers for the majority of the fuel cell maintenance needs. The three fuel cell generating facilities achieved commercial operations in September 2011.

b. Risk Management

Chapter 2 of this exhibit describes how Electric Operations is using the Enterprise and Operational Risk Management (EORM) Program to manage electric system risks. A foundational element of the EORM Program is the EO Risk Register which includes enterprise risks, asset

risks and process risks. This section explains how fossil-specific risks (both asset and process risks) are identified and mitigated.

The remainder of this section is organized as follows:

- Risk Identification: Identifies the risks from the EO Risk Register that align with activities and expenditures included in this chapter and outlines the MWCs for capital and expense that correspond with these risks.
- Controls/Mitigations and MWC for Risk Register Mapping: Describes controls that in place or are being proposed for this GRC to mitigate these risks.
- Risk-Informed Budget Allocation (RIBA): Discusses how the projects in this chapter are scored in the RIBA process.

1) Risk Identification

Table 5-3 lists the items from the EO Risk Register that align with the work activities and expenditures this chapter covers.

TABLE 5-3
FOSSIL AND OTHER GENERATION ASSET AND PROCESS RISKS

Line No.	Station	EO Risk Designation	Risk Score
1	Failure of Generation Facility (Catastrophic)	PG3	189
2	Fossil High Energy Systems	PG4	33
3	Fossil Turbine – Generation Systems	PG5	98
4	Fossil Protection and Control Systems	PG6	27
5	Fossil Balance of Plant	PG7	23
6	Fossil Chemical Systems	PG8	98
7	Fossil Fuel Systems	PG9	103
8	Fuel Cell Systems	PG16	18
9	Photovoltaic Systems	PG17	18
10	Fossil Risks – General	NA	NA

2) Controls/Mitigation and MWC to Risk Register Mapping

Risk mitigation occurs through various controls such as contracted maintenance services, reliability projects, work management system, environmental services, process/procedures, and condition assessment/monitoring programs.

a) Contracted Maintenance Services (MWCs KL, KR)

- Contracted services such as the LTSAs with GE that provide the necessary preventive maintenance on the CTs and STs at GGS and CGS.
- PV equipment maintenance covered before and after the manufacturer warranties begin to expire in 2016.
- O&M Agreement with the fuel cell manufacturers for the majority of the fuel cell maintenance needs.

Contracted maintenance services are applicable to the following risks from Table 5-3: Fossil Turbine – Generation Systems, Fuel Cell Systems, and Photovoltaic Systems.

b) Reliability Projects (MWC 2S)

Proactive identification of reliability projects to install and/or replace equipment that addresses potential failure points in the plant systems are critical for maintaining reliability of the various systems and mitigating these risks. PG&E uses single point of failure analyses, life cycle assessments, routine/periodic testing, and industry benchmarking to identify these critical projects. Examples of projects included in the GRC forecast include:

- Installation of new BFP at CGS to avoid potential plant de-ratings in the event of a pump failure.
- Life cycle replacement of the ST generator rewind at GGS which prevent failures to the ST generator.
- Replacement of CGS and GGS NO_x Catalysts which prevent failure of the Protection and Control Systems.

This type of work is generally applicable to Fossil Turbine – Generation Systems, Fossil Protection and Control Systems, Fossil Chemical Systems, and Fossil Balance of Plant.

c) SAP Work Management (MWC KL, KR, KK, KQ)

PG&E uses Systems Applications and Products Work Management System (SAP WMS) to efficiently inspect, maintain, and repair plant equipment to mitigate risk. For Fossil and Other Generation, the primary system users are O&M

personnel and the Power Generation Safety, Quality and Standards group. The tool is used to manage the following:

- Routine recurring maintenance work
- Corrective work on equipment and facilities
- Engineering and Asset Management corrective work
- Equipment related corrective actions emanating from Corrective Action Program (CAP) analysis
- Compliance activities

This type of work is applicable to most of the generation asset and process risks in Table 5-3.

d) Process and Procedures (MWC KL, KR, KK, KQ)

Guidance documents outlining various processes, standards and procedures such as PG&E Policy, PG&E Utility Standard Practices, PG&E Utility Procedures, and Power Generation-specific standards, procedures, and bulletins.

- Operations reviews that assure PG&E's generation facilities are operated in a safe and efficient manner and that they are in compliance with standard operating and clearance procedures.
- An incident reporting process that documents problems, activities and events that effect or could potentially effect the performance of systems that assure public and facility safety, reliability, availability, protection of property, and/or environmental or regulatory compliance.
- A corrective action program that documents and tracks corrective actions and commitments.
- An outage planning and scheduling process.
- A work management process that controls maintenance work.
- A project management process that controls project work.
- A design change process for proposing, evaluating, and implementing changes to the design of structures, systems, and equipment.

This type of work is applicable to most of the generation asset and process risks in Table 5-3.

e) Monitoring/Assessment Programs

PG&E has implemented various monitoring and condition assessment programs to mitigate risks.

- **The Piping Integrity Program:** This program is an enhancement to the High Energy Piping Program PG&E implemented at GGS and CGS. It includes the measurement and tracking of hot and cold pipe hanger settings, inspection of operating records for temperature transients, non-destructive examination of critical welds and supports, detection of flow accelerated corrosion, review and inspection of steam trap and drain systems to ensure proper operation. Inspections are focused on the highest risk areas such as the following systems at GGS and CGS: main steam; hot and cold reheat steam; low-pressure steam; auxiliary steam; boiler feed-water; and the condensate system. This project benefits public and employee safety. General Order (GO) 167 maintenance standards require that equipment performance and material condition support reliable plant performance by using a strategy that includes methods to anticipate, prevent, identify, and promptly resolve equipment performance problems and degradation. This program helps assure that contractor and employee safety is maintained and that piping and equipment degradation is appropriately managed at PG&E's fossil fuel power plants.
- **The Machinery Assessment Program:** This program is a combination of predictive diagnostic software and ongoing services that are designed to help avoid unplanned equipment failure. This program helps detect problems before they grow large or catastrophic. Existing data and infrastructure is leveraged to provide early and actionable warnings of impending equipment and process problems—

thus allowing the workforce to focus on fixing problems, not looking for them. This program allows the plant engineers to be more efficient.

- **Material Traceability Program:** This program is a multi-year effort to trace the location and specifications of material used in the construction and the operation or maintenance of the fossil fueled plants throughout their life cycle, from requisition, manufacturing to retirement. This is an ongoing program that will support the Document Storage Program.
- **Corrective Action Program:** This program provides PG&E employees with a process to identify and document issues. The issues are assessed for risk and evaluated. Any resulting corrective and preventive actions are tracked to completion. Additionally, the CAP conducts Root Cause Analyses (RCA) for certain plant equipment failure/ misoperation that cause a forced outage where the root cause is either: (1) not immediately apparent; and/or (2) there are multiple contributing factors requiring dedicated/specialized engineering to conduct a comprehensive investigation. From these analyses, PG&E is able to promptly address plant issues that could otherwise result in future equipment failures in the plant and/or other plants. It also allows PG&E to calibrate/adjust internal controls to reduce future equipment failures, in general.

This type of work is generally applicable to Fossil High Energy Systems, Fossil Risks – General, and Fossil Balance of Plant.

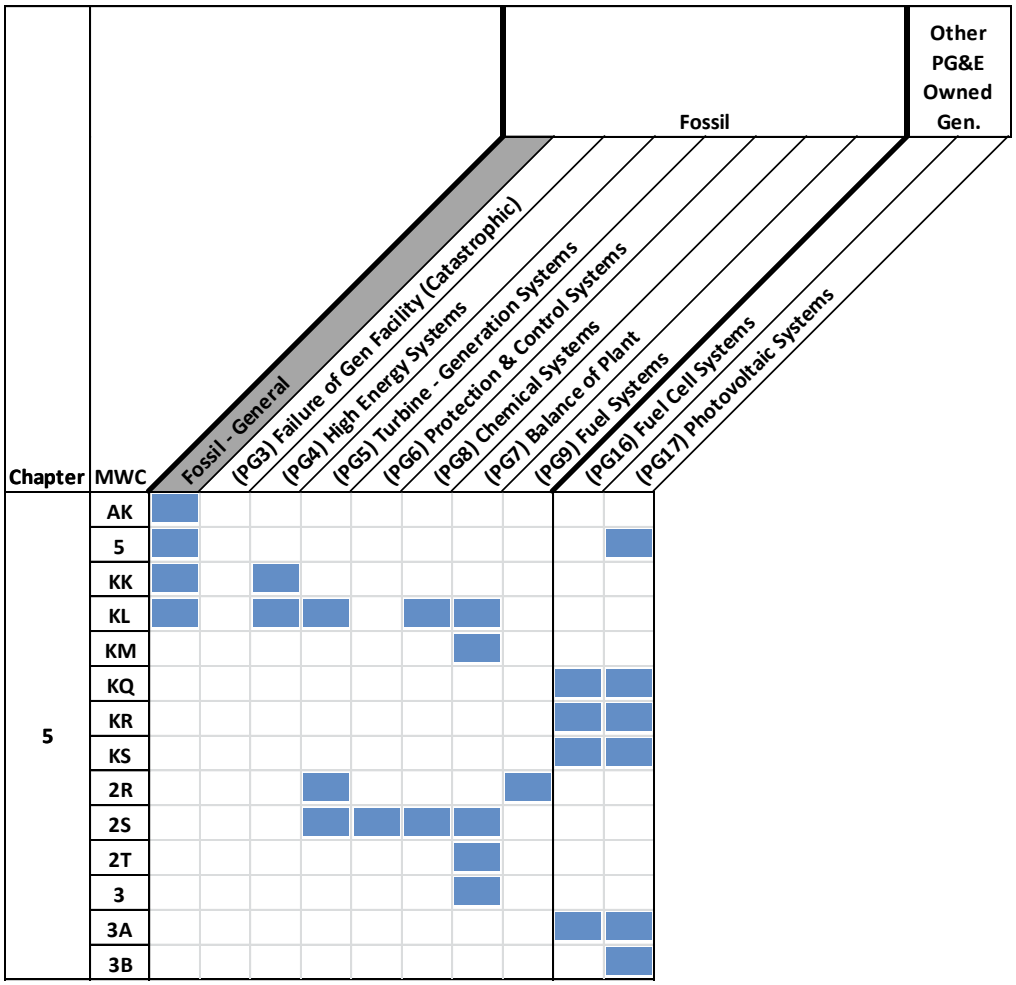
f) Environmental Support Services (MWC AK)

PG&E has dedicated full-time environmental consultants located at each of the fossil plants to address regulatory compliance at CGS, GGS, and HBGS.

Now that risks and associated controls and mitigations have been identified, Figure 5-14 provides an overview of the

mapping of the 2017 Expense and Capital Forecasts to the Fossil Risks on the EO Risk Register by MWC.

FIGURE 5-14
2017 EXPENSE AND CAPITAL FORECAST MAPPING BY MWC TO FOSSIL RISKS ON EO RISK REGISTER



3) Risk-Informed Budget Allocation

All expense and capital line items in this chapter were scored using the RIBA process as described in Exhibit (PG&E-2), Chapter 4.

As mentioned above, projects are a critical type of risk mitigation activity for PG&E's Fossil plants, and PG&E executes numerous projects each year. Each project is scored to represent the risk to safety, the environment and reliability of not executing the

project. These scores are then used by management (along with other key data) to prioritize proposed work.

c. Management Structure

1) Organization and Staffing

Fossil Operations, a part of Power Generation, was formed in 2010 as PG&E expanded its PG&E-owned fossil portfolio. This organization is responsible for managing PG&E's fossil, PV and fuel cell generating assets to provide safe, reliable, affordable, and environmentally responsible generation. The vast majority of the fossil portion of the O&M organization is located at the three generating stations.

The fossil and other generation operations function is overseen by one director. An organizational chart is included in the workpapers.[9]

a) Fossil and Other Generation Operations Staff

1. **Gateway Generating Station** – GGS staffing includes a total of 21 full-time employees. The staff consists of one senior plant manager, one operations supervisor, one maintenance supervisor, one power plant assistant, and 17 power plant technicians (PPT). The GGS plant engineer, not included in the staffing number above, is in the Power Generation Safety, Quality and Standards Department. The GGS environmental consultant, not included in the staffing number above, is in the Environmental Services Organization.
2. **Colusa Generating Station** – CGS staffing includes a total of 26 full-time employees. The staff consists of one senior plant manager, one maintenance supervisor, one operations supervisor, one maintenance planner, one power plant assistant, and 21 PPTs. The reason CGS has four more PPTs than GGS is that CGS has a zero liquid discharge

---

9 See WP 5-81 and WP 5-82, Exhibit (PG&E-5).

system that requires three additional PPTs for operations and one additional PPT for maintenance. The CGS plant engineer, not included in the staffing number above, is in the Power Generation Safety, Quality and Standards Department. The CGS environmental consultant, not included in the staffing number above, is in the Environmental Services organization.

3. **Humboldt Bay Generating Station** – HBGS staffing includes a total of 17 full-time employees. The staff consists of one plant manager, one O&M supervisor, one power plant assistant, two lead PPTs, and 12 PPTs. The HBGS plant engineer, not included in the staffing number above, is in the Power Generation Safety, Quality and Standards Department. The HBGS environmental consultant, not included in the staffing number above, is in the Environmental Services organization.

4. **PV and Fuel Cell Generating Facilities** – One generation supervisor, located in the Fresno area, supervises five solar technicians who maintain all the PV stations and the fuel cells. The generation supervisor and four of these solar technicians are located in Carruthers. One solar technician headquartered in Concord maintains VDSS, the San Francisco PV sites, and the fuel cells.

b) Support Organizations and Contract Services

1. **Power Generation Centralized Organization** – Power Generation's centralized organization function provides oversight, direction, and support to ensure that critical resources, personnel and technical information and advice are available to support the operational needs. Power Generation centralized organizations that support fossil and other generation operations include the Safety, Quality and Standards team, Project Execution, and Planning. These organizations are discussed in Chapter 4 of this exhibit.

2. **Environmental Services Organization** – PG&E's Environmental Services organization also provides direct support to the fossil and other generation operations, with a focus on regulatory compliance. Environmental consultants are located at each of the fossil fuel generating stations and at or near the PV and fuel cell facilities to support the facility staff.
3. **Supply Chain Organization** – PG&E's Supply Chain organization delivers cost effective and valued supply chain services through strategic, diverse and sustainable business solutions.
4. **Contract Services** – PG&E uses contract services for much of its major maintenance work at its fossil, PV and fuel cell generating assets. For GGS and CGS, an LTSA for the CTs and STs is provided by GE, the original equipment manufacturer for the CTs and STs. For the PV sites, PG&E is responsible for the maintenance but contracts out certain work such as weed abatement, pest control, and module washing. For the fuel cells, PG&E has entered into an O&M Agreement with the original equipment manufacturers.

2) Key Metrics and Other Performance Measures

PG&E uses many metrics to assess its progress towards achieving its business priorities.

a) Safety

PG&E's top priority is public and employee safety and its goal is to safely operate and maintain its generation facilities.

Unlike electric and gas transmission and distribution systems that are located throughout PG&E's service territory, the fossil and other generation facilities are located on single sites. Thus, PG&E's safety efforts are focused on the safe operation of each facility at its respective site location. PG&E operates each of its fossil and other generation facilities in compliance with all local, state and federal permit and operating

requirements such as state and federal Occupational Safety and Health and GO 167. PG&E's metrics for this area include recordable Injury (RI), Lost Work Day (LWD) cases, and Motor Vehicle Incidents (MVI). PG&E's fossil and other generation facilities have maintained an exemplary safety record as can be seen in Table 5-4 below. Fossil and other generation has experienced only one RI in the past four years; no LWD cases in the past four years; and has never experienced a MVI.

TABLE 5-4
FOSSIL RECORDABLE INJURY, LWD CASES, MVIS RESULTS 2009-2014

		Recordable Injury		Lost Work Day Cases Motor Vehicle Incidents			Motor Vehicle Incidents			
Line No.	Year	Incidents	Rate	Incidents	Days Off	Rate	Incidents	Rate	Serious Incidents	Serious Rate
1	2014	1	1.353	0	0	0.000	0	0.000	0	0.000
2	2013	0	0.000	0	0	0.000	0	0.000	0	0.000
3	2012	0	0.000	0	0	0.000	0	0.000	NA	NA
4	2011	0	0.000	0	0	0.000	0	0.000	NA	NA
5	2010	2	2.092	2	4	2.092	0	0.000	NA	NA
6	2009	1	1.425	0	0	0.000	0	0.000	NA	NA

Note 1: Recordable Injury and Lost Work Day Case Rate are based on 200,000 man-hours worked.
Note 2: Motor Vehicle Incident Rates are based on 1,000,000 miles driven.

b) Reliability

PG&E's goal is to responsibly operate and maintain all generation facilities to ensure that these facilities can reliably generate electricity whenever needed to meet customer needs.

- **Fossil Facilities**

PG&E's reliability metrics for the fossil facilities include the equivalent availability factor (EAF) and forced outage factor (FOF). PG&E uses data from North American

Electric Reliability Corporation Generating Availability Data System (NERC-GADS) as a benchmark for performance.[10]

FOF is a ratio of the hours a unit is forced out of operation to the total hours in the operation period (i.e., month, year). The fossil portfolio average FOF over the 2012-2014 period was 1.90 percent, which exceeds the industry benchmark of 1.93 percent.[11]

In 2014, Colusa experienced a series of forced outages that were the result of equipment failures caused by original equipment manufacturers design and manufacturing issues.[12]

TABLE 5-5
FOSSIL PORTFOLIO FORCED OUTAGE FACTOR

Line No.	Station	2012 FOF (%)	2013 FOF (%)	2014 FOF (%)	Avg. FOF (%)
1	GGS	0.40	0.00	0.29	0.23
2	CGS	1.49	0.00	9.25	3.58
3	HBGS	0.44	0.83	0.54	0.61
4	Fossil Portfolio	0.88	0.11	4.20(a)	1.90
5	Benchmark				1.93

(a) 2014 Fossil Portfolio FOF is 0.22 percent excluding Colusa original equipment manufacturer design and manufacturing issues forced outages.

EAF is a ratio of the total amount of hours a unit is in operation less the planned and unplanned outage and curtailment hours to the total amount of hours in a given year. The fossil portfolio average EAF over the 2012-2014

10 The fossil portfolio industry benchmarks are from the NERC-GADS brochure titled "2009-2013 Generating Unit Statistical Brochure – All Units Reporting." The benchmarks are a capacity-weighted average of the combined cycle plants (CGS and GGS) and the reciprocating engine plant (HBGS). See WP 5-99 and WP 5-100, Exhibit (PG&E-5).

11 See WP 5-98, Line 6, Exhibit (PG&E-5).

12 This subject is addressed in PG&E's 2014 ERRA Compliance Application.

period was 91.5 percent. This EAF is significantly better than the industry benchmark of 87.3 percent.[13]

TABLE 5-6
FOSSIL PORTFOLIO EQUIVALENT AVAILABILITY FACTOR

Line No.	Station	2012 EAF (%)	2013 EAF (%)	2014 EAF (%)	Avg. EAF (%)
1	GGS	91.0	93.6	92.2	92.3
2	CGS	92.2	92.8	76.2	87.1
3	HBGS	95.4	95.4	94.9	95.2
4	Fossil Portfolio	92.1	93.5	87.8(a)	91.5
5	Benchmark				87.3

(a) 2014 Fossil Portfolio EAF is 96.3 percent excluding Colusa original equipment manufacturer design and manufacturing issues forced outages.

- **PV Facilities**

The metric for PG&E's PV facilities is expected generation compared to actual generation.

Decision 10-05-052 states the following:

> Pacific Gas and Electric Company is authorized to recover its actual operations and maintenance costs[14] in its General Rate Case subject to a reasonableness review. Should the average performance of Pacific Gas and Electric Company's Utility-owned generation systems fall below 80% of expected output as provided in its compliance filings, it will weigh heavily in favor of disallowing or refunding some of the operations and maintenance costs to ratepayers. In its filing for recovery of these costs, Pacific Gas and Electric Company shall consolidate all operations &

13 See WP 5-98, Line 3, Exhibit (PG&E-5).

14 PG&E has interpreted the phrase "actual operations and maintenance costs" in this OP to refer to recovery of the full forecast of such costs, rather than as a requirement to do a retroactive true-up of forecast O&M costs to actual recorded costs. This interpretation is based upon the narrative in Decision 10-04-052, which states: "PG&E shall file for recovery of its O&M costs for utility-owned generation (UOG) projects deployed pursuant to this program in its GRC, consistent with standard Commission practice, and subject to a reasonableness review." Decision 10-04-052 at 35. As illustrated by this GRC Application, the "standard Commission practice" for cost recovery of UOG O&M costs in a GRC is to recover in rates the approved forecast. This interpretation is also consistent with PG&E's PV Program Application and accompanying testimony in Application 09-02-019, which only sought to true up forecasted initial capital costs to actuals, and did not request a mechanism to true up O&M costs.

> maintenance costs incurred pursuant to this program and provide a specific breakdown of costs by activity area.[15]

In compliance with this decision, PG&E has included the recorded and forecast costs for its 10 ground-mounted PV solar stations in Table 5-7. PG&E's forecast for the maintenance of its nine utility owned PV facilities is $3.5 million or $1.5 million less than the Commission authorized in Decision 10-05-052.[16]

The work in MWC KQ includes the cost to operate the 10 ground-mounted PV solar stations. The work in MWC KR includes the cost to maintain the generation equipment at the 10 ground-mounted PV solar stations. This includes the cost of preventive maintenance and corrective maintenance associated with the generation equipment such as inverters and solar modules. The work in MWC KS includes the cost to maintain the buildings and grounds at the 10 ground-mounted PV solar stations. This includes the cost of pest control, weed abatement, building HVAC maintenance, and security.

PG&E has also included a comparison of the 2014 expected generation to the actual generation in Table 5-8. The PV stations significantly outperformed the 80 percent generation benchmark with a performance of 101.1 percent of expected generation.

---

15 Decision 10-05-052, Ordering Paragraph 7.

16 See WP 5-55, Line 82, Exhibit (PG&E-5) and WP 5-53, Line 15, Exhibit (PG&E-5).

TABLE 5-7
FOSSIL AND OTHER GENERATION
PHOTOVOLTAIC OPERATIONS AND MAINTENANCE COSTS 2012-2017
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2012 Recorded	2013 Recorded	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	KQ	Operate Alternative Generation	$141	$69	$362	$171	$450	$460
2	KR	Maintain Alternative Generation Equip	1,424	1,142	1,513	2,071	1,571	2,422
3	KM	Maintain Fossil Bldgs/Grnds/Infr.	198	575	364	477	580	592
4		Total	$1,763	$1,785	$2,239	$2,665	$2,600	$3,474

Note: See WP 5-55, Lines 79-82, Exhibit (PG&E-5).

TABLE 5-8
PV NET GENERATION IN MEGAWATT-HOURS (MWH) 2014

Line No.	Station	Net Generation (MWh)	Expected Net Generation (MWh)	Recorded – Expected Net Generation (MWh)
1	Total	336,537	332,852	3,685
2	% of Expected Generation			101.1%

Note: See WP 5-94, Lines 11-12, Exhibit (PG&E-5) and Decision 10-04-052, OP 7.

- **Fuel Cells**

The metrics for PG&E's fuel cells include availability, capacity factor, and efficiency.

Decision 10-05-028 approving PG&E's fuel cell projects requires PG&E to submit annual compliance reports that include for each project: annual capacity factor; system availability during system peak hours; annual fuel consumption; annual electrical output; annual thermal output; overall electrical efficiency for the year; overall system efficiency for the year; and any other information that would be useful in helping the CPUC's Energy Division assess the performance of the systems. PG&E reported to the Commission in its April 30, 2014 annual compliance

report that year 2014 fuel cell availability during system peak hours, annual capacity factor, and overall electrical efficiency (Lower Heating Value) was 94.7 percent, 74.6 percent, and 42.3 percent, respectively.

C. Activities and Costs by MWC

PG&E manages its fossil and other generation assets through a centralized program management process. PG&E allocates funds to address not only priority efforts and developing or emerging work, but also routine work and long-term needs. Program management assures consistency in budgeting and priorities across the generating assets. The expense and capital budgeting process requires each facility to develop annual plans to address labor, materials and contracts, using individual charge numbers or "Order Numbers"[17] for each activity, project, or scope of work. These order numbers are then rolled under PG&E defined groupings called MWCs. The use of MWCs standardizes cost groups that allow an evaluation of the planned expenditures against historic spending levels for similar projects and similar activities. The MWCs are also grouped under various functions like operations, maintenance, environmental, or capital projects.

Work at the fossil and other generating facilities is grouped under one of four categories: (1) operations; (2) maintenance; (3) environmental; and (4) capital projects. Annual plans vary based on one-time system or component upgrades resulting from changing state or federal regulations or needed inspections or repairs. The remainder of this section outlines the process used in the development of the annual expenditures and elaborates on the key drivers introduced in Section B to explain the year-to-year variations of those planned expenditures.

Fossil decommissioning projects and fuel oil inventory are also discussed in this section.

---

[17] Order Numbers are internal identification numbers and include sub-identifiers like Specific Orders and Standing Orders to allow PG&E facilities and personnel to budget and subsequently charge time and materials to specific accounts for tracking and trending expenditures.

1. Operations (MWCs KK and KQ)

The operations function includes activities such as the labor to operate the fossil, PV, and fuel cell facilities, and required clerical and engineering support. This function also includes site management as well as support services; materials such as chemicals and lube oil; and contracts associated with operating a safe and reliable plant. MWC KK (Operate Fossil Generation) is used by GGS, CGS and HBGS for planning and performing routine operations of the fossil units. MWC KQ (Operate Alternative Generation) is used by the PV and fuel cell generation facilities to plan and perform operations of the PV and fuel cell facilities. These MWCs do not include the cost of fuel.

a. MWC KK

The forecast for MWC KK, which is primarily labor costs, is based on the recorded 2014 costs with additions and reductions for specific purposes. The recorded 2014 costs were $15.9 million.

TABLE 5-9
MWC KK
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	KK	Operate Fossil Generation	$15,870	$15,402	$16,724	$17,134

The forecast for MWC KK is $15.4 million for 2015; $16.7 million for 2016; and $17.1 million for 2017.[18]

Escalation of O&M costs accounted for a majority of the increase from 2014 recorded to 2017 forecast. The base recorded labor and non-labor costs for 2014 were escalated consistent with the escalation rates specified in Exhibit (PG&E-12), Chapter 4.

b. MWC KQ

The forecast for MWC KQ is based on the recorded 2014 costs with additions and reductions for specific purposes. The recorded 2014 costs were $0.6 million.

---

18 See WP 5-1, Line 3, Exhibit (PG&E-5).

TABLE 5-10
MWC KQ
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	KQ	Operate Alternative Generation	$649	$457	$790	$802

The forecast for is $0.5 million for 2015; $0.8 million for 2016; and $0.8 million for 2017.[19]

Escalation of O&M costs accounted for a majority of the increase from 2014 recorded to 2017 forecast. The base recorded labor and non-labor costs for 2014 were escalated consistent with the escalation rates specified in Exhibit (PG&E-12), Chapter 4.

2. Maintenance (MWCs KL, KM, KR and KS)

The maintenance function is used to address activities such as the labor to maintain the fossil, PV, and fuel cell facilities as well as materials and required contracts such as the LTSAs and other maintenance and engineering services. MWC KL (Maintain Fossil Generating Equipment) is used by GGS, CGS and HBGS for planning and performing maintenance of the fossil generation facilities. MWC KM (Maintain Fossil Buildings, Grounds and Infrastructure) is used by GGS, CGS and HBGS for planning and performing maintenance of its common facilities. MWC KR (Maintain Alternative Generation Generating Equipment) is used by the PV and fuel cell facilities for planning and performing maintenance of the PV and fuel cell generation facilities. MWC KS (Maintain Alternative Generation Buildings, Grounds and Infrastructure) is used by the PV and fuel cell generation facilities for planning and performing maintenance of its common facilities.

a. MWC KL

The forecast for MWC KL, which is primarily contract costs, is based on the recorded 2014 costs with increases and decreases for specific purposes. The recorded 2014 costs were $32.3 million.

---

19 See WP 5-1, Line 6, Exhibit (PG&E-5).

TABLE 5-11
MWC KL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	KL	Maintain Fossil Generating Equipment	$32,267	$33,267	$36,314	$36,797

The forecast for MWC KL is $33.3 million for 2015; $36.3 million for 2016; and $36.8 million for 2017.[20] The forecast increase is primarily due to increased costs associated with the LTSAs and escalation. The base recorded labor and non-labor costs for 2014 were escalated consistent with the escalation rates specified in Exhibit (PG&E-12), Chapter 4. The forecast decreases is primarily driven by a reduction in one-time expenditures and project decreases.

1) Long Term Service Agreement for CGS and GGS

PG&E is forecasting a $4.4 million increase in LTSA costs from 2014-2017. PG&E's LTSA forecast includes cost adjustments in the following categories: (1) quarterly variable payments; (2) periodic milestone payments; (3) use taxes; and (4) other obligations.

The maintenance of the CTs and STs at GGS and CGS is a significant portion of the O&M costs. LTSAs are commonly used in the industry as a way to provide high reliability and efficiency for combined cycle power plants. The LTSAs provide an effective cost control measure for the major planned and unplanned maintenance activities at GGS and CGS. The LTSAs cover all the planned maintenance costs for the CTs and STs and include all inspections, maintenance, replacements and/or repairs due to wear and tear. GE performs planned maintenance inspections and repairs over the term of the LTSAs.

The variable payments are due quarterly and are calculated based upon the assumed operating profile of the plant. PG&E's forecast in this GRC assumes that the quarterly variable payments

[20] See WP 5-1, Line 4, Exhibit (PG&E-5).

each year will be consistent with the mean of the 2012-2014 recorded costs.

The periodic milestone payments include either a hot gas path milestone payment or major inspection milestone payment. Milestone payment amounts are specified in the LTSAs and are made six months prior to each hot gas path inspection and six months prior to each major inspection.

PG&E is responsible for paying a use tax for new CT and ST parts that are installed in the CTs and STs as part of the LTSA. PG&E has forecast the expected use tax based on an estimate provided by GE.

PG&E is also responsible for owner-furnished items/services required to support the hot gas path and major inspection outages that are not included in the scope of GE's work under the LTSAs. These are denoted as LTSA Other Obligations and include items such as scaffolding, crane rental, insulation removal and installation, instrumentation removal and installation, and materials.

PG&E's 2011 and 2014 GRC decisions approved PG&E's proposal to spread out the periodic LTSA costs such as the periodic milestone payments and use tax effectively levelize the cost stream over several years.

The primary drivers for the 2017 combined GGS and CGS $4.4 million ($1.8 million for GGS plus $2.5 million for CGS) increase in LTSA costs over recorded 2014 include: (1) increase in the quarterly variable payment forecast; (2) inclusion of LTSA other obligations in the LTSA forecast; (3) increase in milestone payments; and (4) increase in Use Tax.[21]

The current forecast in Quarterly Variable Payments (QVP) is higher in 2017 compared to 2014 recorded since PG&E used a 3-year average of recorded QVPs from 2012-2014 to forecast 2017. Understanding the assumed operating profile of the plants, using a historical 3-year average is a prudent approach for estimating the

[21] See WP 5-43, Line 51, Exhibit (PG&E-5).

expected future QVPs. Since CGS did not go into operation until late 2010, PG&E used the last recorded year (2011) in the 2014 GRC to forecast the QVPs. At that time, due to the minimal historical data there was less of an ability to accurately forecast the QVPs. Now, PG&E has four full years of operating experience with both GGS and CGS, it is prudent to use a three year average to arrive at a more accurate forecast for the QVPs. This results in an increase in the 2017 forecast costs for the LTSA above 2014 recorded by $1.5 million.[22]

The LTSA other obligation costs are lumpy in nature since they occur each time GGS or CGS experiences a hot gas path or major inspection. It is reasonable to spread out or normalize these costs consistent with the previously Commission approved method of spreading out or normalizing the hot gas path or major inspection milestone and use tax costs. This results in an increase in the 2017 forecast costs for the LTSA above 2014 recorded by $1.4 million.[23]

The current forecast in milestone payments as a result of an increase in escalation rates has resulted in an increase in the 2017 forecast costs for the LTSA costs above 2014 recorded of $1.0 million.[24] The escalation rates to be used in the LTSA are specified in the LTSA. PG&E used Global Insights for its forecast escalation rates and chose the indices that most closely matched the LTSA specified indices.

Finally, the forecast use tax is $0.4 million higher in 2017 compared to 2014 recorded.[25] This is primarily due to an increase in the forecast of CT parts replacement for the CGS 2019 major inspection.

It is possible that a milestone payment may become due earlier than PG&E forecast if, for example, a power plant is dispatched

---

[22] See WP 5-43, Line 47, Exhibit (PG&E-5).

[23] See WP 5-43, Line 49, Exhibit (PG&E-5).

[24] See WP 5-43, Line 48, Exhibit (PG&E-5).

[25] See WP 5-43, Line 50, Exhibit (PG&E-5).

more frequently than anticipated. As PG&E and the CAISO work to manage the increasingly complex challenge of balancing the system to address intermittent renewable resources, PG&E expects that fast ramping, efficient resources like PG&E's GGS and CGS may be called on more frequently. To the extent a milestone payment is accelerated, PG&E requests that the Commission authorize PG&E to adjust on a prospective basis the schedule for amortization of milestone payments so that PG&E can true up its recovery of milestone payments in the next GRC.

2) Other

One time reductions in expenditures that occurred in 2014 that will not re-occur in 2015 and expense project decreases accounted for a $0.9 million decrease from 2014 recorded to 2017 forecast.

b. MWC KM

The forecast for MWC KM, which is primarily contract costs, is based on the recorded 2014 costs with increases and decreases for specific purposes. The recorded 2014 costs were $2.6 million.

TABLE 5-12
MWC KM
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	KM	Maintain Fossil Buildings	$2,580	$2,622	$2,746	$2,804

The forecast for MWC KM is $2.6 million for 2015; $2.7 million for 2016; and $2.8 million for 2017.[26] The forecast increase is primarily due to escalation. The base recorded labor and non-labor costs for 2014 were escalated consistent with the escalation rates specified in Exhibit (PG&E-12), Chapter 4.

[26] See WP 5-1, Line 5, Exhibit (PG&E-5).

c. MWC KR

The forecast for MWC KR is based on the recorded 2014 costs with additions and reductions for specific purposes. The recorded 2014 costs for KR was $2.6 million.

TABLE 5-13
MWC KR
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	KR	Maintain Alternative Generation Equip	$2,641	$3,116	$2,690	$3,563

The forecast for MWC KR is $3.1 million for 2015; $2.7 million for 2016; and $3.6 million for 2017.[27] The forecast increase is primarily due to warranty expirations associated with the PV program maintenance and escalation. The base recorded labor and non-labor costs for 2014 were escalated consistent with the escalation rates specified in Exhibit (PG&E-12), Chapter 4.

1) PV Program Maintenance

PG&E's PV facilities maintenance 2017 forecast is $0.8 million higher than 2016 forecast as a result of the expiration of equipment warranties.[28] Equipment warranties generally last for five years. PG&E's warranties will end in 2016, 2017, and 2018 for its program year 1, year 2, and year 3 facilities, respectively. This forecast is based on historical failure rates of specific equipment and the cost to repair or replace the failed equipment.

d. MWC KS

The forecast for MWC KS is based on the recorded 2014 costs with additions and reductions for specific purposes. The recorded 2014 costs for KS was $0.4 million.

---

27 See WP 5-1, Line 7, Exhibit (PG&E-5).

28 See WP 5-26, Line 16, Exhibit (PG&E-5).

TABLE 5-14
MWC KS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	KS	Maintain Alternative Generation Buildings	$371	$552	$656	$670

The forecast for MWC KS is $0.6 million for 2015; $0.7 million for 2016; and $0.7 million for 2017.[29] The forecast increase is primarily due to weed abatement costs at the PV solar sites and escalation. The base recorded labor and non-labor costs for 2014 were escalated consistent with the escalation rates specified in Exhibit (PG&E-12), Chapter 4.

PG&E is forecasting a total increase in the cost for weed abatement at the solar PV sites as a result of an increase in contracting costs of $0.3 million.

3. Environmental Compliance (MWC AK)

MWC AK is the environmental function used to address waste management and required environmental permits. This function is also used for associated internal labor, associated environmental support services, materials and contracts required for various fees and disposal of waste materials.[30] MWC AK (Manage Environmental Operations) is used by GGS, CGS and HBGS for planning and performing environmental compliance-related activities. The recorded 2014 costs for were $2.8 million.

---

29 See WP 5-1, Line 8, Exhibit (PG&E-5).

30 The planned activities include environmental monitoring, laboratory analysis of environmental samples, waste disposal and transportation, training, environmental and hazardous material fees, technical hazardous material and environmental services provided by other internal departments or contractors and other miscellaneous environmental compliance-related activities.

TABLE 5-15
MWC AK
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	AK	Manage Environmental Operations	$2,832	$2,974	$3,197	$3,264

The forecast for MWC AK is $3.0 million for 2015; $3.2 million for 2016; and $3.3 million for 2017.[31] The forecast increase is primarily due to environmental compliance cost increases and escalation. The base recorded labor and non-labor costs for 2014 were escalated consistent with the escalation rates specified in Exhibit (PG&E-12), Chapter 4.

a. Environmental Compliance Cost Increases

PG&E's environmental compliance 2017 forecast is $0.3 million higher than the 2014 recorded as a result of an increase in waste treatment and disposal costs, staffing costs, and permits and fees.[32]

The 2014 CGS waste treatment costs were lower than normal as a result of low service hours in 2014. The low service hours were a result of the 2014 outage of the ST generator. PG&E anticipates Colusa waste treatment and disposal costs to increase going forward due to an expected increase in service hours.

2014 labor costs associated with the Environmental Coordinator at HBGS was low due to an extended leave for one-third of the calendar year. The 2015-2017 Environmental Coordinator's labor hours are forecast based on a full work-year with labor escalations.

Finally, an increase in the State of California greenhouse gas emission fees is expected for GGS, CGS, and HBGS.

4. Capital Projects

Fossil and Other Generation capital projects over the 2015-2019 period primarily include projects that are required to install or replace fossil generating equipment to increase reliability or improve the operational flexibility of the plants. Other capital projects are required in order to

---

31 See WP 5-1, Line 2, Exhibit (PG&E-5).

32 See WP 5-28, Line 4, Exhibit (PG&E-5).

address environmental regulatory and safety risks and needed infrastructure improvements.

There are 11 MWCs used to track different types of capital improvements or replacements at the fossil, PV, and fuel cell facilities in the forecast period. These include MWCs 03 (Office Furniture and Equipment); 05 (Tools and Equipment); 12 (Implement Environmental Projects); 2R (Install/Replace for Fossil Safety and Regulatory Requirements); 2S (Install/Replace Fossil Generating Equipment); 2T (Install/Replace Fossil Building and Grounds); 2U (Construct New Fossil Generation); 3A (Install/Replace for Alternative Generation Safety and Regulatory); 3B (Install/Replace Alternative Generation Generating Equipment); 3C (Install/Replace Alternative Generation Buildings, Grounds, and Infrastructure); and 3D (Construct New Alternative Generation). The capital improvements and replacements in each of these categories are described below.[33]

a. MWCs 2S and 2R: Install/Replace Fossil Generating Equipment and Install/Replace Fossil Safety and Regulatory Requirements

TABLE 5-16
MWC 2S
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	2S	Instal/Repl Fosl Gen. Eqp	$8,701	$10,184	$18,173	$11,051	$1,355	$4,058

PG&E forecasts 2015-2019 capital expenditures of $10.2 million, $18.2 million, $11.1 million, $1.4 million, and $4.1 million, respectively, for MWC 2S.[34]

[33] There are no capital improvements or replacements included in the 2017 GRC for MWCs 12, 2U, and 3D.

[34] See WP 5-57, Line 5, Exhibit (PG&E-5).

TABLE 5-17
MWC 2R
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	2R	Instl/Rpl for Fossil Safety&Reg	$657	$280	$2,650	$2,600	$500	–

PG&E forecasts 2015-2019 capital expenditures of $0.3 million, $2.7 million, $2.6 million, $0.5 million, and $0 million, respectively, for MWC 2R.[35]

The majority of the MWC 2S and 2R forecasts is driven by reliability, operational flexibility, environmental regulatory compliance, and safety projects.

1) Reliability: Life Cycle Replacement/Single Point of Failure

This category includes equipment replacement due to age and run-time of the plants based on periodic testing, condition assessments, operating and maintenance history, or equipment manufacturer issues. It also includes projects related to equipment identified in the plants that would cause extended forced outage time if the equipment were to fail. These projects aim to provide additional capacity, redundancy, or newer technology to remove these potential failure points from the various systems in the plant.

a) CGS New Boiler Feed Pump

CGS base design requires both boiler feed pumps (BFPs) to be in service to achieve peak load at the plant. If for any reason one of the BFPs is out of service the plant can only provide base load capacity and the peaking capability is derated up to 80 MW. This project will increase the size of the existing BFPs and/or provide an additional BFP to provide additional redundancy and capacity to avoid peaking capability restrictions and a derating in the event of a BFP failure.

35 See WP 5-57, Line 4, Exhibit (PG&E-5).

A project summary for this project is included in the workpapers supplementing this testimony.[36]

b) Gateway ST Generator Rewind

The purpose of this project is to rewind the ST generator field due to degradation of the windings based on condition assessments performed on the windings and industry experience in order to prevent a future extended forced outage. PG&E is leveraging GE's ST generator field rewind exchange program to use a rewound generator field that is compatible with the existing GGS generator. This approach eliminates the schedule risks of rewinding the generator field during the planned outage. Additionally, GE's generator team is comprised of highly trained and experienced generator specialists and winders. These specialists and winders have been through stringent training and certification. In addition, a thorough quality control plan containing all the required tests, inspection and procedures has been developed and will be used. GE's exchange program allows PG&E to maintain the reliability of the ST generator while minimizing outage time and costs.

c) HBGS Spare Transformer

The purpose of this project is to purchase a spare step-up transformer for HBGS. The need for a spare transformer has been identified as a single point of failure to local area reliability needs. As discussed in Section B.2.a. HBGS is critical for Humboldt area reliability. During periods of high customer electrical demand or unavailability of electric transmission import capability feeding the Humboldt area, HBGS must be available to support he local area electrical needs. If a single transformer fails at HBGS, three generating units associated with that transformer (approximately 48 MW) will be forced out of service for an extended period of time. PG&E estimates that

---

36 See WP 5-67, Exhibit (PG&E-5).

it would take eight to twelve months to procure a replacement transformer. This extended outage time would put PG&E at risk of not being in compliance with NERC reliability criteria.

2) Operational Flexibility

These upgrades are needed to implement advanced control technologies on the CTs at GGS and CGS that address key modes of operations required to meet the market conditions while maintaining plant life. Original equipment/parts life cycles were not designed to handle the additional starts/stops and lower emission requirements that may be required in the near-term to meet market needs. By implementing these upgrades, PG&E maximizes the utilization of the plant equipment/parts, since they were not originally designed to meet the increasing cycling frequency and load responsiveness needs of the CAISO. The key operational flexibility enhancements included in PG&E's forecast are discussed below.

a) CGS/GGS Op Flex Balance and Advantage

These projects will improve the flexibility of CGS and GGS CTs through installation of GE advanced control technology, termed Op Flex Balance and Advantage.

The technology consists of software that monitors and calibrates the CTs for weather changes, fuel property variation, grid frequency excursions, CT compressor fouling, and CT hardware aging. This results in automatic retuning of the CTs for variations in fuel composition and ambient temperature and humidity. These projects allow for an optimized heat rate by constantly maintaining the gas fuel temperature. Additionally, the projects reduce NO_x emissions allowing GGS and CGS to operate in a more flexible manner in order to meet the needs of customers. Additionally, they improve the reliability of the plant CTs and allows plant operation at reduced loads improving the ability to dispatch more frequently resulting in significant benefits to customers.

A project summary for these projects is included in the workpapers supplementing this testimony.[37]

b) Op Flex Ready/Steam Turbine Blankets

These projects provide GE steam turbine advanced control technologies, termed Op Flex Ready, for CGS and GGS allowing for improved operating profiles in the following areas of steam turbine start-up: (1) increased fuel heating operable temperature range and reduced need for turbine holds; (2) improved management of NO_x emission permit restriction to more closely match desired operating profile; (3) reduced purge time resulting in reduced start-up time and less fuel consumption; and (4) start-up automation and enhanced control resulting in reduced start-up time, variability, fuel consumption and emissions.

Additionally, installation of steam turbine heating blankets at CGS and GGS in conjunction with the GE Op Flex Ready technology, will provide a reduction in start-up time resulting in less fuel usage and less emissions. This will allow PG&E to operate CGS and GGS in a more flexible manner resulting in the ability to better respond to the intermittent renewables integration challenge discussed in Section A.3.

A project summary for this project is included in the workpapers supplementing this testimony.[38]

3) Environmental Regulatory Compliance & Safety

a) CGS and GGS NO_x/CO Catalysts

CGS and GGS each have a SCR system inside each HRSG. The SCRs include a catalyst that reacts with the HRSG flue gas and ammonia to reduce NO_x emissions. GGS also has a CO catalyst that reduces CO emissions. The SCR systems are required to meet environmental regulatory requirements.

---

37 See WP 5-74, Exhibit (PG&E-5).

38 See WP 5-70, Exhibit (PG&E-5).

Over time, the catalysts deteriorate and do not efficiently reduce emissions as designed. Age, high flue gas temperatures, water content in the flue gas, insulation debris, cyclic duty and fuel gas quality all contribute to the deterioration of the catalyst components. Although the life spans have been extended through diligent operating and maintenance practices, degradation of the catalyst does occur over time. Annual testing of the catalyst components, inspection and continuous emission monitoring is used to track and determine the condition and the expected remaining life of the catalyst. Plant performance and operation is dependent on proper operation of the catalysts. A poor or non-performing catalyst component will not meet the stringent regulatory emission requirements and will result in reduced plant capacity or the need to take the power plant out of service.

PG&E has determined that the catalysts are likely due for replacement within the next 3-5 years.

b) ACC Fan Blade Replacement

The ACC at CGS has experienced multiple failures of the fan blades. PG&E has determined this to be a safety hazard as a result of the potential mode of failure of the blades, since the blade(s) could dislodge while in operation. An RCA concluded that the bolt heads failures were being caused by uneven loading. This uneven loading was a result of the variation in the assembly due to deficiencies in the manufacturing of the blades. In order to improve reliability of the ACC and to avoid a failure that could result in personnel injury, the project scope consists of new blades with less dimensional variation, and optimization of the assembly techniques to compensate for remaining dimensional variation.

b. MWC 2T: Install/Replace Fossil Building and Grounds

TABLE 5-18
MWC 2T
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	2T	Instl/Repl Fossil Bldg/Grnd/Infrst	$49	$1,200	$300	$150	$500	–

PG&E forecasts 2015-2019 capital expenditures of $1.2 million, $0.3 million, $0.2 million, $0.5 million, and $0 million, respectively, for this MWC.[39]

1) Critical Infrastructure

The majority of this forecast is driven by the CGS Canal Bridge Replacement project. This project is required to increase the load rating of the bridge to handle fossil generation equipment replacements.

The Dirks Road Bridge crosses the Glenn Colusa Irrigation District (GCID) canal and was built in 1966 for access to the Delevan Compressor Station. It was not originally designed for the extreme loads required to support the operation and maintenance of CGS. A temporary bridge was used during the construction of CGS. There have been two occurrences since construction requiring a specific engineering review to confirm the ability for the bridge to support the shipment of the ST generator rotor and a spare transformer. There will continue to be extreme loads passing over this bridge during the remainder of the operating life of CGS. A replacement bridge will allow for an increased capacity to support the maximum equipment load rating of the plant. The inability to transport equipment to the plant during the event of a system/equipment failure would result in extended forced outage time of the plant.

[39] See WP 5-57, Line 6, Exhibit (PG&E-5).

c. MWCs 3A, 3B, 3C: Install/Replace Alternative Generation Equipment Safety and Regulatory

TABLE 5-19
MWCS 3A, 3B, AND 3C
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	3A	Instl/Rpl for AltGen Safty&Reg	$28	$29	$30	$30	$31	$32
2	3B	Instal/Repl AltGen GneratngEqp	187	150	121	281	237	248
3	3C	Instl/Rpl AltGn BldgGrndInfrst	–	10	–	–	–	–
4		Total	$215	$189	$150	$311	$268	$279

PG&E forecasts 2015-2019 capital expenditures of $0.2 million, $0.2 million, $0.3 million, $0.3 million, and $0.3 million, respectively, for these MWCs. These forecasts are for safety and regulatory required capital expenditures at PG&E PV and fuel cell generation facilities.[40]

d. MWCs 03, 05: Office Furniture, Tools, and Equipment

TABLE 5-20
MWCS 03 & 05
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	03	Office Furniture & Equip	–	–	–	$50	–	–
2	05	Tools & Equip	$256	$300	$372	$330	$337	$345

For MWC 3, PG&E forecasts $0.1 million for 2017 and no dollars forecast for 2015-2016 and 2018-2019. This forecast is for office furniture and equipment.[41]

For MWC 5, PG&E forecasts 2015-2019 capital expenditures of $0.3 million, $0.4 million, $0.3 million, $0.3 million, and $0.3 million,

---

40 See WP 5-57, Lines 8-10, Exhibit (PG&E-5).

41 See WP 5-57, Line 1, Exhibit (PG&E-5).

respectively, for this MWC. This forecast is for tools and equipment at PG&E fossil, PV, and fuel cell generation facilities.[42]

5. Fossil Decommissioning Projects

In previous decisions, the Commission has authorized PG&E to accrue funds during the useful life of fossil generation facilities in order to decommission them after they are retired from service. During this GRC period, PG&E expects to have three fossil generation facilities undergoing decommissioning. In addition, PG&E provides updated decommissioning estimates for Hunters Point Power Plant (HPPP), HBPP, Kern Power Plant (KPP), GGS, CGS, and HBGS.

a. Decommissioning for Hunters Point, Humboldt Bay and Kern Power Plants

The decommissioning forecast for HPPP, HBPP, and KPP is $16.0 million for 2015, $16.4 million for 2016, $8.6 million for 2017, $7.3 million for 2018, and $1.8 million in 2019.[43]

Additional detail on the environmental decommissioning and remediation forecasts is provided in Exhibit (PG&E-7), Chapter 7, Environmental Program.

Under a settlement in the Kern Power Plant OII, Investigation 14-08-022, PG&E agreed to a ratemaking adjustment of $3,269,313 in costs associated with the Kern Power Plant decommissioning project. This ratemaking adjustment is described in Exhibit (PG&E-10), Chapter 10.

b. Decommissioning for GGS, CGS and HBGS

The updated decommissioning forecast for GGS, CGS and HBGS is $18.5 million, $19.5 million and $9.6 million, respectively.[44]

The demolition forecast for GGS, CGS and HBGS is based on studies performed by TLG Services, Inc., that were adopted by the Commission in the 2011 and 2014 GRCs. PG&E only updates the

---

42 See WP 5-57, Line 2, Exhibit (PG&E-5).

43 See WP 5-83, Lines 13-17, Exhibit (PG&E-5).

44 See WP 5-84, Lines 18-20, Exhibit (PG&E-5).

forecast escalation rates used in its forecast in this GRC. The TLG Services, Inc. forecasts remain unchanged.

D. Estimating Method

Expense forecasts include the base costs and project costs necessary to operate and maintain PG&E's fossil, PV, and fuel cell facilities. Base costs are typically consistent year-to-year. Expense project costs tend to vary each year, are forecast on a project-by-project basis. Expense projects are typically major maintenance/repair work needed on equipment to address key reliability, safety, environmental or regulatory compliance risks. These projects, when contracted, follow the same method of estimating as capital projects. Otherwise, it is accounted for within the annual base O&M costs.

Fossil Operation's base costs include the costs of routine and ongoing expenditures including the cost of personnel who operate and maintain the units, materials, and contracts such as the payments made under the LTSAs. These costs are generally forecast based on the last recorded year.

The base costs necessary to operate and maintain PG&E's PV and fuel cell facilities include the costs of routine and ongoing expenditures including the cost of personnel who operate and maintain the units, materials, and contracts such as the payments made under the O&M agreements. These costs are generally forecast based on last recorded year.

Capital forecasts are primarily driven by project costs that tend to vary each year. Projects are forecast on a project-by-project basis. PG&E's forecast is based on a bottom-up calculation of the expected costs for the projects to be implemented in the forecast year. These cost estimates for these projects were developed using a combination of the following: (1) actual costs for similar work, adjusted as appropriate; (2) the knowledge and experience of PG&E's project managers; (3) contractor and consultant experience with similar work; and (4) estimates from potential vendors.

E. Cost Tables by MWC

1. Expense

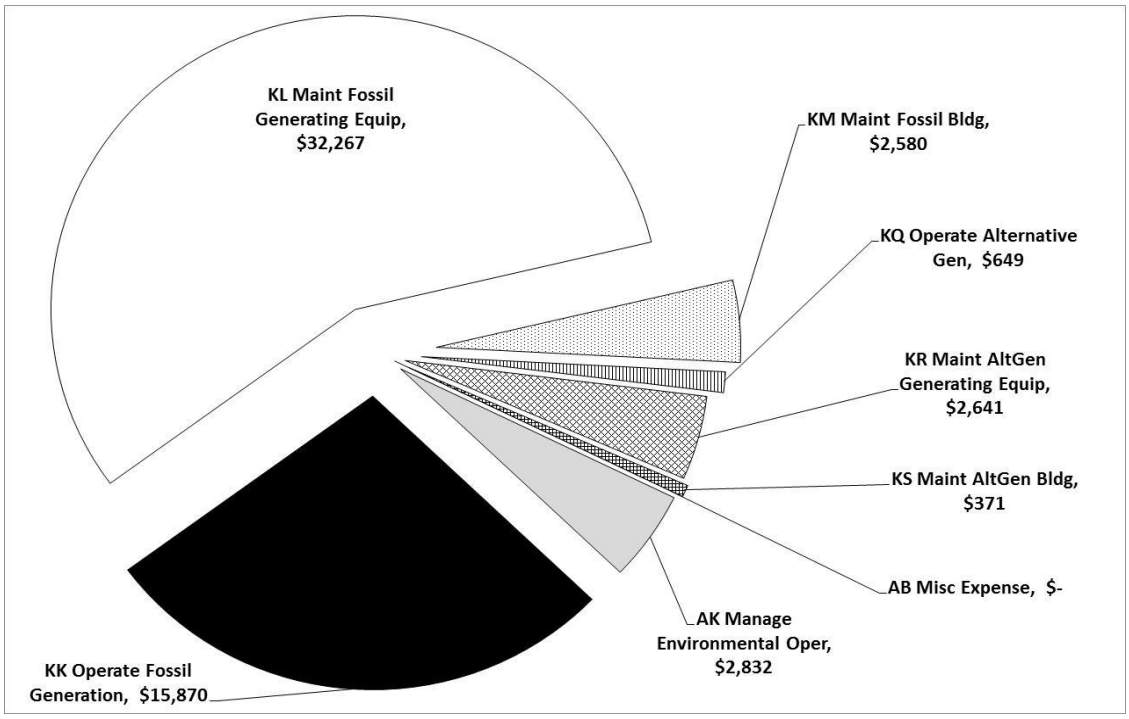
Table 5-21 below provides the 2010-2014 recorded O&M expense and 2015-2017 forecast O&M expense by MWC. Figure 5-15 and 5-16 provide 2014 recorded and 2017 forecast O&M expense in a pie chart format.

TABLE 5-21
FOSSIL AND OTHER GENERATION EXPENSES BY MAJOR WORK CATEGORY
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2010 Recorded Adjusted	2011 Recorded Adjusted	2012 Recorded Adjusted	2013 Recorded Adjusted	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	Workpaper Reference
1	AB	Misc Expense	$64	$-144	$6	–	–	–	–	–	WP 5-9, Line 2
2	AK	Manage Environmental Oper	1,649	3,894	2,655	$2,220	$2,832	$2,974	$3,197	$3,264	WP 5-9, Line 11
3	KK	Operate Fossil Generation	9,853	12,445	13,476	13,949	15,870	15,402	16,724	17,134	WP 5-9, Line 29
4	KL	Maint Fossil Generating Equip	12,499	26,956	30,323	30,164	32,267	33,267	36,314	36,797	WP 5-10, Line 69
5	KM	Maint Fossil Bldg	846	2,081	2,647	2,975	2,580	2,622	2,746	2,804	WP 5-10, Line 76
6	KQ	Operate Alternative Gen	228	9	187	76	649	457	790	802	WP 5-11, Line 103
7	KR	Maint AltGen Generating Equip	107	671	2,514	2,442	2,641	3,116	2,690	3,563	WP 5-11, Line 131
8	KS	Maint AltGen Bldg	–	–	201	763	371	552	656	670	WP 5-11, Line 156
9		Total	$25,246	$45,912	$52,010	$52,590	$57,210	$58,389	$63,118	$65,036	WP 5-11, Line 157

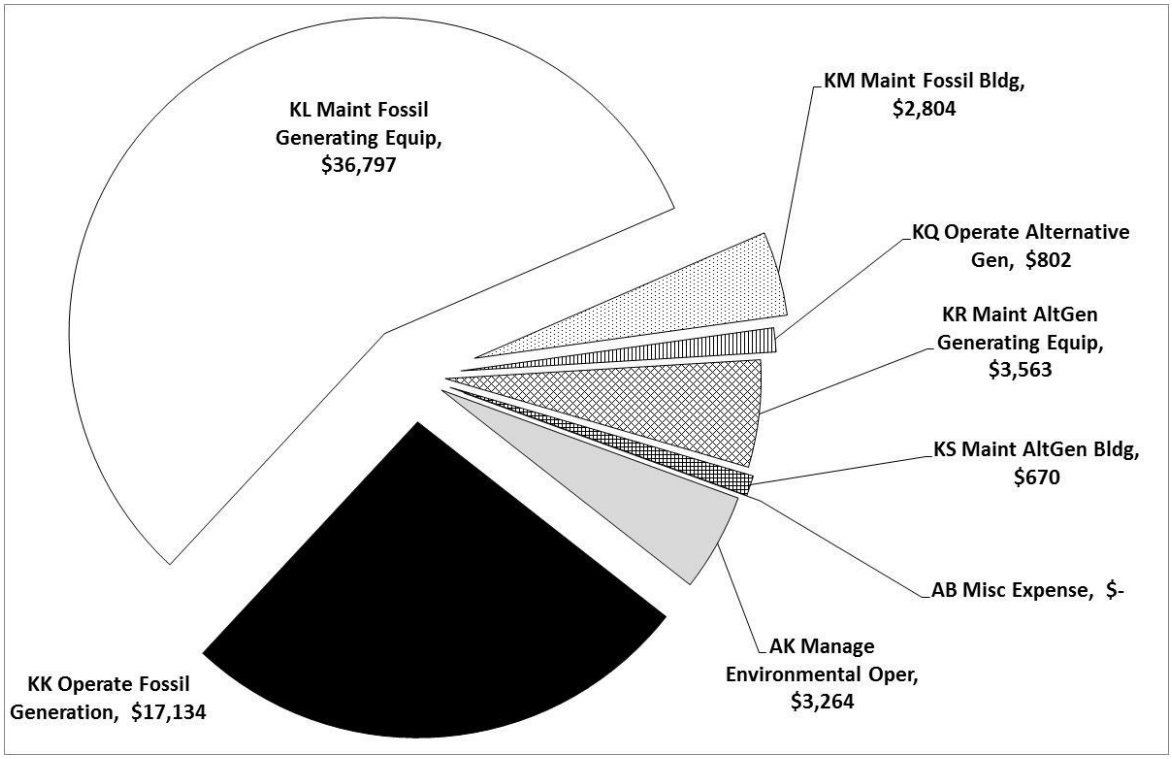
Note: See WP 5-1, Exhibit (PG&E-5).

FIGURE 5-15
FOSSIL AND OTHER GENERATION O&M EXPENSE BY CATEGORY
BY MAJOR WORK CATEGORY 2014
(THOUSANDS OF NOMINAL DOLLARS)



Note: See WP 5-1, Exhibit (PG&E-5).

FIGURE 5-16
FOSSIL AND OTHER GENERATION O&M EXPENSE BY CATEGORY 2017
(THOUSANDS OF NOMINAL DOLLARS)



Note: See WP 5-1, Exhibit (PG&E-5).

2. Capital

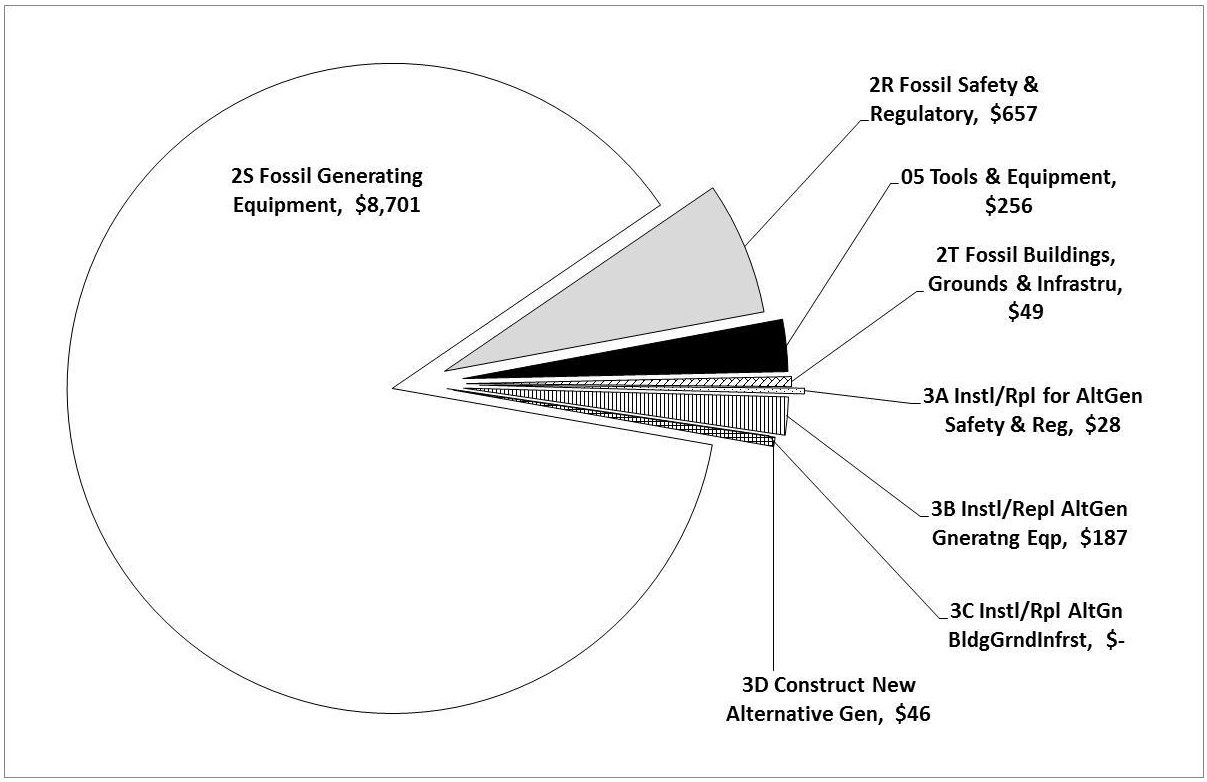
Table 5-22 below provides the 2010-2014 recorded capital expenditures and 2015-2017 forecast capital expenditures by MWC. Figure 5-17 and 5-18 provide 2014 recorded and 2017 forecast capital expenditures in a pie chart format.

TABLE 5-22
FOSSIL AND OTHER GENERATION CAPITAL EXPENDITURES BY MAJOR WORK CATEGORY
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2010 Recorded Adjusted	2011 Recorded Adjusted	2012 Recorded Adjusted	2013 Recorded Adjusted	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Workpaper Reference
1	03	Office Furniture & Equipment	–	$48	$12	$17	–	–	–	$50	–	–	WP 5-61, Line 6
2	05	Tools & Equipment	$304	454	65	88	$256	$300	$372	330	$337	$345	WP 5-61, Line 16
3	12	Implement Environment Projects	191	-2	–	–	–	–	–	–	–	–	WP 5-61, Line 18
4	2R	Instl/Rpl for Fosil Safety&Reg	327	431	394	1,134	657	280	2,650	2,600	500	–	WP 5-61, Line 44
5	2S	Instal/Repl Fosil Gnerating Eqp	514	3,179	7,371	3,694	8,701	10,184	18,173	11,051	1,355	4,058	WP 5-63, Line 137
6	2T	Instl/Repl Fosl Bldg/GrndInfrst	–	371	126	141	49	1,200	300	150	500	–	WP 5-63, Line 153
7	2U	Construct New Fossil Gen	283,981	11,395	3,151	-1	–	–	–	–	–	–	WP 5-63, Line 157
8	3A	Instl/Rpl for AltGen Safty&Reg	–	–	–	31	28	29	30	30	31	32	WP 5-64, Line 163
9	3B	Instal/Repl AltGen GneratngEqp	–	282	–	–	187	150	121	281	237	248	WP 5-64, Line 173
10	3C	Instl/Rpl AltGn BldgGrndInfrst	–	–	–	–	–	10	–	–	–	–	WP 5-64, Line 175
11	3D	Construct New Alternative Gen	23,175	280,298	137,233	156,767	48	–	–	–	–	–	WP 5-64, Line 180
12		Total	$308,492	$296,456	$148,353	$161,872	$9,923	$12,153	$21,645	$14,493	$2,960	$4,683	

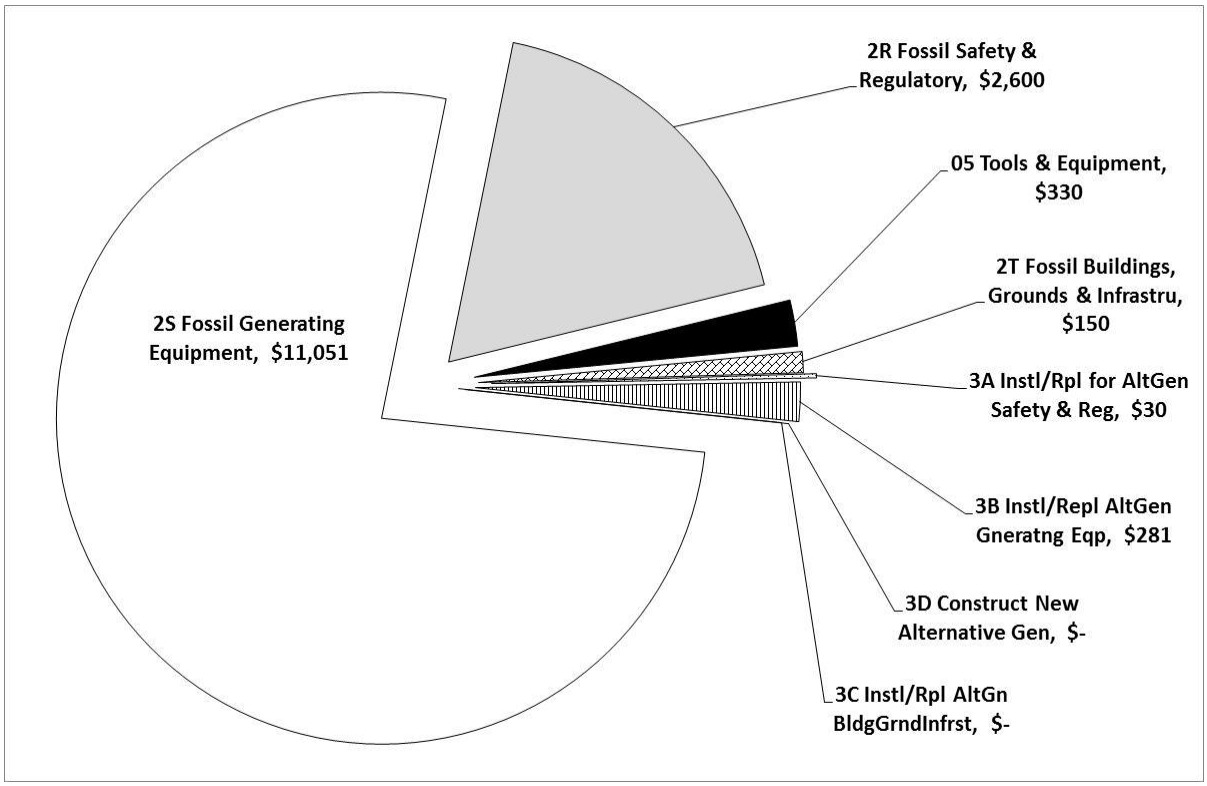
Note: See WP 5-57, Exhibit (PG&E-5).

FIGURE 5-17
FOSSIL AND OTHER GENERATION
CAPITAL EXPENDITURES BY MAJOR WORK CATEGORY 2014
(THOUSANDS OF NOMINAL DOLLARS)



Note: See WP 5-57, Exhibit (PG&E-5).

FIGURE 5-18
FOSSIL AND OTHER GENERATION
CAPITAL EXPENDITURES BY MAJOR WORK CATEGORY 2017
(THOUSANDS OF NOMINAL DOLLARS)



Note: See WP 5-57, Exhibit (PG&E-5).

3. Fossil Decommissioning

TABLE 5-23
FOSSIL DECOMMISSIONING
MAJOR WORK CATEGORY 55
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Facility	Through 2014	2015	2016	Remaining Forecast
1	Humboldt Bay Power Plant	$55,298	$3,032	$11,129	$16,060
2	Hunters Point Power Plant	$149,750	$8,470	$2,352	$7,207
3	Kern Power Plant	$11,431	$4,506	$2,934	$4,253
4	Gateway Generating Station	–	–	–	$18,461
5	Colusa Generating Station	–	–	–	$19,452
6	Humboldt Bay Generating Station	–	–	–	$9,579
7	Total	$216,480	$16,007	$16,415	$75,012

Note: See WP 5-83, Lines 25-33, Exhibit (PG&E-5).

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ENERGY PROCUREMENT ADMINISTRATION COSTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
ENERGY PROCUREMENT ADMINISTRATION COSTS

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
ENERGY PROCUREMENT ADMINISTRATION COSTS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
ENERGY PROCUREMENT ADMINISTRATION COSTS

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to demonstrate that Pacific Gas and Electric Company's (PG&E or the Company) forecasts of expense and capital for the planning, procurement, management, and administration of its electric and gas supply portfolios are reasonable and should be adopted by the California Public Utilities Commission (CPUC or Commission).

PG&E delivers electricity to approximately 5.3 million households and businesses and natural gas to approximately 4.4 million households and businesses. Electricity is supplied through: (1) utility-owned generation (UOG) assets, which account for approximately 39 percent of the Company's electric deliveries to customers; and (2) procurement from third-party generators, which represents approximately 61 percent of the Company's deliveries to customers.[1] PG&E supplies natural gas to its core customers (residential and small commercial) through procurement contracts with producers and marketers in both Canada and the United States (U.S.). PG&E also contracts for natural gas transportation from the points at which it takes delivery (typically in Canada, the southwestern U.S., and the Rockies) to the points at which PG&E's natural gas transportation system begins. PG&E uses natural gas storage capacity in northern California to manage gas resources during winter peak loads and to minimize customer costs. PG&E also supplies natural gas to its UOG fossil generation and contracted third-party electric generators. PG&E recorded a total combined cost of electricity and natural gas procurement in 2014 of approximately $6.6 billion.

The Energy Procurement (EP) organization is responsible for both the front-office and back-office functions associated with power procurement. Front-office functions entail planning, procuring, scheduling, and dispatching

---

1 See WP Table 6-12, Exhibit (PG&E-5).

electricity and natural gas for PG&E's customers. Back-office functions entail administering procurement agreements and ensuring that timely and accurate payments are made to the California Independent System Operator (CAISO) and third-party power suppliers. In addition, EP is responsible for long-term planning, policy development, and compliance functions related to PG&E's energy portfolio.

The EP organization has grown substantially over the past decade for a number of reasons, including: PG&E's resumption of procurement responsibilities on January 1, 2003; the increasing complexity of the California energy markets; and additional legislation and regulation arising from public policy initiatives. At the end of 2014, EP had a planned headcount (including vacancies and part-time staff) of 321 positions. In 2017, PG&E projects the number of positions in EP to increase by 14 resulting in a total of 335 positions for a total funding request of $61.0 million.

The purpose of this chapter is to describe the external federal and state legal mandates and market changes that are driving additional resource needs in EP, along with the related internal initiatives to ensure service reliability, affordability, and operating efficiencies in response to the external drivers. This chapter provides an in-depth description of each organization within EP, including responsibilities, functions, and current and projected staffing levels.

2. Summary of Request

The cost drivers underlying EP's incremental expense request between 2014 and 2017 include: (1) cost escalation (inflation); (2) portfolio complexity, driven by changes in the composition of PG&E's procurement portfolio, increasing regulatory mandates, and market changes; and (3) technology implementation efforts to enable efficiency gains and respond to increased reporting requirements as EP faces greater procurement complexity. Each of these cost drivers is described in detail in Section B.3, (Key Drivers of 2017 Expense and Capital Increases).

a. Expense

PG&E requests that the Commission adopt its 2017 forecast of $61.0 million for total EP expense costs, as shown in line 6 of Table 6-1 below. This represents an increase of $6.3 million (see Table 6-2, line 5) from EP's 2014 recorded costs. All Information Technology (IT)-related expense costs are requested and described in more detail in PG&E's Exhibit (PG&E-5), Chapter 7. Section C.5, below, summarizes the IT expense costs requested in PG&E's Exhibit (PG&E-5), Chapter 7.

PG&E's request represents the appropriate level of spending to manage EP activities to meet PG&E's customers' needs in a cost-effective manner while complying with all federal, state and local regulatory requirements.

b. Capital

EP's capital forecast costs for the years 2015-19 consist entirely of IT costs that are requested and described in PG&E's Exhibit (PG&E-5), Chapter 7. Accordingly, those costs are not requested as part of this chapter, although Section B.3.b of this chapter justifies the business need for the EP-related IT capital costs and Section C.6 of this chapter summarizes the IT capital costs requested in PG&E's Exhibit (PG&E-5), Chapter 7.

B. Activities and Costs

1. Overview of Recorded and Forecast Costs

The drivers of the projected expense increase are reflected in lines 2 through 5 of Table 6-1. Each of these four areas is explained in detail below in Section B.3.a of this chapter.

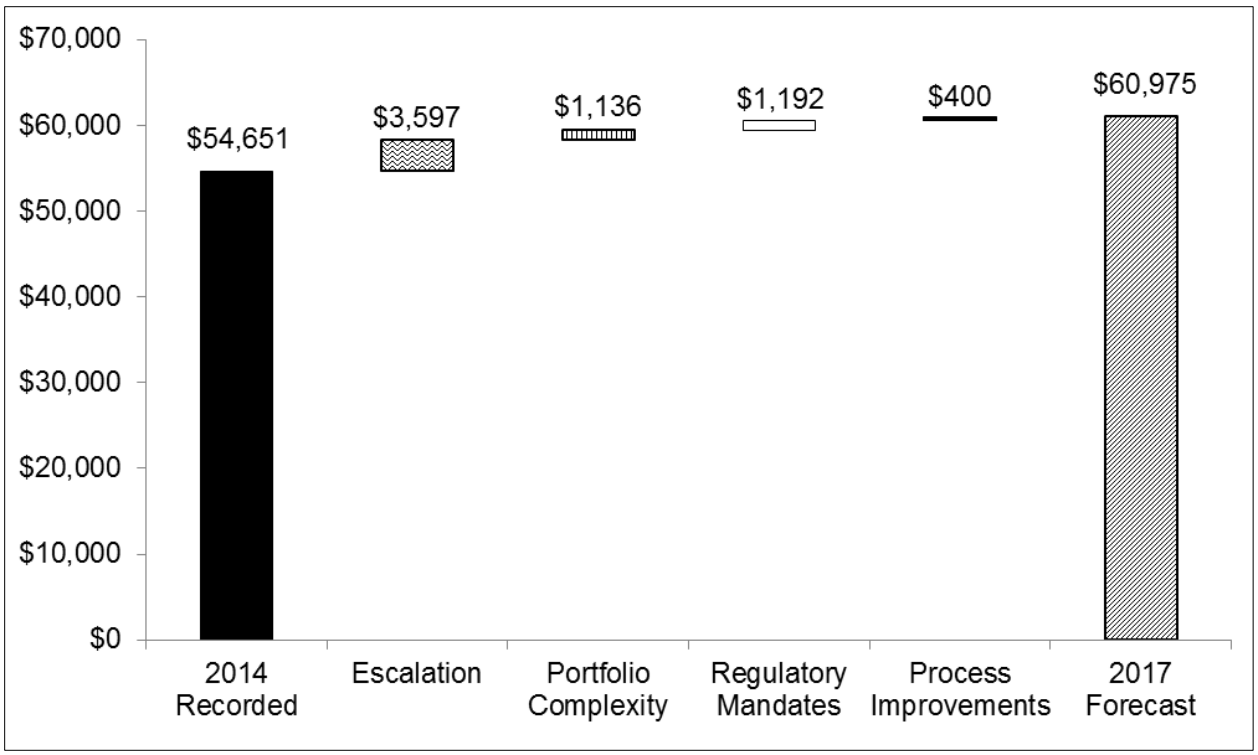
TABLE 6-1(a)
EP COSTS
EXPENSE FORECAST BY YEAR
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	Actuals/Forecast	54,651	54,651	56,550	58,700
2	Escalation	–	-101(b)	1,950	1,748
3	Portfolio Complexity	–	800	–	336
4	Regulatory Mandates	–	800	200	192
5	Process Improvements	–	400	–	–
6	Total	54,651	56,550	58,700	60,975

(a) See WP Table 6-6, Exhibit (PG&E-5).

(b) Escalation is noted as a net decrease in 2015, as it accounts for a labor attrition adjustment as described in Section D, Estimating Methods.

FIGURE 6-1
EP ADMINISTRATION EXPENSE WALK
2014-2017
(THOUSANDS OF NOMINAL DOLLARS)



The cost drivers identified above in Figure 6-1 have the following contributions to EP's total 2017 increase in operating expense above its 2014 recorded costs.

TABLE 6-2(a)
EP COST INCREASE
2015-2017 EXPENSE BY COST DRIVER

Line No.	Description	Increase in Thousands of $	Percent of Total Increase
1	Escalation	3,597	57
2	Portfolio Complexity	1,136	18
3	Regulatory Mandates	1,192	19
4	Process Improvements	400	6
5	Total	6,324	100

(a) See WP Table 6-6, Exhibit (PG&E-5).

The work performed by EP has been steadily growing in volume and complexity in response to legislation and regulation to meet and comply with various state and federal energy policies and mandates. Additional employees are needed to manage this increased workload. Thus, the forecast of additional positions needed by EP is expected to increase between 2014 and 2017 as identified in Table 6-3 below.

TABLE 6-3(a)
EP HEADCOUNT
NUMBER OF PLANNED POSITIONS

Line No.	Description	2014 Positions	2015 Forecast	2016 Forecast	2017 Forecast
1	EP Administrative Office	4	4	4	4
2	Energy Supply Management (ESM)	126	131	131	134
3	Renewable Energy (RE)	38	40	40	41
4	Energy Policy, Planning and Analysis (EPPA)	46	46	46	46
5	Value Based Reliability (VBR)	10	12	12	12
6	Energy Contract Management and Settlements (ECMS)	79	80	80	80
7	Energy Compliance and Reporting (ECR)	18	18	18	18
8	Total	321	331	331	335

(a) See WP Table 6-7, Exhibit (PG&E-5).

a. Capital

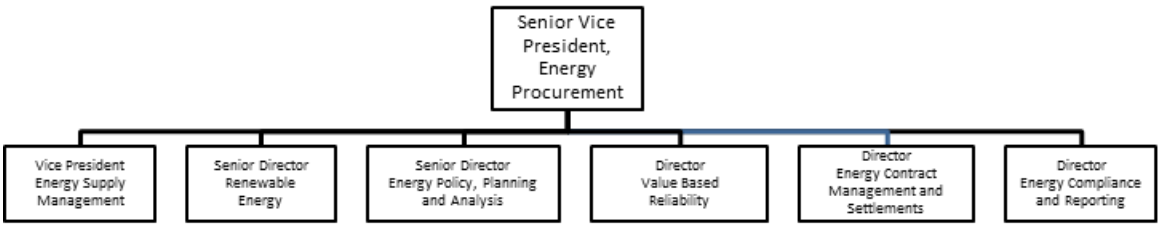
EP's forecasted capital costs from 2015-2019 consist entirely of IT programs that support EP. These costs are described and requested in PG&E's Exhibit (PG&E-5), Chapter 7 and are therefore not included in the total forecast presented in this chapter. Section B.3.b, below, provides a summary of the IT capital projects supporting EP and describes the business need for those projects.

2. Program Description

a. Management Structure

EP is comprised of six departments: Energy Supply Management (ESM); Renewable Energy (RE); Energy Policy, Planning and Analysis (EPPA); Value Based Reliability (VBR); Energy Contract Management and Settlements (ECMS); and Energy Compliance and Reporting (ECR). At year-end 2014, EP was organized as shown in Figure 6-2.

FIGURE 6-2
EP ORGANIZATIONAL STRUCTURE
AT YEAR-END 2014



1) Organization and Staffing

The following section provides a detailed description of each department in the EP organization and summarizes its purpose, primary function, objectives, and resource needs. Table 6-3, above, provides a summary of the changes in employees between 2014 and forecasted for 2017 for each of the primary organizations listed below.

a) EP Administrative Office

EP administration consists of the Senior Vice President (SVP) who is in charge of the entire EP organization, a chief-of-staff that handles both administrative and various commercial matters, and two administrative personnel. As of year-end 2014, the department had four employees. There are no staffing additions planned for the department by 2017.

b) Energy Supply Management

ESM executes the physical and financial transactions necessary to ensure adequate gas and electric supply for our customers and that associated greenhouse gas (GHG) obligations are met. This department is responsible for the short-term and mid-term purchase and sale of natural gas and electricity and the dispatch of PG&E's portfolio to enable the CAISO to balance supply and demand on a daily, hourly, 15-minute and 5-minute basis. Second, ESM is responsible for the procurement of pipeline and storage capacity, resource adequacy (RA) capacity, and procurement from certain other

types of resources including Qualifying Facilities (QF) and combined heat and power (CHP). Third, ESM develops the load forecasts used to support risk reporting and mid-term (up to 24 months) electric and gas procurement. Fourth, ESM is responsible for financial hedging activities to manage customers' price risk associated with the gas and electric portfolios. Fifth, ESM is responsible for procuring and submitting GHG compliance products (allowances and offsets) to the California Air Resources Board (ARB). Finally, ESM makes daily resource bidding, dispatch, and scheduling decisions for PG&E's portfolio.

- The ESM organization includes the following departments: (1) Short-Term Electric Supply (STES); (2) Portfolio Management; (3) Core Gas Supply (CGS); (4) Electric Gas Supply (EGS); (5) Market Initiatives, Design, Analysis and Strategy (MIDAS); and (6) an administrative office consisting of the Vice President of ESM and an executive assistant.

  ESM was comprised of 126 positions at the end of 2014 and plans to add eight positions by 2017: six positions in STES; one position in EGS; and one position in Portfolio Management Section B.3 below describes why additional headcount is needed in ESM.

Short-Term Electric Supply

STES[2] is responsible for buying and selling electricity in the short-term time horizon to meet PG&E retail load, and is the single point of contact with the CAISO for all generation

[2] As part of the Smart Grid Pilot Deployment Projects Implementation Plan (D.13-03-032), STES is currently piloting a load forecasting methodology to test whether new granular sources of data can improve the accuracy of PG&E's short-term electricity forecasts for bundled customer demand. This pilot, which is progressing on track, has been funded through 2016 as part of the Smart Grid Implementation Plan. Full deployment of the project requires CPUC approval following the pilot phase of the project with quantitative demonstration of benefits. As this project has not yet been completed, PG&E is not seeking funding for incremental positions to implement and operate a full deployment at this time.

dispatch instructions on a 24-hour-a-day basis, seven days a week for a portfolio of resources representing capacity of over 20,000 megawatts. The procurement process focuses on the fundamental principle of least-cost dispatch (LCD), and includes the use of load and price forecasts, bidding and scheduling PG&E's utility-owned and contracted resources, optimization of resources including a large and dynamic hydroelectric portfolio, and outage management. The STES Department is divided into the following sections: (1) Day-Ahead Operations and (2) Real-Time Operations.

- **Day-Ahead Operations**

  The Day-Ahead Operations section is primarily responsible for managing, optimizing, and scheduling PG&E's UOG resources and contracted resources. On a day-ahead basis, Day-Ahead Operations procures in the electricity markets consistent with LCD and "tags" transactions at the interties with other control areas. Day-Ahead Operations also participates in the development of structured transactions. Day-Ahead Operations develops and maintains the systems required to interact with the CAISO. This team is also responsible for near- and mid-term hydro optimization in collaboration with Power Generation.

- **Real-Time Operations**

  The Real-Time Operations section is responsible for communicating and responding to dispatch instructions from the CAISO for the portfolio in the real-time markets, which includes the 15-minute and 5-minute market on a 24 hours-a-day, seven-days-per-week basis. This team monitors UOG and contracted generation to ensure compliance and meet reliability obligations. Constant assessment of the portfolio requires the need to re-evaluate and submit modified bids and schedules to the CAISO, and communicate changes to the switching centers and power

plants. Real-Time Operations is also responsible for overseeing the operations of EP's alternative headquarters in Vacaville which may be activated due to the loss of the primary San Francisco headquarters helping to ensure system reliability. Real-Time Operation's asset managers also communicate directly with the CAISO and PG&E Grid Operations during system restoration events when generator coordination is crucial to ensure grid reliability.

Portfolio Management

The Portfolio Management Department is responsible for developing and implementing procurement strategies for electric products and negotiating contracts to fulfill various energy and capacity needs, including conventional energy, CHP, QFs, operational flexible resources, RA, congestion revenue rights (CRR), and financial hedging products. This department provides mid-term load forecasting to support various EP activities. Portfolio Management also provides commercial guidance to help inform policy positions for other EP Departments. In addition, the department is also responsible for procuring GHG compliance instruments (allowances and offsets) to meet PG&E's contractual and compliance obligations. Finally, this department is responsible for the data that is filed in the compliance filing with the CPUC, CAISO, and the ARB that demonstrates compliance with RA and GHG procurement requirements.

Core Gas Supply

PG&E's Core Gas Supply Department is responsible for meeting the natural gas requirements of PG&E's bundled core gas customers who receive both gas commodity and gas distribution service from PG&E. Department work activities include: (1) developing gas purchase and hedging plans to maintain supply reliability, preserve affordability, and manage price volatility; (2) initiating and maintaining contracts with suppliers, pipelines and storage operators; (3) executing

transactions to acquire gas supplies, pipeline and storage services; (4) executing gas financial transactions; (5) selling gas supplies not needed to meet core demands; (6) releasing unused pipeline transportation capacity; (7) scheduling the receipt and delivery of natural gas supplies on pipelines and storage fields; (8) optimizing pipeline and storage assets to balance customer demands with supplies, and to meet pipeline requirements; (9) representing Core Gas Supply in regulatory matters before federal, state and Canadian regulatory agencies; and (10) developing compliance documents, including the Core Procurement Incentive Mechanism reports.

Electric Gas Supply

The Electric Gas Supply Department is responsible for managing natural gas supply in support of LCD for PG&E's natural gas-fired UOG facilities, and PG&E-contracted tolling agreements. In addition, this group manages the financial exposure of the electric portfolio to volatility in gas prices. Work activities include: (1) developing the gas supply and hedging plans; (2) developing annual supply plans; (3) executing transactions for physical natural gas pipeline capacity and storage; (4) trading and scheduling physical natural gas; (5) executing financial natural gas transactions; (6) tracking physical and financial portfolio positions; and (7) developing reports and testimony for the Quarterly Procurement Transaction Compliance Report and the Energy Resource Recovery Account (ERRA) compliance proceedings.

Market Initiatives, Design, Analysis and Strategy

The MIDAS Department addresses evolving rules and monitoring of energy, capacity, and emissions markets, including proposals in the CAISO stakeholder processes and regulatory proceedings at the Federal Energy Regulatory Commission (FERC) and the CPUC, and performs analysis for the development and advocacy of PG&E's positions in these forums. MIDAS is divided into the following sections: (i) Market

Design; (ii) Market Monitoring/Analysis; (iii) Market Initiatives; and (iv) Strategy.

- **Market Design**

  The Market Design section performs analysis for the development and advocacy of PG&E's positions on evolving rules in energy and capacity markets, including proposals in the CAISO stakeholder processes and regulatory proceedings at the FERC.

- **Market Monitoring/Analysis**

  The Market Monitoring/Analysis section reviews market performance, identifies market inefficiencies, and detects aberrations in the market for further investigation and follow-up with the CAISO or other parties as appropriate. On a daily, weekly and quarterly basis, the Market Monitoring team gathers data, calculates and reviews market performance metrics, and summarizes the results into regular reports for management.

- **Market Initiative**s

  The Market Initiatives section provides a centralized Project Management Office (PMO) and is responsible for the implementation of the wholesale electricity market initiatives and internal systems needed to support operation in the CAISO's evolving market. The Market Initiatives team works with internal and external stakeholders to translate the CAISO's complex Markets and Performance initiatives into the required business processes, software applications, and systems interface to continue PG&E's participation in the CAISO market.

- **Strategy**

  The Strategy section examines evolving market issues that span multiple departments to facilitate cross-organization dialogue and solutions. For example, the Strategy section helped organize the process by which standard contract terms should be vetted across impacted

groups within EP and is the central coordinator for STES, RE, Portfolio Management and ECMS in the development of the processes and systems needed to implement the economic bidding of renewable contracts in response to changes to the CAISO market.

c) Renewable Energy

The RE organization leads PG&E's commercial renewable procurement activities through solicitations and bilateral negotiations, along with providing leadership for the Company on all renewable legislative and policy activities. The RE organization is responsible for achieving renewable EP mandates and energy storage procurement targets. Departments within Renewable Energy include: (i) Renewable Transactions; (ii) Competitive Solicitations; (iii) Renewable Energy Strategy, Policy and Development (RESPD); and (iv) the Energy Storage PMO. At the end of 2014, the RE organization had 38 positions and plans to add three positions by 2017. Section B.3, below, describes why additional headcount is needed in Renewable Energy.

Renewable Transactions

The Renewable Transactions Department is responsible for negotiating and closing transactions to meet PG&E's renewable energy mandates and energy storage procurement obligations. These transaction structures include long-term power purchase agreements (PPA) and acquisitions, energy storage agreements, contract renegotiations, and proposal screening and analysis.

Competitive Solicitations

The Competitive Solicitations Department designs solicitation plans, protocols, and form PPAs. The Competitive Solicitations Department also supports regulatory compliance filing requirements for executed contracts. The team's objective is to achieve procurement targets through well-designed solicitation processes to ensure regulatory compliance and cost

recovery objectives. The department also implements strategic commercial initiatives that ensure procurement compliance, system reliability, and other policy goals. Two incremental full-time employees are forecast by 2017 to primarily manage the feed-in tariff programs.

Renewable Energy Strategy, Policy and Development

RESPD develops PG&E's positions on renewable energy and energy storage policy issues and represents PG&E before regulatory agencies and the legislature on these issues. RESPD also develops PG&E's plan to achieve and maintain compliance with the Renewables Portfolio Standard (RPS). The department prepares, tracks, and serves as the clearinghouse for RPS reporting both internally and externally. Finally, RESPD manages pilot projects for emerging technologies, including the Department of Energy-sponsored Compressed Air Energy Storage Program.

Energy Storage Program Management Office

The Energy Storage PMO coordinates all energy storage activities to ensure a companywide approach to implementing the CPUC's energy storage target. One incremental headcount is forecast by 2017.

d) Energy Policy, Planning, and Analysis

EPPA has responsibility within EP for participating in regulatory proceedings addressing overarching procurement policy issues and ensuring that procurement policies enable PG&E to continue to provide reliable, affordable, and clean energy resources. EPPA also provides internal analytical support for the transactions undertaken by ESM. EPPA's areas of focus include: policy formulation and implementation for GHG; CHP; integrated resource planning; resource evaluation; portfolio analysis; and competitive analysis. EPPA analyzes future energy supply resources compared to energy demand forecasts, creates fully integrated, long-term demand- and

supply-side electric resource plans, and develops the long-term gas portfolio strategy.

The specific departments within EPPA are: (i) Integrated Resource Planning (IRP); (ii) Long-Term Energy Policy (LTEP); (iii) Energy Policy Modeling and Analysis (EPMA); and (iv) Energy Policy Initiatives (EPI). EPPA also contains individuals working on the Comprehensive Procurement Framework initiative focused on RA policy and the CPUC-CAISO Joint Reliability Plan.

EPPA had 46 positions at the end of 2014. EPPA is not planning additional positions by 2017.

Integrated Resource Planning

The IRP Department is responsible for developing the Long-Term Procurement Plan (LTPP) and for forecasting PG&E's electric generation costs for use in various regulatory proceedings and other external efforts. IRP is responsible for long-term planning to meet the needs of bundled electric customers and core gas customers. This requires analysis and integration of supply-side and demand-side resources, with transmission to develop plans to meet PG&E customers' needs with service that is reliable, affordable, and environmentally responsible.

Long-Term Energy Policy

The LTEP Department is responsible for analytics, policy development, and commercial strategy support on matters related to GHG emissions at the local, state, subnational, and federal levels. LTEP is also responsible for analytics, policy development, and commercial implementation support on matters related to CHP and QFs.

Energy Policy Modeling and Analysis

The EPMA Department is responsible for estimating avoided cost and cost-effectiveness for resource alternatives; devising evaluation frameworks for commercial and regulatory strategies, new products, and emerging markets; providing

analytical support for the design of evaluation protocols for Requests for Offers; and supporting regulatory activities and communication with external stakeholders on these and related issues.

Energy Policy Initiatives

EPI is responsible for strategy formulation, business intelligence, project management, and ensuring smooth transition from policy to implementation for special projects. Current project areas include clean energy, resource integration, distributed energy resources, and long-term strategy for the bundled electric portfolio.

e) Value Based Reliability

VBR is responsible for developing and implementing the strategy for improving coordination of outage scheduling across PG&E's utility-owned and contracted resources portfolio. This includes developing analytical tools and enhancing business process and governance procedures across Energy Procurement, Power Generation, and the Diablo Canyon Power Plant organizations.

VBR also includes the FERC Refund group that oversees the company's recovery of electric market refunds stemming from the 2000-2001 energy crisis. The FERC Refund group is responsible for providing support and expert analyses in the FERC Refund proceedings and other forums, refund negotiations with suppliers and bankruptcy issues related to claims filed by the market suppliers that participated in the CAISO and the California Power Exchange[3] markets.

As of year-end 2014, the VBR organization had 10 positions. By 2017, VBR will add two additional positions for

[3] On January 31, 2001, the California Power Exchange (CALPX) closed its markets and on March 9, 2001 filed for Chapter 11 bankruptcy protection. However, the CALPX continues operations to wind up its FERC-related activities, including the resolution of amounts owed and owing for purchases and sales during the energy crisis.

a total of 12 positions. Section B.3, below, describes why additional headcount is needed in VBR.

f) Energy Contract Management and Settlements

ECMS is responsible for the administration, monitoring, testing, and settlement activities related to all electric and gas procurement contracts, system-balancing energy settlements related to the CAISO, and PG&E policies and reporting requirements. These are commonly referred to as EP's "back office" functions. Groups within ECMS include: (a) Contract Management; (b) Electric Settlements; (c) CAISO Settlements; and (d) Fuel Settlements.

As of year-end 2014, the ECMS organization had 79 positions. ECMS is planning one additional headcount in 2017.

Contract Management

Contract Management's (CM) central function is the prudent administration of the terms and conditions in EP contracts. These include all renewable, conventional, California Department of Water Resources, and QF energy and capacity contracts, as well as contracts for RA, GHG, and financial products. CM acts as the primary interface with the counterparty, and also performs contract interpretation and dispute resolution, project development monitoring, and generator performance testing.

Electric Settlements

Electric Settlements is responsible for the financial settlement of PG&E's portfolio of electricity contracts. Electric Settlements also provides data analysis and reporting expertise to Corporate Accounting for internal and external reporting requirements. The group is divided into three areas: Renewable Contracts, Qualifying Facility and Combined Heat and Power Contracts, and Tolling Contracts.

CAISO Settlements

CAISO Settlements is responsible for all financial settlements between PG&E and the CAISO. This includes the payment, validation, and reporting of all charges and revenues associated with PG&E's electric portfolio activities in the CAISO markets on a daily basis. The CAISO Settlements Department also manages all Settlement Quality Meter Data (SQMD) processes between PG&E and the CAISO, validating and submitting SQMD to CAISO for each trade day.

Fuel Settlements

Fuel Settlements manages, controls, settles, and accounts for all fuel transactions originating from CGS and EGS. Fuel Settlements also provides internal and external reporting to various entities to comply with corporate risk governance and compliance. Specifically, the Fuel Settlements functions include: U.S. and Canadian gas settlements for physical, financial and transportation deals; trading floor daily operations support; and gas-related reporting to Corporate Accounting.

g) Energy Compliance and Reporting

ECR is responsible for cost recovery of all gas and electric procurement activities, compliance with EP-related regulatory and reporting requirements, designing and implementing system and process improvements throughout the EP organization, and managing internal governance and compliance for EP. ECR oversees implementation of EP's risk, compliance, and corrective action management programs.

ECR is responsible for overseeing the demonstration of compliance with PG&E's LTPP through ERRA compliance proceedings and consultation with the Procurement Review Group (PRG), a formal consultation process with non-market

participants.[4] ECR also administers the Independent Evaluators (IE) pool on behalf of the CPUC's Energy Division. IE's are used to monitor long-term resource solicitations. ECR develops and implements an annual IE work plan, conducts the biennial IE review and re-evaluation process, including Request for Bid process, and ensures compliance with use of the CPUC's IE guidelines.

In addition, ECR provides support to EP's technology governance processes and continuous improvement initiatives, leveraging Lean Six Sigma methodologies such as process mapping, controls assessments and root-cause analyses.

Finally, ECR reports and ensures timely, accurate, and consistent responses to data requests and other regulatory inquiries. ECR programs are central to mitigating the compliance risks identified in Section B.2.b below.

As of year-end 2014, the ECR organization had 18 positions. ECR is not planning additional positions by 2017.

b. Key Risks and Mitigations

EP's operations primarily pose financial risks to both PG&E and its customers. Accordingly, the programs and projects forecasted in this chapter seek primarily to mitigate such financial risks.

EP's financial risks can be further categorized as either price risk or compliance risk.

1) Price Risk

Price risk is the inability to procure adequate gas and/or electricity at prices that are acceptable to customers and/or regulators. Such risk may be exacerbated by sustained spikes in wholesale natural gas or electricity costs. Potential causes of price risk could include prolonged summer heat storms, defaults on

---

4 In Decision 02-08-071, the CPUC required each investor-owned utility to establish a PRG whose members have the right to consult with the utility and review the details of the utility's overall procurement strategy, proposed procurement processes, and proposed procurement contracts, before those contracts are submitted to the CPUC for review.

deliveries by large counterparty suppliers, natural or man-made disasters causing supply disruptions, and the increasing complexity of the CAISO and other energy markets, which could lead to unnecessarily high costs due to market design inefficiencies or even the manipulation or "gaming" of markets by counterparties if flaws aren't prevented and corrected as markets evolve.

EP, in coordination with the Chief Risk and Audit Officer's Market and Credit Risk Management organization, has put in place strategies to monitor and mitigate price risks related to EP. These strategies include: (1) portfolio diversification; (2) the use of physical and financial hedging instruments; and (3) review of market design changes and market analysis. The first two of these strategies are implemented principally through formal governance policies and controls.

Portfolio diversification refers to having a mix of resources in the energy portfolio to supply power to meet the needs of PG&E's customers. The resource mix includes renewable generation, hydroelectric generation (Hydro), nuclear generation and fossil-fired generation. Some of these resources are utility-owned, while others are owned by third-parties with contracts of varying lengths. A diverse portfolio allows PG&E greater flexibility in managing its supply need, which minimizes exposure to a single resource type or third party, while also reducing costs through diversification, to provide affordable service to customers.

Physical and financial hedging instruments refer to the product options, whether a specific power contract, or a financially-backed contract, available to PG&E. All of the hedging instruments are approved by the Commission in PG&E's Bundled Procurement Plan in the LTPP proceeding. These instruments provide EP additional flexibility to minimize risk of price volatility in managing the portfolio to meet electric procurement needs at an affordable cost for customers.

Finally, EP mitigates price risk through analysis of market design changes and proposals and the review of market

performance to identify market inefficiencies and detect market aberrations. If detected, PG&E can then employ strategies to protect its customers from these market failures and/or bring them to the attention of regulators for remediation. EP's MIDAS Department is responsible for this market design and analysis. This market analysis will be critical in the 2017-2019 GRC period given PG&E's expectation that new market products will be introduced and that existing markets and balancing areas may expand to more fully integrate the western region.

As described in Section B.2.a, the EP organization is structured to monitor market activities, plan and procure power, operate the system, and ensure contract management and settlement in compliance with the guidelines and requirement specified and approved by the Commission. As the portfolio continues to evolve to include more complex and new resources, revisions to and implementation of the various products and tools are continuing to evolve and requires additional headcount within EP to manage, operate, and settle an increasingly complex and diverse portfolio. Section B.3 describes the need for additional headcount in more detail.

2) Compliance Risk

EP programs mitigate the risk of non-compliance with legal and market requirements. EP has corrective action management programs to proactively identify, validate and mitigate key operational risks, and to monitor regulatory compliance with state and federal rules and obligations.

EP has staff to oversee the demonstration of compliance with PG&E's LTPP through its ERRA compliance filings, which are filed on an annual basis. In addition, EP leads the PRG.

As has been previously noted, the increasing portfolio complexity and anticipated market changes reflect the need to ensure there is sufficient staffing to monitor and manage these programs. As described in Section B.2.a, the EP organization is

structured to ensure continued compliance with the Commission requirements.

3. Key Drivers of 2017 Expense and Capital Increases

a. Expense

The key drivers for the forecasted increase in EP expense costs between 2014 and 2017 are: (1) cost escalation for existing personnel; (2) additional personnel to address increasing portfolio complexity; (3) additional personnel to address new and ongoing regulatory mandates; and (4) EP business process improvement support for technology implementation. This section describes these drivers and the need they create for incremental funding in EP.

Table 6-3, above, summarizes the additional EP employees proposed in the 2017 GRC.

1) Cost Escalation for Existing Resources

Cost escalation due to inflation represents $3.6 million (see Table 6-2, line 1), of the projected $6.3 million 2017 cost increase over 2014 recorded expense. EP is assuming a 2.97 percent labor escalation factor, which is consistent with Company guidelines for support functions. Escalation rates for non-labor resources are also consistent with Company guidelines.[5]

2) Portfolio Complexity

The electric industry continues to become more complicated and complex in response to policy changes and regulatory mandates. Increased costs associated with managing portfolio complexity represent $1.1 million of the forecasted increase in 2017 EP expense over 2014 recorded expense.

Portfolio complexity is a result of both portfolio composition and market changes. These drivers add complexity and increased operational challenges in managing the procurement portfolio. Since the 2014 GRC, significant changes have occurred in the procurement business, including the CPUC's adoption of an energy

---

5 See PG&E's Exhibit (PG&E-12), Chapter 3 for standard escalation rate assumptions.

storage procurement target, the CAISO's implementation of the new 15-minute real-time market (FERC Order 764), the Energy Imbalance Market (EIM), and the continued evolution of new products and services that are needed to integrate renewable resources into PG&E's business operations.

As part of the CAISO process, the CAISO conducts a stakeholder initiative catalogue process each year that allows market participants the opportunity to identify, discuss and rank needed market changes which the CAISO should prioritize in the coming year. As a result of the CAISO's 2015 catalogue process, the CAISO staff presented to its Board of Governors 19 different stakeholder initiatives that would be underway in 2015 alone. Within these 19 initiatives, major initiatives include:

- Energy Storage (ongoing through 2017);
- Reliability Services (currently scheduled to go through the end of 2016);
- Flexible Ramping Product to address load and generation uncertainty; and
- EIM enhancements to address changes needed to effectively incorporate NV Energy, Puget Energy, and Arizona Public Service.

In addition to the 19 stakeholder initiatives, the CAISO identified an additional 50 potential stakeholder initiatives, some of which are discretionary to address market or reliability issues, while others are FERC-mandated. Every indication from the CAISO is that the pace of market changes will not slow down in the next several years.

Most of these market changes will require substantial engagement with the CAISO by PG&E's MIDAS Department to ensure that the CAISO market operates economically and reliably. In addition, most of these initiatives will also requires corresponding changes to PG&E's front office activities associated with forecasting, bidding, scheduling, efforts associated with contracting and re-contracting activities, as well as PG&E's settlements processes.

Each CAISO initiative requires changes to PG&E's monitoring processes to ensure that the new market feature is providing the intended benefits and that there are no unintended consequences such as gaming the market rules. For example, when the EIM and Full Network Model[6] went live in the Fall of 2014, PG&E established detailed procedures to identify any potential market flaws (such as price spikes caused by insufficient ramp or uplift charges from transmission modeling differences borne by PG&E customers).

Finally, with the increasing amounts of intermittent renewables coming online and changing system conditions, PG&E anticipates an increase in the frequency of events that will trigger action in the real time operational environment to support system reliability. Such actions include, but are not limited to, responding to CAISO contingency dispatch instructions and overgeneration, resulting in the need for personnel to be available to respond to these conditions.

A major driver for additional funding of the EP organization is the increasing diversity, complexity and number of contracts within PG&E's electric portfolio. The growth in and distinct characteristics of resources that reside in the portfolio are increasing the costs associated with how PG&E operationalizes new resources that are added to the portfolio and how PG&E administers and settles these contracts. The need to integrate renewables, the introduction of new technologies (such as storage), and the increasing volume of contracts that are smaller in capacity size are all contributing to the increasing costs PG&E forecasts in 2017.

The CAISO market is rapidly and fundamentally evolving. CAISO's EIM, which affords out-of-state utilities the opportunity to participate in CAISO's real-time dispatch, has four members who have either joined or announced their intentions to join.

---

6 Full Network Model is the expansion of the CAISO's dispatch model to provide visibility into neighboring balancing authorities dispatch and improve efficiencies through more accurate representation of electrical flows throughout the Western Electricity Coordinating Council.

Furthermore, PacifiCorp and the CAISO have proposed to include PacifiCorp in the future as a full Participating Transmission Owner in the CAISO.[7] Integration of new transmission systems and co-optimization on a real-time basis of differing pools of load and resource categories must be done carefully to avoid unintended consequences.

The future impacts of renewable integration are still being analyzed and recommendations on how to address these issues have not yet been determined, which poses significant uncertainty in how the markets will respond and what other actions may need to be undertaken at the state or federal level. Similarly, as new resources are developed or are dispatched in new ways, further adjustments may be needed.

During the 2015 through 2017 timeframe, it is anticipated that over 70 new generation projects will be coming online, which represents over 20 percent of the current portfolio. As new resources are getting ready to come online, it takes significant time and effort to coordinate and incorporate these new projects into the portfolio and into the CAISO markets.

a) Short-Term Electric Supply

By 2017, managing the changing procurement portfolio is forecasted to require six additional headcount in the STES Department. As described in Section B.2.a, the STES Department is responsible for real-time and day-ahead operations in EP.

As the Company executes additional procurement of intermittent renewable generation contracts in order to comply with the 33 percent RPS requirement by 2020, increased levels of over-generation will create the need for additional analytics to successfully integrate the renewables while maintaining system

7 See *CAISO. New Participating Transmission Owner Memorandum of Understanding*, April 13, 2015 (available at http://www.caiso.com/Documents/NewParticipatingTransmissionOwnerMemorandum_Understanding.pdf).

reliability. This will include the need for STES to manage an increased number of, and complexity in, the dispatch instructions for PG&E's portfolio in real time operations.

STES will also need additional headcount to perform complex short-term optimization of, address operational feasibility issues related to, and ensure dispatch of the increasing number of RPS contracts with a wide variety of contract terms and conditions. The analyses required to integrate these contracts into daily operations is sophisticated and complex.

Additionally, personnel will be needed to manage and provide subject matter expertise associated with the increasing amounts of system modifications and implementation associated with market and portfolio changes, as well as systems needed to support those changes as described in PG&E's Exhibit (PG&E-5), Chapter 7.

With the changes in the portfolio and market changes, there is a need for additional personnel to ensure STES is staffed to effectively manage daily operations.

b) Portfolio Management

Portfolio Management requests an increase of one full-time employee by 2017. The increase is required for analyzing and managing the additional portfolio complexity associated with the increase in renewables contracts and technologies and new market initiatives.

As PG&E's resource mix changes due to the influx of renewables, its overall generation profile is beginning to change drastically as well. As a result, there is a need to develop new methods and metrics to model and understand how these new resources will impact overall generation in the mid-term (1 month – 5 year) time frame. These tools and analyses will identify and quantify new areas of portfolio need, and be used to guide Portfolio Management in procuring the right kind of contracts and products in its mid-term procurement activities,

including the impacts of increasing amounts of distributed generation.

New market initiatives are also having an effect on Portfolio Management. For example, Portfolio Management is responsible for mid-term congestion price management and CRR procurement. A necessary component in these activities is congestion price forecasting. The recent changes in the CAISO with the EIM has resulted in greater complexity in the forecasting process as new areas of the West need to be modeled in the price forecasting tool. As the CAISO markets continue to evolve, Portfolio Management must make improvements to its congestion price forecasting and other analytical tools so that its procurement activities continue to be effective.

3) Regulatory Mandates

Regulatory mandates to implement state policy objectives have a direct impact on EP activities and resource needs. PG&E's response to incremental regulatory mandates accounts for approximately $1.2 million of EP's 2017 forecasted expense increase over 2014 recorded costs.

PG&E expects that in 2017, it will need to respond to regulatory requirements and initiatives that are intended to meet the state's GHG and renewable energy mandates, energy storage targets, and other mandatory procurement programs. PG&E will require adequate expertise to conduct policy analysis on new regulatory proposals, submit comments and proposals on the optimal design of new programs, and ensure compliance with new requirements resulting from changes in the CAISO wholesale market design.

As described below, PG&E anticipates that many recent or anticipated regulatory initiatives related to EP will result in higher administrative costs throughout the program implementation process.

a) Renewable Energy

The Renewable Energy Department is requesting an increase in headcount of three in 2017 to manage an increased number of solicitations and other EP programs throughout the Company that are running concurrently.

Recent examples of such specialized programs include the Renewable Auction Mechanism (RAM) Program, the Renewable Market-Adjusting Tariff (ReMAT) Program, the Biogas Market-Adjusting Tariff (BioMAT) Program, and the Green Tariff Shared Renewables (GTSR) Program. These programs are expected to add a large number of new, relatively small-volume contracts to PG&E's procured power portfolio. Moreover, these contracts also have unique and/or non-modifiable terms and conditions, which require significant resources to negotiate through a multi-stakeholder public proceeding and additional incremental resources to administer once the contracts have been executed. The set-up, execution, and implementation processes include continual procurement activities as long as these programs remain active. These requirements increase the need for additional resources to implement these programs. In the case of the GTSR Program, this specialized procurement obligation also requires the creation of new systems to separate Green Tariff procurement from other RPS-eligible procurement, since the two systems must be legally distinct.

The Commission's recently approved energy storage procurement target[8] provides a useful example of the types of incremental administrative costs associated with new regulatory requirements. The energy storage program is a new and significant undertaking that requires additional expertise, coordination across multiple lines of business (LOB), and planning to ensure the program is in compliance with the

[8] D.13-10-040.

regulatory requirements. The energy storage program calls for projects interconnecting at the transmission, distribution, and customer levels and has multiple complex objectives (e.g., wholesale market sales, grid optimization, renewable integration). The Renewable Energy Department is responsible for coordinating this effort.

In addition, PG&E requests funds to implement safety programs to administer safety-related terms and conditions in procurement contracts and to evaluate market participant's offers for consistency with Prudent Electrical Practice.

Prudent Electrical Practice is the contractual standard for safe and reliable operation of electric power resources. PG&E will assess certain types of physical electric transaction offers through the use of qualified third-party consultants. The consultants will perform a structured, consistent Process Hazard Analysis or functionally equivalent process to evaluate offers for energy, capacity, and/or other electricity products. This analysis will be conducted in accordance with relevant U.S. OSHA and/or other related industry and regulatory guidelines.

The third-party consultants will provide written deliverables describing the consistency, or lack thereof, of the market participant's plan to operate the facility consistent with Prudent Electrical Practice. PG&E estimates additional funds are required to hire third-party consultants, add additional FTEs, and provide needed training to PG&E employees.

b) Electric Gas Supply

The Electric Gas Supply Department requests an increase of one full-time employee between 2014 and 2017. This additional employee is needed to implement FERC Order 809.

FERC Order 809 requires changes to natural gas scheduling processes across all interstate pipelines in the U.S. California local distribution companies, including PG&E, will have to adopt these changes as well. FERC Order 809

changes the timing of the natural gas scheduling cycles and adds a third intra-day scheduling cycle, which will extend gas scheduling activities into the evening hours.

EGS will require an additional gas scheduler position to cover the additional scheduling activities under FERC Order 809. This will enable EGS to better match its gas deliveries with electric portfolio gas demand.

c) Energy Contract Management and Settlements

The Energy Contract Management and Settlements Department requests an increase of one full-time employee between 2014 and 2017. This additional employee is needed to manage the incremental workload associated with the 33 percent RPS requirement and GHG implementation.

In addition to the need described immediately above, the ISO Settlements Department within ECMS is managing increasingly complex CAISO market data with the implementation of FERC Order 764 (15-minute scheduling) in 2014 and other market initiatives The demands associated with managing these new mandates is increasing the workload, but is being offset by increased efficiency in reporting related to Transmission. As a result, ECMS staff will spend less time on work activities recovered under the electric Transmission Owner (TO) filing. While this move of staff from TO-related work to GRC-funded work results in no additional EP headcount, there is GRC-funded labor increase on existing employees of $200,000 between 2014 and 2017.

4) Process Improvements

In addition to the increased complexity and regulatory mandates associated with PG&E's changing portfolio, there are other critical EP business efforts that are supported by IT infrastructure. In VBR, two incremental positions are needed to address the additional workload associated with enhancing and maintaining business processes and supporting analytical tools to govern decisions on the

optimal time to schedule power plant outages given market conditions, constraints, and other relevant considerations.

b. Overview of Business Need for IT Capital Costs to Support EP

The request presented in this chapter does not include any capital expenditures. However, because some of the capital costs requested in Exhibit (PG&E-5), Chapter 7, are IT projects that support EP business needs, this section provides an overview of the business justification for the requested funding in that chapter.

The key drivers behind EP-related capital expenditures in the 2015-2019 IT forecast are investments related to software to meet new or changing CAISO requirements and enhancements to further automate or streamline existing processes or replacement of obsolete software that is no longer supported by the vendor.

In addition to creating the need for additional employees, the portfolio complexity and regulatory mandates described in Section B.3.a, above, create a corresponding need for investments in IT programs to enable EP employees to efficiently manage an increasingly complex portfolio and respond to market and regulatory changes. Specifically, this section describes the business needs driving the following IT initiatives: CAISO Market Initiatives Implementation (MII); Resource Integration; Foundational Platforms; and Application Consolidation/ Simplification/Upgrades.

1) CAISO Market Initiatives Implementation

Expansion of the CAISO footprint and changes to the types of products traded, bidded, and scheduled within CAISO, as discussed in Section B.3.a.2, will require corresponding changes to EP's IT software and systems. PG&E's CAISO MII Program, discussed in more detail in PG&E's Exhibit (PG&E-5), Chapter 7, enables PG&E to adapt its business processes to implement CAISO market changes and enhancements. The MII Program continues the development and enhancements of market operation platforms which is the collection of technology components that enable portfolio optimization, bidding, scheduling, and CAISO settlements.

2) Resource Integration

The sharp increase in renewable resources and expansion of the CAISO footprint discussed above in Section B.3.a.2 also creates a need for IT enhancements to manage integration of intermittent generation resources. To ensure system reliability and cost-effective operations, STES will need access to near-real time meteorological and generation data for PG&E's entire portfolio and the ability to automatically communicate market signals and dispatch instructions to generation facilities operated by PG&E. The Resource Integration Program, discussed in more detail in PG&E's Exhibit (PG&E-5), Chapter 7, provides these operational enhancements.

3) Foundational Platforms

Building upon earlier efforts during the 2011 and 2014 GRC periods, the EP organization has a continuing need to replace multiple legacy systems with consolidated systems that lead to greater data integration, increase efficiencies, and help to mitigate compliance risks in the face of rapid market and regulatory changes. PG&E's Exhibit (PG&E-5), Chapter 7, provides more detail on the scope of this effort, including development of power scheduling and CM foundational platforms.

4) Application Consolidation/Simplification/Upgrades

The EP organization's heavy reliance on IT systems necessarily creates a continuing need for ongoing support and maintenance for the software, lifecycle updates for hardware and software, and upgrades to stay compliant with vendor support and usability. PG&E's Exhibit (PG&E-5), Chapter 7, provides more detail on the incremental work in this area proposed for the 2017 GRC period.

C. Activities by Major Work Category

EP operation and maintenance expenses and capital costs are allocated to the following Major Work Categories (MWC). These definitions are included to provide insight to the MWC cost break down provided in the workpapers.

1. Operations and Maintenance (O&M) Expense – Administration (AB)

This represents the overall administration costs for the SVP of EP and also includes the *pro-rata* portions for the SVP of Energy Supply, EP Ratemaking, Business Finance and general support provided to EP from other PG&E LOBs.

TABLE 6-4(a)
EP ADMINISTRATION EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	AB	Administration	2,701	2,563	2,589	2,784

(a) See WP Table 6-1, Exhibit (PG&E-5).

2. O&M Expense – Acquire and Manage Electric Supply (CT)

This MWC represents the majority of the EP budget. As described throughout this chapter, the drivers for increased costs in this MWC are escalation due to inflation and the increased resource needs to support new and existing compliance requirements that are expected to increase the complexity of PG&E's portfolio.

TABLE 6-5(a)
ACQUIRE AND MANAGE ELECTRIC SUPPLY
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	CT	Acq & Manage Elect Supply	47,761	49,775	51,858	53,693

(a) See WP Table 6-1, Exhibit (PG&E-5).

3. O&M Expense – Acquire and Manage Gas Supply (CV)

This MWC represents the CGS function, Gas Settlements and the resources necessary to implement Assembly Bill 32 GHG cap-and-trade requirements for Gas Operations.

TABLE 6-6(a)
ACQUIRE AND MANAGE GAS SUPPLY
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	CV	Acq & Manage Gas Supply	3,928	4,043	4,083	4,329

(a) See WP Table 6-1, Exhibit (PG&E-5).

4. O&M Expense – Maintain Buildings (BI)

This MWC represents costs associated with real estate projects that support EP, such as the alternative Energy Procurement Headquarters, which is used as an emergency back-up site for EP operations.

TABLE 6-7(a)
MAINTAIN BUILDINGS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	BI	Maint Buildings	262	170	170	170

(a) See WP Table 6-1, Exhibit (PG&E-5).

5. O&M Expense – Maintain IT Applications and Infrastructure (JV)

This MWC represents expense costs associated with developing and implementing new software or systems to meet specific business needs for the customer. These costs are provided here for informational and contextual purposes only; the request for these forecasted costs is made in PG&E's Exhibit (PG&E-5), Chapter 7.

TABLE 6-8(a)
MAINTAIN IT APPLICATIONS AND INFRASTRUCTURE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	JV	Maintain IT Apps & Infrastructure	1,353	467	730	2,100

(a) See WP Table 7-1, Exhibit (PG&E-5).

6. Capital – Build IT Applications and Infrastructure (2F)

This MWC represents capital costs associated with development of in-house solutions, or costs from procurement through external software vendors to meet specific business needs. These costs are provided here for informational and contextual purposes only; the request for these forecasted costs is made in PG&E's Exhibit (PG&E-5), Chapter 7. The significant increases in EP's IT infrastructure over the years is in response to the rapidly changing business needs and market environment. For more information, please refer to PG&E's Exhibit (PG&E-5), Chapter 7.

TABLE 6-9(a)
BUILD IT APPLICATIONS AND INFRASTRUCTURE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	2F	Build IT Apps & Infrastructure	18,837	15,866	17,550	17,500	17,700	19,500

(a) See WP Table 7-12, Exhibit (PG&E-5).

D. Estimating Methods

EP's expense-related forecast arises primarily through inflation applied to existing resources and through changes in the total number of full-time employees within EP. The needs are therefore estimated by:

1. Application of the PG&E standard for inflation against existing labor and non-labor resources based on 2014 recorded costs. For additional information on cost escalation rates used for determining the effect of inflation, please refer to PG&E's Exhibit (PG&E-12), Chapter 3.
2. A labor adjustment for attrition of $1.7 million was applied to the 2015 forecast. This reduction to the forecast is to reflect expectations that there will be unplanned turnover in the department in part due to the favorable economic climate for employees with skill sets in renewable energy and clean energy technology. As such turnover occurs EP also looks for opportunities to re-level positions to manage labor costs. This was calculated as a high level estimate assuming 3 percent of the 2014 recorded costs.

3. For new employee hires, a cost per employee is developed according to the type of position being hired. This cost includes salary and benefits, materials, vehicle usage, IT and facility burdens and all other employee expenses.[9]
4. New employee hires are assumed to be staged in through 2014-2017, per the hiring timelines forecasted by the departmental leads.

E. Compliance With 2014 General Rate Case Requirements

In the 2014 GRC Decision, the Commission approved a settlement between PG&E and the Small Business Utility Advocates and ordered PG&E to carry out the settlement.[10] Three of the provisions of that settlement are related to EP functions and are discussed below.

1. Support for Small Electric Generators

Section 3.2 of the settlement provides as follows:

> The Settling Parties agree that as part of the increased number of employees identified for PG&E's Energy Procurement organization…PG&E will assign one FTE for the 2014 GRC period to support small electric generators (i.e., generators that are 5 megawatts or less) under the Commission's Renewable Performance Standard (RPS) program or similar mandated procurement programs, such as the Senate Bill 1122 Feed-in Tariff program. PG&E' s agreement to assign an FTE as described above is contingent on Commission approval of substantially all of the FTEs under the RPS Contract Administration and GHG requirements, as requested in Exhibit (PG&E-6), Chapter 5, p. 5-20, Table 5-7, Lines 2-3; provided, however, that PG&E will consider this assignment in good faith regardless of the number of FTEs approved by the Commission.

The Commission did not adopt PG&E's request in the 2014 GRC to hire 12 new employees in the Energy Procurement organization to implement and administer GHG-related requirements.[11] Accordingly, PG&E was relieved of its obligation under the settlement to dedicate one full-time employee to support small electric generators. Nevertheless, EP has sought to use its existing resources to continue enhancing outreach to the small business community. For example, PG&E provides a link on its external website that allows any business to complete a distribution list form

---

9 See WP Table 6-7, Line 15, Exhibit (PG&E-5).

10 D.14-08-032 at 740 (Ordering Paragraph 37). The settlement was included as Appendix F-2 to D.14-08-032.

11 Id. at 430-431.

in order to receive notification of PG&E's solicitations and other procurement-related information. (www.pge.com/rfo.) PG&E also has personnel within EP to develop and implement the BioMAT Program, the ReMAT Program, and the RAM Program, all of which are programs focused on procurement from small electric generators.

2. GHG Compliance Outsourcing

Section 3.4.1 of the settlement provides:

> PG&E currently intends to fulfill work related to GHG compliance and carbon offsets with internal staff. The Settling Parties agree that if and when PG&E determines to outsource this work, PG&E will engage in written outreach and education to alert small businesses of such contracting opportunities in advance of issuing any bids or requests for proposals.

PG&E does not currently outsource this work and has no current plan to do so.

3. Outreach and Education Regarding Requests for Proposals

Section 3.4.2 of the Settlement provides:

> The Settling Parties agree that PG&E will require any FTE positions funded for [Assembly Bill (AB)] 32 compliance and responsible for setting commercial strategies, procuring GHG emission allowances, and pursing contracts with offset providers, as described in PG&E's 2014 GRC, Exhibit (PG&E-6), p. 5-12, to engage in written outreach and education to alert small businesses of any attendant contracting opportunities in advance of issuing any bids or requests for proposals.

As previously stated, the Commission did not adopt PG&E's request in the 2014 GRC to hire 12 new employees in the Energy Procurement organization to implement and administer GHG-related requirements, therefore this provision does not apply. However, PG&E has done the following:

- PG&E provides a link on its external website that allows any business to complete a distribution list form in order to receive notification of PG&E's solicitations and other procurement-related information. (www.pge.com/rfo.)
- Additional information is available at www.pge.com/supplierdiversity, which includes steps to doing business with PG&E and its minimum contractor requirements, Technical Assistance Program, Prime Supplier Program, CPUC diverse business certification, and a list of frequently

asked questions and responses regarding doing business with PG&E. At this website small businesses can learn about specific advantages that they may qualify for as a Diverse Business Enterprise, including emerging technologies opportunities through the University of California Advanced Technology Management Institute.

- PG&E currently has GHG procurement solicitation outreach programs to Women, Minority, or Disabled Veteran Owned Business Enterprises (WMDVBE) and Lesbian, Gay, Bisexual, and Transgender (LGBT) businesses in line with the Commission's General Order 156. Many of these WMDVBE and LGBT businesses are also small businesses.
- PG&E also updates monthly an online calendar of outreach and training events of interest to small businesses.

F. Cost Tables

TABLE 6-10(a)
EP
EXPENSES HISTORICAL AND FORECAST BY YEAR AND MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast
1	AB	Administration	$2,701	$2,563	$2,589	$2,784
2	BI	Maint Buildings	262	170	170	170
3	CT	Acq & Manage Elect Supply	47,761	49,775	51,858	53,693
4	CV	Acq & Manage Gas Supply	3,928	4,043	4,083	4,329
5		Subtotal	$54,651	$56,550	$58,700	$60,975
6	JV	Maintain IT Apps & Infrastructure(b)	$1,353	$467	$730	$2,100

(a) See WP Table 6-1, Exhibit (PG&E-5).

(b) MWC JV expense forecast is requested in PG&E's Exhibit (PG&E-5), Chapter 7 and is provided here for contextual purposes only.

TABLE 6-11(a)
EP
CAPITAL EXPENDITURE HISTORICAL AND FORECAST BY YEAR AND MWC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
1	2F	Build IT Apps & Infrastructure(b)	$18,837	$15,866	$17,550	$17,500	$17,700	$19,500
2		Total	$18,837	$15,866	$17,550	$17,500	$17,700	$19,500

(a) See WP Table 7-12, Exhibit (PG&E-5).

(b) MWC 2F capital forecast is requested in PG&E's Exhibit (PG&E-5), Chapter 7 and is provided here for contextual purposes only.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

ENERGY SUPPLY TECHNOLOGY PROGRAMS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
ENERGY SUPPLY TECHNOLOGY PROGRAMS

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
ENERGY SUPPLY TECHNOLOGY PROGRAMS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
ENERGY SUPPLY TECHNOLOGY PROGRAMS

TABLE OF CONTENTS
(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
ENERGY SUPPLY TECHNOLOGY PROGRAMS

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to demonstrate that Pacific Gas and Electric Company's (PG&E or the Company) forecasts of capital and expense costs for Technology Programs, Projects, and Systems supporting PG&E's Energy Supply (ES) function are reasonable and should be adopted by the California Public Utilities Commission (CPUC or Commission).

The technology work described in this chapter is necessary to maintain, consolidate, upgrade, integrate, and, as necessary, enhance ES technology systems during the 2017-2019 forecast period. These systems enable and control the operational processes and programs critical to planning, generating, acquiring, and supplying energy to PG&E's customers in a safe, reliable, environmentally-sensitive, and affordable manner.

This chapter also includes the Energy Supply-related costs associated with the Company's cybersecurity program. The cybersecurity program addresses risk evaluation and mitigation strategies to reduce operational risks and improve the safety and reliability of the Company's cyber assets. Because of the operational sensitivity concerning this work, PG&E has centralized its discussion of all cybersecurity work, including this work to be initiated by the Energy Supply line of business (LOB), in one location. Therefore, for a description of the forecasted cybersecurity work and justification of the forecast, please see Exhibit (PG&E-7), Chapter 10.

As PG&E's ES function responds to changing markets, operational demands, performance requirements and regulatory requirements, the supporting technology systems must be updated to assure that they continue to meet business needs. Additionally, in order to maintain integrity and compliance, technology systems must be upgraded or replaced as they age.

PG&E Energy Supply technology plans through 2019 focus on three interdependent areas that together provide the technology-based

capabilities upon which Energy Supply can execute its mandate to produce and procure safe, clean, reliable and cost-effective electricity and natural gas to serve PG&E's customers. These areas are:

- *Telecommunications and field data collection technology infrastructure* that provide the data and voice telecommunications and data acquisition technologies required to operate and monitor PG&E and third party generation plants and hydro generation infrastructure,[1] and also to support critical business and emergency systems. These systems include telephony, radio, and voice and data access both to PG&E's facilities and, as required, to facilities of third parties for whom PG&E provides market scheduling services or from whom PG&E acquires energy.
- *Foundational platforms* that provide capabilities for PG&E to conduct market analysis, forecasting, trading, bidding, scheduling, optimization, and settlement. These operations enable PG&E to participate effectively and efficiently in California's complex energy markets and to ensure compliance with all applicable regulations.
- *Software applications and end-user technologies* that allow PG&E's Energy Supply workforce to work both in the office and in the field safely and efficiently, while remaining compliant with regulatory and other compliance requirements. These applications and technologies rely upon the infrastructure and foundational platforms described above.

The modernization, upgrade and new projects in these three interdependent technology areas, and the continued maintenance, remediation and consolidation of existing systems, that are proposed in this chapter together provide the necessary technology-based capabilities to support Energy Supply's planning, construction, maintenance, compliance and generation, and market operations duties safely, reliably, and efficiently in the rapidly evolving market and regulatory landscape.

This chapter describes, forecasts, and justifies technology-related expense and capital costs for work specific to PG&E's ES function.[2] For

---

1 Such as water transport (conveyances), water storage, and related assets and infrastructure having critical workforce and public safety and reliability considerations.

2 Enterprise-wide technology initiatives are discussed in Exhibit (PG&E-7), Chapter 8.

ease of reference, citations are provided to other ES chapters, where relevant.[3]

2. Summary of Request

PG&E's ES function includes three major business areas: Nuclear Generation, Power Generation (PG), and Energy Procurement (EP).[4] The technology project-related requests for each of these major business areas are presented in Exhibit (PG&E-5), Chapter 7, both cumulatively and separately in these subsections.

PG&E requests that the Commission adopt its 2017 forecast of ES technology expense of $7.4 million.[5] PG&E also requests that the Commission adopt PG&E's capital forecast for ES technology projects of $39.0 million for 2015, $54.5 million for 2016, $52.3 million for 2017, $45.1 million for 2018, and $43.5 million for 2019.[6]

This level of funding is necessary to ensure that the ES function can provide safe, reliable, environmentally-sensitive, and cost-effective energy to PG&E's customers while complying with all complex and changing regulatory, operational, and market requirements.

a. Expense

PG&E's $7.4 million ES technology-related expense request consists of $1.65 million for PG, $1.85 million for Nuclear, $2.1 million for EP, and $1.8 million for cybersecurity as shown in Table 7-1.

---

3 The Energy Supply business area chapters are: Nuclear Operations Costs, Chapter 3; Hydro Operations Costs, Chapter 4; Fossil and Other Generation Operations Costs, Chapter 5; and Energy Procurement Administration Costs, Chapter 6. Where a chapter is cited without an exhibit reference, this Energy Supply Exhibit (PG&E-5), Chapter 7 is implied. Additionally, a section reference without a chapter implies a reference to Exhibit (PG&E-5), Chapter 7.

4 PG includes Hydroelectric Generation (Hydro), and fossil-fueled and other generation resources. While Hydro, and fossil and other generation are presented in separate chapters in Exhibit (PG&E-5) for purposes of technology support, PG is treated as a consolidated organization.

5 See WP 7-2, Line 1, Exhibit (PG&E-5).

6 See WP 7-47, Line 3, Exhibit (PG&E-5).

TABLE 7-1
ENERGY SUPPLY TECHNOLOGY PROGRAMS & CYBERSECURITY EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	Workpaper Reference
1	JV	Nuclear	$ -	$ 247	$ 3,600	$ 1,850	WP 7-43 Line 24
2	JV	Power Generation	$ 772	$ 361	$ 3,100	$ 1,650	WP 7-44 Line 23
3	JV	Energy Procurement	$ 1,353	$ 467	$ 730	$ 2,100	WP 7-45 Line 26
4	**JV**	**Non-Cyber Subtotal**	**$ 2,124**	**$ 1,075**	**$ 7,430**	**$ 5,600**	
5	JV	Cyber Security	$ -	$ 500	$ 750	$ 1,800	WP 7-15 Line 580
6	**JV**	**Total**	**$ 2,124**	**$ 1,575**	**$ 8,180**	**$ 7,400**	

Note: Cybersecurity Programs are described in Exhibit 7, Chapter 10.

b. Capital

Table 7-2, below, shows ES technology recorded and forecast capital costs for 2014-2019. The drivers for the three technology cost forecasts are described in Sections B.3.a.-c., below.

TABLE 7-2
ENERGY SUPPLY TECHNOLOGY PROGRAMS & CYBERSECURITY CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Workpaper Reference
1	2F	Nuclear	$ 6,276	$ 6,019	$ 12,400	$ 13,550	$ 12,050	$ 10,250	WP 7-57 Line 37
2	2F	Power Generation	$ 13,901	$ 6,979	$ 13,400	$ 11,950	$ 12,100	$ 10,700	WP 7-59 Line 40
3	2F	Energy Procurement	$ 18,837	$ 15,866	$ 17,550	$ 17,500	$ 17,700	$ 19,500	WP 7-61 Line 48
4	**2F**	**Non-Cyber Subtotal**	**$ 39,014**	**$ 28,864**	**$ 43,350**	**$ 43,000**	**$ 41,850**	**$ 40,450**	
5	2F	Cyber Security	$ -	$ 4,000	$ 8,000	$ 9,300	$ 3,200	$ 3,000	
6	3M	SmartGrid Pilot	$ 155	$ 6,089	$ 3,100	$ -	$ -	$ -	WP 7-47 Line 2
7	**2F/3M**	**Total**	**$ 39,169**	**$ 38,953**	**$ 54,450**	**$ 52,300**	**$ 45,050**	**$ 43,450**	

Note: Cybersecurity Programs are described in Exhibit 7, Chapter 10.

B. Activities and Costs

1. Overview of Recorded and Forecast Costs

a. Expense

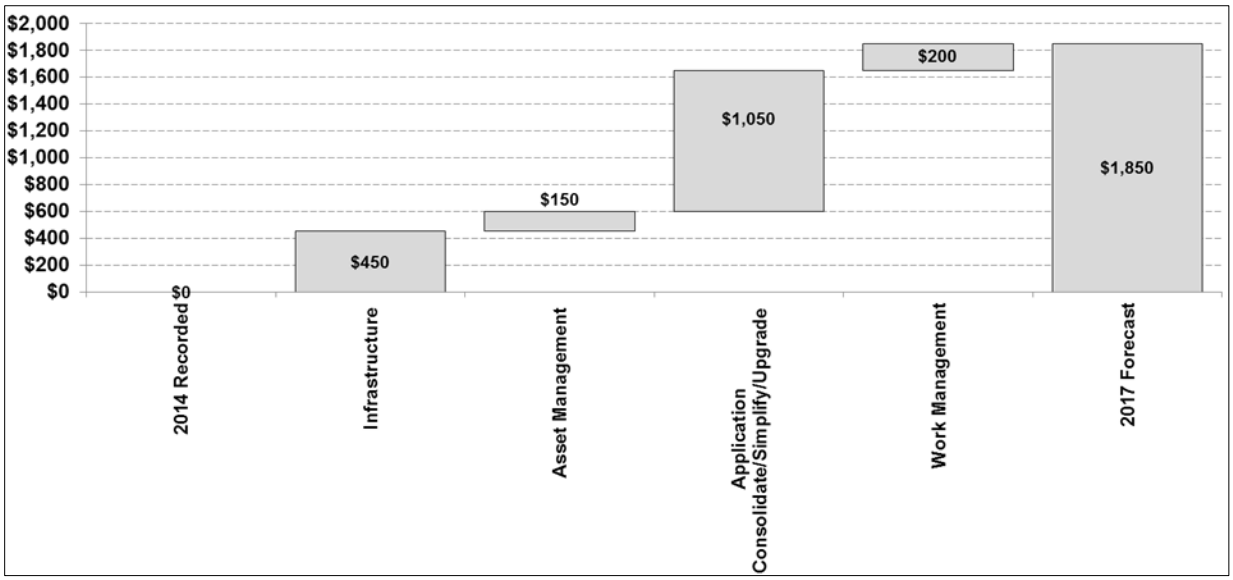
This section describes the changes in forecasted technology expense costs in 2017 compared to recorded 2014 expense costs by major business area.

Overall, ES technology expense costs are increasing primarily due to additional cybersecurity expenses, which represent about one-third of the expense increase between 2014 and 2017. These cybersecurity programs are described in Exhibit (PG&E-7), Chapter 10. The remainder of the increase is due to increased support and implementation costs on projects, particularly at Diablo Canyon Power Plant (DCPP), where additional capital Information Technology (IT) projects are planned over the General Rate Case (GRC) period for implementation, consolidation, and upgrades to key software and supporting IT infrastructure systems.

1) Nuclear Generation Technology Expense Overview

Figure 7-1 shows the drivers behind changes in Nuclear Generation technology-related expense costs between 2014 and 2017. The principal driver of the increase in that time period is application consolidation and upgrades to several key applications. Each of the drivers is described in detail in Section B.3.a, below.

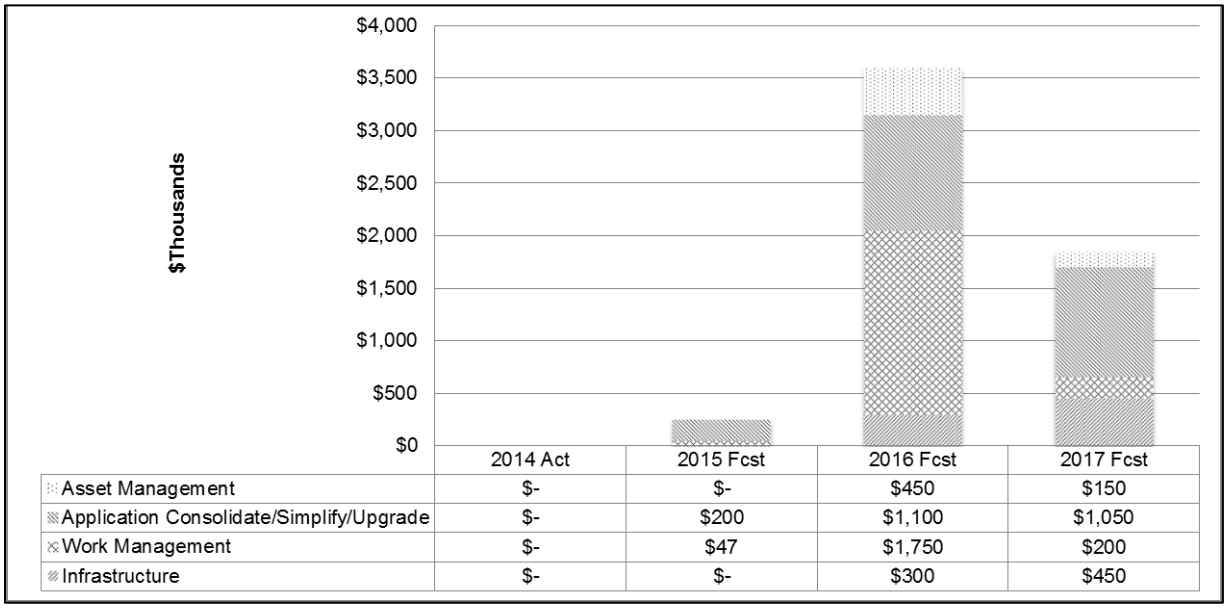
FIGURE 7-1
ENERGY SUPPLY NUCLEAR GENERATION TECHNOLOGY PROGRAM
NON-CYBER SECURITY EXPENSE WALK
(2014-2017)(a)
(THOUSANDS OF NOMINAL DOLLARS)



(a) See WP 7-43, Lines 9, 12, 18, 23, 24, Exhibit (PG&E-5).

Figure 7-2 shows Nuclear Generation technology-related expense totals for each year in the 2014-2017 period. The significant forecast expense increase in 2016 to $3.6 million is due to an increase in capital projects over 2015, and, in particular, a project that involves converting work procedures from paper to an electronic format. The lower 2017 forecast of $1.85 million, in turn, reflects the completion of work procedures electronic conversion and deployment onto mobile platforms in 2016.

FIGURE 7-2
ENERGY SUPPLY TECHNOLOGY PROGRAM NUCLEAR GENERATION
NON-CYBERSECURITY ACTUAL/FORECAST – EXPENSE
(2014-2017)(a)
(THOUSANDS OF NOMINAL DOLLARS)



	2014 Act	2015 Fcst	2016 Fcst	2017 Fcst
Asset Management	$-	$-	$450	$150
Application Consolidate/Simplify/Upgrade	$-	$200	$1,100	$1,050
Work Management	$-	$47	$1,750	$200
Infrastructure	$-	$-	$300	$450

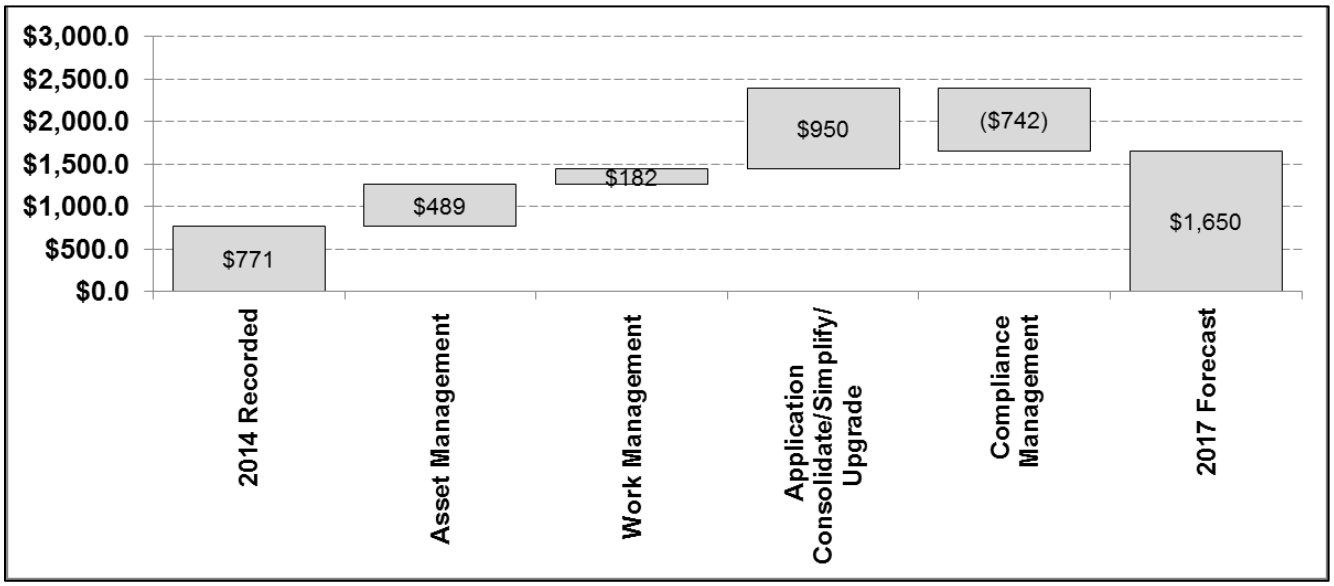
(a) See WP 7-43, Lines 9, 12, 18, 23, 24 Exhibit (PG&E-5).

2) Power Generation Technology Expense Overview

Figure 7-3 shows the drivers behind changes in PG technology-related expense costs between 2014 and 2017. These drivers are described in more detail in Section B.3.b, below. The recorded 2014 expense is predominately driven by Compliance Management projects that are expected to end before 2017, resulting in decreases for that category in the figure. The major

increase from 2014-2017 is for Application Consolidation/Simplify/ Upgrade activities to maintain application health and suitability.

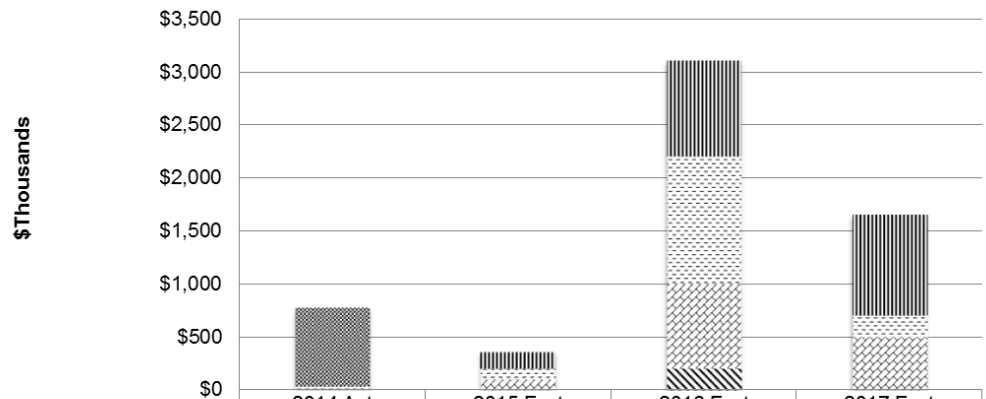
FIGURE 7-3
ENERGY SUPPLY POWER GENERATION TECHNOLOGY PROGRAM
NON-CYBER SECURITY EXPENSE WALK
(2014-2017)(a)
(THOUSANDS OF NOMINAL DOLLARS)



(a) See WP 7-44, Lines 6, 12, 14, 16, 22, 23, Exhibit (PG&E-5).

Figure 7-4 shows PG technology-related expense totals for each year in the 2014-2017 period.

FIGURE 7-4
ENERGY SUPPLY POWER GENERATION TECHNOLOGY PROGRAM
NON-CYBERSECURITY ACTUAL/FORECAST – EXPENSE
(2014-2017)(a)
(THOUSANDS OF NOMINAL DOLLARS)



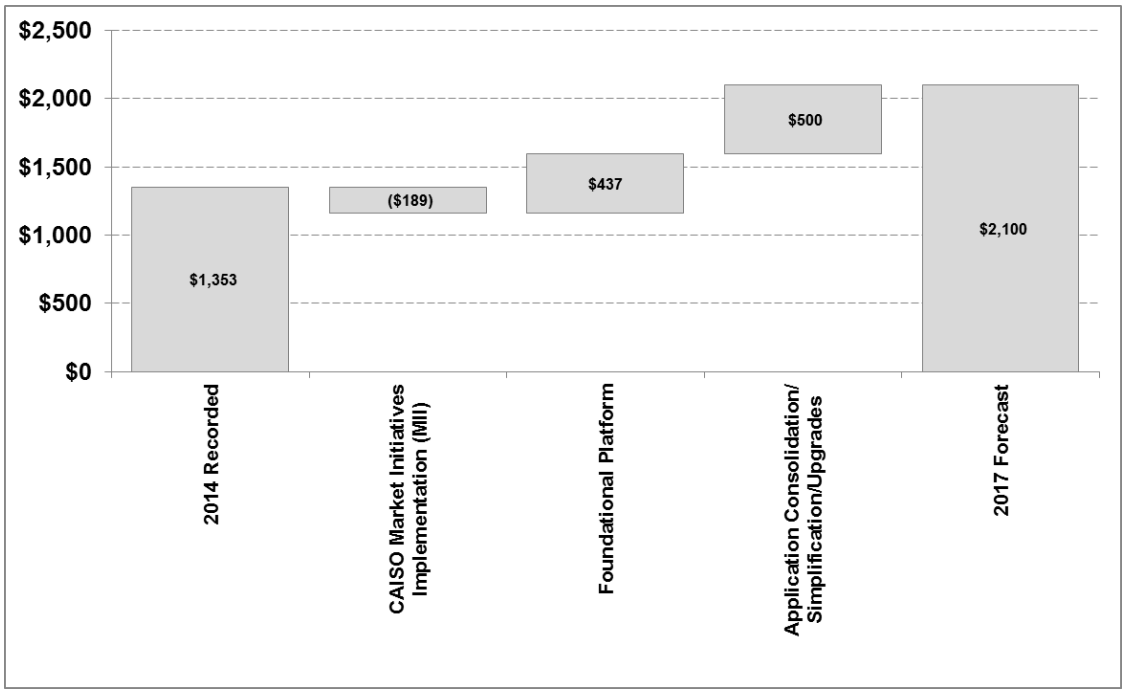
	2014 Act	2015 Fcst	2016 Fcst	2017 Fcst
Compliance Management	$742	$-	$-	$-
Application Consolidate/Simplify/Upgrade	$-	$161	$900	$950
Work Management	$18	$100	$1,200	$200
Asset Management	$11	$100	$800	$500
Infrastructure	$-	$-	$200	$-

(a) See WP 7-44, Lines 6, 12, 14, 16, 22, 23, Exhibit (PG&E-5).

3) Energy Procurement Technology Expense Overview

Figure 7-5 shows the drivers behind changes in EP technology-related expense costs between 2014 and 2017. The principle drivers of the increase in that time period are investments in foundational platforms and the consolidation and retirement of legacy applications and their respective data. Each of the drivers is described in detail in Section B.3.c., below.

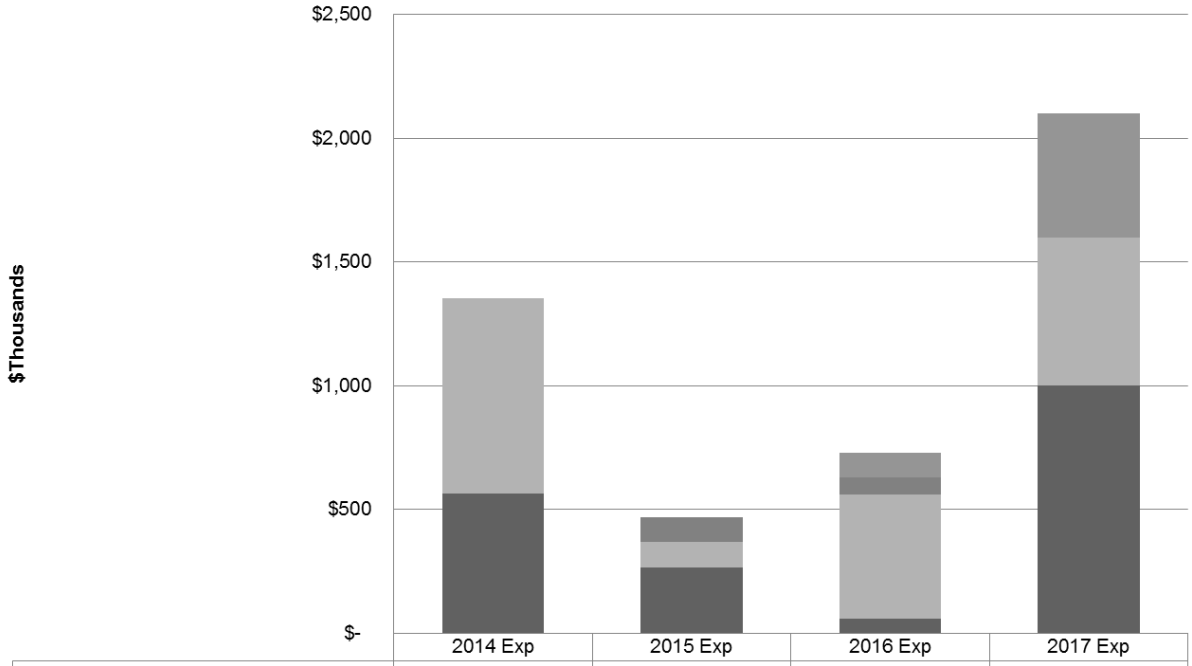
FIGURE 7-5
ENERGY SUPPLY ENERGY PROCUREMENT TECHNOLOGY PROGRAM
NON-CYBERSECURITY EXPENSE WALK
(2014-2017)(a)
(THOUSANDS OF NOMINAL DOLLARS)



(a) See WP 7-45, Lines 4, 16, 21, 25, 26, Exhibit (PG&E-5).

Figure 7-6 shows EP technology-related expense totals for each year in the 2014-2017 period.

FIGURE 7-6
ENERGY SUPPLY TECHNOLOGY PROGRAM ENERGY PROCUREMENT
NON-CYBERSECURITY ACTUAL/FORECAST – EXPENSE(a)
(THOUSANDS OF NOMINAL DOLLARS)



	2014 Exp	2015 Exp	2016 Exp	2017 Exp
Application Consolidation/Simplification/Upgrades	$-	$-	$100	$500
Resource Integration		$100	$70	$-
CAISO Market Initiatives Implementation (MII)	$789	$100	$500	$600
Foundational Platforms	$563	$267	$60	$1,000

(a) See WP Table 7-45, Lines 4, 16, 21, 25, 26, Exhibit (PG&E-5).

b. Capital

This section describes ES technology-related capital expenses from 2014-2019 by major business area.

Overall, the $13.1 million total increase in ES technology capital spending forecast between 2014 and 2017 and shown in Table 7-2, above, is largely driven by cybersecurity ($9.3 million). These cybersecurity programs are described in Chapter 10 of Exhibit (PG&E-7). The remaining increase ($3.8 million) is primarily comprised of improvements to IT infrastructure, resource integration capabilities, application consolidation and upgrade efforts, and Asset and Work Management systems, across the Energy Supply function. Among the larger capital projects described in more detail below are the

replacement of the radio and telephone systems at DCPP and continued strengthening and extension of the telecommunications infrastructure supporting Hydro operations.

1) Nuclear Generation Technology Capital Overview

Figure 7-7 shows the relative technology-related capital expenditures in Nuclear Generation by driver in 2014. Figure 7-8 presents a similar figure for 2017.

Infrastructure projects represent approximately one-half of the 2014 capital costs for Nuclear, with Work Management (WM) activities covering most of the remainder.[7] Each of these categories of capital costs is described in Section B.3.a., below.

In 2017, PG&E forecasts a significant increase in technology capital spending at DCPP to replace both the plant's radio and telephone systems. This results in infrastructure investments totaling over half the capital spending in that year. Work Management, Asset Management, and application consolidation and upgrades are the other major drivers of the 2017 capital project portfolio.

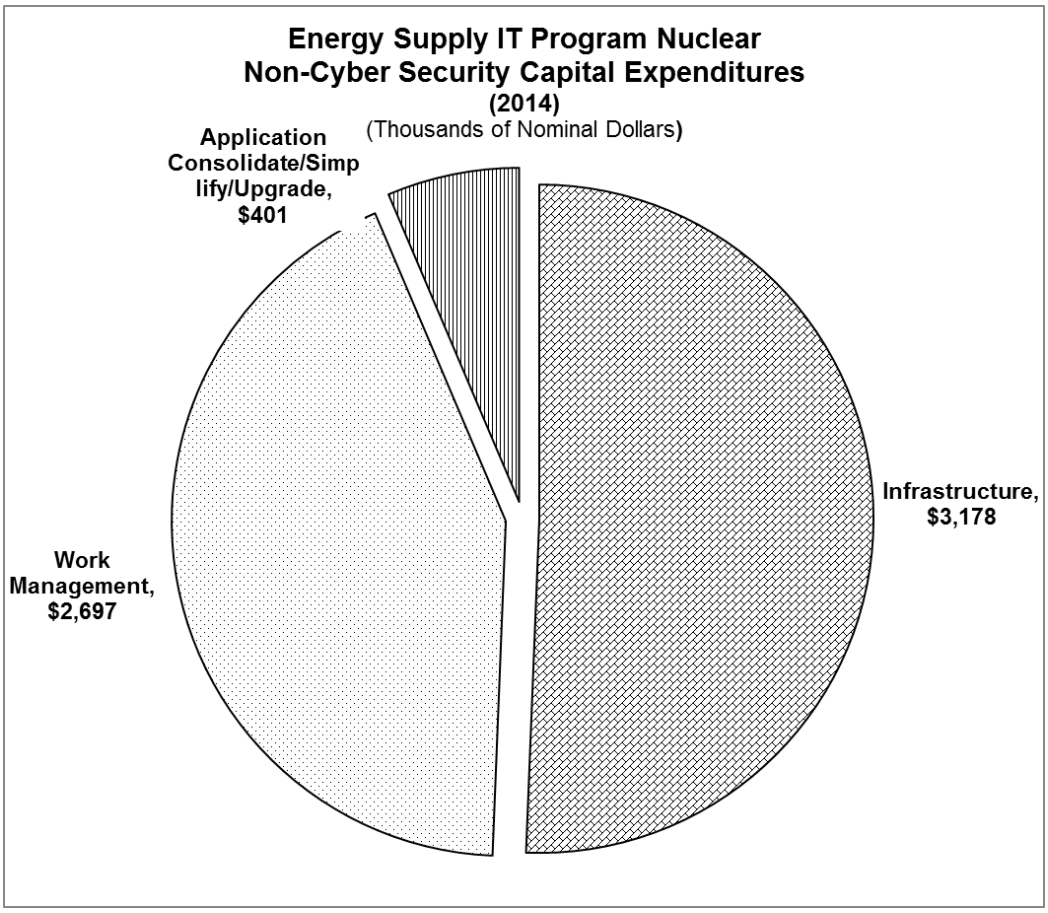
Figure 7-9 shows total technology-related capital expenditures recorded or forecasted for the Nuclear Generation organization in the years 2014-2019. PG&E anticipates that capital spend in 2017-2019 will rise and then steadily decline through the balance of the forecast period. The significant increase between 2015 and 2016 reflects projects that were rescheduled in 2014 and 2015 as an outcome of PG&E's companywide annual integrated planning process.[8]

---

7 In this Exhibit (PG&E-5), Chapter 7, Infrastructure refers to telecommunications and other permanently installed technology systems that enable business capabilities such as Asset Management (AM) and WM.

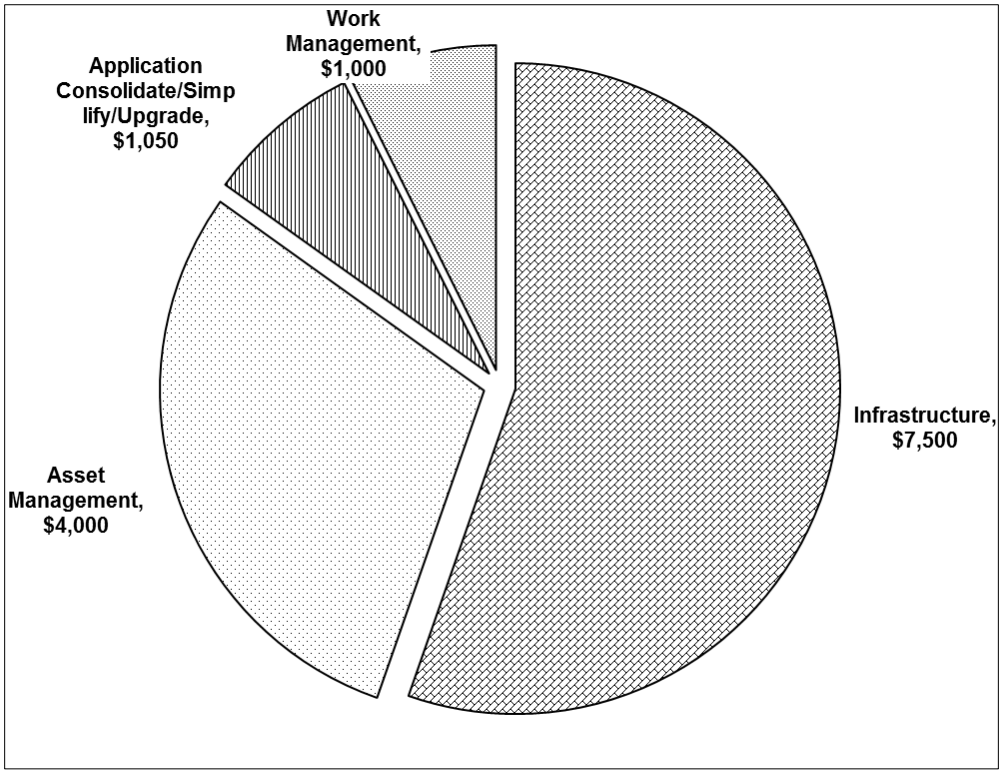
8 See Exhibit (PG&E-2), Chapter 4 for discussion and support for the Company's Integrated Planning Process.

FIGURE 7-7
ENERGY SUPPLY TECHNOLOGY PROGRAM NUCLEAR
NON-CYBERSECURITY CAPITAL EXPENDITURES
(2014)(a)
(THOUSANDS OF NOMINAL DOLLARS)



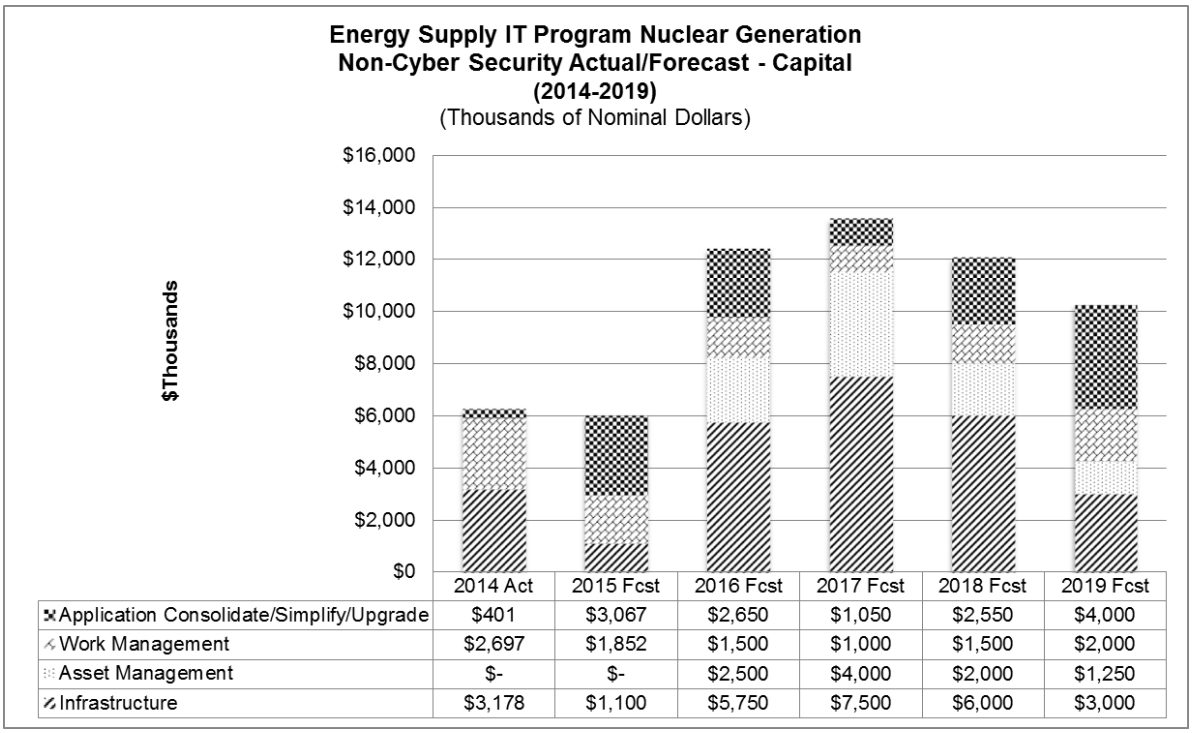
(a) See WP 7-57, Lines 11, 30, 36, Exhibit (PG&E-5).

FIGURE 7-8
ENERGY SUPPLY TECHNOLOGY PROGRAM NUCLEAR
NON-CYBERSECURITY CAPITAL EXPENDITURES
(2017)(a)
(THOUSANDS OF NOMINAL DOLLARS)



(a) See WP 7-57, Lines 11, 15, 30, 36, Exhibit (PG&E-5).

FIGURE 7-9
ENERGY SUPPLY TECHNOLOGY PROGRAM NUCLEAR GENERATION
NON-CYBERSECURITY ACTUAL/FORECAST – CAPITAL
(2014-2019)(a)
(THOUSANDS OF NOMINAL DOLLARS)



	2014 Act	2015 Fcst	2016 Fcst	2017 Fcst	2018 Fcst	2019 Fcst
Application Consolidate/Simplify/Upgrade	$401	$3,067	$2,650	$1,050	$2,550	$4,000
Work Management	$2,697	$1,852	$1,500	$1,000	$1,500	$2,000
Asset Management	$-	$-	$2,500	$4,000	$2,000	$1,250
Infrastructure	$3,178	$1,100	$5,750	$7,500	$6,000	$3,000

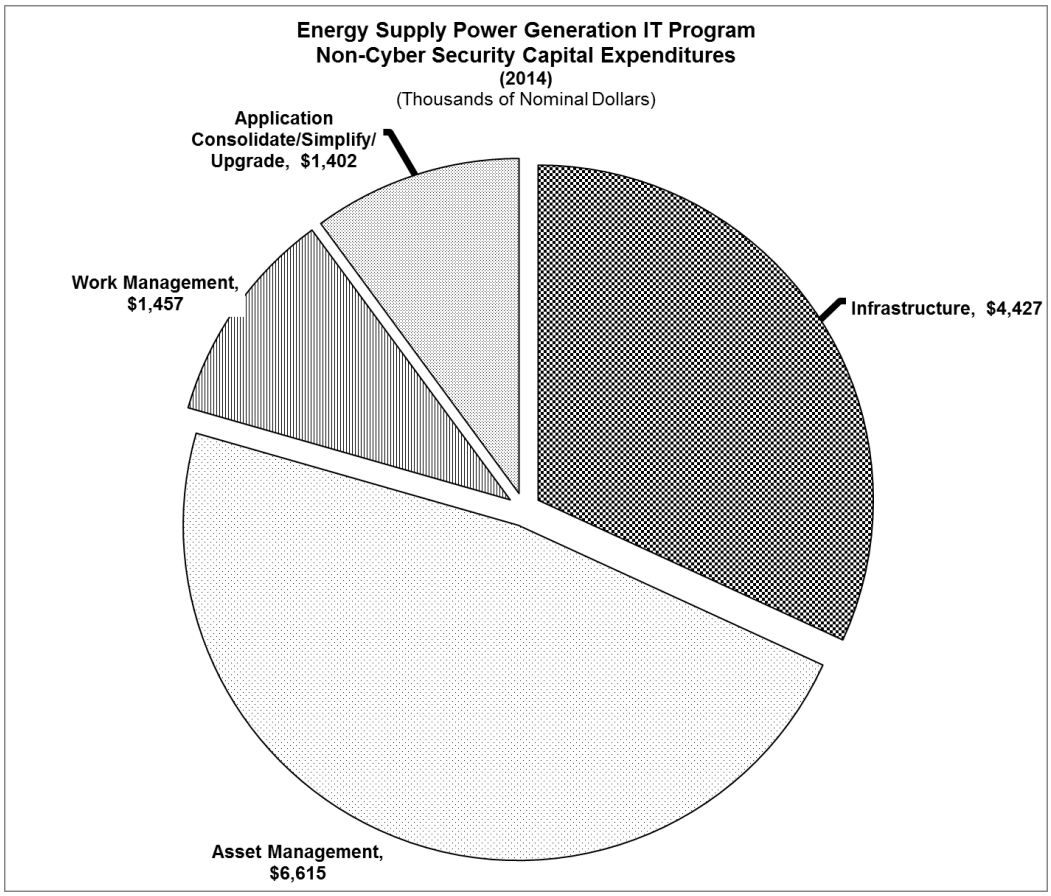
(a) See WP 7-57, Lines 11, 15, 30, 36, Exhibit (PG&E-5).

2) Power Generation Technology Program Capital Overview

Figure 7-10 shows the relative technology-related capital expenditures in PG by driver in 2014. Figure 7-11 presents a similar figure for 2017.

Approximately one-half of the 2014 capital costs are for Asset Management Program activities and almost one-third for Infrastructure. The balance is split about equally between Work Management and application consolidation project-related activities. Each of these categories of capital costs is described in Section B.3.b., below.

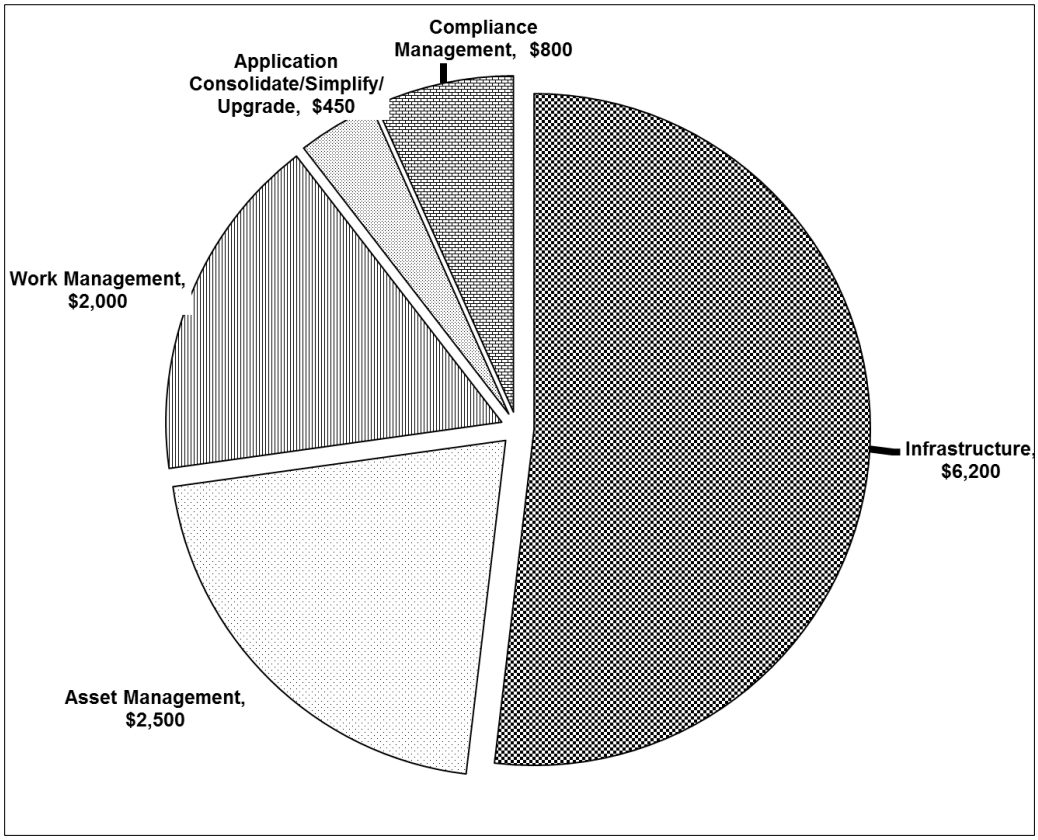
FIGURE 7-10
ENERGY SUPPLY POWER GENERATION TECHNOLOGY PROGRAM
NON-CYBERSECURITY CAPITAL EXPENDITURES
(2014)(a)
(THOUSANDS OF NOMINAL DOLLARS)



(a) See WP 7-58, 59, Lines 8, 21, 32, 39, Exhibit (PG&E-5).

In 2017, as shown in Figure 7-11, the share of technology infrastructure work increases to approximately half the total capital expenditures. WM and AM activities together are forecasted to comprise about one-third of the capital expenditures, with the balance in other programs.

FIGURE 7-11
ENERGY SUPPLY POWER GENERATION TECHNOLOGY PROGRAM
NON-CYBERSECURITY CAPITAL EXPENDITURES
(2017)(a)
(THOUSANDS OF NOMINAL DOLLARS)

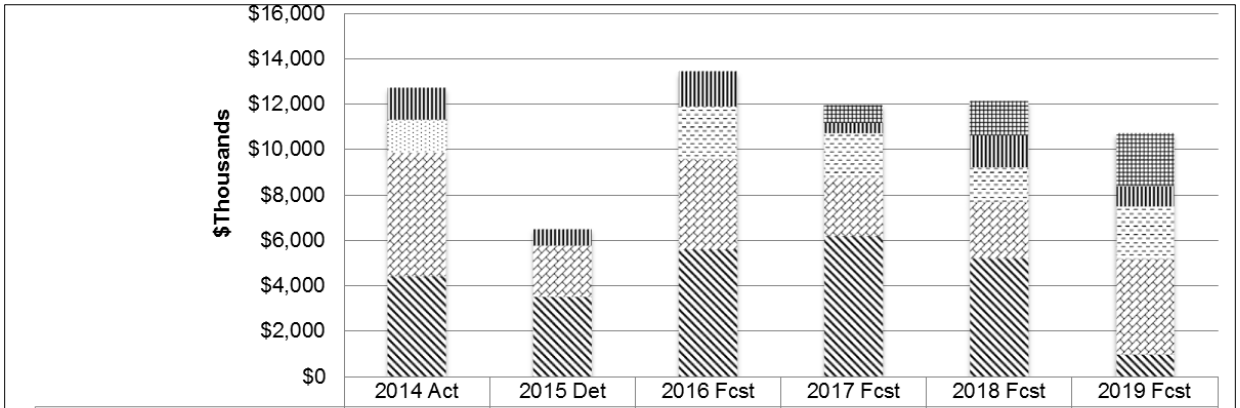


(a) See WP 7-58, 59, Lines 8, 21, 24, 32, 39, Exhibit (PG&E-5).

Figure 7-12 shows total technology-related capital expenditures recorded or forecasted for the PG organization in the years 2014-2019. PG&E anticipates that capital spend in 2017-2019 will be slightly below the 2014 recorded spend, with a downward trajectory thereafter. The significant increase between 2015 and 2016 reflects projects that were rescheduled pursuant to the Company's annual Integrated Planning Process.[9]

[9] See Exhibit (PG&E-2), Chapter 4 for discussion and support for the Company's Integrated Planning Process.

FIGURE 7-12
ENERGY SUPPLY POWER GENERATION TECHNOLOGY PROGRAM
NON-CYBERSECURITY ACTUAL/FORECAST – CAPITAL
(2014-2019)(a)
(THOUSANDS OF NOMINAL DOLLARS)



	2014 Act	2015 Det	2016 Fcst	2017 Fcst	2018 Fcst	2019 Fcst
Compliance Management	$-	$-	$-	$800	$1,500	$2,300
Application Consolidate/Simplify/Upgrade	$1,383	$700	$1,500	$450	$1,400	$900
Work Management	$1,450	$-	$2,300	$2,000	$1,500	$2,300
Asset Management	$5,440	$2,300	$4,000	$2,500	$2,500	$4,200
Infrastructure	$4,427	$3,500	$5,600	$6,200	$5,200	$1,000

(a) See WP 7-58, 59, Lines 8, 21, 24, 32, 39, Exhibit (PG&E-5).

3) Energy Procurement Technology Program Capital Overview

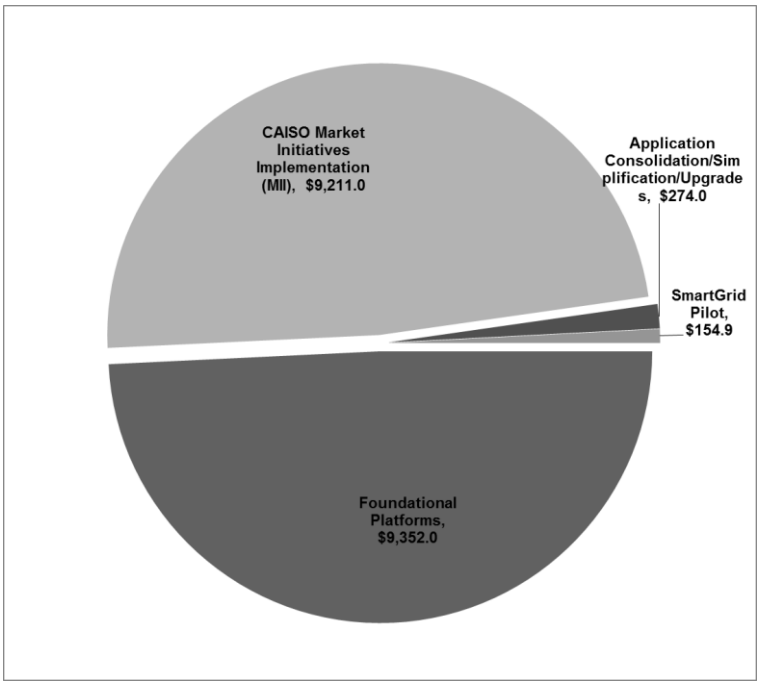
Figure 7-13 shows the relative ES technology-related capital expenditures in EP by driver in 2014. Figure 7-14 presents a similar figure for 2017.

In 2014, work on implementing the California Independent System Operator's (CAISO) Market Initiatives and investments on foundational business platforms comprised nearly all the EP technology-related capital expenditure. Each of these capital cost categories is described in Section B.3.c., below.

In addition, Figures 7-13 also shows recorded and forecast capital expenditures for the Smart Grid Pilot project costs, namely the Short Term Demand Forecasting Pilot, which is a separately funded pilot project as part of the CPUC approved Smart Grid Pilot Deployment Projects Implementation Plan (D.13-03-032). PG&E's forecast for 2017 and beyond does not include expenditures to complete work previously approved in the Smart Grid Pilot

Application. Any further deployment will be addressed at a later date should the pilot prove successful. However, capital expenditures for the pilot are being consolidated in this GRC for purposes of recovering undepreciated capital.[10]

FIGURE 7-13
ENERGY SUPPLY ENERGY PROCUREMENT TECHNOLOGY PROGRAM
NON-CYBERSECURITY CAPITAL EXPENDITURES
(2014)(a)
(THOUSANDS OF NOMINAL DOLLARS)

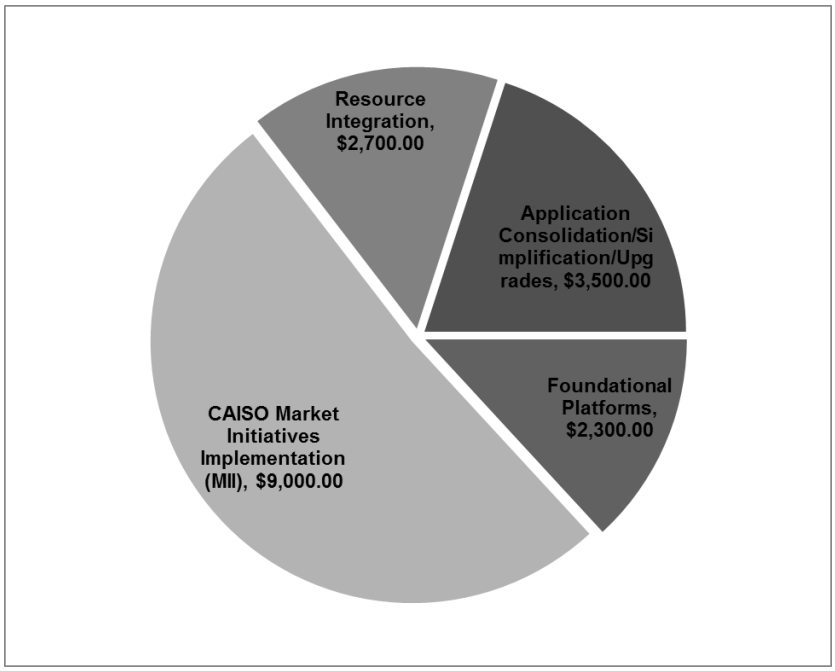


(a) See WP 7-46, Line 6 and WP 7-60 and 7-61, Lines 8, 30, 42, 47, Exhibit (PG&E-5).

In 2017, the continuing technology capital expenditures forecasted are related to CAISO's Market Initiatives and continued investments on foundational business platforms. In addition, key programs implementing a solution for Resource Integration, and to continue to consolidate, simplify and upgrade applications for Energy Procurement-specific use are being forecasted in 2017.

10 See Section E for a discussion of SmartGrid Program expenditures.

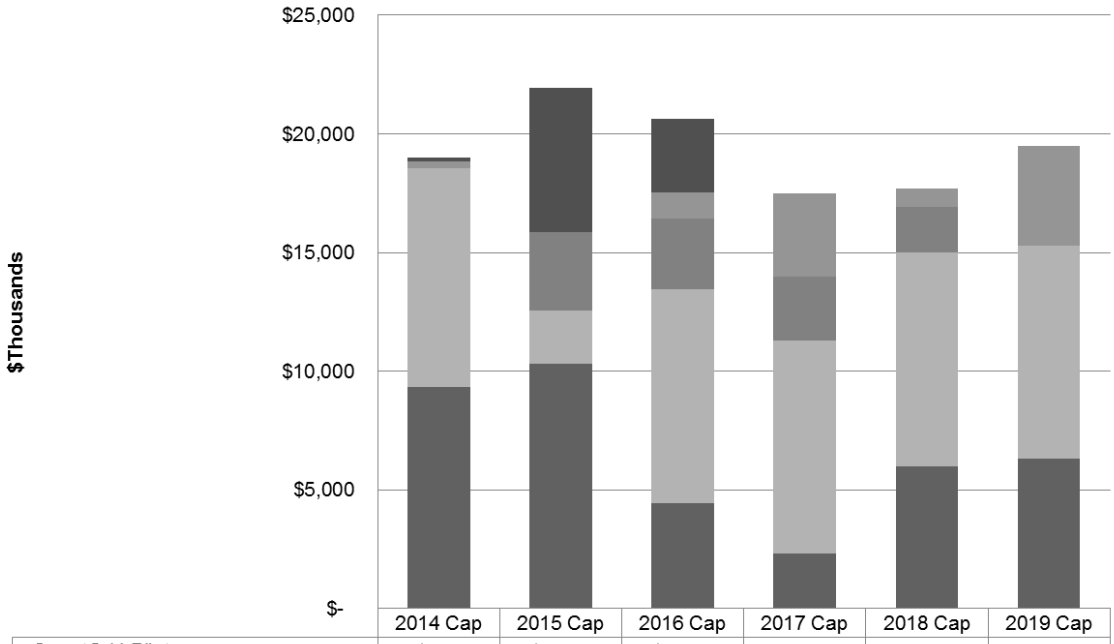
FIGURE 7-14
ENERGY PROCUREMENT ENERGY PROCUREMENT TECHNOLOGY PROGRAM
NON-CYBERSECURITY AND SMARTGRID PILOT CAPITAL EXPENDITURES
(2017)(a)
(THOUSANDS OF NOMINAL DOLLARS)



(a) See WP 7-60 and 7-61, Lines 8, 30, 42, 47, Exhibit (PG&E-5).

Figure 7-15 shows total technology-related capital expenditures recorded or forecasted for the EP organization in the years 2014-2019, not including cybersecurity. PG&E anticipates the additional capital expenditures in 2017-2019 to be fairly flat compared to the authorized amounts for 2014-2016 with a slight downward trajectory. The significant increase between 2015 and 2016 reflects projects that were rescheduled, both due to reprioritization in PG&E's internal strategic planning process and because of external delays (e.g., CAISO's initiation of planned market changes).

FIGURE 7-15
ENERGY SUPPLY ENERGY PROCUREMENT TECHNOLOGY PROGRAM
NON-CYBERSECURITY ACTUAL/FORECAST – CAPITAL
(2014-2019)(a)
(THOUSANDS OF NOMINAL DOLLARS)



	2014 Cap	2015 Cap	2016 Cap	2017 Cap	2018 Cap	2019 Cap
SmartGrid Pilot	$155	$6,089	$3,100			
Application Consolidation/Simplification/Upgrades	$274	$-	$1,100	$3,500	$800	$4,200
Resource Integration	$-	$3,299	$3,000	$2,700	$1,900	$-
CAISO Market Initiatives Implementation (MII)	$9,211	$2,265	$9,000	$9,000	$9,000	$9,000
Foundational Platforms	$9,351	$10,303	$4,450	$2,300	$6,000	$6,300

(a) See WP 7-46, Line 6, and WP 7-60, 61, Lines 8, 30, 42, 47, Exhibit (PG&E-5).

2. Energy Supply Technology Program Description

a. Organization Structure

Energy Supply Business Technology (ESBT) is a standalone department within PG&E, under the Vice President of Business Technology, who in turn reports to PG&E's Chief Information Officer. Business Technology is comprised of groups supporting specific lines of business. The ESBT organization supports technology programs for the EP and PG business areas within the Electric Operations LOB and the Nuclear Generation business area.

The ESBT organization centrally manages technology planning, design, build, deployment, and operations for ES, in coordination with

the rest of the Company's technology organizations to ensure consistency, interoperability, and efficiencies across the Company. ESBT also participates in enterprise-wide technology program and project strategy and planning.[11]

b. Description of Existing Energy Supply Technology Programs

Existing ES technology programs support PG&E's ES business needs and objectives by designing, building, deploying, and maintaining the technology systems necessary for safe, compliant, reliable, and cost-effective operational performance and procurement. Existing activities are divided into the following functional program areas: infrastructure; Asset Management; Work Management; application consolidation/simplification/upgrades; compliance management; CAISO Market Initiatives Implementation (MII); foundational platforms; and data warehouse and analytics. This section describes each of these programs.

1) Infrastructure

The infrastructure program provides critical data and voice communications infrastructure in support of ES operations throughout PG&E's 140,000 acres of hydro lands, the company's nuclear and fossil plants, and PG&E's diverse and communications technologically remote renewables sites.

To date for PG, the program has deployed 18 miles of network cabling and two miles of fiber optic cable in support of over 500 new network connections, while also improving the reliability and serviceability of the existing computing network components. Over 200 pieces of end-of-life network equipment have been upgraded or replaced, and unused equipment has been retired and removed from service. Over 100 wireless access points have been installed to provide WIFI service in some critical facilities.

As part of the infrastructure program, PG&E has also addressed safety risks. For example, a satellite phone system has been installed at the remote Helms pumped storage generating station to

[11] See Exhibit (PG&E-7), Chapter 9.

provide backup communications in the event of the loss of the primary system, and cabling and equipment labeling, grounding, and fire protection systems have been improved throughout the Hydro system.

The infrastructure program has also substantially improved voice and data communications network bandwidth in two key Hydro locations. This work was required to support the consolidation of Hydro Switching Centers where operators control and monitor Hydro and generation-related assets.[12]

At DCPP, existing infrastructure program activities have included: Installing permanent network infrastructure in the plant's two containment buildings; upgrading the telecommunications infrastructure in the plant's control room; and replacing control systems for the regional early warning system. Infrastructure work at DCPP has also involved emergent work such as implementing a plant-funded extension to the plant's telephone system to provide required capabilities until the system can be replaced. This extension allowed rescheduling the telephone system replacement authorized in the 2014 GRC until 2017and will help accommodate the now-required replacement of the plant's security and general radio systems that is planned to commence in 2016.[13]

The PG infrastructure program's steering committee is comprised of leaders from both the PG business and the ESBT organization. The committee prioritizes program activities against a program roadmap while addressing emergent issues, including those identified as field assessment, design, and construction work progresses. High value and critical assets and work locations are prioritized highest, and feedback from local area experts is incorporated into the project plan. As a broader nuclear technology

---

12 See Section B.3.b.1 for discussion about the Backhaul Upgrades initiative that will formalize this effort within the infrastructure program.

13 The plant telephone system replacement project is the "Upgrade/Enhance Intercom to Voice Over Internet Protocol/Wireless" project authorized in the 2014 GRC. See Section B.3.a.1.

infrastructure program develops in 2016, the nuclear technology project steering committee will similarly guide the Nuclear Infrastructure Program.

2) Asset Management

ESBT's Asset Management Program currently has three primary activities: (1) asset risk management and assessment systems; (2) document management system implementation; and (3) Linear Asset Management.

First, ESBT has begun developing the Generation Risk Information Tool (GRIT) asset risk management and assessment system to score and quantify the failure risk and consequence of key asset types within PG&E's Hydro system.[14] This helps hydro planners and operators identify and mitigate reliability and safety risks.

ESBT has modeled within GRIT 15 of the 26 identified asset types and moved asset condition and consequence data and program analysis for these asset types into a centralized system of record. GRIT will later form the basis of the Asset Risk Analytics program discussed in Section B.3.b.2 of Exhibit (PG&E-5), Chapter 7.

Second, ESBT's Asset Management Program continues to support the configuration of PG&E's Documentum Records Management system. The project is aligned with and supported by the Enterprise Records and Information Management (ERIM) program.[15] To date, 113 PG document types have been configured to accept and categorize records, 134,000 legacy PG documents have been loaded, and 250 personnel have been trained. The implementation of Documentum helps to mitigate risks associated with records management.[16] To help mitigate the Records

---

14 See Exhibit (PG&E-5), Chapter 4, Section B.3.a.3 for further discussion about PG&E's Power Generation asset risk assessment and quantification program.

15 See Exhibit (PG&E-7), Chapter 8B for discussion and support for the ERIM Program that provides foundational records management capabilities.

16 See Exhibit (PG&E-5), Chapter 4, Section B.3.b.4.

Management Risk as discussed in Section B.3.b.2, this program will continue into the forecast period.

Third, the Linear Asset Management Project is building upon work done in Electric and Gas Technology to develop and define into linear segments within the SAP Asset Management system the special characteristics of Hydro conveyances that vary along their length.[17] This allows analysts, planners, and operations personnel to quickly identify and assess geographically-centered information about these conveyances through integration with and use of Geographic Information Systems (GIS) locational data and user interfaces. Linearized and GIS-based representation of water conveyances in turn support GRIT modeling of these critical assets reflecting localized conditions and consequences along their length.

3) Work Management

ESBT systems support the ES business' maintenance and operations organizations in their day-to-day operations and planning activities. The Work Management Program focuses on enhancing and sustaining these systems. The following three examples help to illustrate existing activities within this program.

ESBT has developed mobile applications to streamline routine inspections of PG plant and equipment. For example, ESBT is developing a GIS-based platform to support Hydro water conveyance patrols. This activity helps mitigate compliance and safety risks in Hydro operations.[18] A related mobile application called Operator Rounds allows direct entry of manually collected data readings into systems of record thereby improving traceability, accuracy, and quality of data. These and similar field-based systems use the capabilities provided by the telecommunications infrastructure, described in Sections B.2.b.1 and B.3.b.1, that ESBT

---

17 Conveyances are canals, flumes, waterways, siphons, tunnels, penstocks and related systems that transfer water between hydro assets like lakes, powerhouses, etc.

18 Exhibit (PG&E-5), Chapter 4, Section B.3.b.

is deploying throughout PG&E's Hydro system and at PG&E's fossil and renewables and nuclear sites.

Work Process Safety Systems provide software to supplement and support Power Generation procedures for managing work clearances that assure worker safety when equipment is removed from service for repair and replacement.

Under the DCPP application mobilization program, ESBT is creating and deploying both mobile electronic work packages and electronic procedures for plant maintenance personnel. This groundbreaking program replaces the current requirement to manually assemble into binders and maintain tens of thousands of paper documents required to perform plant work. Electronic work packages provide the electronic equivalents on mobile devices that travel with the workers into their work areas. Sign-offs and approvals are electronic; after-the-fact scanning and filing is largely eliminated; and paper and its acquisition, processing and storage are markedly reduced.

Electronic Procedures provides work procedures, checklists, and processes within the mobile device along with the work packages. As with electronic work packages, electronic procedures reduces the maintenance and production and printing of paper documents that govern and guide plant work activities and provide the information electronically to the worker at the worker's work location.

Both procedure and work package version control are significantly simplified, thus helping assure that up-to-date information is provided to the plant worker. This improves both plant worker and document management personnel efficiency. Plant worker safety is improved by lessening the chance for out-of-date procedures or work packages to be deployed.

4) Application Consolidation/Simplification/Upgrade

ESBT maintains application health and functionality as critical business needs evolve and technology continues to advance. The "application consolidation/simplification/upgrade" programs address

business needs to consolidate data and functionality from disparate systems in order to continue to produce and expand useful information for decision-making. The program also includes activities that simplify the use of current systems and applications to gain efficiencies. The program's objective is to upgrade system software to stay compliant with technology and vendor requirements.

ESBT is consolidating and simplifying interfaces between hydrologic data sources and systems of record, modernizing the user interfaces, and implementing additional minor changes as required to the core SAP work and AM system of record to improve and streamline hydro operations IT systems. This furthers PG&E's goal to provide information to its workforce where and when it's needed through projects like Field Workforce Systems.

ESBT will also migrate the PG-wide Project and Portfolio Management (PPM) system into PG&E's enterprise system. This will improve project planning's integration, accessibility and context for the Energy Supply workforce, and will enable tighter integration with ongoing work and more efficient methods to capture and initiate new work, and to report on the book of work across PG&E.

ESBT will integrate construction project estimating and job tracking processes and software systems tightly with SAP and with PPM and the Primavera project scheduling system. This will provide straight-through processing from initial project planning, to detailed cost estimation, to bid package development and bid and contractor management, to detailed scheduling and time and materials cost tracking for PG's major construction projects.[19]

ESBT is also executing two application upgrade projects at DCPP as part of this Applications program. First, a difficult-to-support radiological effluent permit management system and related computing hardware is being replaced with a commercial off-the-shelf system. An extended outage of this system

---

19 See Section B.3.b.4 (Project Estimation and Management Tools).

could affect plant operations. This project will help keep the system in compliance with regulatory requirements, and will reduce the risk and consequences of its failure. Second, the system that manages DCPP work clearances and maintenance and that facilitates the safe operation of the facility is being upgraded to a vendor-supported version. An extended outage of this system could also affect plant operations.

In the EP business area, two projects are being executed as part of this program. First, EP has initiated an upgrade to PG&E's centralized trading and settlement system to accommodate changing business needs and expanded use of the system. Without the upgrade to the system and infrastructure, the system will fall out of compliance with the supporting vendor thereby jeopardizing support, and will not take advantage of upgraded functionality to the system. This project is critical to keeping the system functioning efficiently over its useful lifetime. Second, the enterprise records and document management solution is replacing the legacy EP system allowing EP to migrate electronic versions of contracts from the legacy system into an enterprise solution. Other system upgrades and simplification work are forecasted in the 2017 years.

5) Compliance Management

Noncompliance with regulatory and performance requirements is a key risk for ES.[20] Maintaining compliance with regulatory and internal requirements requires tracking and performing thousands of tasks annually. To manage the requirements, ESBT's compliance management program has created dashboards to track air quality and Federal Energy Regulatory Commission (FERC) licensing-related tasks. These allow leadership to monitor the real-time state of compliance activities, identify work groups responsible for the various activities, assess task backlog, and see upcoming tasks. These dashboards have helped PG&E maintain a high rate of FERC Hydro-related compliance.

---

20 See Exhibit (PG&E-5), Chapter 4, Section B.3.b.

Additional compliance task tracking and management, such as environmental compliance task monitoring, is planned as an expansion to this database and dashboard beginning in 2017.[21] Also in 2017, PG&E plans to begin integrating the compliance tracking database with work and AM systems to make compliance tasks more accessible to field personnel as part of ES-wide initiatives to provide information and job-execution capabilities to its field workforce while they are in the field, thereby improving workforce safety and efficiency.

6) Foundational Platforms

Foundational technology platforms are critical, core application solutions that provide essential business functionality and the ability to build out and layer functionality to the evolving business. These foundational technology platforms provide the critical components for ESBT to build and maintain the capabilities that deliver and support the critical business functions for EP. In addition, work on these platforms allows ESBT to efficiently comply with emerging market and regulatory changes.

In the EP area, the 2011 and 2014 GRC periods saw investments in foundational platforms to modernize legacy custom and commercial solutions, consolidate systems to increase support and capabilities, and reduce the complexity of system integration. This program began the implementation of a centralized trading and settlement platform to replace five legacy, vendor supported systems. In addition, this platform was expanded to include compliance with mandatory regulatory and market changes, including the introduction of greenhouse gas trading and Dodd-Frank controls.

As part of this program, requirements for a centralized short- and mid-term optimization platform were identified and a common platform was built to optimize hydro generation resources in those time horizons. Using the same technology platform, this

---

21 See Section B.3.b.5 for the Compliance Management Program.

program provided the basis for the economic evaluation of the timing of generation outages with consideration for multiple physical and financial constraints. Further forecasted work in this program area is described in Section B.3.c.

7) California Independent System Operator (CAISO) Market Initiatives Implementation

The CAISO publishes an annual Stakeholder Initiatives Catalog outlining the prioritization of mandated and proposed market redesign and technology initiatives. The published initiatives are a series of enhancements to address regulatory and reliability requirements as mandated by the FERC or the CAISO. Through a defined stakeholder process, the CAISO assesses mandated deadlines and market capacity to implement these initiatives and schedules the implementation of these and other initiatives, some that are not captured in the Catalog, into the Master Stakeholder Engagement Plan. These CAISO market changes can affect market procedures, models and the technology that supports them both in and out of state.

In response to these CAISO initiatives, PG&E has continued the Project Management Office (PMO) structure established during the initial implementation of the CAISO Market Redesign and Technology Upgrade (MRTU). The PMO manages the CAISO initiatives through the MII Program. The MII Program succeeds the CAISO "Market and Performance Program" and its predecessor, the MRTU. Through the CAISO MII Program, PG&E adapts its business processes and technology to implement CAISO market changes and enhancements necessary to maintain compliance. The MII Program, in lockstep with the CAISO Implementation schedule, manages changes to processes involving portfolio optimization, bidding, scheduling, and CAISO settlements. These processes are supported by technology components comprised of business applications, databases and data integration.

In 2014, CAISO introduced a new 15-minute market in response to FERC Order 764 and also expanded its footprint in the real-time

market with the Energy Imbalance Market initiative. These significant market changes, along with other initiatives in the CAISO's Master Stakeholder Engagement Plan, triggered technology projects which included: enhancements to software used for bidding, scheduling, and settlements; data acquisition application updates for market data analytics; implementation of settlement software and hardware; the initial stages of implementing a new outage management system; as well as other enhancements to market operation platforms.

8) Resource Integration

PG&E's generation portfolio continues to expand and become more complex with the increased introduction of intermittent renewables. As well, the market conditions are changing and introducing operational challenges to maintaining reliability. This program provides a solution that supports system reliability by integrating, monitoring, and communicating with all types of generation within PG&E's portfolio. The majority of the program implementation is forecasted in 2017-2019 and is described further in Section B.3.c.4.

3. Key Initiatives

The key initiatives described in this section include new and continuing major activities that drive the 2017 expense forecast, as shown in Table 7-1, above, or are significant contributors to forecasted capital spending in 2015-2019 as shown in Table 7-2, above. This section is organized by each of the major business areas supported by ESBT and, within each business area, by key driver.

Some of the projects described below were originally forecasted to occur in part or entirely within the 2014-2016 GRC period but were subsequently rescheduled, both due to reprioritization in PG&E's internal strategic planning process and because of external delays (e.g., CAISO's initiation of planned market changes).[22]

---

22 See PG&E's Exhibit (PG&E-2), Chapter 4.

a. Nuclear Generation Key Initiatives

The key ES technology-related initiatives to support Nuclear Generation in the forecast period are the following programs: Infrastructure; Asset Management; Work Management; and Application Consolidation, Simplification, and Upgrades. This section discusses each of these programs. Table 7-3 summarizes the Nuclear Technology Capital and Expense recorded and forecast values.

TABLE 7-3
NON-CYBER SECURITY ENERGY SUPPLY NUCLEAR TECHNOLOGY PROGRAMS: 2014-2019 RECORDED AND FORECAST
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Workpaper Reference
1	Capital (MWC-2F)	$ 6,276	$ 6,019	$ 12,400	$ 13,550	$ 12,050	$ 10,250	WP 7-57 Line 37
2	Expense (MWC JV)	$ -	$ 247	$ 3,600	$ 1,850			WP 7-43 Line 24
3	**Total**	**$ 6,276**	**$ 6,266**	**$ 16,000**	**$ 15,400**	**$ 12,050**	**$ 10,250**	

Note: Cybersecurity Programs are described in Exhibit 7, Chapter 10.

1) Infrastructure

PG&E forecasts $0.45 million in 2017 expense[23] and $1.1, $5.75, $7.5, $6.0, and $3.0 million in 2015-2019 capital costs, respectively,[24] for the Nuclear Generation-related technology infrastructure program. The 2017 expense forecast accounts for 24 percent of the total increase in expense costs for Nuclear Generation technology programs between 2014 and 2017.[25] The $7.5 million in forecasted capital cost in 2017 is 55 percent of total technology non-cybersecurity 2017 capital spending for Nuclear Generation.

The general objectives of the ES Infrastructure Program are described in Section B.2, above. In 2017, forecast expense costs for the Nuclear Generation technology Infrastructure Program are primarily associated with the replacement of the DCPP telephone

---

23 See WP 7-43, Line 18, Exhibit (PG&E-5).

24 See WP 7-57, Line 30, Exhibit (PG&E-5).

25 See WP 7-43, Lines 18, 24, Exhibit (PG&E-5).

system. Additionally, infrastructure capital expenditures in this GRC forecast period are primarily focused on the following projects: Power Block Wireless Infrastructure ($2.0, and $2.5 million, 2016 and 2017, respectively); IT Network Infrastructure Upgrade ($1.0 million in each of 2016 and 2017); Replace the Plant Radio System ($1.0, $2.0, and $2.0 million in 2016-2018, respectively); Replace the Plant Telephone System ($2.0, and $4.0 million in 2017 and 2018, respectively); Data Center Replacement ($3.0 million in 2019); and completing the Containment Radio Project ($0.85, and $1.15 million in 2015 and 2016, respectively).[26]

a) Power Block Wireless Infrastructure Project

This project will extend DCPP's wireless network access to the turbine building power block (the turbine building, auxiliary building, and containment).[27]

The wireless network connectivity the project provides will allow employees to access and share electronic work packages, procedures, inspection notes, data collection and equipment validation systems, to collect video and voice recordings within the power block, and to have voice and video collaboration with engineers and supervisory personnel through the capabilities delivered by the Field Workforce Systems Project (FWSP), thereby reducing and eliminating needs to enter and exit plant protected and hazardous areas and the associated worker time and processes with doing so. Until this project is deployed, mobile applications in that facility must be used in an off-line, non-collaborative mode.

b) IT Network Infrastructure Upgrade Project

The IT Network Infrastructure Upgrade Project will improve internal plant telecommunications network bandwidth and reliability within DCPP. This increased capability is required as more processes are digitized, and the Project will also address

---

26 See WP 7-57, Lines 18, 19, 24-29, Exhibit (PG&E-5).

27 See WP 7-74, Exhibit (PG&E-5) for Project Summary.

aging telecommunications infrastructure needs within the facility.

c) Plant Telephone and Radio System Replacement Projects

As discussed in Section B.2.b.1, the 2014 GRC decision authorized replacing the DCPP telephone, which PG&E had expected to commence in 2014. Upon further consideration, PG&E determined that it could extend the life of the telephone system by a few years, and that replacing the plant's radio system is a higher priority.

The DCPP plant radio system that was installed in 2003 is a critical local and emergency responder communications technology platform.[28] The system is reaching its end of life with vendor support ending by 2018, and the system has started exhibiting performance and reliability issues and must be upgraded to sustainable equipment to continue meeting the nuclear security strategy and Nuclear Regulatory Commission (NRC) commitments.[29] Consequently, PG&E plans to replace the DCPP plant radio system beginning in 2016, and continuing into 2017 and 2018.[30] The DCPP telephone system replacement has in turn been re-scheduled to 2017.[31]

d) Data Center Replacement Project

The 2017 GRC forecast includes funds to relocate the on-site DCPP data center to an off-site PG&E data center. This Project furthers PG&E's goal of consolidating critical applications and systems to its corporate-wide data centers, reduces local staffing requirements and the infrastructure needs to maintain a high-availability data center at the plant.[32]

---

28 The plant radio system supports plant security, fire, operations, and maintenance functions as well as regional first responder communications.

29 Portions of the system are already beyond vendor support.

30 See WP 7-84, Exhibit (PG&E-5) for Project Summary.

31 See WP 7-78, Exhibit (PG&E-5) for Project Summary.

32 See WP 7-65, Exhibit (PG&E-5) for Project Summary.

2) Asset Management

PG&E forecasts $0.15 million in 2017 expense[33] and $2.5, $4.0, $2.0, and $1.25 million in 2016-2019 capital costs, respectively,[34] for the Nuclear Generation technology-related Asset Management Program. This program accounts for $0.15 million, or 8 percent, of the total increase in expense costs for non-cybersecurity Nuclear Generation technology between 2014 and 2017.[35] It also accounts for $4.0 million in forecasted capital cost in 2017, or 28 percent of total ES technology capital spending for Nuclear Generation in 2017.

The general objectives of the ES Asset Management technology program are described in Section B.2, above. In 2017, forecast expense costs for the Nuclear Generation Asset Management technology program are associated with legacy document processing for records management. Additionally, AM capital expenditures in this GRC forecast period are primarily focused on: the Nuclear Records Management System Migration Project ($1.5 million in each of 2016-2018); the Deploy OSISoft PI Data Historian Project ($1.0, and $2.5 million in 2016 and 2017, respectively);[36] and the Nuclear Data Analytics and Visualization Project ($0.5, and $1.25 million in 2018 and 2019, respectively).[37]

a) Nuclear Records Management System Migration Project

PG&E plans to migrate the current nuclear records management systems to the centralized corporate records management system beginning in 2016 and extending into the 2017 GRC period.[38]

---

33 See WP 7-43, Line 12, Exhibit (PG&E-5).

34 See WP 7-57, Line 15, Exhibit (PG&E-5).

35 See WP 7-43, Lines 12, 24, Exhibit (PG&E-5).

36 "PI" is a software product by OSISoft, LLC. See WP Table 7-57, Line 12, Exhibit (PG&E-5).

37 See WP 7-57, Lines 12-14, Exhibit (PG&E-5).

38 See Exhibit (PG&E-7), Chapter 8B for discussion and support for the ERIM Program that provides foundational records management capabilities.

The existing DCPP records management system is no longer supported by the vendor, and the technology infrastructure on which it operates is at end-of-life and due for lifecycle replacement. An extended outage of this system may affect plant operations, and the systems need replacement.[39]

b) Deploy OSI PI Data Historian Project

The OSI PI Data Historian Project will make operational data available outside of the limited access operational network at the plant, thereby facilitating analyses of and reporting of plant operational results using PG&E standard toolsets and applications. Including DCPP within the corporate data historian makes possible integrating operational analytics and information into daily work processes. This Project will also allow PG&E to combine operational analytics with asset, WM, and other key information to provide a holistic view and framework for analysis. The Project will improve operational data latency and availability for both on-and off-site PG&E personnel, including PG&E's EP staff who do not now have near-real time visibility into DCPP operations.[40]

c) Nuclear Data Analytics and Visualization Project

The Nuclear Data Analytics and Visualization Project will deploy advanced, operational-data driven equipment failure predictive tools that employ state-of-the-art data analysis and trending algorithms. These tools use data from the data historian, data warehouse, and other systems of record for their analyses and will provide leading indications in near real-time about key equipment actual performance against expected performance.

The Nuclear Data Analytics and Visualization Project also involves the development of operational data-based situational awareness dashboards and a real-time operational

---

39 See WP 7-81, Exhibit (PG&E-5) for Project Summary.

40 See WP 7-67, Exhibit (PG&E-5) for Project Summary.

management display system that provide consolidated plant and regional views to enhance DCPP operational and plant and ES-wide leadership awareness of critical events affecting, or that may affect, the DCPP plant and ES operations.

This project will also allow critical non-DCPP operational personnel, such as EP operations planners, bidders, and real-time operators, to have the same visibility into the operational state of this 2,200 megawatt facility as do on-site DCPP plant personnel and management.

Plant analytics and operational data visibility will also be provided to Field Workforce Systems (FWS) to supplement and enhance operational and maintenance activities and the safety of maintenance personnel.

3) Work Management

PG&E forecasts $0.2 million in 2017 expense[41] and $1.9, $1.5, $1.0, $1.5, and $2.0 million in 2015-2019 non-cybersecurity capital costs, respectively,[42] for the Nuclear Generation technology-related Work Management Program. This program accounts for $0.2 million, or 11 percent, of the total increase in expense costs for Nuclear Generation ESBT between 2014 and 2017.[43] It also accounts for seven percent of total technology-related non-cybersecurity capital spending for Nuclear Generation in 2017.

The general objectives of the Work Management Program are described in Section B.2, above. In 2017, forecast expense costs for Nuclear Generation technology-related WM are primarily associated with the FWSP. Additionally, WM capital expenditures in this GRC forecast period are primarily focused on the Mobility Applications project ($1.85, and $1.5 million in 2015 and 2016,

---

41 See WP 7-43, Line 23, Exhibit (PG&E-5).

42 See WP 7-57, Line 36, Exhibit (PG&E-5).

43 See WP 7-43, Lines 23, 24, Exhibit (PG&E-5).

respectively), and the FWSP ($1.0, $1.5, $2.0 million, in 2017-2019, respectively).[44]

a) Field Workforce Systems Project

The FWSP was described generally in Section B.3.a.1., above. This project will take full advantage of the wireless access and network infrastructure being deployed at DCPP. Live video monitoring and peer and supervisory collaboration will be added to existing systems, and asset identification components like near field communication, information from Radio Frequency Identification Deployment (RFID) tags, and bar codes will help plant personnel identify and validate tool and equipment location and status, along with the users' location within the facility. Added capabilities for routine data collection and inspection activities with integration to appropriate systems of record will streamline those processes and improve data quality and completeness.

The addition of 3-D rendering of key equipment and hazardous work locations will help mitigate safety risks and lessen radiation dose exposure through virtual walkthroughs of work procedures and locations and integration with plant AM and maintenance systems.[45]

4) Application Consolidate/Simplification/Upgrade

PG&E forecasts $1.05 million in 2017 expense[46] and $3.1, $2.7, $1.1, $2.6, and $4.0 million in 2015-2019 capital costs, respectively,[47] for the Nuclear Generation Application Consolidation, Simplification, and Upgrade Program (ACSUP). This program accounts for $1.05 million, or 57 percent, of the total increase in non-cybersecurity expense costs for Nuclear Generation

---

44 See WP 7-57, Lines 33-35, Exhibit (PG&E-5).

45 See WP 7-70, Exhibit (PG&E-5) for Project Summary.

46 See WP 7-43, Line 9, Exhibit (PG&E-5).

47 See WP 7-57, Line 11, Exhibit (PG&E-5).

technology systems between 2014 and 2017.[48] It also accounts for eight percent of the total ES technology-related capital spending for non-cybersecurity Nuclear Generation projects in 2017.

The general objectives of the ACSUP are described in Section B.2.b.4, above. In 2017, forecast expense costs for the program are primarily associated with routine SAP enhancements, enhancement to the plant's radiation protection system technology components and non-capitalized work to assure the health and fitness for purpose of the over 140 applications for which ESBT is responsible on behalf of Nuclear Generation. Non-cybersecurity nuclear ACSUP capital expenditures in this GRC forecast period are primarily focused on the following projects: ESOMS Upgrade ($2.0 million in 2015);[49] Implementing PPM for DCPP ($1.0 million in 2016);[50] Replace the Radiological Effluent Management System (REMS) with OpenEMS ($1.1, and $0.65 million in 2015 and 2016, respectively),[51] Asset & Equipment Monitoring Application Upgrade ($1.5 million in each of 2018 and 2019), SSIS Upgrade ($1.0 million in each of 2016 and 2017),[52] Mainframe Archiving and Retirement ($1.0, and $0.5 million in 2018 and 2019, respectively), and Project Scheduling System Upgrades ($2.0 million in 2019).[53,54]

---

48 See WP 7-43, Lines 9, 24, Exhibit (PG&E-5).

49 eSOMS (electronic Shift Operations Management System) is a software product by ABB, Inc. that is critical for DCPP management of safety clearances and work processes.

50 This project was named Long-Term Plan and Project Tools in the 2014 GRC and was delayed until 2016 to leverage the capabilities provided by the Enterprise Project and Portfolio Planning Project, and thereby avoid deploying a standalone system for DCPP.

51 OpenEMS is a software product by Canberra Industries, Inc. used for managing radiological effluent permits that are required whenever such products are moved within the plant. PG&E's in-house developed system reached its end of life and needed replacement.

52 SSIS (Security Screening Information System) is a software product by Scientech, a business unit of the Curtiss-Wright Flow Control Company.

53 PG&E uses the Oracle Primavera system for DCPP project scheduling and anticipates a required upgrade by 2019 to maintain compatibility with computing environments and to include additional features that would be provided in the then-current release.

54 See WP 7-57, Lines 3 - 10, Exhibit (PG&E-5).

a) Asset and Equipment Monitoring Application Upgrade Project

The Ventyx Equipment Reliability Suite (ER) is a nuclear industry-standard systems intelligence application suite that supports DCPP engineering, human performance, and plant equipment and systems monitoring, health trending and process improvements by mining data from the SAP asset and WM systems, and by analyzing longer-term data trends, events, and issue notifications tracked at DCPP. Functions provided by portions of the suite meet regulatory requirements, and PG&E needs to maintain the currency of the suite with vendor releases. The current lag in updates is requiring manual workarounds and maintenance to the applications. PG&E plans to initiate upgrades to the ER application suite beginning in 2018.[55]

b) SSIS Upgrade Project

The DCPP system that manages plant personnel access and badging and fitness for duty programs is planned for upgrade to a more maintainable and standardized version beginning in 2016, continuing in 2017. The functions provided by the application are mandated by the NRC, and the system PG&E uses is the industry standard. The upgrade will also help consolidate workforce processing tasks into an upgraded system from an obsolete application residing on a mainframe computer that is itself slated for retirement beginning in 2018. Therefore, this work is a required precursor to the mainframe archive and retirement project.

c) Mainframe Archiving and Retirement

The DCPP legacy mainframe computer is reaching its end of life and is planned for retirement within the forecast period.[56] The project will provide the 50-year archiving required for

---

55 See WP 7-62, Exhibit (PG&E-5) for Project Summary.

56 Parts and support are difficult to obtain.

nuclear records residing on the system and will transfer remaining functionality off of the mainframe to other systems.[57]

d) Project Scheduling System Upgrade

The ASCUP program will facilitate maintaining application health and suitability. The Oracle Primavera project scheduling system is a critical component DCPP uses to schedule and manage the routine and outage-related work at the plant. Primavera is central to efficient work performance and minimizing routine plant outage durations. PG&E anticipates that this key system will require upgrading within the forecast period to maintain its health and to acquire new functionality as it is released.

b. Power Generation Key Initiatives

The key ES technology-related initiatives to support Power Generation in the forecast period are the following programs: Infrastructure; Asset Management; Work Management; Application Consolidation, Simplification, and Upgrades; and Compliance Management. This section discusses each of these programs. Table 7-4 summarizes the Power Generation Technology Capital and Expense recorded and forecast values.

TABLE 7-4
NON-CYBER SECURITY ENERGY SUPPLY POWER GENERATION TECHNOLOGY PROGRAMS: 2014-2019
RECORDED AND FORECAST
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Workpaper Reference
1	Capital (MWC-2F)	$ 13,901	$ 6,979	$ 13,400	$ 11,950	$ 12,100	$ 10,700	WP 7-59 Line 40
2	Expense (MWC JV)	$ 772	$ 361	$ 3,100	$ 1,650			WP 7-44 Line 23
3	**Total**	**$ 14,673**	**$ 7,340**	**$ 16,500**	**$ 13,600**	**$ 12,100**	**$ 10,700**	

Note: Cybersecurity Programs are described in Exhibit 7, Chapter 10.

57 The SSIS upgrade project will replace workforce processing tasks currently performed on the mainframe, thereby helping facilitate the mainframe retirement project.

1) Infrastructure

PG&E forecasts $3.5, $5.6, $5.2, $4.2, and $0.3 million in 2015-2019 non-cybersecurity PG technology-related infrastructure capital costs, respectively,[58] to continue strengthening and extending the telecommunications infrastructure supporting Hydro operations through the following programs and projects: Watershed Modernization ($3.5, $4.0, $4.0 and $3.0 million in 2015-2018 respectively); Backhaul Upgrades Projects ($1.0, $1.2, and $1.2 million in 2016-2018, respectively); and the Mobile Telecommunications Hubs Project ($0.6, and $0.3 million in 2016 and 2019, respectively). Similar technology infrastructure capital work will also be performed to support fossil-fueled and renewable generation facilities through the Generation Station Technology Infrastructure Project (GSTIP) ($1.0, $1.0, and $0.7 million in 2017-2019, respectively).[59] In combination, these projects account for $6.2 million in forecasted capital cost in 2017, or 52 percent of total PG technology-related project 2017 non-cybersecurity capital spending.[60]

a) Watershed Modernization Project

The Watershed Modernization Project, in conjunction with the related Backhaul Upgrades Project described below, will improve the reliability and capability of the technology infrastructure within the 140,000 acres of the PG&E Hydro system.[61] That infrastructure is critical to continued reliable and safe generation operations and provides the capability to deploy and support current and emergent technologies that rely on a robust and reliable telecommunications network. These efforts provide the infrastructure foundation necessary to support the amount and quality of the voice and data traffic necessary to

---

58 See WP 7-58, Sum of Lines 25-30 for hydro projects, Exhibit (PG&E-5).

59 See WP 7-58, Line 31 for fossil project, Exhibit (PG&E-5).

60 See WP 7-58, 59, Lines 32 and 40, Exhibit (PG&E-5).

61 See WP 7-99, Exhibit (PG&E-5) for Project Summary.

operate and maintain generation and related facilities safely and reliably, to enable the digital utility and grid of things for PG, and to support the deployment of Field Data Collection Systems (FDCS) and FWS that automate data collection and provide analytic and data collection tools to field workers.[62,63]

Specifically, the Watershed Modernization Project prioritizes activities that help to mitigate safety and reliability risks identified by the Hydro Operations Department.[64] One example is work to extend telecommunication networks to provide communication capabilities where none have existed, thereby markedly improving the safety of personnel visiting those areas, as well as reducing the need for travel to often remote sites for inspections or data acquisition. Another example involves replacing obsolete and at- or over-capacity equipment with current generation telecommunications equipment that supports the reliability and network capacity requirements of each area within the watershed based on the criticality of the area's communications requirements.

b) Backhaul Upgrades Project

The Backhaul Upgrades Project augments and complements the Watershed Modernization Project by addressing watershed-specific network bandwidth constraints, and communication path redundancy needs, that impact Hydro operations.[65] The Watershed Modernization Project has identified bandwidth constraints that limit the ability to transmit data and voice from and within watersheds to the PG&E core networks. The Backhaul Upgrade Project will strengthen microwave, lease line, and fiber optic connections to ensure

---

62 See Exhibit (PG&E-7), Chapter 1 for PG&E's Digital Utility vision.

63 See Sections B.3.b.2 and B.3b.3 for FDCS and FWS discussions.

64 See Exhibit (PG&E-5), Chapter 4, Section B.

65 See WP 7-90, Exhibit (PG&E-5) for Project Summary.

satisfactory network capability between the local areas and the larger corporate network.

This work is necessary both to provide adequate bandwidth for current and expected future digital network loads, including both wireless access points and additional hardwired computer network connections. This bandwidth will also enable enhanced FDCS and FWS that allow PG&E's workforce in the very remote field to see, collect, and analyze information on electronic tablets and other devices and to automatically collect information at unstaffed remote locations where it is not feasible to deploy Supervisory Control and Data Acquisition (SCADA). The technology to provide access to the data necessary for asset reliability analyses and to perform routine work in remote or difficult-to-access locations without return travel to more central locations improves both worker safety and efficiency through fewer miles driven and reduced time spent driving, thereby mitigating operational safety risk.

Backhaul upgrades also include "last mile" connectivity replacements and upgrades between PG&E's Hydro SCADA system and key Hydro system sensors and equipment.[66] This connectivity is crucial to maintaining reliable data acquisition and control. Telephone company-provided copper lease lines that have been the historic standard for these communications are becoming unreliable, will become unsupported by the telephone company owners within the forecast period, and therefore must be replaced.

c) Generation Station Technology Infrastructure Project

Technology infrastructure is crucial to the continued safe, reliable, and affordable operation of not only Hydro, but also of PG&E's fossil-fueled, fuel cell, and photovoltaic (PV) generators. The GSTIP will ensure that this infrastructure

---

66 The SCADA system is used by hydro operators to monitor and control Hydro generation and water flows, levels, etc., and related information throughout the PG&E Hydro system.

remains reliable and continues to serve the needs of each of these facilities.

Fossil-fueled and other non-Hydro technology infrastructure is similar to the infrastructure supporting Hydro; it includes the basic components that provide operational connectivity within the plants and between the plants and the greater PG&E telecommunications network. These systems support reliable operation and other related functions, including physical and cybersecurity. Additional elements, not found in Hydro, like Continuous Emissions Monitoring Systems, and plant Digital Control Systems, require supporting technology infrastructure remediation and enhancements. The GSTIP includes these activities to mitigate reliability, safety, and other operational risks.[67]

The GSTIP also provides adequate network infrastructure to support mechanical, electrical, and environmental monitoring systems and devices located at the plants. These systems, called FDCS, help support the business objective to increase the operational flexibility of generation facilities.[68] Additionally, these systems support condition-based maintenance and predictive maintenance programs that mitigate reliability risks.

Technology infrastructure enhancements for the PV facilities that are forecasted as part of this GRC forecast will include improved WIFI coverage, support for equipment infrared inspection and analysis, and additional PV facility data acquisition required to increase operational flexibility.

The GSTIP forecast also addresses additional operational flexibility requirements through planned enhancements to PG&E's Automated Dispatch System (ADS). The ADS distributes CAISO five-minute dispatch instructions (e.g., market awards) across PG&E's generation fleet. PG&E has piloted an

---

67 See Exhibit (PG&E-5), Chapter 5, Section B.2.b.

68 See Section B.3.b.2 for further discussion about FDCS.

ADS solution to automate the five-minute dispatch of solar and battery energy storage resources in addition to Hydro and fossil. Additional technology infrastructure is needed to fully operationalize that system. That infrastructure will also support the Real-Time Automation and Control Project described in Section B.3.c.4, below.

2) Asset Management

PG&E forecasts $0.5 million in 2017 expense[69] and $2.6, $4.0, $2.5, $2.5, and $4.2 million in 2015-2019 capital costs, respectively,[70] for the non-cybersecurity PG technology-related Asset Management Program. The program's 2017 expense forecast expense cost is 30 percent of the total PG technology programs' expense spending in 2017.[71] The program's $2.5 million in 2017 forecast capital cost is 21 percent of total PG technology programs' non-cybersecurity capital spending in 2017.

The PG technology–related Asset Management Program is described in Section B.2, above. In 2017, forecast expense costs for this program are primarily associated with the transfer of legacy documents into the records management system. Additionally, AM capital expenditures in this GRC forecast period are primarily focused on the following projects: the Asset Risk Management Database Project ($0.5, and $1.5 million in 2015 and 2016, respectively); the Asset Reliability Analytics Project ($1.0, $1.0, and $1.5 million in 2017-2019, respectively); the Asset Inventory and Materials Management Project ($1.0, and $1.2 million in 2018 and 2019, respectively); the Records Management Initiative (RMI) Documentum Configuration Project ($1.0 million in each of 2015-2017); the Linear Asset Management Project ($0.8, and

---

69 See WP 7-44, Line 12, Exhibit (PG&E-5).

70 See WP 7-58, Line 21, Exhibit (PG&E-5).

71 See WP 7-44, Lines 12 and 23, Exhibit (PG&E-5).

$1.5 million in 2015 and 2016, respectively); and the FDCS Project ($0.5, $0.5, and $1.5 million in 2017-2019, respectively).[72]

a) Asset Reliability Analytics Project

The asset risk management and assessment system described in Section B.2.b has laid the foundation for advanced reliability and maintenance and investment planning analytics for PG&E's Hydro system. The Asset Reliability Analytics Project will develop these tools leveraging information from FDCS,[73] operational SCADA systems, data warehouse and historian systems, AM systems, WM systems, and other systems that are used to manage outages, maintenance work, environmental risks, inventory, and other aspects of PG assets.[74]

The Asset Reliability Analytics Project will provide PG engineers and planners with information that improves their decision-making and reduces asset failure risk.[75] GIS-based user interfaces and visualization tools will enhance the ability of these personnel to consolidate and synthesize this information into investment, maintenance, and operational plans that are developed using a wide cross-section of information from and about PG&E's Hydro assets.

b) Asset Inventory and Materials Management Project

The Asset Inventory and Materials Management Project will improve its parts, equipment and materials tracking by instituting cradle-to-grave labeling and identification systems within the ordering and AM systems.[76] This project will support PG&E's

---

72 See WP 7-58, Lines 10-13, and 16-20, Exhibit (PG&E-5).

73 See Section B.3.b.2.d.

74 See WP 7-87, Exhibit (PG&E-5) for Project Summary.

75 Exhibit (PG&E-5), Chapter 4, Section B.3.

76 These systems include barcode, RFID, Quick Response (QR) coding, etc., that digitize the traceability, identity and data collection capabilities for key equipment elements.

asset, work, and maintenance management and planning, as well as project execution.

This project will support the Asset Reliability Analytics Project described immediately above by facilitating the tracking of individual key components' and systems' health, the operational and maintenance history of those items, the manufacturer, lot, type, and information about where else in the system those same items are in use. WM efficiency, safety, and reliability will be improved as field workers use their FWS to positively identify equipment on which they are working or collecting data readings.

c) RMI Documentum Configuration Project

The RMI Documentum Project builds upon the foundational work being performed to provide enterprise-wide records management capabilities.[77]

This project will continue developing and configuring the Documentum system to manage PG documents and to transfer legacy documents into the system.[78] As additional document types are identified, they are prioritized and the records management system is configured to accept them. Legacy documents are then loaded into the system. New documents are loaded by PG as part of the normal course of business.

d) Field Data Collection Systems Project

The FDCS Project will deploy environmental, electrical, and mechanical sensors and equipment to collect information supporting operational monitoring and assessment of generation and generation-related assets. This information supports AM and WM activities in support of increased safety and reliability and operational flexibility.

This project extends elements of the Hardware Improvements for Usability and Work Efficiency initiative in the

---

77 See Exhibit (PG&E-7), Chapter 8B for a discussion of the ERIM Program.

78 See WP 7-107, Exhibit (PG&E-5) for Project Summary.

2014 GRC. That project, in conjunction with the Watershed Modernization Project, has focused on delivering the basic telecommunications infrastructure for the PG&E Hydro system. The FDCS project focuses on delivering the automated data collection systems PG&E requires to acquire, do in-field processing as required, and transmit that data to systems of record for analytic and reporting purposes.

The deployment of systems such as mechanical vibration and electrical transient monitoring, Light Detection and Ranging, video and infrared camera systems, temperature, pressure, flow and other sensors for analytic (and intrusion detection) purposes will provide the additional data necessary for those purposes, while also reducing the load on operational systems such as SCADA that presently are the only method to collect what is often non-operational data. Improvement in data collection at PG assets will improve employee and public safety and asset reliability.

The FDCS Project will also include infrared monitoring of PG&E's solar facilities, including over 720,000 solar modules, 299 inverters and 154 transformers across PG&E's 10 ground-based solar sites.[79]

3) Work Management

PG&E forecasts $0.2 million in 2017 expense[80] and $2.3, $2.0, $1.5, and $2.3 million in 2016-2019 capital costs, respectively,[81] for the non-cybersecurity PG technology-related Work Management Program. This program accounts for a $0.18 million increase in expense costs for PG ESBT between 2014 and 2017.[82] The program's $2.0 million in 2017 forecast capital cost is nine percent

---

79 See Exhibit (PG&E-5), Chapter 5, Section B.2.a.4 for a full description of PG&E's solar facilities.

80 See WP 7-44, Line 22, Exhibit (PG&E-5).

81 See WP 7-58, Line 39, Exhibit (PG&E-5).

82 See WP 7-44, Line 22, Exhibit (PG&E-5).

of total PG technology-related programs' non-cybersecurity capital spending in 2017.

The PG technology–related Work Management Program is described in Section B.2, above. The primary driver of the reduced expense cost for this program between 2014 and 2017 is the 2015 transfer of a project to another Business Technology department.[83] Additionally, WM capital expenditures in this GRC forecast period are primarily focused on the following projects: the Mobile Applications for Workforce Project ($1.5 million in 2016); FWSP ($1.2, $1.5, and $2.3 million in 2017-2019, respectively); and the Work Process Safety Systems Project ($0.8 million, in each of 2016 and 2017).[84]

a) Field Workforce Systems Project

The FWSP will provide tools and applications to support PG personnel working either locally within and around PG&E's generation and related assets, or very remotely in the farthest reaches of PG&E's service territory. These tools and applications will rely upon and integrate the data from multiple technology systems to make this information more readily accessible to field personnel.[85]

The FWSP will use the mobile platforms currently under development and expand the capabilities of these platforms to include asset identification with barcode or RFID tags, access to electronic work procedure libraries, use of GIS-based applications, and the collection of field data through audio, video, and specialized sensors.

Through the FWSP, field personnel will have largely immediate and reliable access to asset and operational data, and the data they collect will electronically transfer to the

---

83 The SAP Project Systems Integration Project was transferred to Electric Distribution Technology as of 2015. See Exhibit (PG&E-4), Chapter 15.

84 See WP 7-58, 59, Lines 36 - 38, Exhibit (PG&E-5).

85 See WP 7-94, Exhibit (PG&E-5) for Project Summary.

appropriate systems of record. The elimination of paper processes for data collection and storage improves the ability for analysis, compliance, and records management and accuracy and completeness of data collection and its usefulness in reporting, metrics, and analytics.

4) Application Consolidate/Simplify/Upgrade

PG&E forecasts $0.95 million in 2017 expense[86] and $0.7, $1.5, $0.45, $1.4, and $0.9 million in 2015-2019 capital costs, respectively,[87] for the PG technology-related ACSUP. This program accounts for $0.95 million, or 58 percent, of the total non-cybersecurity 2017 expense costs for PG technology programs.[88] It also accounts for two percent of the total ES technology-related capital spending for non-cybersecurity PG technology projects in 2017.

The general objectives of the PG ACSUP are described in Section B.2, above. In 2017, forecast expense costs for the program are primarily associated with routine SAP enhancements, and non-capitalized work to assure the health and fitness-for-purpose of the over 55 applications for which ESBT is responsible on behalf of PG.[89] Additionally, the PG ASCUP capital expenditures in this GRC forecast period are primarily focused on the following projects: In-House PPM on Enterprise Platform, ($1.0, and $0.25 million in 2016 and 2017, respectively); Water Management Tools; ($0.7, and $0.5 million in 2015 and 2016, respectively); and Project Construction Estimation and Management Tools ($1.2, and $0.7 million in 2018 and 2019, respectively).[90]

---

86 See WP 7-44, Line 6, Exhibit (PG&E-5).

87 See WP 7-58, Line 8, Exhibit (PG&E-5).

88 See WP 7-44, Lines 6, 23, Exhibit (PG&E-5).

89 See WP 7-44, Line 2, and WP 7-58, Line 7, Exhibit (PG&E-5).

90 See WP 7-58, Lines 4, 5, 6, Exhibit (PG&E-5).

5) Compliance Management

The PG technology-related Compliance Management Program accounts for a $0.7 million decrease in total expense costs between 2014 and 2017.[91] PG&E forecasts $0.8, $1.5, and $2.3 million in 2017-2019 capital costs, respectively, for the non-cybersecurity PG technology-related Compliance Management Program.[92] The program's $2.5 million 2017 forecast capital cost is four percent of total PG technology-related programs' non-cybersecurity capital spending in 2017.

Compliance Management capital expenditures in this GRC forecast period are primarily focused on the following projects: the Compliance Task Tracking and Management Project ($0.8, $1.0, and $0.8 million in 2017-2019, respectively); and the Operational Metric Monitoring and Rollup Project ($0.5, and $1.5 million in 2018 and 2019, respectively).[93] These projects develop and improve the efficiency of systems that provide both leadership and the workforce on the ground with information critical to identifying, tracking, and maintaining compliance with regulatory and other compliance requirements and with producing and tracking metrics that help PG&E track its performance and adherence to requirements.

c. Energy Procurement Key Initiatives

The key ES technology-related initiatives to support Energy Procurement, as discussed in PG&E's Exhibit (PG&E-5), Chapter 6, in the forecast period are the following programs: Foundational Platforms; Application Consolidation, Simplification, and Upgrade; CAISO Market Initiatives Implementation; and Resource Integration. This section discusses each of these programs. Table 7-5 summarizes the Energy Procurement Technology Capital and Expense recorded and forecast values.

---

91 There is no expense forecast for 2017 for this program. See WP 7-44, Line 14, Exhibit (PG&E-5).

92 There is no capital forecast for 2015 and 2016. See WP 7-58, Line 24, Exhibit (PG&E-5).

93 See WP 7-58, Lines 22 - 23, Exhibit (PG&E-5).

TABLE 7-5
NON-CYBER SECURITY ENERGY SUPPLY ENERGY PROCUREMENT TECHNOLOGY PROGRAMS: 2014-2019 RECORDED AND FORECAST (THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Workpaper Reference
1	Capital (MWC-2F)	$ 18,837	$ 15,866	$ 17,550	$ 17,500	$ 17,700	$ 19,500	WP 7-61 Line 48
2	Expense (MWC JV)	$ 1,353	$ 467	$ 730	$ 2,100			WP 7-45 Line 26
3	**Total**	**$ 20,189**	**$ 16,333**	**$ 18,280**	**$ 19,600**	**$ 17,700**	**$ 19,500**	

Note: Cybersecurity Programs are described in Exhibit 7, Chapter 10.

1) Foundational Platforms

PG&E forecasts $1.0 million in 2017 expense,[94] and $10.3, $4.5, $2.3, $6.0, and $6.3 million in 2015-2019 capital costs, respectively,[95] for the EP technology-related Foundational Platform Program. This program accounts for $0.44 million, or 58.4 percent, of the total increase in technology-related expense costs for EP between 2014 and 2017.[96] It also accounts for 13.1 percent of total technology-related capital spending for EP in 2017.

The foundational platforms program is described generally in Section B.2.6, above and PG&E's Exhibit (PG&E-5), Chapter 6, Section B.3.b.3. As this program continues, the forecasted work for the 2017 GRC period includes investments in existing platforms supporting critical business functions and development of new platforms to replace manual business processes. Collectively, these foundational platform projects will enable EP to comply with increasingly complex market changes and regulatory requirements, as well as, improve core business capabilities with technology.[97] This program will focus on:

- Improving contract management capabilities from bid evaluation to contract retirement;

---

94 See WP 7-45, Line 16, Exhibit (PG&E-5).

95 See WP 7-60, Line 30, Exhibit (PG&E-5).

96 See WP 7-45, Lines 16, 26, Exhibit (PG&E-5).

97 See Exhibit (PG&E-5), Chapter 6, Section B.3.a.2 and B.3.a.3 for a discussion about PG&E's portfolio complexity and regulatory mandates.

- Establishing a centralized platform for customer load and generation meter data to replace six unsupported legacy systems;
- Planning for the implementation of an E-tagging system to improve the management of increasing power imports and exports within the portfolio; and
- Implementing mandated enhancements to existing platforms to comply with tariffs and regulatory policies.

This program will enhance the foundational platforms, while maintaining the ability to conduct critical EP business functions such as: trading, market operations, and settlements, as well as supporting Least Cost Dispatch demonstration requirements.

The capital forecast associated with this program in the 2017 GRC period is primarily focused on the following projects: the Meter Data Platform Implementation Project ($2.0, and $2.0 million in 2018-2019, respectively); the Trading Platform Enablement Project ($0.8, $2.0, and $0.8 million in 2017-2019, respectively); the Contract Management Integrated Solution Project ($0.5, and $2.0 million in 2018-2019, respectively); the Contract Compliance Enablement Project ($0.8, $0.8, and $0.8 million in 2017-2019, respectively); the Market Operations Platform Enablement Project ($0.4, $0.4, and $0.4 million in 2017-2019, respectively); and CAISO Market Data Migration ($0.3, $0.3, and $0.3 million in 2017-2019, respectively).[98]

a) Contract Management Integrated Solution Project

EP currently manages over 400 power contracts and expects this number to grow.[99] The current solution does not address the full contract lifecycle and is not a strong technical platform to build upon thus requiring the implementation of a full Contract Management Solution. This project will provide

---

98 See WP 7-60, Lines 20, 21, 23, 24, 26, 27, Exhibit (PG&E-5).

99 See Exhibit (PG&E-5), Chapter 6, Section B.3.a.3.c. for discussion around the expected increase in contracts.

functionality to manage energy contracts through their full lifecycle and will accommodate the expanding contract portfolio, which will reduce the risk of the current system and manual processes. The solution will support all stages of the contract lifecycle including assessment, agreement, solicitation, negotiation, execution, operation, and expiration. In addition, this solution will integrate to other foundational systems to allow contract terms to automatically update the optimization, bidding, scheduling, outage management, and contract settlement systems.

b) Trading Platform Enablement Project

This project will enhance PG&E's trading platform, OpenLink Financial's Endur (Endur) product, to ensure continued compliance with regulatory and market changes.[100] These enhancements include the introduction of new traded products and the ability to incorporate regulatory mandated requirements. For example, this project will enable PG&E's trading platform to capture, model, and settle new energy storage contracts intended to meet the state's recently updated energy storage targets. The Renewable Market-Adjusting Tariff (ReMAT) Program and the Biogas Market-Adjusting Tariff (BioMAT) Program are also enabled through the Endur platform.

c) Meter Data Platform Implementation Project

Energy Procurement has six different meter data management systems that collect, load, and aggregate meter data for generation and bundled load. Each system has limitations with respect to bundled load and generation data management, data validation, and analytics. In addition, these systems use dated technologies with limited vendor support.

The expected expansion and diversification of PG&E's generation portfolio to meet regulatory targets and to address load segmentation as it evolves necessitates the ability to

[100] See WP 7-121, Exhibit (PG&E-5) for Project Summary.

capture, validate, and analyze meter data quickly. This project will establish a centralized meter data repository for load and generation data, at the lowest granularity available from enterprise sources of record and will serve as the data source for downstream functions including settlements, compliance reporting, and resource planning. It will also provide advanced data validation and versioning and trending analysis. This project will mitigate current risks associated with manual data management processes.[101]

2) Application Consolidate/Simplify/Upgrade

PG&E forecasts $0.5 in 2017 expense[102] and $1.1, $3.5, $0.8, and $4.2 million in 2016-2019 capital costs, respectively,[103] for the Application Consolidate/Simplify/Upgrade Program. This program accounts for $0.5 million, or 67 percent, of the total increase in technology–related expense costs for EP between 2014 and 2017.[104] It also accounts for 20.0 percent of total technology-related capital spending for EP in 2017.

The general objectives of the Application Consolidation/ Simplification/Upgrades Program are described in Section B.2.b.4, above and PG&E's Exhibit (PG&E-5), Chapter 6, Section B.3.b.4. The proposed incremental work in the 2017 GRC period is intended to keep PG&E's critical systems in compliance with vendor maintenance requirements and to replace and retire legacy systems. The critical legacy systems support business functions including commodity trading, market operations, and settlements.

Expense costs in this program are primarily tied to data migration from retired to new systems. The goal for the program is to consolidate business functions on modern platforms, remain

---

101 See WP 7-115, Exhibit (PG&E-5) for Project Summary.

102 See WP 7-45, Line 4, Exhibit (PG&E-5).

103 See WP 7-60, Line 8, Exhibit (PG&E-5).

104 See WP 7-45, Lines 4, 26, Exhibit (PG&E-5).

compliant with vendor technology standards, and simplify the technology supporting Energy Procurement.

The capital forecast associated with this program in the 2017 GRC period is primarily focused on the following projects: the Trading Systems Compliance & Upgrade Project ($3.5, and $0.8 million in 2017 and 2018, respectively); the Market Operations System Compliance & Upgrade Project ($1.5 million in 2019); the Settlement System Compliance & Upgrade Project ($1.2 million in 2019); Analytics Compliance & Upgrades ($0.5, $0.5, and $0.5 million of expense expenditures in 2017, 2018, and 2019, respectively); and the Legacy System Consolidation and Remediation Project ($1.5 million in 2019).

a) The Trading Systems Compliance and Upgrades Project

PG&E's trade capture and settlement system is OpenLink Financial's (OLF) Endur system. Per the OLF contract, PG&E is required to maintain a supported version of Endur. Failure to comply can result in financial penalties and reduced support. PG&E currently requires an upgrade to be compliant. The upgrade project will include updating the infrastructure and software, as well as functional testing and data integration to and from the connected systems.[105]

3) CAISO Market Initiatives Implementation

PG&E forecasts $0.6 million in 2017 expense[106] and $2.3, $9.0, $9.0, $9.0, and $9.0 million in 2015-2019 capital costs, respectively,[107] for the CAISO MII Program. This program's 2017 expense forecast is a $0.2 million, or 23.4 percent decrease from recorded 2014 expense related to the program. In addition, the program accounts for 51.4 percent of total EP technology-related capital spending in 2017.

---

[105] See WP 7-123, Exhibit (PG&E-5) for Project Summary.

[106] See WP 7-45, Line 21, Exhibit (PG&E-5).

[107] See WP 7-61, Line 42, Exhibit (PG&E-5).

The general objectives of the on-going CAISO MII Program[108] are described in Section B.2.b.7. As described in PG&E's Exhibit (PG&E-5), Chapter 6, Sections B.3.a.2 and B.3.b.1, the complexity of PG&E's portfolio is increasing due to new products and services being developed to integrate the growing renewable resources and changing market conditions. In 2017, forecast expense costs for the MII Program are primarily associated with capital projects implementing CAISO initiatives. The capital projects are required to automate business processes through updating or enhancing applications and infrastructure in order to be compliant with the mandated changes from the CAISO Stakeholder Initiatives Catalog.[109] The implementation readiness for each initiative's CAISO Go-Live is critical to ensure the critical daily to sub-hourly market interfaces with the CAISO—such as scheduling, bidding, and settling—are not interrupted, which could lead to financial consequences if tariff deadlines are missed or the inability to validate CAISO charges.

In order to forecast CAISO changes, PG&E evaluated each of the proposed initiatives from the current CAISO Stakeholder Initiatives Catalog. Each initiative was assessed on estimated operative date and impact of policy change on business processes and technology. Although the catalog provides a general roadmap for CAISO initiatives, the actual implementation plans published by CAISO can include items that are not in the catalog. For example, the Energy Imbalance Market had major business and technology impacts but was not published in the catalog.

Below are the initiatives assumed for implementation based on the current catalog, for 2017-2019:

<u>2017</u>

- Bid Cost Recovery for Units Running over Multiple Days
- Ancillary Services Substitution

---

108 See WP 7-112, Exhibit (PG&E-5) for Project Summary.

109 CAISO 2015 Stakeholder Initiatives Catalog – http://www.caiso.com/Documents/Final_2015StakeholderInitiativesCatalog.pdf

- Energy Storage Initiative and Aggregated Distributed Energy Resources
- Expanding Metering and Telemetry Options

2018

- Full Network Model Expansion Phase 2
- Generator Contingency Modeling
- Aggregated Pumps and Pump Storage
- Storage Generation Plant Modeling

2019

- Fractional Megawatt Regulation Awards
- Outage Notification Requirements
- Joint Reliability Plan
- Energy Products Delivered on Interties
- Full Network Expansion

The following stakeholder initiatives are an illustrative sample of catalog initiatives and the anticipated implementation scope for each.

a) Energy Storage Initiative and Aggregated Distributed Energy Resources

This initiative is focused on enhancing the participation of storage and aggregations of energy storage and other distributed energy resources (DER) in the CAISO markets. As part of the initiative, existing CAISO requirements, rules, market products, models, and policies will be evaluated and enhanced to better integrate energy storage and the aggregations of DERs in the CAISO markets. These proposed changes will require enhancements to all market operations and supporting systems, including: short term and midterm optimization models; bidding functions; scheduling and market systems; CAISO settlement systems; and data collection and management for all facets of energy storage and aggregated DERs.

b) Full Network Model Expansion

Through this initiative, the CAISO is proposing to expand its full network model to improve reliability and market solution accuracy. In association with FERC and North American Electric Reliability Corporation (NERC) recommendations, the CAISO expects to expand the model of the physical electric network to include other balancing authorities and include balancing across system interconnections so they are represented within the market. These proposed changes will impact applications that model the network, including: network changes in planning and optimization applications; expansion of bidding systems to properly account for network changes; modification of settlement systems to acquire necessary data and potential new prices; and extensions of market data acquisition systems and the associated infrastructure to account for the increase in volume of market data.

c) Aggregated Pumps and Pump Storage

This initiative focuses on resources that are capable of storing energy through pumping systems and implementing market and model changes to represent these assets in the market. These proposed changes would impact all market-supporting systems, and could include: optimization systems will need to apply the model changes; bidding and scheduling applications will need to provide additional functionality; settlement systems will need to implement new charge codes; and market data acquisition systems will be required to retrieve new data reflecting pump storage.

4) Resource Integration

PG&E forecasts $3.3, $3.0, $2.7, and $1.9 million in 2015-2018 technology-related capital costs, respectively,[110] for the Resource Integration Program. The program accounts for 15.4 percent of total forecasted technology-related capital spending for EP in 2017.

---

110 See WP 7-61, Line 47, Exhibit (PG&E-5).

The general objectives of the Resource Integration are described in Section B.2.b.8, above and PG&E's Exhibit (PG&E-5), Chapter 6, Section B.3.b.2.

PG&E's owned and procured generation portfolio is rapidly increasing in diversity, volume, and complexity. As a result, the volatility and unpredictability of the energy delivered is also increasing. For market purposes, monitoring production and communicating dispatch for flexible ramping instructions become more challenging. The capital forecast for this program and GRC period are primarily focused on the Real-Time Automated Communication Project ($3.3, $3.0, $2.5, and $1.5 million in 2015-2018, respectively); and Forecasting Expansion ($0.2. and $0.4 million in 2017 and 2018, respectively).[111]

a) Real-Time Automated Communication Project

Increasing amounts of intermittent renewables are coming online and changing system operational conditions, hence PG&E anticipates an increase in the frequency of events that will trigger action in the real time operational environment to support system reliability. Such actions include, but are not limited to, responding to CAISO "contingency dispatch" instructions (i.e., responding to large volumes of dispatch within 10 minutes to maintain system reliability) and over-generation (a system reliability condition), resulting in the need for systems and personnel to be available to respond to these conditions. Additionally, as new resources are developed or are dispatched in new ways, further adjustments will be needed including new systems to be able to respond quickly to more resources being on the system, and the increasing movements and dispatch of flexible resources to help balance renewables on the system.

During the 2015 through 2017 timeframe, it is anticipated that over 70 new generation projects will be coming online, which represents over 20 percent of the current portfolio. With

[111] See WP 7-61, Lines 43-46, Exhibit (PG&E-5).

the increasing volume of projects, and likelihood of increasing frequency of dispatch instructions, the current situation of predominantly manual communications and limited visibility of resource output will not keep pace. Failure to implement a system could result in negative impacts to system reliability if PG&E is unable to respond to large volumes of dispatch instructions in the required timeframe.

This project[112] will provide PG&E the capabilities to monitor and acquire production, meteorological, and related generation data in near real-time, and to automate communications of market signals, dispatches, and instructions to generation facilities both in and out of PG&E's control and operational area.[113]

The project will evaluate and enable bi-directional communication through infrastructure connectivity to each PG&E owned or contracted resource within PG&E's control area. For out of state resources, connectivity will be developed based on the existing infrastructure and network capabilities at each site. This communication framework will be the foundation for delivering data to repositories that collect and store generation, meteorological, fuel consumption, and other related data. The project will further integrate optimization and forecasting models to be able to generate short-term and real-time market forecasts and schedules. In addition, the proposed solution will allow for the seamless communication of market dispatches, curtailments, and intra-hour market changes to connected generation resources. In order to continually monitor the portfolio and to enhance PG&E's ability to make market-based decisions, the solution will also provide near real-time data visualization and alarm dashboards.

---

112 See WP 7-118, Exhibit (PG&E-5) for Project Summary.

113 See (PG&E-5), Chapter 6, Section B.3.a.2 for further discussion about PG&E's Portfolio Complexity driver.

C. Activities and Costs by Major Work Category

All activities discussed in Exhibit (PG&E-5), Chapter 7 fall within the Major Work Categories (MWC) JV and 2F for expense and capital, respectively.

MWC JV covers expense costs related to projects delivering technology-related capabilities in support of the Energy Supply business areas: Nuclear Generation, PG, and EP. MWC 2F similarly covers the capital costs for projects that deliver technology-related capabilities to Energy Supply.

The cost tables presented in Section F below present the annual non-cybersecurity costs associated with MWCs JV and 2F, by program, for each ES business area.

D. Estimating Method

The Project Estimating Tool is the primary method used to determine initial capital and expense forecasts for technology projects covered in this chapter.[114] Additionally, forecasts are determined using a combination of the following: (1) actual costs for similar work, adjusted as appropriate; (2) the knowledge and experience of PG&E's program and project managers; (3) contractor and consultant experience with similar work; and (4) estimates from potential vendors.

E. Relationship of the Programs Discussed in this Chapter and Other Proceedings

1. Smart Grid Pilot Program

PG&E filed its Smart Grid Deployment Plan with the Commission in June 2011, and filed its first application under that plan for approval of Smart Grid pilot deployment projects in Application 11-11-017. In that application, PG&E proposed to consolidate its capital-related revenue requirements in its 2017 GRC. Table 7-6[115] summarizes the recorded and forecast capital expenditures associated with Energy Procurement's Smart Grid Pilot

---

[114] For further discussion on the Project Estimating Tool, please see Exhibit (PG&E-7), Chapter 9.

[115] The amounts in this table may vary slightly from the values in the Results of the Operations (RO) model provided to the Office of Ratepayer Advocates on September 1, 2015. Subsequent iterations of the RO model will be corrected to reflect the amounts in this table.

project – Short Term Demand Forecasting[116] – that will be consolidated into the revenue requirements in this application.[117]

The pilot is progressing on track. As the project has yet to be completed and evaluated, PG&E does not intend to seek funding for production deployment and implementation at this time.

TABLE 7-6
ENERGY PROCUREMENT SMARTGRID PILOT 2014-2019
CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Workpaper Reference
1	3M	Smart Grid Short Term Demand Forecasting	$ 155	$ 6,089	$ 3,100	$ -	$ -	$ -	WP 7-47 Line 2
2	**3M**	**SmartGrid Total**	**$ 155**	**$ 6,089**	**$ 3,100**	**$ -**	**$ -**	**$ -**	

Note: The amounts in this table may vary slightly from the values in the Results of the Operations (RO) model provided to the Office of Ratepayer Advocates on September 1, 2015. Subsequent iterations of the RO model will be corrected to reflect the amounts in this table.

F. Cost Tables

PG&E's forecast and recorded costs for Non-Cyber Security ES technology programs are summarized in the following tables. Tables 7-7 through 7-12 show by ES business area:

- 2014 recorded adjusted expenses and 2015 through 2017 forecast expenses by MWC and ES technology Program, and
- 2014 recorded adjusted capital expenditures and 2015 through 2019 forecast capital expenditures by MWC and ES technology program.

[116] See WP 7-125, Exhibit (PG&E-5) for Project Summary.

[117] Additional Smart Grid Pilot capital expenditures associated with Electric Distribution are shown in Exhibit (PG&E-4), Chapter 15.

1. Nuclear

a. Expense

TABLE 7-7
NUCLEAR GENERATION NON-CYBERSECURITY TECHNOLOGY PROGRAMS
EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	Workpaper Reference
1	JV	Infrastructure	$ -	$ -	$ 300	$ 450	WP 7-43 Line 18
2	JV	Asset Management	$ -	$ -	$ 450	$ 150	WP 7-43 Line 12
3	JV	Work Management	$ -	$ 47	$ 1,750	$ 200	WP 7-43 Line 23
4	JV	Application Consolidate/Simplify/Upgrade	$ -	$ 200	$ 1,100	$ 1,050	WP 7-43 Line9
5	**JV**	**Non-Cyber Total**	**$ -**	**$ 247**	**$ 3,600**	**$ 1,850**	

Note: Cybersecurity Programs are described in Exhibit 7, Chapter 10.

b. Capital

TABLE 7-8
NUCLEAR GENERATION NON-CYBERSECURITY TECHNOLOGY PROGRAMS
CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Workpaper Reference
1	2F	Infrastructure	$ 3,178	$ 1,100	$ 5,750	$ 7,500	$ 6,000	$ 3,000	WP 7-57 Line 30
2	2F	Asset Management	$ -	$ -	$ 2,500	$ 4,000	$ 2,000	$ 1,250	WP 7-57 Line 15
3	2F	Work Management	$ 2,697	$ 1,852	$ 1,500	$ 1,000	$ 1,500	$ 2,000	WP 7-57 Line 36
4	2F	Application Consolidate/Simplify/Upgrade	$ 401	$ 3,067	$ 2,650	$ 1,050	$ 2,550	$ 4,000	WP 7-57 Line11
5	**2F**	**Non-Cyber Total**	**$ 6,276**	**$ 6,019**	**$ 12,400**	**$ 13,550**	**$ 12,050**	**$ 10,250**	

Note: Cybersecurity Programs are described in Exhibit 7, Chapter 10.

2. Power Generation

a. Expense

TABLE 7-9
POWER GENERATION NON-CYBERSECURITY TECHNOLOGY PROGRAMS
EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	Workpaper Reference
1	JV	Infrastructure	$ -	$ -	$ 200	$ -	WP 7-44 Line 16
2	JV	Asset Management	$ 11	$ 100	$ 800	$ 500	WP 7-44 Line 12
3	JV	Work Management	$ 18	$ 100	$ 1,200	$ 200	WP 7-44 Line 22
4	JV	Compliance Management	$ 742	$ -	$ -	$ -	WP 7-44 Line 14
5	JV	Application Consolidate/Simplify/Upgrade	$ -	$ 161	$ 900	$ 950	WP 7-44 Line 6
6	**JV**	**Non-Cyber Total**	**$ 772**	**$ 361**	**$ 3,100**	**$ 1,650**	

Note: Cybersecurity Programs are described in Exhibit 7, Chapter 10.

b. Capital

TABLE 7-10
POWER GENERATION NON-CYBERSECURITY TECHNOLOGY PROGRAMS
CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Workpaper Reference
1	2F	Infrastructure	$ 4,427	$ 3,540	$ 5,600	$ 6,200	$ 5,200	$ 1,000	WP 7-58 Line 32
2	2F	Asset Management	$ 6,614	$ 2,552	$ 4,000	$ 2,500	$ 2,500	$ 4,200	WP 7-58 Line 21
3	2F	Work Management	$ 1,457	$ 92	$ 2,300	$ 2,000	$ 1,500	$ 2,300	WP 7-59 Line 39
4	2F	Compliance Management	$ -	$ -	$ -	$ 800	$ 1,500	$ 2,300	WP 7-58 Line 24
5	2F	Application Consolidate/Simplify/Upgrade	$ 1,403	$ 795	$ 1,500	$ 450	$ 1,400	$ 900	WP 7-58 Line 8
6	**2F**	**Non-Cyber Total**	**$ 13,901**	**$ 6,979**	**$ 13,400**	**$ 11,950**	**$ 12,100**	**$ 10,700**	

Note: Cybersecurity Programs are described in Exhibit 7, Chapter 10.

3. Energy Procurement

a. Expense

TABLE 7-11
ENERGY PROCUREMENT NON-CYBERSECURITY TECHNOLOGY PROGRAMS
EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	Workpaper Reference
1	JV	Foundational Platforms	$ 563	$ 267	$ 60	$ 1,000	WP 7-45 Line 16
2	JV	CAISO Market Initiatives Implementation	$ 789	$ 100	$ 500	$ 600	WP 7-45 Line 21
3	JV	Resource Integration		$ 100	$ 70	$ -	WP 7-45 Line 25
4	JV	Application Consolidate/Simplify/Upgrade	$ -	$ -	$ 100	$ 500	WP 7-45 Line 4
5	**JV**	**Non-Cyber and SmartGrid Total**	**$ 1,353**	**$ 467**	**$ 730**	**$ 2,100**	

Note: Cybersecurity Programs are described in Exhibit 7, Chapter 10.

b. Capital

TABLE 7-12
ENERGY PROCUREMENT NON-CYBERSECURITY TECHNOLOGY PROGRAMS
CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	2014 Recorded Adjusted	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	Workpaper Reference
1	2F	Foundational Platforms	$ 9,351	$ 10,303	$ 4,450	$ 2,300	$ 6,000	$ 6,300	WP 7-60 Line 30
2	2F	CAISO Market Initiatives Implementation	$ 9,211	$ 2,265	$ 9,000	$ 9,000	$ 9,000	$ 9,000	WP 7-61 Line 42
3	2F	Resource Integration	$ -	$ 3,299	$ 3,000	$ 2,700	$ 1,900	$ -	WP 7-61 Line 47
4	2F	Application Consolidation/Simplification/Upgrade	$ 274	$ -	$ 1,100	$ 3,500	$ 800	$ 4,200	WP 7-60 Line 8
5	**2F**	**Non-Cyber Total**	**$ 18,836**	**$ 15,866**	**$ 17,550**	**$ 17,500**	**$ 17,700**	**$ 19,500**	
6	3M	Smart Grid Short Term Demand Forecasting	$ 155	$ 6,089	$ 3,100	$ -	$ -	$ -	WP 7-47 Line 2
7	**2F/3M**	**Non-Cyber and SmartGrid Total**	**$ 18,991**	**$ 21,955**	**$ 20,650**	**$ 17,500**	**$ 17,700**	**$ 19,500**	

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

ENERGY SUPPLY RATEMAKING

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
ENERGY SUPPLY RATEMAKING

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
ENERGY SUPPLY RATEMAKING

A. Introduction

The purpose of this testimony is to address Pacific Gas and Electric Company's (PG&E or the Utility) ratemaking issues for the Energy Supply function in the 2017 General Rate Case (GRC). There are several ratemaking topics addressed in this chapter. Specifically, PG&E requests that the Commission issue findings that approve PG&E's proposals to:

- Continue the two-way balancing accounts for managing the capital and expense forecasts associated with Federal Energy Regulatory Commission (FERC) hydro relicensing and new/amended license conditions and implementation of Nuclear Regulatory Commission (NRC) rulemaking requirements associated with nuclear safety and security.
- Continue to credit to the generation revenue requirement the refunds received as a result of PG&E's successful litigation settlement with the Department of Energy (DOE) regarding DOE's delay in taking and permanently storing spent nuclear fuel from PG&E's nuclear facilities.
- Include the costs associated with the Diablo Canyon Power Plant (Diablo Canyon) Long Term Seismic Program (LTSP) in the generation revenue requirement in the 2017 GRC.
- Levelize the costs of the second refueling outage at Diablo Canyon and of the costs associated with the Colusa and Gateway Generating Station major outages associated with their Long-Term Service Agreements (LTSAs) over the 2017 GRC period.
- Include the ongoing revenue requirement associated with its Photovoltaic (PV) assets in the generation revenue requirement as required by Decision 10-04-052,[1] and continue to credit the capital cost savings related to the PV Program to the Utility Generation Balancing Account (UGBA).
- Include the ongoing revenue requirements associated with the costs of Smart Grid pilot deployment projects in the 2017 GRC.

---

1 Page 33.

Each of these topics is discussed in more detail below.

Because electric generation and power procurement costs are recovered in a number of related proceedings, this testimony also provides an overview of how other generation-related proceedings interact with this proceeding.

B. Energy Supply Ratemaking Overview

1. General Rate Case

Decision 02-04-016, the utility-retained generation decision, placed all of PG&E's Utility Owned Generation (UOG) on cost-of-service ratemaking. Prior to that, the costs of owning and operating non-nuclear generation were collected under transition ratemaking established as part of Assembly Bill (AB) 1890, and Diablo Canyon costs were recovered pursuant to a modified settlement agreement approved in Decision 97-05-088.

Currently, the costs of owning and operating PG&E-owned generation facilities, except for the cost of fuel and water purchases, are generally recovered through GRCs. The initial ratemaking for PG&E's new fossil and solar generation facilities was established outside the GRC pursuant to separate applications and California Public Utilities Commission (CPUC or Commission) decisions. All of these facilities have become operational and PG&E incorporates the costs of these facilities in its generation revenue requirement forecast in this application.

2. Energy Resource Recovery Account

Decision 02-10-062 established the Energy Resource Recovery Account (ERRA) as the mechanism for recovering the cost of PG&E's fuel and purchased power costs. Currently, costs recovered through ERRA include:

- PG&E-owned generation fuel costs
- Purchased power costs
- Qualifying Facility contract costs
- California Independent System Operator charges net of Reliability-Must-Run revenues
- Hedging costs and fuel costs for third-party generator contracts

3. Other Generation-Related Proceedings

There are other proceedings that will establish interim mechanisms to determine non-fuel generation revenue requirements outside the GRC.

a. Nuclear Decommissioning

Decision 03-10-014 requires PG&E to file a separate Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) application. The NDCTP establishes funding levels for the Diablo Canyon and Humboldt Bay nuclear decommissioning trusts and Humboldt Safe Storage activities. PG&E anticipates that it will file a new NDCTP application in December 2015. The cost of Diablo Canyon and Humboldt Bay nuclear decommissioning trusts and Humboldt Safe Storage activities, therefore, are not included in this application.

b. Diablo Canyon License Renewal

In January 2010, PG&E requested that the Commission find that it is cost effective and in the best interest of PG&E's customers to preserve the option to operate Diablo Canyon for an additional 20 years beyond the expiration of the current operating licenses for Units 1 and 2, which are 2024 and 2025, respectively (A.10-01-022). PG&E requested authority to recover in rates the costs to obtain the state and federal approvals related to renewal of the Diablo Canyon operating licenses (the License Renewal project). The application was dismissed without prejudice pending completion of the seismic studies described below. PG&E does not request recovery of any costs associated with license renewal for Diablo Canyon in this application.

C. Continuation of Balancing Accounts for Hydro and Nuclear Regulatory Requirements

PG&E intends to continue the two-way balancing accounts for managing the capital and expense forecasts associated with FERC hydro relicensing and new/amended license conditions (the Hydro Licensing Balancing Account (HLBA)) and implementation of NRC rulemaking requirements associated with nuclear safety and security (the Nuclear Regulatory Commission Rulemaking Balancing Account (NRCRBA)). The balancing accounts were approved in PG&E's 2014 GRC [2]

---

[2] D.14-08-032, Ordering Paragraphs (OP) 24-27. See also Exhibit (PG&E-12), Chapter 9, Balancing Accounts, Section B.1.b Hydro Licensing Balancing Account and Section B.1.c Nuclear Regulatory Commission Rulemaking Balancing Account.

As discussed in more detail in Chapter 4 of this exhibit, the FERC relicensing process is a multi-year process that seeks to balance the beneficial use of the water resource. However, the timing of issuance of the licenses is uncertain and therefore the cost and timing of relicensing and license implementation expenditures are equally uncertain. It is difficult to forecast when FERC will issue new licenses for hydro projects because the regulatory process includes a number of stakeholders and includes several separate state and federal reviews that run in parallel with the FERC process. Experience since establishing the HLBA in 2014 has proven this point. As demonstrated in Tables 8-1 and 8-2 below, PG&E experienced several significant delays in the issuance of new FERC hydro licenses and this deferred the timing of tens of millions of dollars in license implementation-related work that was forecasted in the 2014 GRC. Since the revenues collected for this purpose were not needed, the over collection will be returned to customers.

TABLE 8-1(a)
HYDROELECTRIC RELICENSING EXPECTED LICENSE ISSUANCE DATES
2017 GRC VERSUS 2014 GRC

Line No.	FERC License	Project Name	Expected License Issuance	
			2014 GRC	2017 GRC
1	2155	Chili Bar	Nov-12	License received in Aug-14
2	803	DeSabla-Centerville	Dec-12	Oct-16
3	2105	Upper NF Feather River	Dec-12	Jun-17
4	2107	Poe	Dec-12	Jun-18
5	2106	McCloud – Pit	Jul-14	Apr-18
6	606	Kilarc-Cow Creek Surr.	Dec-14	Jun-16
7	2467	Merced Falls	Feb-16	Feb-16
8	2310	Drum-Spaulding	Apr-16	Feb-19
9	619	Bucks Creek	Dec-20	Dec-20

(a) See Chapter 4, Exhibit (PG&E-5).

TABLE 8-2(a)
HYDROELECTRIC LICENSING AND LICENSE IMPLEMENTATION FORECASTS
2017 GRC VERSUS 2014 GENERAL RATE CASE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019
1	2014 GRC Expense Forecast	$553	$6,371	$6,286	–	–	–	–	–
2	2017 GRC Expense Actuals/Forecast	–	–	$305	$454	$635	$5,139	–	–
3	2014 GRC Capital Forecast	$16,958	$13,303	$28,646	$38,572	$48,387	–	–	–
4	2017 GRC Capital Actuals/Forecast	$16,935	$16,088	$17,227	$21,325	$20,314	$20,160	$45,039	$49,866

(a) See Chapter 4, Exhibit (PG&E-5).

Likewise, as shown in Table 8-3, the costs associated with the NRCRBA in the 2014 GRC were estimated to be higher than the current forecast of costs included in the 2017 GRC.

TABLE 8-3
NUCLEAR REGULATORY COMMISSION REGULATORY BALANCING ACCOUNT
COMPARISON OF 2014 GRC AND 2017 GRC
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	Prior Recorded	2014 Recorded	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	Capital Expenditures						
2	2014 GRC Forecasts	$47,514	$45,210	$60,903	$62,639	–	–
3	2017 GRC Actuals/Forecast	39,711	44,099	59,700	36,068	$13,304	$5,157
4	Difference	$7,803	$1,111	$1,203	$26,571	$(13,304)	$(5,157)
5	Expense						
6	2014 GRC Capital	–	$14,560	$11,409	$10,000	–	–
7	2017 GRC Actuals/Forecast	–	8,339	11,200	14,817	$9,400	–
8	Difference	–	$6,221	$209	$(4,817)	$(9,400)	–

Continued implementation of the balancing accounts is beneficial to customers for the following reasons: (1) the proposal will ensure full funding of and compliance with new difficult to predict but critically important regulatory conditions associated with these categories of work; (2) to the extent that this work is delayed or costs are less than expected, unspent funds will be returned to customers; and (3) to the extent that the cost of this work is greater than expected, the mechanism will provide a vehicle for cost recovery in the next

GRC and will not affect the funding for other important work. In addition, the proposed balancing accounts will obviate the need for possible separate applications seeking recovery of any hydro license and license conditions costs and NRC rulemaking implementation cost that are substantially above the forecast included in this application.

Tables 8-4 and 8-5 show the capital expenditures and expense amounts associated with the hydro relicensing and NRC rulemaking for which PG&E is proposing balancing account treatment in the 2017 GRC.

TABLE 8-4
BALANCING ACCOUNT CAPITAL EXPENDITURES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014 CWIP	2015	2016	2017	2018	2019
1	Hydro Relicensing	$165,191	$22,394	$21,586	$26,986	$40,971	$47,143
2	NRC Rulemaking	62,884	59,700	36,068	13,304	5,157	–
3	Total	$228,075	$82,094	$57,654	$40,290	$46,128	$47,143

TABLE 8-5
BALANCING ACCOUNT EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2014	2015	2016	2017
1	Hydro Relicensing	$286	$454	$558	$3,942
2	NRC Rulemaking	8,339	11,200	14,817	9,400
3	Total	$8,625	$11,654	$15,375	$13,342

PG&E requests that the Commission adopt these forecasts for the Hydro and Nuclear Balancing Accounts for the 2017-2019 period.

In addition, under the Hydro and Nuclear Balancing Accounts, PG&E is required to return to customers any excess revenues or seek to recover any revenue shortfall in the following GRC. PG&E has calculated the difference between the revenue requirements for 2014-2016 authorized in the 2014 GRC and the current forecasted revenue requirements based on the recorded 2014 costs and updated forecasts for 2015 and 2016.

PG&E's adjusted forecast for the HLBA for the 2014-2016 period is that there will be an over collection of $46.9 million. This is due primarily to delays in

the issuances of new hydroelectric licenses by FERC. Since PG&E did not incur costs associated with implementation of these delayed FERC licenses, PG&E will refund the over collection in the HLBA to customers in this GRC cycle.

PG&E's adjusted forecast for the NRCRBA for the 2014-2016 period is that there will be an over collection of $24.4 million. This is primarily due to the rescheduling of regulatory-required fire protection system modifications into the 2017-2018 period, and the refinement of the scope of the Fukushima-related work.

As a result of the above credits, PG&E expects to reduce its 2017 generation-related revenue requirement by $71 million.[3]

D. Credit of DOE Litigation Awards

The Commission approved a joint proposal between The Utility Reform Network (TURN), Marin Energy Authority (MEA) and PG&E on the treatment of DOE settlement refunds in the 2014 GRC decision.[4] PG&E proposes to continue to credit the litigation settlement proceeds using the same methodology approved in the joint proposal. The settlement requires any proceeds received during a given year be returned to customers the following year. PG&E forecasts that this will result in a reduction to generation rates of approximately $20 million in 2017.

PG&E will continue to credit to customers the refunds received as a result of its September 5, 2012 settlement in the DOE litigation. The DOE Litigation is described in Chapter 3 of this exhibit.

In the 2014 GRC, PG&E reached a joint proposal with TURN and MEA for crediting the proceeds of the DOE litigation settlement to generation rates (for reimbursement of spent fuel related storage costs for Diablo Canyon) and to nuclear decommissioning rates (for reimbursement of spent fuel related storage costs for Humboldt Bay Nuclear Power Plant).[5] For the period 2017-2019, PG&E will continue to use the allocation method for "future claims proceeds" in the joint proposal – 72 percent of the proceeds in the Department of Energy

---

3 Specifically, PG&E will transfer the December 31, 2016 recorded balance in this account to the UGBA, and return to customers through the Annual Electric True-Up (AET) Advice Letter filing.

4 D.14-08-032, OP 28; Appendix F-5.

5 D.14-08-032, Appendix F-5.

Litigation Balancing Account (DOELBA) will be allocated to the UGBA and 28 percent of the proceeds will be credited to the Nuclear Decommissioning Adjustment Mechanism (NDAM) Settlement proceeds will be credited upon receipt to the DOELBA and transferred, net of any outside litigation costs, to the UGBA and NDAM in January of the year following receipt.

PG&E forecasts that it will continue to collect approximately $20 million per year from DOE under the administrative claims procedure in the settlement to compensate PG&E for the costs of storing spent nuclear fuel at Diablo Canyon and Humboldt Bay. This forecast is consistent with the recent results. For the period June 1, 2012 to May 31, 2013, PG&E received approximately $20.8 million from DOE. For the period June 1, 2013 to May 31, 2014, PG&E received approximately $20.9 million from DOE.

Using the allocation factors adopted in the joint recommendation, Diablo Canyon is allocated 72 percent of these estimated proceeds—$14.4 million. PG&E's forecast of the revenue credits is included in Table 8-6.

The original DOE settlement agreement resulted in a lump sum to cover PG&E's costs through the end of 2010. In addition, PG&E received annual payments for three years under an administrative claims process. The annual claims process was extended through the end of 2016 in an amendment to the settlement agreement that was reached in 2013. PG&E anticipates that DOE will extend a second time the annual administrative claims process at the end of 2016. PG&E's forecast for the period 2017-2019 is based on this assumption. If the settlement is not extended, PG&E will be required to file a new lawsuit against DOE to recover the costs of spent fuel storage starting in 2017. PG&E will continue to track actual costs and proceeds from the DOE in the DOELBA and will true-up the December 31 balance in the account on an annual basis through an adjustment to generation rates in the AET.

Table 8-6 shows PG&E's estimate of the DOE Litigation Award.

TABLE 8-6
ESTIMATED DOE LITIGATION SAVINGS
(MILLIONS OF NOMINAL DOLLARS)

Line No.	Description	2015	2016	2017	2018	2019
1	DOE Litigation Award	$20	$20	$20	$20	$20

The forecasts in Table 8-6 are estimates and the magnitude and the timing will require adjustment to reflect the actual litigation proceeds realized.

E. Recovery of Diablo Canyon Long Term Seismic Program Costs in GRC

In the 2014 GRC decision, the Commission adopted a proposal by A4NR to remove $4.84 million in costs associated with PG&E's LTSP and transfer the costs to the Diablo Canyon Seismic Studies Balancing Account for recovery and review in the annual ERRA compliance proceeding. The Commission granted this and other related A4NR proposals in order to "assure the proper integration of the AB 1632 seismic studies with the LTSP and the Senior Seismic Hazards Analysis Committee (SSHAC) process."[6] As described in detail in Chapter 3 of this exhibit, the AB 1632 seismic studies authorized in Decision 12-09-008 and the SSHAC process referenced in the decision are now completed. PG&E will not incur any additional costs associated with these activities in 2017 or beyond. As there is no longer a need to coordinate cost recovery review of these processes, PG&E has once again included LTSP costs in the GRC.

The LTSP costs for 2017-2019 included in Chapter 3 of this exhibit, include the labor and consultant costs in PG&E's Geosciences Department associated with PG&E's ongoing NRC commitment to continuously study and update the state of knowledge regarding seismic hazards affecting Diablo Canyon. These types of labor cost and expense are normally recovered in base rates in the GRC. Given that there is no longer a need to coordinate cost recovery of LTSP activities with review of the costs of the now-completed AB 1632 advanced seismic studies in the ERRA, it is reasonable to include LTSP costs in the GRC. There is no reason to encumber the 2017 ERRA compliance review and in later years with issues that are entirely unrelated to cost recovery of electric power procurement.

---

6 D.14-08-032, pp 410-412.

F. Three Year Levelization of Diablo Canyon Second Refueling Outage and Fossil LTSA Major Outage Costs

PG&E typically conducts one nuclear refueling outage each year at Diablo Canyon. However, the need to balance the optimization of the fuel cycle with the desire to avoid shutdowns during the high-demand summer-months results in a two-outage year approximately once every five years. In 2019, Diablo Canyon will have two refueling outages. The last year that Diablo Canyon had two refueling outages was in 2014.

In order to smooth out the impacts to customers, PG&E proposes to spread the costs of the second refueling outage over the 3-year GRC period, such that one-third of the costs would be recovered in 2017, 2018 and 2019. This is the same treatment of the second refueling outage that was adopted in the 2014 GRC.[7] The one-third amortization amount included in 2017 for the second refueling outage is $20.2 million.

As described in detail in Chapter 5 of this exhibit, PG&E also proposes to levelize the costs associated with the major LTSA outages at its Gateway and Colusa generating stations. These major outages also occur every few years (based on run rates and stops/starts) and result in “lumpy” costs. PG&E proposes to smooth-out the costs by amortizing them over the 2017-2019 period.

G. PV Cost Savings Credit

In Decision 10-04-052, the Commission approved a 5-year 250 megawatts (MW) UOG PV Program expected to have a capital cost of $1.45 billion. The Commission adopted a revenue requirement based on the estimated capital cost, but required PG&E to true-up the revenue requirement to reflect the actual capital cost if it was below the estimate at the end of the 5-year program. In accordance with Decision 10-04-052, the Commission established the Photovoltaic Program Memorandum Account (PVPMA) to “…track the difference between the revenue requirement associated with the capital costs incurred as a result of PG&E’s PV Program and the authorized revenue requirement set forth for this program in Decision 10-04-052.”

---

7 D.14-08-032, p. 386.

PG&E has successfully completed construction of the first three program years, or 150 MW, of the PV UOG Program at a total estimated capital cost substantially below the capital cost assumed in the PV decision. In Decision 14-11-026, the Commission approved PG&E's request to terminate the PV Program after the first three program years, so the construction of the PV UOG Program facilities is now concluded.

In its 2014 GRC Application, PG&E proposed, and the Commission approved, crediting back to customers the savings associated with the first three years of the PV UOG Program.[8] Accordingly, PG&E transferred a credit equal to one-third of the December 31, 2013 balance in the PVPMA as a credit to UGBA in January 2014 and January 2015. PG&E will transfer the final third of the December 31, 2013 balance to UGBA in January 2016. The credits have been and will be included as an offset to generation revenues in the year of the credit.

In addition, as proposed and approved in the 2014 GRC, PG&E transferred the December 31, 2014 balance to UGBA in January 2015, and it plans to transfer the December 31, 2015 PVPMA balance to UGBA in January 2016.

PG&E's 2014 GRC testimony stated that any activity in the PVPMA account in 2016 would be handled in the 2017 GRC. Accordingly, PG&E proposes to continue as in past years and transfer the December 31, 2016 PVPMA balance to UGBA in January 2017, and close the PVPMA. Table 8-7 shows PG&E's estimate of the PV cost savings for 2015 and 2016.

TABLE 8-7
ESTIMATED PV PROGRAM COST SAVINGS
(MILLIONS OF NOMINAL DOLLARS)

Line No.	Description	2015	2016
1	PV Program Cost Savings	$41.1	$40.7

The forecasts in Table 8-7 are estimates and the magnitude may require adjustment based upon the actual final initial capital costs for developing the PV UOG facilities. PG&E anticipates filing a Tier 2 Advice Letter in the second half

8 D.14-08-032 at 9; PG&E's Prepared Testimony, A.12-11-009, Exhibit (PG&E-6), pp. 6-6 to 6-8.

of 2015 calculating the final cost savings and demonstrating PG&E's eligibility for a shareholder incentive award, consistent with Decision 10-04-052.

Finally, now that PG&E has successfully completed construction of the PV UOG Program, PG&E has incorporated the ongoing revenue requirement associated with this program into its UOG revenue requirement.[9]

H. Smart Grid Pilot

PG&E filed its Smart Grid Deployment Plan with the Commission in June 2011, and filed its first application under that plan for approval of Smart Grid pilot deployment projects in Application 11-11-017. In that application, PG&E proposed to consolidate its capital-related revenue requirements in the 2017 GRC. Table 7-6 in Chapter 7 of this exhibit summarizes the 2014-2016 capital costs associated with the Energy Procurement Smart Grid Pilot projects that will be consolidated into the revenue requirements in the 2017 GRC.[10]

I. Conclusion

PG&E's expense and capital forecasts for its Energy Supply operations in this GRC are reasonable and are consistent with the amounts adopted by the Commission in the 2014 GRC.[11] As discussed above, the GRC is one part of an integrated set of ratemaking mechanisms designed to recover the cost of providing safe, reliable, cost-effective, and environmentally-responsible electric generation to PG&E customers. PG&E's ratemaking proposals in this application are reasonable and should be adopted by the Commission.

---

9 See Exhibit (PG&E-12), Chapter 9, Section G, regarding PG&E's proposal to close the account upon transfer of the recorded December 31, 2016 balance in the account.

10 Additional Smart Grid Pilot capital expenditures associated with Electric Distribution are shown in Exhibit (PG&E-4), Chapter 15.

11 See workpapers supporting Exhibit (PG&E-5), Chapter 8.