PACIFIC GAS AND ELECTRIC COMPANY

RETIREMENT OF DIABLO CANYON POWER PLANT, IMPLEMENTATION OF THE JOINT PROPOSAL, AND RECOVERY OF ASSOCIATED COSTS THROUGH PROPOSED RATEMAKING MECHANISMS

PREPARED TESTIMONY
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PREPARED TESTIMONY

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<td>EM&amp;V</td>
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<td>FTE</td>
<td>Full-Time Equivalent</td>
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<td>IBEW</td>
<td>International Brotherhood of Electrical Workers</td>
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<td>Independent Evaluator</td>
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<td>Institute of Nuclear Power Operations</td>
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<td>kWh</td>
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<td>Once Through Cooling</td>
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<td>Pacific Gas and Electric Company</td>
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<td>Power Purchase Agreement</td>
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<td>PPP</td>
<td>Public Purpose Program</td>
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<td>Qualifying Facility</td>
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<td>Resource Adequacy</td>
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<td>Safety Evaluation Report</td>
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<td>Systems, Structures, and Components</td>
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<td>STARS</td>
<td>Strategic Teaming and Resource Sharing</td>
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<td>TLAA</td>
<td>Time Limited Aging Analysis</td>
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<td>UGBA</td>
<td>Utility Generation Balancing Account</td>
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<td>WTW</td>
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A. Introduction and Overview

Pacific Gas and Electric Company (PG&E), International Brotherhood of Electrical Workers Local 1245 (IBEW), Coalition of California Utility Employees, Friends of the Earth, Natural Resources Defense Council, Environment California, and Alliance for Nuclear Responsibility (together, the Joint Parties) have developed a “Joint Proposal”¹ to retire PG&E’s Diablo Canyon Power Plant (Diablo Canyon or DCPP) at the close of its current operating license period and replace it with a portfolio of greenhouse gas (GHG)-free resources. In addition, the California Energy Efficiency Industry Council, a leading association for Energy Efficiency (EE) providers, has indicated that it also supports the Joint Proposal.

PG&E has joined with labor, leading environmental organizations and a community-based nuclear safety advocacy group to imagine a different kind of energy future. The Joint Parties represent diverse interests, but we are all united in our commitment to helping California achieve its clean energy vision. Together, we developed a proposal that would increase investment in EE, renewables and storage, while phasing out nuclear power in California in 2024 and 2025. The proposal includes a PG&E commitment to a 55 percent renewable energy target in 2031—an unprecedented voluntary commitment by a major U.S. energy company.

This broad coalition of partners with diverse points of view collectively came to a shared vision for what we believe is the best and most responsible path forward for Diablo Canyon. A key element of this vision is that it recognizes the value of carbon-free nuclear power as an important bridge strategy over the next eight to nine years. This transition period will help to ensure that power remains affordable and that we do not increase the use of fossil fuels while we move forward with California’s energy vision. Equally important, this transition

¹ The Joint Proposal is included as Attachment A to PG&E’s Application.
will also provide essential time needed for our valued employees and for the community to effectively plan for the future.

The Joint Parties respectfully request that the California Public Utilities Commission (CPUC or Commission) approve this Application and authorize PG&E to implement its clean energy roadmap. With the Commission’s support and guidance, we believe that the Joint Proposal will move California forward to a future where clean, affordable, renewable energy dominates our energy supply and helps us build a better California while doing more than any other state in the nation to protect our environment.

The Joint Proposal:

- Calls for the cost-effective and orderly replacement of Diablo Canyon with GHG-free resources;
- Provides a responsible and supportive transition for Diablo Canyon employees and the community; and
- Facilitates renewables integration through a safe, reliable and more flexible resource mix.

Under the Joint Proposal, PG&E will continue to operate Diablo Canyon at current levels through the current license periods. In 2024, PG&E will retire Unit 1, and in 2025 will retire Unit 2. To ensure the orderly replacement of Diablo Canyon with GHG-free resources, the Joint Proposal includes specific procurement requirements starting in 2018 and continuing through 2045. First, PG&E will procure 2,000 gross gigawatt-hours (GWh) of new EE projects and programs to be installed from 2018-2024. As a second step, PG&E will procure another 2,000 GWh of EE or GHG-free energy resources to be initiated between 2025 through 2030. Finally, PG&E commits to procure the necessary levels of renewables to meet a 55 percent Renewables Portfolio Standard (RPS) by 2031 through 2045.² In addition to these procurement targets, the Joint Parties agree to support before the CPUC and the California Independent System Operator the use of GHG-free resources, including but not limited to pumped hydroelectric storage, for additional reliability and resource integration solutions which may be required to replace Diablo Canyon.

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² The Joint Proposal specifies that the commitment would start in 2031 and terminate on the earlier of 2045 or when superseded by law or CPUC policy.
Diablo Canyon has reliably served the electricity needs of PG&E’s customers since 1985. However, California’s electric grid is in the midst of a significant shift that creates challenges for the facility in the coming decades. Changes in state policies, the electric generation fleet, and market conditions combine to reduce the need for large, inflexible baseload power plants. These forces reduce the need for Diablo Canyon’s output beyond the current license period. PG&E is faced with four primary planning challenges associated with operating Diablo Canyon beyond the current license period:

1. **Uncertain PG&E Electricity Supply Needs:** Three key trends have significantly reduced PG&E’s electricity sales in recent years and will likely have even greater impacts in the future. This downward pressure on sales is reducing the need for electricity from Diablo Canyon. First, ongoing and aggressive EE policies are projected to reduce overall electricity consumption. Second, customers are likely to increase the amount of electricity generated through Distributed Generation (DG), especially privately-owned solar resources. Finally, PG&E’s bundled customer base is likely to decrease as some households and businesses buy their generation from alternative providers, either through Direct Access (DA) or Community Choice Aggregation (CCA). The precise impact each of these factors on PG&E’s electricity supply needs is not certain, though they combine to support a clear downward trend on PG&E electricity sales.

2. **Decreasing Need for Baseload Generation:** As the electric grid in California continues to evolve, so too will the character of resources needed to operate the California electric system reliably. Given California’s energy goals that require increasing reliance on renewables—at least 50 percent by 2030—the California electric system will need more flexible resources while the need for baseload electricity supply will decrease. PG&E will need less non-renewable baseload generation to supply its electricity customers. Hence the need for baseload power from Diablo Canyon will decrease after 2025.

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3 Throughout this Chapter, “PG&E electricity sales” refers to PG&E’s bundled retail sales (i.e., “bundled” electricity, transmission and distribution services).
3. **Challenges With Renewable Overgeneration:** Another aspect of this changing California electric system is the prospect of mounting “overgeneration” conditions. As more solar generation comes on line over time, and when its output is at peak supply (e.g., in the middle of the day), there is less room on the electric system for energy from inflexible and large baseload resources such Diablo Canyon. Overgeneration conditions can force the system operator to take action to curtail generation (e.g., dispatch generators down, or even disconnect supply from the grid) in order to maintain electric system reliability. Retirement of Diablo Canyon on the timeframe agreed to in the Joint Proposal will allow for increased flexibility for the California electric system so as to help maximize the value of solar and other variable resources that will be a crucial part of meeting PG&E’s renewable targets and California’s renewable and GHG emissions goals. Additionally, due to expected overgeneration throughout parts of the year, Diablo Canyon may contribute to higher system costs as its current generation profile causes challenges for efficiently integrating renewable resources. Therefore, if Diablo Canyon were not relicensed, the cost to integrate renewables could be lower.

4. **Ongoing Costs for Diablo Canyon:** Diablo Canyon has served as a valuable resource providing reliable electricity for decades. However, future operating costs are uncertain due to a variety of potential regulatory and other factors and could increase as the facility ages. California’s environmental protection regulations and other state and federal requirements may increase future costs beyond 2025. These include, for example, any environmental mitigation or compliance measures required by California resource agencies, retrofits to comply with the State Water Resources Control Board’s Once Through Cooling (OTC) regulation, or additional regulations or orders from the Nuclear Regulatory Commission (NRC) in response to federal regulatory or legislative changes either currently under consideration or in the future.

   The Joint Proposal benefits PG&E customers and the state of California by reducing emissions, supporting a reliable and cost-effective electric system, and supporting PG&E employees and the community PG&E serves. The key benefits of the joint proposal are:
Lowering GHG Emissions: PG&E’s portfolio has long been one of the lowest emitting in the country. Half or more of its procured electricity is consistently GHG-free, and RPS procurement has more than doubled in the last seven years. Under the Joint Proposal, PG&E commits to reaching 55 percent RPS deliveries, representing nearly a doubling of today’s RPS procurement and a 10 percent increase over state regulatory requirements for 2030. Combined with existing policies and the Joint Proposal’s EE measures, this will contribute to a significant decrease in GHG emissions. As discussed in Chapter 3, by 2031, 80 to 95 percent of all delivered energy for PG&E’s bundled electric customer load is projected to be GHG-free.

Maintaining Reliability: The Joint Parties are confident that Diablo Canyon can be retired while continuing to maintain a cost-effective PG&E electric system. Numerous studies have shown that Diablo Canyon could be removed from the California electric system without harming reliable operation of the grid; indeed, PG&E’s transmission system has been maintained and designed in order to withstand the loss of both Diablo Canyon units. Furthermore, the Joint Proposal provides for a deliberate and orderly phase out of Diablo Canyon, allowing time to replace the facility with GHG-free resources and to ensure the transition occurs while maintaining reliability.

Maintaining Cost-Effective Electricity Service: GHG-free replacement resources will be procured through CPUC-approved competitive bidding processes, which will ensure that the lowest-cost clean resources are used to replace Diablo Canyon, and that the Commission and relevant stakeholders are involved in monitoring the procurement process and reviewing and approving the results.

Continuing Commitment to PG&E Employees and Community: Key provisions of the Joint Proposal reflect the fact that PG&E depends upon and has been committed to its employees and the communities in which the utility operates and serves customers. Under the Joint Proposal, it will be critical to retain existing employees, who are highly qualified and will drive continued safe and reliable operations for the next nine years of operations at Diablo Canyon. PG&E will provide a comprehensive retention program and severance payments upon completion of employment, both of
which are critical to maintaining the same high levels of safety and reliability during the plant’s final years of operation. PG&E will help employees transition to new positions through a retraining and development program to facilitate redeployment of a portion of plant personnel to the decommissioning project. Additionally, Diablo Canyon is one of the largest employers, taxpayers, and charitable contributors in the San Luis Obispo County area. PG&E proposes to provide $49.5 million in funding to San Luis Obispo to assist the local community to prepare and plan for the long-term loss of economic stimulus that the operating plant provides.

B. Scope of Application

The Joint Proposal requires approval and implementation of discreet plan elements through a number of state and federal regulatory agencies. For example, on June 28, 2016, the California State Lands Commission approved the extension of DCPP’s submerged lands leases through the end of the NRC operating licenses, as contemplated in Section 6.1 of the Joint Proposal. In addition, on June 21, PG&E asked the NRC to suspend consideration of PG&E’s license renewal application, as specified in Section 1 of the Joint Proposal.

The next key milestone is Commission consideration and approval of Sections 2, 3, 4 and 5 of the Joint Proposal. In the Application, PG&E proposes a procedural schedule that would include testimony to be served in the fall, hearings in December, briefs in January and a proposed decision by May 2017. Receiving a final decision from the Commission by the end of June 2017 will enable PG&E to proceed with the procurement of EE and GHG-free resources in order to achieve Joint Proposal milestones for obtaining orderly replacement of Diablo Canyon’s energy.

In this Application, the Joint Parties seek Commission approval of these four critical aspects of the Joint Proposal:

1. GHG-Free Energy Replacement Commitment and Cost Allocation Proposal

   As specified in Section 2 of the Joint Proposal, PG&E seeks Commission approval of its plan to replace a portion of DCPP with GHG-free
energy resources procured in three tranches over a 12-year period.

This includes:

- Adding 2,000 gross GWh of EE in PG&E’s service territory in 2018-2024. This provides a head start on energy savings before Diablo Canyon retires.

- Holding a competitive solicitation for 2,000 GWh of GHG-free energy for delivery in 2025-2030. EE and RPS energy resources, as well as other GHG-free energy resources, will compete to fill this opportunity.

- Adopting a voluntary 55 percent RPS commitment for PG&E’s bundled service customers, which is a 10 percent increase above the existing 2030 RPS mandate. The commitment would start in 2031 and terminate on the earlier of 2045 or when superseded by law or CPUC direction.

With Diablo Canyon ceasing operations, PG&E’s Northern and Central California service territory will lose approximately 18,000 GWh of GHG-free energy by 2025. The retirement of Diablo Canyon will have a significant impact in a service territory with an approximate system load of 80,000 GWh. The capability and the willingness of Load Serving Entities (LSE) in Northern and Central California to address the resulting resource deficit is hindered by tremendous future planning uncertainty:

- It is unclear what GHG-free resources, including RPS, EE and DG, will develop between now and then to help fill the gap;

- It is uncertain how much load growth there will be between now and 2025 and, as customer loads shift to CCA and other alternatives, it is equally unclear which LSE bears responsibility to meet customer needs in 2025; and

- There is also great uncertainty about the scope and timing of future compliance requirements that will apply in order to implement the State’s GHG emission reduction target of 40 percent below 1990 levels by 2030 as stated in Public Utilities Code Section 454.52.

In the face of this uncertainty, the natural reaction is to defer making any new GHG-free resource additions until a GHG emissions reduction compliance obligation is adopted by the Commission and, with the passage of time, there is sufficient clarity on the future resource mix and the size of its customer loads.
PG&E and the Joint Parties believe that non-action and deferral at this
critical moment in time is a short-sighted tactic that could undermine the
State’s ability to achieve its GHG-free vision. State law has already
established a 40 percent below 1990 GHG emissions level reduction target.
While there is no procurement compliance obligation to implement this
vision yet, there will be one. With the uncertainty, PG&E and the Joint
Parties believe that bold steps are required today. Therefore, PG&E and the
Joint Parties propose to proceed through the three tranches of procurement
with an initial base amount of GHG-free resources for the benefit of the
entire Northern and Central California service territory.

The three tranches of GHG-free resource procurement are a significant
first step in achieving California’s goal for 2030 GHG reductions. However,
alternative procurement beyond that specified in the Joint Proposal will be
needed on a systemwide basis. The Joint Parties envision that this issue
will primarily be addressed through the Commission’s Integrated Resource
Planning process. The Joint Parties are fully committed to supporting
policies that result in replacing the output of Diablo Canyon with GHG-free
resources.

Section 2.6 of the Joint Proposal recognizes that the commitment to
procure GHG-free resources is for the benefit of all customers in PG&E’s
service territory and that implementation of an equitable non-bypassable
charge that allocates costs and benefits to all benefiting customers is
a condition of this commitment. This is not a new or novel concept. Prior
Commission decisions have adopted the Power Charge Indifference
Adjustment (PCIA) and Cost Allocation Mechanism to assign proper cost
responsibility for investor-owned utility resource commitments.

PG&E proposes to enhance the existing cost-allocation mechanisms by
implementing a new Clean Energy Charge to allocate the benefits of
Tranche #2 and #3 procurement as well as actual market costs. Unlike the
PCIA mechanism in place today, cost allocation for new GHG-free energy
resources will be based on the difference between the contract price and

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4 All energy efficiency program costs will continue to be allocated in accordance with
the Commission’s existing Public Purpose Program charge.
actual market prices at the time the energy is generated, not an administratively determined forecast. Under the Clean Energy Charge proposed by PG&E, customers will also receive renewable energy and resource adequacy attributes for the life of the contract which can be used to meet existing and future Commission compliance requirements.

In addition, for those LSEs that are willing to step up and commit to procuring equivalent new GHG-free energy resources, PG&E has proposed a “self-provision” option that would exempt existing DA and CCA loads from the Clean Energy Charge. The self-provision option is consistent with provisions in the recently enacted Senate Bill 350, which provide for the allocation of renewable resource integration costs to CCA and electric service providers, but also allows CCAs to self-provide renewable integration resources instead of being allocated a portion of the costs. The proposed new charge and cost allocation mechanism are described in Chapter 5.

In support of Section 2 of the Joint Proposal, PG&E’s DCPP need analysis is presented in Chapter 2 and the replacement of DCPP with the three tranches is described in Chapter 3. Chapter 4 describes the implementation plan for the Tranche #1 EE. PG&E requests authority to recover its forecasted program costs of $1.3 billion for the Tranche #1 Program through an annual revenue requirement of $187 million over the period 2019 through 2025, which is described further in Chapters 4 and 10. Chapter 5 describes the implementation plan for the Tranche #2 Request for Offers. Chapter 6 describes PG&E’s 55 percent RPS commitment.

2. **Employee Retention and Benefits**

Second, PG&E seeks approval of the Diablo Canyon Employee Program which includes employee retention, retraining and severance programs that will be offered to Diablo Canyon staff to retain them during the remaining years of operations. The Joint Proposal reflects the fact that PG&E and the state have benefited from a well-trained, highly skilled and dedicated workforce at Diablo Canyon for its 31 years of operations. Diablo Canyon has provided electricity over 90 percent of the time, only stopping output for planned refueling and maintenance. PG&E employs
more than 1,400 workers at the facility, plus additional temporary workers
during high activity times such as refueling.

PG&E is committed to continuing the safe and secure operation of
Diablo Canyon through its current license period. To do so, it is critical to
retain existing employees, who are highly qualified and will drive continued
safe and reliable operations. PG&E proposes to implement a retention
program to achieve this objective. Additionally, PG&E will help employees
transition to new positions through a retraining and development program
to facilitate redeployment of a portion of plant personnel to the
decommissioning project. There will also be severance payments at the
end of employment. As specified in Section 3 of the Joint Proposal, the
Joint Parties strongly support approval of the Employee Program.

PG&E has executed labor agreements with IBEW Local 1245, the
Engineers and Scientists of California, Local 20 and the Service Employees
International Union to implement the retention program. PG&E requests
Commission approval of these programs, and authority to recover its.forecasted costs of: $352.1 million for the Employee Retention Program,
to be recovered through an annual revenue requirement of $50.9 million
over the period 2018 through 2025; and $11.3 million for the Employee
Retraining Program, to be recovered through an annual revenue
requirement of $2.3 million over the period 2021 through 2025, as described
further in Chapters 7 and 10 of the Prepared Testimony.

3. Community Impacts Mitigation

Diablo Canyon has provided reliable, safe, and economic greenhouse
gas-free electricity for PG&E’s customers for more than 30 years. It has
done so with the support and assistance of the local community that has
provided a home for DCPP and its employees. Over many years, the local
community has both reaped the many benefits and also borne the costs—
both realized and potential—associated with hosting an operating nuclear
power plant. Simply put, Diablo Canyon could not have realized its
tremendous value to all of PG&E’s customers without the help and willing
partnership of the local community. Diablo Canyon is one of the largest
employers, taxpayers, and charitable contributors in the San Luis Obispo
County area. It currently contributes approximately $22 million in annual
property taxes to the local community. In order to continue to support this local community even as the facility begins to retire, PG&E proposes to provide $49.5 million in funding to San Luis Obispo over a 9-year period to assist the local community to prepare and plan for the long-term loss of economic stimulus that the operating plant provides. PG&E requests approval to recover these program costs through an annual revenue requirement of $6.3 million over the period 2018 through 2025, as described further in Chapter 10. The mitigation payment would be recovered through Nuclear Decommissioning funding. In addition, PG&E proposes to continue its support for state and local emergency planning and preparedness, including continuing support for the San Luis Obispo County early warning system, until the decommissioning of Diablo Canyon Power Plant is complete. PG&E and the other Joint Parties believe that this Community Program strikes the right balance between providing appropriate transitional assistance to the community while also recognizing that the community must manage this transition so that it can thrive in the longer term without the historic levels of spending and taxes funded by PG&E customers. This program and the associated costs are described in Chapter 8.

4. Diablo Canyon Cost Recovery and Decommissioning

Section 5 of the Joint Proposal addresses cost recovery for Diablo Canyon during the remaining nine years of operations and defines the process ahead for decommissioning. As described in Chapter 10 of the Prepared Testimony, PG&E requests that the Commission approve a new two way balancing account to track the amortization of Diablo Canyon’s net book value and capital additions and implement annual rate adjustments so that the book value is depreciated to zero and the costs are fully recovered in rates by the time Diablo Canyon ceases operations at the end of its NRC operations licenses. For decades, PG&E’s generation rates have been set to recover PG&E’s investment in DCPP by the time its NRC operating licenses expire in 2024 and 2025. The Joint Proposal simply fine tunes the existing ratemaking mechanism to achieve this objective by adding an annual true-up of depreciation and capital spending.

In addition, the Joint Proposal specifies that PG&E should be authorized to recover in rates the approximately $53 million dollars incurred in the
federal and state license renewal process to perform technical and environmental assessments. PG&E requests approval to recover these costs through an annual revenue requirement of $6.7 million over the period 2018 through 2025. The Joint Parties agree that it was reasonable for PG&E to incur these costs in order to preserve all options, including license renewal, during a period of resource planning uncertainty that resulted in the decision reflected in the Joint Proposal. Chapter 9 describes the costs incurred by PG&E for the license renewal project. Chapter 10 presents the associated revenue requirement.

Section 5.4 of the Joint Proposal addresses the process for decommissioning Diablo Canyon. It states that PG&E will prepare a detailed, site-specific decommissioning plan for Diablo Canyon that will be filed with the CPUC no later than the date when the 2018 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) will be submitted. This plan will update the cost estimate for the decommissioning project. Other than approving the Diablo Canyon Employee and the Community Impacts Mitigation programs described above, there is no other action or approval requested by the Joint Parties in connection with the future decommissioning application.

Chapter 10 requests authorization to establish a new, two-way balancing account, the Diablo Canyon Retirement Balancing Account, as described in Chapter 10, effective January 1, 2017, to track and implement cost recovery, as described above.

5. Public Workshops in Advance of Filing

On July 12, 2016, PG&E and the Joint Parties held a public workshop at PG&E's office in San Francisco to give interested parties an opportunity to

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5 A4NR did not join in this section of the Joint Proposal.

6 As authorized by 10 Code of Federal Regulations 50.82(a)(80(ii) and the Diablo Canyon Master Trust Agreement Amendment 9 Section 2.01(7), PG&E will fund these planning activities through the Diablo Canyon tax-qualified decommissioning trust fund. PG&E will track these costs with unique cost order numbers and will present these costs for reasonableness review at a time to be determined in a future NDCTP.
review, ask questions, and potentially join in the Joint Proposal. PG&E also held two public workshops in San Luis Obispo on July 20 and two public workshops in South San Francisco on July 22 to answer questions about the Joint Proposal and hear comments. A report prepared by M.J. Bradley summarizing the issues raised at these sessions is included as Attachment A to this testimony. As a result of the public workshops and further discussions, the California Energy Efficiency Industry Council has indicated that it also supports the Joint Proposal.

Finally, after the Joint Proposal was announced, the Joint Parties initiated a number of meetings with representatives of CCA and DA providers and customers regarding the procurement to replace Diablo Canyon outlined in the Joint Proposal. So far, the parties have been able to discuss issues, concerns, and potential solutions, and have agreed to continue discussions after this Application is filed. The Joint Parties are hopeful that they can work collaboratively with CCA and DA representatives to reach a resolution of issues that will work for all of the parties involved.

C. **CPUC Reporting**

PG&E proposes to make the following reports and advice letter filings to update the Commission and implement the Joint Proposal.

1. **Diablo Canyon Capital Depreciation**

   In May of each year, PG&E will file a Tier 3 advice letter to set the revenue requirement for the next year, true-up for any depreciation expense over- or under-collections during the previous year, and report on any variances with capital additions for the prior year.

2. **Energy Procurement Activities**

   PG&E will use the RPS Compliance Report spreadsheet most recently adopted by the CPUC and the volumes reported in final verified compliance

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reports for each applicable year to demonstrate compliance with the 55 percent RPS target during the period 2031 and 2045 under Tranche #3.

3. **Energy Efficiency Activities**

   PG&E will report its progress towards meeting the Tranche #1 target annually.

4. **Employee Program**

   PG&E will inform the CPUC through a Tier 1 information-only advice letter should PG&E determine that it will incur costs in excess of the forecasted expenditures for the Employee Program as provided in Chapter 7.

D. **Conclusion**

   PG&E has joined with labor, leading environmental organizations and a community-based nuclear safety advocacy group in the Joint Proposal, all united in our commitment to helping California achieve its clean energy vision. Together, we can build a better California where clean, affordable, renewable energy dominates our energy supply.

   The Joint Proposal begins the orderly replacement of Diablo Canyon with GHG-free resources. The proposal builds on the realities of a changing electricity landscape in the state, one that includes increasing levels of EE, DG, CCA, and renewable energy resources, all of which decrease PG&E’s need for other sources of generation. These forces reduce the need for Diablo Canyon’s output beyond the current license period.

   California’s path toward achieving aggressive and critical environmental targets is recognized and reflected in the proposal, which builds upon these targets and offers additional commitments for EE and renewables that go beyond existing requirements. The Joint Proposal turns toward the procurement of cost-effective GHG-free resources and flexible integrating resources that will be a crucial part of meeting California’s renewable and GHG emissions goals. The Joint Proposal will help California set the stage for even deeper GHG reductions that will be required to meet long-term emissions targets. The proposal also ensures that this transition is conducted while maintaining system reliability and supporting PG&E employees and the local community.
PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT A
JOINT PROPOSAL FOR THE ORDERLY REPLACEMENT OF DIABLO CANYON POWER PLANT WITH ENERGY EFFICIENCY AND RENEWABLES: SUMMARY REPORT OF JOINT PROPOSAL PUBLIC WORKSHOP AND PUBLIC MEETINGS
Joint Proposal for the Orderly Replacement of Diablo Canyon Power Plant with Energy Efficiency and Renewables

Summary Report of Joint Proposal Public Workshop and Public Meetings

AUGUST 11, 2016
Introduction

In June 2016, Pacific Gas & Electric (PG&E), International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, Friends of the Earth, Natural Resources Defense Council, Environment California, and Alliance for Nuclear Responsibility (together, the Parties) released a Joint Proposal to retire PG&E’s Diablo Canyon Power Plant at the close of its current operating license period and replace it with a portfolio of greenhouse gas (GHG)-free resources. Implementation of the Joint Proposal will require, among other things, review and approval from the California Public Utilities Commission (Commission). To initiate this review, PG&E will submit an Application to the Commission (as detailed in this report and in the Joint Proposal). In advance of that submission, PG&E on behalf of the Parties reached out to the public and stakeholders involved in other ongoing Commission proceedings to receive stakeholder input. This report summarizes the feedback received by PG&E through this process.

Brief Overview of the Joint Proposal

Under the Joint Proposal, PG&E will continue to operate Diablo Canyon at current levels through the current license period. In 2024, PG&E will retire Unit 1, and in 2025 will retire Unit 2. Through the Joint Proposal, PG&E has committed to replacing Diablo Canyon with GHG-free resources.

To ensure the orderly replacement of Diablo Canyon with GHG-free resources, the proposal lays out specific procurement requirements starting in 2018 and continuing through 2031, including 2,000 gigawatt-hours (GWh) of new energy efficiency projects and programs to be installed over the 2018 to 2024 timeframe and another 2,000 GWh of energy efficiency or GHG-free energy to be initiated between 2025 through 2030. PG&E also commits to procure the necessary levels of renewables to meet a 55 percent Renewables Portfolio Standard (RPS) by 2031. These procurement provisions are intended as a reasonable first step for replacing Diablo Canyon; however, additional resources may be needed. The Parties envision that additional procurement decisions will primarily be addressed through the Commission’s Integrated Resource Planning process. The Parties have agreed to support the use of GHG-free resources to meet any reliability and resource integration needs along with overall energy requirements resulting from the retirement of Diablo Canyon.

The Joint Proposal also includes provisions designed to support the Diablo Canyon community, including employees and local residents and businesses. This includes a proposed Employee Program, which will provide incentives to retain current employees in order to continue safe and effective operation of the facility, as well as a severance, retraining, and placement programs to help transition employees to other jobs upon completion of Diablo Canyon operations. The Parties also propose a Community Impacts Mitigation Program that is designed to provide additional monetary support to the surrounding community to help mitigate the decrease in funding available to those communities as Diablo Canyon phases out commercial operation.
More information about the contents and drivers of the Joint Proposal can be found here; the full text of the Joint Proposal is available here.

**Stakeholder Feedback Process**

As a first step in gathering feedback from interested stakeholders, PG&E held five meetings in San Luis Obispo and the San Francisco area to solicit feedback and respond to questions. On July 12, PG&E held the first meeting, a Public Workshop for potential participants in the Commission proceeding. On July 20 and July 22, 2016, PG&E held a series of four Public Meetings to solicit input and feedback, and to respond to detailed questions, from the communities affected by the Joint Proposal. Two meetings were held in San Luis Obispo on July 20, while the July 22 meetings were in South San Francisco.

M.J. Bradley & Associates was retained to facilitate these meetings and record input received from attendees. This report will be filed as a part of PG&E’s Application to the Commission and will be part of the public record. Interested stakeholders are encouraged to follow or join this process for additional opportunities to provide input and feedback.

This report provides an overview of key areas of discussion from all five meetings. The first section summarizes the July 12th Public Workshop. The format for this meeting encouraged interactive dialogue between participants and the Parties. Our summary for this meeting attempts to capture major points of comments from participants and responses from the Parties.

The second section of this report summarizes the four Public Meetings. Discussion in the Public Meetings primarily focused on comments from participants that were stated for the record. In some portions of this discussion, we provide additional detail gleaned from the approximately 60 e-mails sent to PG&E’s Diablo Canyon address by the date of this report’s finalization and from informal dialogue that occurred at the meetings. Our summary of the Public Meetings synthesizes all major written and oral comments and includes limited responses from the Parties reflecting the format of the meetings.

The opinions expressed in this report do not reflect those of M.J. Bradley and Associates or the Parties, and we do not address their accuracy here. We have added additional detail from the Joint Proposal where appropriate to provide more context for specific points raised in the meetings.
Public Workshop

PG&E sent notice of this Public Workshop to more than 1,000 potential participants (identified based on the service lists of 10 Commission proceedings). Approximately 34 participants joined the meeting in person, while another 43 registered to participate remotely via dial-in.

This section summarizes the comments from Parties and participants at the Public Workshop, and is organized into five topic areas: 1) the importance of a deliberate transition; 2) cost estimates and allocation; 3) procurement of GHG-free resources; 4) regulatory and administrative processes; and 5) benefits of the Joint Proposal to the community and employees. Unless otherwise noted, Section references throughout this report are to the Joint Proposal.

I. Importance of A Deliberate Transition

In the Preamble to the Joint Proposal, the Parties note that this plan would initiate an eight- to nine-year transition period to prepare for the closure of Diablo Canyon, and replace the energy with new GHG-free replacement resources.

At the Public Workshop, Parties reiterated the importance of this long transition period, and the need to start planning with a broad stakeholder group immediately. This transition, Parties noted, would provide significant benefits to the community, allowing PG&E to continue to act as a responsible steward in its local community. Parties also expressed the importance of a deliberate transition period for employees to ensure continued safe and reliable operation at Diablo Canyon. A long planning horizon will also help ensure that GHG-free energy will be procured to replace any remaining needs upon Diablo Canyon’s retirement. Finally, Parties noted that the transition period will allow for a robust stakeholder and regulatory process before the Commission and other regulatory agencies.

In statements throughout the Public Workshop, many participants noted and reinforced the benefits afforded by the proposed transition period.

II. Cost Estimates and Allocation

Implementation of the Joint Proposal will result in specific costs. As detailed in the Joint Proposal, these costs include those associated with decommissioning activities, community and workforce support, and procurement of GHG-free energy to replace Diablo Canyon output. Participants at the Public Workshop discussed four key issues related to the estimate and allocation of these costs.

A. Use of Non-Bypassable Charges to Recover Select Costs

Under the Joint Proposal, the Parties propose to recover the costs of certain activities and procurement through non-bypassable charges, or NBCs. Typically, this type of charge is imposed on the bills of every PG&E system.
customer, which includes bundled customers (i.e., those customers for which PG&E procures and delivers electricity) as well as community choice aggregation (CCA) and direct access (DA) customers, for which PG&E only provides delivery service. Past non-bypassable charges have included the “public purpose program” charge, which funds state policy initiatives that benefit all customers, and nuclear decommissioning fund charges.

The Joint Proposal would use NBCs to recover costs associated with procurement of GHG-free resources. Some participants at the Public Workshop questioned the mechanics of how this non-bypassable charge would be calculated and imposed. Concerns were raised that this procurement would benefit only PG&E bundled customers, while DA and CCA customers would also be required to pay for this procurement; other participants also noted that CCAs and other providers have been procuring beyond state environmental requirements without requiring that non-CCA customers directly pay for this procurement. Respondents from the Parties pointed out provisions of the Joint Proposal that require that all costs and benefits, including RPS and resource adequacy benefits, be equitably allocated (see Section 2.6), thus ensuring that costs and benefits are both shared among all affected customers and service providers. Parties also noted that all GHG-free procurement would help ensure that California meets its environmental and climate change policies.

Additionally, there were questions as to which specific costs would be included in non-bypassable charges. Some participants questioned how procurement costs would be approved, and whether the RPS-related procurement costs would be included in non-bypassable charges. As detailed by respondents from the Parties and summarized below in Section IV.A of this report, the Joint Proposal lays out a specific structure for receiving approval and ratemaking authority for each Tranche of procurement. For example, the incremental revenue requirement associated with procurement of energy efficiency under Tranche 1 will be estimated and submitted to the Commission for approval in the Application seeking approval of this Joint Proposal, while the costs under Tranche 2 will be submitted in a separate filing to the Commission for review and approval (see Section 2.3.3).

B. Use of the Decommissioning Fund

Under existing Public Utilities Code, any electric utility that owns or operates a nuclear facility must maintain an externally managed, segregated fund for the purposes of nuclear facility decommissioning. The Commission allows utilities to “collect sufficient revenues in rates” over the life of any nuclear facility. The Joint Proposal would have PG&E fund certain activities through the established decommissioning fund. For example, pursuant to Public Utilities Code § 8330, the costs of the proposed retention and severance programs will be funded through the Diablo Canyon decommissioning rate recovery mechanism (see Section 3.1).

Some participants at the Public Workshop requested more information on how the decommissioning fund would be used to cover some costs of the Joint Proposal, and whether this would require amendments to the existing decommissioning fund plan. Respondents from the Parties noted that the exact amounts to be recovered through the fund must be approved through the proposed Commission and Nuclear Regulatory Commission (NRC) processes, but that the Joint Proposal intends to use the decommissioning funding mechanism to recover these costs from customers.

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1 See Pub. Util. Code Sections 8321-8830
C. Proposed Funds Allocated to Community Support

The Joint Proposal would allocate $49.5 million to a Community Impacts Mitigation Program that is proposed to be funded through the nuclear decommissioning mechanism (see Section 4.1). Some participants at the Public Workshop requested more information on the calculation of this number, and details on how these funds will be spent. Per the Joint Proposal, a portion of these funds will be used for a payment in lieu of taxes. In addition, respondents indicated that the overall goal of the Program is to provide a transition to the community, and that there is a high degree of interest from the Parties to work with the community and other stakeholders to identify specific uses of this funding.

D. Treatment of License Renewal Costs

Beginning in 2009 and before entering into the Joint Proposal, PG&E had begun regulatory and planning activities related to pursuing the relicensing of the Diablo Canyon facility. As of June 21, 2016, PG&E has suspended these activities, including officially suspending the license renewal application at the NRC. Under the Joint Proposal, PG&E will request recovery of the already-incurred costs associated with these activities – estimated at $50 million – which it believes reflect prudent decision-making and planning through a period of resource planning uncertainty (see Section 5.2). During the Public Workshop, some participants requested more information on the status of the official relicensing application, and expressed disapproval of any recovery of these already-incurred costs from customers.

III. Procurement of GHG-Free Resources

Under the Joint Proposal, PG&E would pursue, at a minimum, three rounds of procurement of GHG-free resources (called “Tranches” in the Joint Proposal). These will include: 1) 2,000 gross GWh of energy efficiency savings to be implemented between 2018 and 2024; 2) 2,000 GWh of GHG-free energy resources (including energy efficiency or renewable generation) that will commence deliveries or savings between 2025 and 2030; and 3) commitment to achieve a 55% RPS starting in 2031. In addition, PG&E commits to procuring any additional GHG-free resources needed to ensure the orderly replacement of Diablo Canyon. Questions and comments at the Public Workshop about the specifics and effects of this procurement can be grouped into five main categories.

A. Ensuring Procurement of GHG-Free Resources

Under the terms of the Joint Proposal, the Parties have committed to the use of GHG-free resources to replace Diablo Canyon. This includes the Joint Proposal’s specific procurement provisions for GHG-free energy efficiency and renewables (see Sections 2.1-2.4), as well as a commitment to strongly support the use of GHG-free resource solutions to support integration of these new resources and support grid reliability (see Section 2.5). In addition, the Parties note that additional procurement beyond that specified in the three tranches may be needed on a system-wide basis to replace Diablo Canyon, and that these needs will most likely be assessed through the state’s Integrated Resource Planning (IRP) process. The Parties support using GHG-free resources to meet any additional replacement needs that are identified through this process.

At the Public Workshop, some participants questioned what provisions or requirements could be put in place to ensure that all resources used to replace Diablo Canyon generation be GHG-free. In addition to reiterating the strong commitment to GHG-free procurement as expressed in the Joint Proposal, the Parties noted that the unique structure of the Joint Proposal allows for eight to nine years to plan for the replacement of Diablo Canyon.
analyses and decisions during this transition period which will be overseen by the Commission and include stakeholder engagement offers a methodical process to ensure that GHG-free resources are in place in time to serve customer needs when Diablo Canyon ceases operation.

B. Additionality of Procurement

Each Tranche of procurement will require PG&E to pursue new contracts and resources that would otherwise not be procured. Some participants to the Public Workshop requested more information on specifically how this procurement would be accounted for, and whether it would be additional to existing programs, such as the state’s RPS targets and energy efficiency programs.

Concerning energy efficiency, a selection of participants asked whether energy efficiency savings would be incremental to the requirements in Senate Bill (SB) 350, which requires the state to double annual energy efficiency savings. Because the exact way in which SB 350 will be implemented is still before the Commission, it is unclear exactly how this would affect PG&E’s energy efficiency targets; however, members from the Parties emphasized that the energy efficiency procurement under the Joint Proposal will constitute new contracts and/or new programs that would be in addition to ongoing and existing procurement and programs.

A similar discussion occurred concerning the additionality of renewable generation, and whether procurement under Tranche 2 would be in addition to RPS requirements (Tranche 3 is, by definition, committing to an increase over current renewable procurement requirements).

C. Energy Efficiency RFO & Competitive Solicitations

The Joint Proposal specifies at least two Requests for Offers (RFOs) that include energy efficiency— one for strictly energy efficiency under Tranche 1, and another “all source” RFO that will be open to both energy efficiency and other GHG-free generation sources. Some participants at the Public Workshop encouraged PG&E to allow a broad selection of parties to participate in these RFOs, both through aggregators and directly as individual projects. They also recommended that requirements for these RFOs (which are detailed, in part, in Sections 2.2 and 2.3 of the Joint Proposal and will be further detailed in Applications before the Commission) include a lifetime requirement for energy efficiency projects to ensure long-term energy savings, and a resource valuation methodology that includes distribution benefits of resources located on the distribution system.

Other participants to the Public Workshop expressed concern that these RFOs could set precedent for broader energy efficiency procurement policy (for example, by utilizing specific cost-effectiveness tests, as identified in Section 2.2.3). Representatives from the Parties agreed that the intention is not to contest issues that are being addressed in other proceedings, and believe that the Joint Proposal is in line with programs that are currently in operation or undergoing updates (in some cases, these updates are in response to recent legislative action). Further, parties noted that finalization of these RFO requirements and the Joint Proposal – which would initiate the largest energy efficiency RFO ever conducted by PG&E – will require innovation and coordination with many stakeholders.
D. Role of Energy Storage

In the Joint Proposal, the Parties identify the potential for the retirement of Diablo Canyon to affect system needs for energy storage, specifically to assist with the challenges associated with resource integration and system and local reliability (see Section 2.5). The Parties agree to strongly support, before both the Commission and the California Independent System Operator (CAISO), the use of cost-effective GHG-free resource solutions, which may include additional large pumped storage and utility-owned storage projects.

A selection of participants at the Public Workshop requested additional detail on the role that storage would play in achieving the reliable retirement of Diablo Canyon, including whether any energy storage would be procured through the All Source RFO and the use of PG&E’s pumped storage projects. Respondents from the Parties reiterated that the role for storage, as envisioned by the Joint Proposal, is as an important integrating resource. The Parties noted that for this reason, there are not specific procurement targets for storage included in the Joint Proposal (and that, in fact, energy storage is not eligible for the All Source RFO, as detailed in Section 2.3.1), but that it will be considered as a complementary resource in achieving the procurement goals of the Joint Proposal.

E. Non-PG&E Procurement

The Joint Proposal reflects commitment from PG&E to procure GHG-free resources to serve bundled customer electricity needs, which will provide benefits to all customers across PG&E’s service territory by helping to achieve California’s climate change policies. In planning for replacing Diablo Canyon, the Joint Proposal also takes into account a holistic view of other state policy and market factors, such as the rise in customer self-generation, energy efficiency, and community choice aggregation, that will increasingly serve electricity needs; these factors together inform the amount of replacement power that is included in the Joint Proposal’s procurement provisions.

At the Public Workshop, some participants urged Parties to go further in considering the role of procurement by other state entities to assist with the replacement of Diablo Canyon. For example, some participants recommended that community choice aggregators play a defined role in contributing to procuring replacement power.

IV. Regulatory and Administrative Process

Full approval and implementation of the Joint Proposal will require numerous regulatory agencies and robust stakeholder participation and will involve multiple new and ongoing proceedings. Questions and discussion concerning these regulatory and administrative processes can be grouped into five primary categories.

A. Regulatory Proceedings Associated with Joint Proposal Implementation

Replacement of Diablo Canyon with GHG-free resources will require coordination with numerous ongoing proceedings and regulatory processes, as well as new proceedings. Below is a list of potential regulatory
proceedings and filings that will be implicated in the approval and implementation of the Joint Proposal and that were addressed at the Public Workshop:  

- **Joint Proposal Application:** PG&E will submit an Application to the Commission requesting approval of the Joint Proposal (see, in general, Section 7.1). In this Application, PG&E will request approval of the Joint Proposal in its entirety, and specifically request: authorization and funding to hold an RFO for energy efficiency under Tranche 1 (see Section 2.2.4); approval of the specific structure and requirements for the All Source RFO under Tranche 2 (see Section 2.3.1); approval of the non-bypassable cost mechanism for recovering costs associated with and approved under the Joint Proposal (see Section 2.6); approval of the Employee Program (see Section 3), approval of the proposal to amortize Diablo Canyon book value (see Section 5.1); recovery of license renewal costs (see Section 5.2); and approval of the use of the decommissioning trust to fund the site-specific decommissioning study (see Section 5.4.1). Per the Joint Proposal, the Parties will request a Commission Final Decision by December 31, 2017.

- **Filing for approval of Tranche 2 Procurement:** In a separate filing, PG&E will request review and approval from the Commission of winning offers in the All Source RFO for GHG-free resources under Tranche 2.

- **PG&E annual RPS Plan:** each year, PG&E submits an RPS Plan to the Commission that contains, among other things, a progress report on renewables procurement toward RPS targets, as well as a request for approval to undertake additional procurement in order to reach state targets. PG&E will use this plan to help identify renewable procurement needs to reach a 55% renewables portfolio standard under Tranche 3.

- **PG&E annual Energy Revenue Recovery Account (ERRA) Application:** PG&E submits to the Commission each year a detailed ERRA Application, through which PG&E requests recovery of all bundled procurement-related costs from the past year. PG&E will continue to use this application to recover incurred procurement costs, including those associated with the Joint Proposal.

- **PG&E IRP Filing:** as discussed in more detail below, the Parties propose to use the IRP filing to identify, plan for, and request approval of additional procurement beyond that specified in the three tranches that is needed on a system wide basis to replace the output of Diablo Canyon. Parties also envision the IRP as a way to work with the Commission, CAISO, and other stakeholders to review and resolve issues associated with resource integration and system and local reliability.

- **Site-Specific Nuclear Decommissioning Application:** per Section 5.4 of the Joint Proposal, PG&E will update its decommissioning plan at the Commission by submitting a site-specific decommissioning plan as part of the Nuclear Decommissioning Triennial Proceeding; this application will be used to update the costs of decommissioning to take into account the Joint Proposal.

- **State Lands Commission Lease Application:** upon submission of the site-specific decommissioning plan to the Commission, and in order to accommodate decommissioning activities, PG&E will submit a new and separate lease application to the State Lands Commission to allow use of the intake and discharge for the period of time necessary to accommodate decommissioning activities; PG&E expects that the review of this application will also be subject to environmental review under CEQA (see Section 6.1.1).

- **Diablo Canyon License Application:** per Joint Proposal Section 6.3, following final and non-appealable Commission approval of the Joint Proposal, PG&E will withdraw the Diablo Canyon license renewal application before the NRC and request that the proceeding be terminated with prejudice.

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2 This is not meant to be a comprehensive list of all regulatory processes and filings that may be required to approve and implement the Joint Proposal; for more information, see the Joint Proposal.
Joint Proposal: Summary Report of Stakeholder Input

- **Independent Spent Fuel Storage Installation Application**: PG&E’s current NRC license for its Independent Spent Fuel Storage Installation (ISFSI) expires in 2024. PG&E expects to file a license renewal application with the NRC for the ISFSI no later than five years prior to expiration of the current license; per the Joint Proposal, the Parties agree to not oppose this application and related state approvals (see Section 6.4).

**B. Integration with IRP Process**

SB 350, passed by the California legislature in 2015, enacted Public Utilities Code §454.52, which requires the Commission to establish an Integrated Resource Planning process for regulated load serving entities in the state. The Commission has opened a proceeding, R.16-02-007, to develop the process and requirements for PG&E and other utilities, with the intent to finalize those requirements by 2017 and receive the first submission draft IRPs shortly thereafter. Key goals of these plans, as defined in the legislation and in the Commission’s Scoping Memo and Order Instituting Rulemaking, include ensuring that load serving entities are on track to meet state GHG-reduction and renewables procurement targets, ensuring system reliability, and strengthening transmission and distribution systems and demand management.

The Joint Proposal highlights the IRP process as a critical component of planning for and approving additional procurement beyond that specified in the three tranches that may be needed on a system wide basis to replace Diablo Canyon. Parties also envision the IRP as a way to work with the Commission, CAISO, and other stakeholders to review and resolve issues associated with resource integration and system and local reliability.

At the Public Workshop, some participants requested more detail on exactly how the Joint Proposal would be aligned with the IRP process. Respondents from the Parties reiterated that the IRP process would be used to ensure GHG-free resources are used to replace Diablo Canyon, including any additional resources that are needed and not included in the existing Tranches (such as energy storage). Parties also noted that the IRP process is still under development at the Commission, and that the interests of a deliberate transition away from Diablo Canyon were best served by starting procurement and planning outside of the IRP before it was finalized. In that way, the IRP process can be used to identify any future gaps in procurement, and ensure that the Joint Proposal aligns with state procurement and environmental targets.

**C. Commission Approval Process**

In order for the Joint Proposal to take effect, the Commission must approve the Application submitted by PG&E and supported by other Parties (as detailed above, as well as Section 7). The Parties have agreed to request that the Commission issue a final decision approving the Joint Proposal Application no later than December 31, 2017. If the Commission does not adopt the Joint Proposal (or makes modifications), the Parties have agreed to confer per the Commission’s Settlement procedure (i.e., Rule 12) within fifteen days to discuss any rejections or modifications. The Parties specifically agreed to “bargain in good faith to restore the balance of benefits and burdens” of the Joint Proposal (Section 7.2).

At the Public Workshop, some participants expressed concern that the Parties had positioned the Joint Proposal to fail upon any modification by the Commission. These participants noted concern with language in Section 2.6 of the Joint Proposal, which states that, due to the importance of cost-recovery and equitable distribution of costs and benefits among customers, one condition of Joint Proposal adoption is pre-approval of the identified cost...
allocation mechanism. Some participants felt that this section was overly prescriptive and represented a significant chance of failure of the Joint Proposal, putting undue pressure on the Commission to approve these cost recovery terms. Respondents from the Parties emphasized their intention to work with all stakeholders to determine an appropriate cost and benefit allocation mechanism. The Parties also reiterated the process for returning to the table to discuss amendments to the Joint Proposal triggered by a future Commission Decision.

D. NRC Involvement and Process

The Nuclear Regulatory Commission, or NRC, plays a crucial role in overseeing development, operations, and decommissioning of nuclear facilities across the country. PG&E will continue to work closely with the NRC to ensure a safe, efficient, and cost-effective end to operations at Diablo Canyon. Per the Joint Proposal, this will include developing a decommissioning plan for the facility and planning for ongoing treatment of fuel at the site. Because PG&E will continue to maintain fuel storage facilities at the site after Diablo Canyon ceases operations, the Joint Proposal includes provisions related to PG&E’s license for its Independent Spent Fuel Storage Installation (“ISFSI”), which will require renewal after 2024 (see above for detail).

Participants to the Public Workshop expressed two key themes relating to NRC involvement. First, some participants were interested in better understanding how the decommissioning plan would account for any changes in costs, and how the costs would be reflected in customer rates; a more detailed summary of this discussion is above in Section II.B. Participants also had questions about the specifics of the fuel storage and removal plan, such as how long fuel would remain on site, and whether the Joint Proposal could include provisions to accelerate removal of the fuel. Respondents from the Parties provided detail on the fuel storage requirements under the current NRC license, which require spent fuel to remain in wet storage for a period of years. However, Parties also noted that they have already accelerated removal to the extent the existing license allows, and can continue to explore how to further accelerate this process.

E. Treatment of this Joint Proposal under Commission Rule 12

In its Rules of Practice and Procedure, the Commission has established a procedure for reviewing settlement agreements resultant from a proceeding (referred to as “Rule 12”). As noted by some participants at the Public Workshop, because the Joint Proposal is not in response to an existing hearing, it does not yet meet the definition of a settlement agreement under Rule 12. However, the Parties have agreed in the Joint Proposal to, after submitting the Joint Proposal Application to the Commission, complete the process for execution and submission of an associated settlement agreement as specified in Commission Rule 12.

V. Benefits of the Joint Proposal to Community & Employees

Some participants to the Public Workshop expressed strong support for the Joint Proposal’s treatment of workers and the local community. The Joint Proposal includes provisions that would provide for an orderly transition away from Diablo Canyon, providing benefits to the community and the facility’s large employee base. These participants noted that PG&E has been a good neighbor, and that the Joint Proposal continues that trend by allowing for a deliberate transition. Some participants echoed that sentiment, supporting the Joint Proposal’s eight- to nine-year lead time that would allow for continued operation of the facility as well as opportunities for workers to retrain and possibly transition into other related jobs.
Public Meetings

Two Public Meetings were held in San Luis Obispo on July 20. Two additional Public Meetings on July 22 were held in South San Francisco. Community members were informed of these meetings through press release, the PG&E website, a note to employees, and outreach. Nearly 100 community members, non-profit advocates and representatives, Diablo Canyon employees, and public officials attended the collected meetings.

Each meeting had three parts. First, a panel representing a selection of Parties gave brief remarks describing the goals of the Joint Proposal and the Public Meetings. At the San Luis Obispo sessions, the representatives were Steven Malnight, PG&E Senior Vice President of Regulatory Affairs, Edward Halpin, PG&E Senior Vice President of Generation and Chief Nuclear Officer, and Rochelle Becker, Executive Director of the Alliance for Nuclear Responsibility. The panel for the San Francisco sessions included Steven Malnight and James Welsch, Site Vice President for Diablo Canyon. The second portion of the Public Meetings was devoted to receiving public comment. Participants had the opportunity to provide comments on the Joint Proposal and pose questions to panelists, who then responded as appropriate. Finally, all attendees were encouraged to attend open house-type sessions that contained a number of booths related to the Joint Proposal, each staffed by PG&E subject matter experts. Here, participants could follow up on questions or comments raised in the previous sessions. The opening statements and public comment periods were webcast; a recording of all sessions is available here.

Summarized Comments and Questions

Collectively, the participants at the four Public Meetings represented a diverse set of viewpoints. Attendees provided input and suggestions on multiple important aspects of the Joint Proposal and requested more information on a variety of topics. Below, we catalogue the general messages delivered during the time for public comment. These are categorized into seven topic areas: future use of the Diablo Canyon site; impacts on the local community; how the proposal supports employees; support for nuclear energy; concerns over ongoing impacts of Diablo Canyon operations; questions and comments about replacement power and procurement issues; Joint Proposal implementation questions and comments.

A. Future Land Use

Many participants requested that the Joint Proposal include specific provisions relating to the future use of the Diablo Canyon site. These participants believe that the land should be conserved, and not sold or leased to developers. Participants suggested the land could be used to support tourism, to expand biking, hiking, equestrian, and camping opportunities, or possibly protected from all human use in particularly sensitive areas. Some participants suggested this could occur by expanding Montaña de Oro State Park to include the Diablo Canyon site.

Some participants brought up a March 2000 San Luis Obispo Countywide ballot initiative called Measure A or the DREAM Initiative. This advisory measure called upon the county to prohibit development on the property surrounding the Diablo Canyon nuclear power plant when it is decommissioned, and was passed by nearly three quarters of voters. At the Public Meetings, participants requested that PG&E and other Parties respect the decision of the local community and set aside the area for recreation. One participant also noted that the City and
County of San Luis Obispo could be a helpful partner, and noted that partnerships across the region could fund the transfer.

Some participants expressed special interest in Wild Cherry Canyon, an over 2,000-acre parcel of land located near Avila Beach. A potential residential development project has been announced for this area. Participants requested that PG&E ensure that Wild Cherry Canyon is preserved; these participants noted that development would change the tenor of the neighborhood, contribute to traffic congestion, and harm environmentally sensitive lands.

B. Impacts on the Local Community

A number of participants at the San Luis Obispo Public Meetings focused their comments on the impact the Joint Proposal would have on the local community. While many participants expressed appreciation for PG&E and Diablo Canyon’s long partnership with the community, and gratitude for the long notice horizon and willingness to engage with the community over this planning period, these comments emphasized how large of an impact the closure of the facility will have on the community. For example, one participant estimated the direct economic impact of Diablo Canyon is nearly $1 billion annually. Others noted that Diablo Canyon is the third largest employer in the county – providing valuable “head of household jobs,” and first among all sources of tax revenue and public schools funding.

These participants had many specific requests concerning the implementation of the Joint Proposal. Some reminded PG&E that the continued safe operation during the remaining eight to nine years of plant operation is critical. Other participants noted that the eight- to nine-year time period should be fully utilized, with parties starting planning immediately. This planning could include a third-party economic analysis to further facilitate community transition planning, a long-term planning process to identify replacement alternatives for head of household jobs, or other creative solutions to study and limit impacts of plant closure. Other parties requested further study on the options for future use of land and cultural resources, including the economic impacts of such use.

Multiple participants also addressed the Joint Proposal’s $49.5 million proposed set-aside of funds allocated to community assistance. Participants requested additional detail and calculations on how and when this would accrete to the community. Some participants recommended that this fund be distributed based on the existing tax structure, which would be equitable based on current funding patterns and would provide future funding certainty.

Representatives associated with the school district spoke about the large effect closing Diablo Canyon will have on the district: tax revenue paid by PG&E is estimated to be 11% of the district’s annual budget. One representative explained how, due in large part to this funding, the school district is one of the top funded per child in the state. However, future funding for the district is now uncertain. Participants requested more information on how the payments from the community support fund would be distributed and over what time period so that the district could begin planning for the eventual decrease.

Finally, a participant requested more information on how the Joint Proposal would affect the development of a desalinization facility co-located with the Diablo Canyon facility; this participant believed this was important to maintaining water supply for the region.
C. Support for Employees

Some participants spoke about the Joint Proposal’s impact on employees of Diablo Canyon, and the resulting impact on the community (see more below on additional community impacts that were raised). Participants noted that employees were good members of the community, contributing to charitable causes and playing a large role in schools and other local institutions. Some participants, including current employees at Diablo Canyon, expressed gratitude for the long transition time, which can allow employees to develop a plan for post-closure; one participant noted that he hadn’t heard of any other industry that had done this. However, other participants noted that the Joint Proposal did not contain provisions to help transition local contractors who provide plumbing, piping, and construction services for the facility; these participants requested that the Parties consider additional assistance for retraining and transitioning these employees as well as those directly employed by PG&E.

D. Support for Nuclear Energy

Some participants in the Public Meetings expressed strong support for nuclear generation. These participants stated that the best approach would be to maintain operations at Diablo Canyon beyond the current license period. These commenters assert that extending operations at Diablo Canyon would maintain a known, reliable, GHG-free resource, which is the best way to minimize costs and GHG emissions, which is critical to avoiding the impacts of climate change.

These participants stated that the proposal is based on bad science, fear of nuclear, and direction from Parties that are primarily anti-nuclear. They pointed out potential double standards, wherein Diablo Canyon could be held to certain environmental standards, such as required installation of cooling towers to meeting once-through cooling (OTC) regulations, when other facilities are given exceptions to these policies. Participants also claimed that the state’s procurement policies are biased away from nuclear in favor of renewables.

As an alternative to the Joint Proposal, a number of the participants recommended policy changes that would recognize the GHG-free benefits of nuclear generation and allow Diablo Canyon to keep operating. Such proposed policies include a zero-emissions credit program, as is currently under consideration in New York, or a Clean Energy Standard that could replace the RPS and give nuclear generation the same incentive as renewable generation. These commenters argued that ultimately these policies should be used to recognize the value of Diablo Canyon and support long-term operations at the facility.

E. Concerns Over Ongoing Impacts of Diablo Canyon Operations

Some participants were concerned about the potential impacts of Diablo Canyon over the eight- to nine-year transition period. A participant expressed that nuclear plants are almost exclusively run to failure, rather than intentional closure, causing concern that this would occur at Diablo Canyon before proposed closure in 2024 – 2025 under the Joint Proposal. In general, these participants requested that instead of continuing to run Diablo Canyon until 2024 and 2025, PG&E commit to shutting down the facility immediately or as soon as possible in order to limit these potential impacts.

Specifically, some put forward that the recent extension of the State Lands Commission lease meant that Diablo Canyon would be operating without a thoroughly updated Environmental Impact Report, which raised concerns for them about the potential for endangered species and other environmental impacts. Others claimed that without
retrofits to install cooling towers and cease once-through cooling, Diablo Canyon was continuing to heat ocean water and hurt marine life.

A group of participants was concerned with the impacts of nuclear waste, both in terms of its continuing production under operations and its long-term storage. Some participants expressed that a natural disaster could result in failure of storage facilities. These participants provided a number of suggestions to address this concern, including: accelerating the closure of the facility (though others believe a rush could endanger employee safety); setting a new standard for waste storage that would exceed existing NRC requirements; or changing the current type of storage.

Finally, a participant expressed disbelief that nuclear generation is truly GHG-free, due to the energy needed to prepare and store the fuel.

**F. Replacement Power and Procurement**

Comments from participants relating to procurement and energy resources used to replace Diablo Canyon covered a broad range of topics, both supportive and critical of nuclear power.

Some commenters are skeptical of renewable energy’s role in replacing Diablo Canyon output. These participants argued that this would just replace one GHG-free resource with another, but replacing a known quantity – nuclear generation – with unknown and untested renewable generation which has the added complication of being intermittent. A participant suggested that Diablo Canyon not cease operation until all replacement resources are proven and in place. Some participants also questioned how increasing renewable generation would help with system flexibility. Participants also expressed concern over the cost of renewable generation, which is supported by tax credits (which are in turn funded by residents of the state, some of whom are ratepayers as well). Some participants also argued that providing reliable service through renewables would require overbuilding the system to account for intermittency and variability, which would further increase costs. Finally, some commenters expressed concern about the long-term trajectory for renewable generation, and asked if shutting down Diablo Canyon was just delaying addressing inevitable issues with renewable generation. Specifically, comments detailed the cost of need for energy storage, which some participants claim is indefensibly expensive, to mitigate overgeneration and help with renewable integration.

An overlapping group of commenters questioned how the Joint Proposal could be truly GHG-neutral when shutting down Diablo Canyon, a large source of GHG-free electricity. Participants questioned whether the 4,000 MWh indicated in Tranches 1 and 2 were all that the Joint Proposal committed, and how this could fully replace Diablo Canyon. Some participants specifically expressed doubt that electricity needs would truly decrease as much as projected. Other participants asked how the Joint Proposal reflected an improvement in PG&E’s GHG-free portfolio, noting that PG&E already provides 54% GHG-free electricity and questioning how a 55% RPS commitment represented any progress. Participants also asked how the Joint Proposal assured that there would be no increase in fossil generation.

Participants also highlighted the possible effects that the Joint Proposal would have on PG&E’s use of imported power, and how this might affect the utility’s GHG profile. These participants argued that PG&E imports coal from out of state, and that these imports would increase upon closure of Diablo Canyon (especially in light of the proposed changes to the California electricity balancing area to incorporate more deliveries from out of state).
Instead, these participants argued, PG&E should focus on replacing this imported power first, before reducing output from GHG-free nuclear resources.

Other participants addressed additional procurement issues. One commenter recommended that replacement procurement of renewables not be in the hands of PG&E, due to her view that PG&E was not supportive of renewables development. Other commenters asked for more information on how, if at all, the Joint Proposal would affect customer solar installations, asking whether this could increase the credit that such customers receive for their solar output and more general information on how the net energy metering program could play a role in displacing Diablo Canyon. Some participants wanted to know how community choice aggregators would play a role in implementing the Joint Proposal, including how costs would be allocated. A participant requested more information on what procurement might be included beyond the three identified tranches. Finally, participants wanted to know how procurement under the Joint Proposal would be truly additional to existing requirements, asking if the Joint Proposal won’t in effect just implement the requirements of SB 350, or if PG&E would count renewables procurement toward renewable requirements.

G. Implementation

Some participants in the Public Meetings provided comment and asked questions about the implementation of the proposal. Participants were interested in the potential costs of the proposal, and requested more information on the breakdown of costs and how funds would be spent. Some participants asked specifically about decommissioning, requesting more information on how much it would cost, who would pay, and where funding would come from. One participant requested that PG&E shareholders as well as customers bear a portion of the Joint Proposal costs.

As discussed above, other participants were interested in accelerating the timeline of the Joint Proposal instead of waiting until 2024 and 2025 to cease operations. These participants argued PG&E should shut Diablo Canyon immediately or on an accelerated timeline. Other participants agreed with the 2024 – 2025 shutdown date, but emphasized the need to begin planning and community outreach as soon as possible.

A group of participants was interested in the approval process for the Joint Proposal. A few participants explained a belief that unless the Joint Proposal was approved fully by the Commission, the Parties could walk away and dissolve the Joint Proposal. In one case, a commenter asked stakeholders to consider whether it was truly the best outcome to threaten immediate closure of Diablo Canyon now over concerns that the Joint Proposal is not perfect, rather than settling for an imperfect solution that allows for an eight to nine-year planning horizon. Another participant requested more information on whether PG&E could choose – or be forced – to reinitiate the relicensing process if the Joint Proposal was rejected or amended.

In addition, participants requested more information about involvement of the California Energy Commission, pointing out that the CEC has experience with developing renewables. Another participant wished to ensure that the closure of Diablo Canyon was defined as “development” under the California Coastal Act, which this participant believes would implicate changes to relevant permits and plans before any further action could be taken.

Finally, some commenters requested that the Joint Proposal more explicitly address the long-term storage of waste on the Diablo Canyon site, including provisions to safely monitor the waste.
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CHAPTER 2

DIABLO CANYON POWER PLANT NEED ANALYSIS

A. Introduction

Pacific Gas and Electric Company (PG&E) is extremely proud of Diablo Canyon Power Plant’s (Diablo Canyon or DCPP) track record of industry-leading safety and reliability. Diablo Canyon Units 1 and 2 began commercial operation in May 1985 and March 1986, respectively, and are licensed by the Nuclear Regulatory Commission (NRC) to operate until November 2, 2024 and August 26, 2025. Each year Diablo Canyon generates about 20 percent of the annual electricity production in PG&E’s service territory and 9 percent of California’s annual production. In 2009, PG&E filed at the NRC to continue Diablo Canyon’s operations for an additional 20 years.

Over the course of the past decade, California has continued to lead in creating a new energy future for the State; a future that is focused on reducing greenhouse gas (GHG) emissions by providing additional energy supply options, such as Community Choice Aggregation (CCA), for consumers and advancing clean energy technologies, such as renewable resources, distributed energy resources—primarily privately-owned rooftop solar, energy storage, and customer energy management solutions, including robust Energy Efficiency (EE) and Demand Response (DR) programs. Policies to support this vision have accelerated in the past several years, including the passage of Senate Bill (SB) 350, which calls for a doubling of EE goals and achieving a 50 percent Renewables Portfolio Standard (RPS) by 2030.

PG&E has conducted extensive analysis on the cumulative impacts of these policy changes on bundled customer demand and future supply needs. These forecasts show that a substantial portion of DCPP’s energy output is anticipated to not be needed to serve PG&E’s bundled electric customers beyond 2025. In addition, if DCPP were not retired but instead its license renewed, the generation from Diablo Canyon could exacerbate the challenges of integrating increasing amounts of wind and solar into the system. These challenges are anticipated to grow as steady progress is made toward implementing 50 percent RPS by 2030 and as more and more privately owned solar rooftops are installed.
and interconnected to the system. As a result of these and other potential regulatory factors, including implementation of California’s Once Through Cooling (OTC) policy, PG&E’s analysis projects that it would be more expensive from a customer perspective to continue to operate DCPP on behalf of bundled customers than to retire Diablo Canyon when the licenses expire in 2024 and 2025 and implement the Joint Proposal.

PG&E evaluated these factors including the increase of the RPS from 33 percent to 50 percent by 2030; doubling of EE goals; the challenge of managing overgeneration and intermittency conditions under a resource portfolio increasingly influenced by solar and wind production; the growth rate of DG, such as rooftop solar; and increases in the departure of PG&E’s retail customers to CCAs. PG&E concluded that the most efficient and effective path forward for achieving California’s SB 350 policy goal for deep reductions of GHG emissions would be to retire Diablo Canyon at the expiration of its current NRC operating licenses and replace it with a portfolio of GHG-free resources, as provided in the Joint Proposal.

This chapter describes PG&E’s analysis of the factors leading to the decision to retire Diablo Canyon when the current operating licenses for Units 1 and 2 expire in 2024 and 2025, respectively. Chapter 3 addresses the replacement of the energy that will be needed to serve the electricity load of PG&E’s bundled electric customers as a result of this decision.

The remainder of this chapter is organized as follows:

• Section B – explains why DCPP’s full output is no longer needed to serve PG&E’s bundled electric customers after the expiration of DCPP’s current NRC operating licenses;
• Section C – addresses how continued operations of DCPP post-2025 would increase RPS curtailment as a result of over-generation;
• Section D – addresses system and local reliability impacts as a result of the retirement of DCPP; and
• Section E – discusses the cost of operating DCPP from 2025-2045.

B. DCPP Is Not Needed for PG&E’s Bundled Electric Customers

Since DCPP Units 1 and 2 began commercial operation in 1985 and 1986, respectively, dramatic changes in California’s energy policy have occurred resulting in a fundamental shift in the state’s electricity industry and markets.
These changes, which accelerated in the past decade, lead PG&E to the conclusion that at the end of DCPP’s current license period in 2024-2025, a substantial portion of DCPP will no longer be needed to meet the electricity load of PG&E’s bundled electric customers.

There are three key factors that have changed the electricity landscape and lead to the conclusion that a substantial portion of DCPP will no longer be needed to meet the electricity load of PG&E’s bundled electric customers in 2025 and beyond: (1) the development of the California Independent System Operator (CAISO) and associated energy markets; (2) new federal, state and California Public Utilities Commission (CPUC or Commission) program mandates to purchase specified incremental quantities of preferred resources; and (3) reductions in electricity load from PG&E’s bundled electric customers due to customer supply options and EE. Each of these factors is discussed in more detail below.

1. The Development of the CAISO and Energy Markets in California

When Diablo Canyon commenced operation in the mid-1980s, PG&E was responsible for providing its customers with generation, transmission, and distribution services. In 1996, some 10 years after Diablo Canyon commenced operation, California passed the Electric Utility Industry Restructuring Act (Assembly Bill (AB) 1890).\(^1\) AB 1890 initiated a number of significant reforms in the California energy industry, including the creation of the CAISO to manage California’s high voltage electric transmission grid, facilitate the spot market for power, and perform transmission planning.

The creation of the CAISO and development of competitive wholesale spot electricity markets have completely changed how power plant scheduling is done. PG&E and the other investor-owned utilities (IOU) no longer determine which generating units are used to provide electricity to IOU customers. Instead, CAISO-facilitated competitive day-ahead and real-time wholesale electricity markets for energy and ancillary services are

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\(^1\) Stats. 1996, Chapter 854.
used to determine which generating units operate and how the electricity load of Load Serving Entities (LSE) are met.²


Since DCPP began operating, a number of new federal, state and Commission policies and programs have prioritized certain clean energy sources, such as renewables, EE, DG, and DR. California’s clean energy vision prioritizes procurement of electricity from specific types of preferred resources versus other available options, including nuclear.

One of the most significant state policies has been California’s RPS. The RPS was established in 2002 under SB 1078, which required 20 percent of electricity sales be served from eligible renewable energy resources by 2017. In 2006, SB 107 accelerated the 20 percent RPS requirement to 2010. In 2011, SB 2 (1x) increased and extended the RPS requirement to 33 percent by 2020. In 2015, SB 350 increased the RPS requirement to 50 percent by 2030.

California’s renewables policies set procurement targets and established procurement programs for various types of renewable technologies. These programs include the Renewable Auction Mechanism (RAM) established by the Commission in Decision (D.) 10-12-048, the Renewable Market Adjusting Tariff established in D.12-05-035, the bioenergy Feed-In Tariff (FIT) resulting from SB 1122, and a bioenergy RAM Program for high hazard zone forest feedstock generators as established by the Governor’s Emergency Proclamation on October 30, 2015.³

Since DCPP began operating, federal and state mandates related to Qualifying Facilities (QF) and Combined Heat and Power (CHP) procurement have also been implemented. In 2010, the CPUC adopted the Qualifying Facility and Combined Heat and Power Settlement (QF/CHP)⁴ that included a Pro Forma Power Purchase Agreement (PPA) for QFs that are 20 megawatts (MW) or less in size (QF Public Utility Regulatory Policies

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² All LSEs—including PG&E—are required to meet certain Resource Adequacy (RA) requirements established by the Commission and the CAISO. However, these are capacity requirements rather than day-ahead and real-time energy requirements.


⁴ D.10-12-035.
Act PPA), which gives QFs the option to make firm or as-available electricity sales to PG&E. The QF/CHP Settlement also includes provisions for other CHP generators to continue operation.

Further CHP procurement may result from AB 1613, which was passed in 2007. AB 1613 directed the California Energy Commission (CEC), the CPUC, and the California Air Resources Board to implement the Waste Heat and Carbon Emissions Reduction Act, which was designed to encourage the development of new CHP systems in California with generating capacities no greater than 20 MW. The CPUC established a FIT Program for CHP systems, giving generators that begin operations after December 31, 2007 the option to make as-available electricity sales to PG&E.

As a result of the RPS, CHP, and other resource mandates, PG&E has a portfolio of contracted and utility-owned resources to meet the needs of PG&E’s bundled electric customers. While DCPP does currently play an important role in PG&E’s portfolio of resources to meet the electricity load of PG&E’s bundled electric customers without contributing to GHG emissions, this situation is projected to change. As the quantities of preferred clean energy procurement increase, the net amount of electricity load of PG&E’s bundled electric customers is projected to decrease significantly. The consequence is reduced need for DCPP to meet the electricity demands of PG&E’s bundled electric customers.

In some hours, more electricity may be supplied by PG&E-contracted, policy-preferred clean energy resources and PG&E-owned resources than needed to meet the electric load of PG&E’s bundled electric customers. If DCPP were to have its operating licenses renewed and continue operating, this situation is anticipated to be more frequent, with greater quantities of “excess supply” for PG&E’s bundled electric customers. As a result, at the end of the current license period in 2024-2025, a substantial portion of DCPP will no longer be needed to meet the electricity load of PG&E’s bundled electric customers.

The need for DCPP to meet the electricity demands of PG&E’s bundled electric customers has also been affected by the increase, since the passage of AB 1890, of customer choices for electric supply. Today, customer choices include Direct Access (DA), CCA and DG. The electricity load of PG&E’s bundled electric customers is also undergoing substantial changes as a result of the continued substantial growth of EE. Customer choices for electric supply are discussed in greater detail below, as is EE growth.

a. Direct Access

In addition to creating the CAISO, AB 1890 also provided a framework for DA providers to serve electric customers in California. DA initially began in 1998 in order to bring retail competition to the California electric power markets. During the California energy crisis of 2000-2001, new DA service was suspended and DA providers were limited to serving existing customers only. In 2009, SB 695 was passed, allowing for the limited reopening of DA service, subject to a maximum allowable annual limit. As a result of the limited reopening of DA, PG&E’s DA load has increased from 5,574 gigawatt-hours (GWh) in 2009 to 9,833 GWh in 2015.

b. Community Choice Aggregation

Some customers may also have a choice to elect to receive energy service from a CCA provider. California’s CCA Program allows cities, counties, and other qualifying governmental entities within PG&E’s service territory to purchase and/or generate electricity for their residents and businesses. In 2010, Marin Clean Energy was launched, followed in 2013 by Sonoma Clean Power and CleanPower SF in 2016. As the number of CCAs continues to expand, and the electricity

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6 Current DA load for PG&E is based on the CPUC’s Direct Access Implementation Activity Report for April 2016.
load served by these CCAs increase, there are corresponding
decreases in the amount of energy and capacity needed to meet the
electricity load of PG&E’s bundled electric customers.

c. Distributed Generation

The amount of DG has increased considerably over the past
decade. This increase is primarily from privately-owned residential and
commercial solar energy system installations and is predominantly
driven by the Investment Tax Credit (ITC), and Net Energy Metering
(NEM) structure.

The Commission’s NEM Program has stimulated the growth of
distributed solar photovoltaic (PV) systems as customers are able to
serve their own immediate energy needs with generation from their
private solar PV generating system as well as receive compensation for
any net surplus generation on an annual basis. The Commission’s
recent NEM decision (i.e., D.16-01-044) has provided additional
certainty for future DG customers that NEM benefits will continue to be
available under the NEM Successor Tariff once the NEM cap has been
reached under the first NEM Tariff Program. DG levels reached
429 MW in 2010 and have increased an additional 340 percent to
1,897 MW at the end of 2015.

d. Energy Efficiency

EE has long been a top priority for California. Mandatory EE
building and equipment codes and standards and voluntary customer
programs have encouraged California electric customers to use less
electricity. Under California Pub. Util. Code Section 454.5(b)(9)(C), the

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8 The ITC is a 30 percent tax credit that was originally created from the Energy Policy Act
of 2005, and has subsequently been extended several times, most recently by the
Consolidated Appropriations Act of 2016. The latest extension continues the 30 percent
tax credit rate through 2019 before decreasing to 26 percent in 2020, 22 percent in
2021, and 10 percent for non-residential installations only beginning after 2023. See
http://docs.house.gov/billsthisweek/20151214/CPRT-114-HPRT-RU00-SAHR2029-
AMNT1final.pdf.

9 All further statutory references are to the California Pub. Util. Code unless
otherwise noted.
IOUs are required to “meet unmet resource needs with all available EE and demand reduction that is cost-effective, reliable, and feasible.” EE programs in California are projected to continue to significantly reduce California’s energy consumption, including PG&E’s utility bundled customer demand, as a result of two 2015 bills, SB 350 and AB 802. SB 350 requires the Commission, in consultation with the CEC, to establish annual targets for statewide EE savings and demand reduction that will achieve a cumulative doubling of EE savings in electricity and natural gas end uses by January 1, 2030. In addition, AB 802 endorses EE programs to: bring existing buildings up to current California efficiency codes and standards; reduce energy use through operational and behavioral improvements, and support benchmarking energy consumption of buildings. These statutes, as well as the broader California policy supporting EE, are projected to attenuate increases in electricity load even with the projected increase in electric vehicle use within California.

4. **DCPP Generation Has Been Displaced by EE, RPS and DG**

The previous sections describe the changes that have and will continue to occur in California’s electricity industry. These changes continue to move California towards a cleaner energy future, while reducing the projected need for DCPP. DCPP is a baseload power plant; therefore, these changes have the effect of making DCPP a resource on the margin.

Table 2-1 quantifies the displacement of DCPP’s historical generation due to the changes in California’s electricity industry. Table 2-1 displays an amount of energy from DCPP and projected amounts from EE, RPS and DG for PG&E’s bundled electric customers by 2030. A Reference Case and two scenarios are presented. Table 2-1 indicates how DCPP’s annual

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12 The three tranches specified in the Joint Proposal are not included in the quantities displayed in Table 2-1. Including the three tranches would further reduce the net displacement (that is, result in a negative number with greater magnitude) for the Reference Case and each scenario. Chapter 3 discusses the three tranches in the context of replacement for DCPP.
historical output of approximately 18,000 GWh is projected to be systematically displaced by EE, RPS and DG. Table 2-1 displays substantial negative numbers for net displacement in the Reference Case and both scenarios as a result of the changes in California’s electricity industry.

### Table 2-1

**Displacement of DCPP Generation by EE, DG and RPS for PG&E’s Bundled Electric Customers**

<table>
<thead>
<tr>
<th>Category</th>
<th>High Load Scenario</th>
<th>Reference Case</th>
<th>Low Load Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Displacement</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a EE Growth*</td>
<td>(16,366)</td>
<td>(16,312)</td>
<td>(16,117)</td>
</tr>
<tr>
<td>b DG**</td>
<td>(13,688)</td>
<td>(13,669)</td>
<td>(11,734)</td>
</tr>
<tr>
<td>c RPS-Eligible**</td>
<td>(28,539)</td>
<td>(23,115)</td>
<td>(16,435)</td>
</tr>
<tr>
<td><strong>Gross Displacement</strong></td>
<td>(58,593)</td>
<td>(53,096)</td>
<td>(44,286)</td>
</tr>
<tr>
<td>Historical DCPP Generation</td>
<td>18,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Net Displacement</strong></td>
<td>(40,593)</td>
<td>(35,096)</td>
<td>(26,286)</td>
</tr>
</tbody>
</table>

**Notes**

*EE volumes based on incremental EE savings compared to 2015
**DG and RPS volumes are based on total expected generation

5. **PG&E’s Utility Bundled Customer Need Through 2030**

As a result of the changes described above in California’s energy industry since DCPP commenced operation, PG&E projects that a substantial portion of DCPP will no longer be needed to serve PG&E’s bundled electric customers in 2025 and beyond, when DCPP’s current operating licenses expire. The forecasting process is driven by significant uncertainty, which requires consideration of various potential outcomes. In assessing the need for DCPP, PG&E has considered a range of possible outcomes related to CCA/DA departures, continued growth of DG, and the ability to obtain increased levels of EE.

PG&E’s assessment on the need for Diablo Canyon is anchored by a Reference Case. To develop a sense of the range of plausible outcomes, two scenarios are also presented. The resource needs are developed for the periods between 2017 and 2030, which quantifies the impact of these changes.
energy industry changes and aligns with the 50 percent RPS and GHG emission reduction target years.\textsuperscript{13}

\textbf{a. Annual Utility Bundled Customer Need: 2017-2030}

Before the procurement programs and alternative customer supplier options began to mature this decade, PG&E’s bundled electric customers still needed 100 percent of DCPP’s annual output. However, as shown in this section, across the Reference Case and both scenarios, the need for DCPP is projected to be substantially lower than 100 percent.

Table 2-2 is based on information from PG&E’s long-term energy sales forecasts for both PG&E’s bundled electric customers and all customers within PG&E’s service territory.

\begin{table}[h]
\centering
\begin{tabular}{|c|c|c|c|c|c|c|}
\hline
\textbf{Gross Service Territory Sales} & \textbf{2017} & \textbf{2025} & \textbf{2030} \\
\hline
\hline
\textbf{Energy Efficiency} & $-6,482$ & $-18,870$ & $-20,676$ & $-24,797$ & $-24,056$ & $-27,461$ \\
\textbf{Distributed Generation} & $-7,610$ & $-16,663$ & $-18,862$ & $-20,848$ & $-20,120$ & $-23,011$ \\
\textbf{Service Territory Sales} & $82,039$ & $82,132$ & $78,127$ & $72,019$ & $86,977$ & $80,681$ \\
\hline
\textbf{CCA / DA*} & $-14,437$ & $-30,568$ & $-34,273$ & $-38,112$ & $-33,130$ & $-37,068$ \\
\textbf{Utility Bundled Sales} & $67,602$ & $51,564$ & $43,854$ & $33,907$ & $53,847$ & $43,613$ \\
\hline
\textbf{Bundled Sales % of Territory} & $82\%$ & $63\%$ & $56\%$ & $47\%$ & $62\%$ & $54\%$ & $42\%$
\hline
\end{tabular}
\caption{EE, DG AND CCA PROJECTIONS}
\end{table}

\textbf{Notes}
\begin{itemize}
\item*$\text{Includes 360 GWh of other sales}$
\end{itemize}

The Reference Case is based on the expected impact from the three main drivers of CCA, DG, and EE. For CCA, the level of projected load reflects departure from PG&E’s utility bundled portfolio based on departure probabilities. The level of DG is based on projections that take into consideration the expansion of private solar PV resulting from the NEM successor tariff, the extension of the ITC through 2021, as well as moderate adoption of fuel cells, combustion and heat to power

\textsuperscript{13} This chapter assumes GHG emissions target of 40 percent below 1990 levels by 2030 as directed by Executive Order (EO) B-30-15.
technologies and distributed wind. EE represents a forecast based on our several decades history of engagement in EE, the CPUC’s adopted goals for PG&E’s EE programs, and the CPUC’s studies of future potential.

The Low Load and High Load scenarios are relative to the Reference Case. The Low Load scenario indicates that PG&E’s utility bundled sales are “low” because the growth of EE, DG, and CCA is greater than the Reference Case. The High Load scenario indicates that PG&E’s utility bundled sales are “high” because the growth of EE, DG, and CCA is less than the Reference Case.

The High Load and Low Load scenarios were developed considering the probability distributions for three components: EE, DG, and CCA. For each of these components, the difference between the 25th percentile level and the expected level is calculated. These differences are added to the Reference Case to determine a high bundled sales (“High Load”) scenario. Similarly, for each of these components the difference between the 75th percentile level and the Reference Case is calculated. These differences are added to the Reference Case to determine a low bundled sales (“Low Load”) scenario.

Bundled sales for PG&E customers decline across all years for the Reference Case and for both Low Load and High Load scenarios. As reflected in Table 2-2, the decrease in utility bundled sales is due to continued growth in EE, DG, and CCAs. Focusing on the Reference Case in Table 2-2, PG&E projects utility bundled sales to decrease by approximately 35 percent from 2017 to 2030 due to continued growth in EE, DG, and CCA. While the two scenarios indicate there is a range of uncertainty as to how much reduction in sales will occur for bundled customers across the various components, there is little doubt that there

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15 For purposes of this discussion, PG&E assumes that DA will remain capped at current statutory levels. If California statutes are changed to re-open DA, PG&E’s utility bundled customer load will likely decrease even more substantially.
will be reductions in utility bundled sales as a result of EE, DG, and CCA. The net result of these changes is that utility bundled customer demand is anticipated to be substantially lower by the time the DCPP licenses expire in 2024-2025.

Given the range of utility bundled sales reflected in Table 2-2, PG&E examined the need for Diablo Canyon generation to meet the demand for bundled electric customers across the Reference Case and the two scenarios. Figure 2-1 displays, for the Reference Case, the projected change over time in DCPP generation used to serve PG&E’s bundled electric customers, represented as a fraction of the energy requirements (demand plus line losses) of PG&E’s bundled electric customers. The decrease in DCPP needed generation is a result of the procurement policies, increase in EE, and customer supplier options discussed in Section B above. Table 2-3 reflects the associated GWh for the components shown in Figure 2-1. Figure 2-2 displays the projected decrease for the Low Load scenario. Table 2-4 reflects the associated GWh displayed for the components in Figure 2-2. Figure 2-3 displays the projected decrease for the High Load scenario. Figure 2-5 reflects the associated GWh for the components shown in Figure 2-3.

**FIGURE 2-1**
EE, DG CCA AND GENERATION RESOURCE TYPE IN 2017, 2025 AND 2030 REFERENCE CASE
### TABLE 2-3
EE, DG CCA AND GENERATION\(^{(a)}\) RESOURCE TYPE IN 2017, 2025 AND 2030 REFERENCE CASE

<table>
<thead>
<tr>
<th>Generation Requirement</th>
<th>2017</th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Service Territory Sales</td>
<td>96,131</td>
<td>117,665</td>
<td>131,153</td>
</tr>
<tr>
<td>Gross Service Territory Load</td>
<td>105,208</td>
<td>129,408</td>
<td>144,369</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>(6,482)</td>
<td>(20,676)</td>
<td>(27,461)</td>
</tr>
<tr>
<td>T&amp;D Line Losses</td>
<td>(641)</td>
<td>(2,045)</td>
<td>(2,716)</td>
</tr>
<tr>
<td>Distributed Generation</td>
<td>(7,610)</td>
<td>(18,862)</td>
<td>(23,011)</td>
</tr>
<tr>
<td>T&amp;D Line Losses</td>
<td>(753)</td>
<td>(1,865)</td>
<td>(2,276)</td>
</tr>
<tr>
<td>Service Territory Sales</td>
<td>82,039</td>
<td>78,127</td>
<td>80,681</td>
</tr>
<tr>
<td>Service Territory Load</td>
<td>89,722</td>
<td>85,960</td>
<td>88,905</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>(6,482)</td>
<td>(20,676)</td>
<td>(27,461)</td>
</tr>
<tr>
<td>T&amp;D Line Losses</td>
<td>(641)</td>
<td>(2,045)</td>
<td>(2,716)</td>
</tr>
<tr>
<td>Distributed Generation</td>
<td>(7,610)</td>
<td>(18,862)</td>
<td>(23,011)</td>
</tr>
<tr>
<td>T&amp;D Line Losses</td>
<td>(753)</td>
<td>(1,865)</td>
<td>(2,276)</td>
</tr>
<tr>
<td>Service Territory Sales</td>
<td>82,039</td>
<td>78,127</td>
<td>80,681</td>
</tr>
<tr>
<td>Service Territory Load</td>
<td>89,722</td>
<td>85,960</td>
<td>88,905</td>
</tr>
<tr>
<td>Utility Bundled Sales</td>
<td>67,602</td>
<td>43,854</td>
<td>43,613</td>
</tr>
<tr>
<td>Utility Bundled Load</td>
<td>73,857</td>
<td>48,297</td>
<td>48,171</td>
</tr>
<tr>
<td>RPS-Eligible</td>
<td>21,761</td>
<td>20,377</td>
<td>23,115</td>
</tr>
<tr>
<td>Large Hydro</td>
<td>11,677</td>
<td>10,232</td>
<td>10,231</td>
</tr>
<tr>
<td>CHP</td>
<td>5,212</td>
<td>3,195</td>
<td>1,809</td>
</tr>
<tr>
<td>Humboldt Local Reliability</td>
<td>420</td>
<td>419</td>
<td>419</td>
</tr>
<tr>
<td>Renewable Integration</td>
<td>3,405</td>
<td>4,778</td>
<td>4,778</td>
</tr>
<tr>
<td>DCPP Need</td>
<td>18,492</td>
<td>8,778</td>
<td>8,139</td>
</tr>
<tr>
<td>Other</td>
<td>12,890</td>
<td>518</td>
<td>(321)</td>
</tr>
</tbody>
</table>

\(^{(a)}\) Utility bundled customer load represents the total generation that will be needed to serve utility bundled customer sales based on a 9 percent transmission and distribution system energy line loss factor.

### FIGURE 2-2
EE, DG, CCA AND GENERATION RESOURCE TYPE IN 2017, 2025 AND 2030 LOW LOAD SCENARIO

2-13
### TABLE 2-4
**EE, DG CCA AND GENERATION**
**RESOURCE TYPE IN 2017, 2025 AND 2030**

**LOW LOAD SCENARIO**

<table>
<thead>
<tr>
<th>Generation Requirement</th>
<th>2017</th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>GWh</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gross Service Territory Sales</td>
<td>96,131</td>
<td>117,665</td>
<td>131,153</td>
</tr>
<tr>
<td>Gross Service Territory Load</td>
<td>104,954</td>
<td>128,653</td>
<td>143,420</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>(6,482)</td>
<td>(24,797)</td>
<td>(35,225)</td>
</tr>
<tr>
<td>T&amp;D Line Losses</td>
<td>(583)</td>
<td>(2,232)</td>
<td>(3,170)</td>
</tr>
<tr>
<td>Distributed Generation</td>
<td>(7,610)</td>
<td>(20,848)</td>
<td>(25,646)</td>
</tr>
<tr>
<td>T&amp;D Line Losses</td>
<td>(685)</td>
<td>(1,876)</td>
<td>(2,308)</td>
</tr>
<tr>
<td><strong>GWh</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Service Territory Sales</td>
<td>82,039</td>
<td>72,019</td>
<td>70,282</td>
</tr>
<tr>
<td>Service Territory Load</td>
<td>89,594</td>
<td>78,900</td>
<td>77,071</td>
</tr>
<tr>
<td>CCA / DA Sales</td>
<td>(14,437)</td>
<td>(38,112)</td>
<td>(41,019)</td>
</tr>
<tr>
<td>T&amp;D Line Losses</td>
<td>(1,299)</td>
<td>(3,430)</td>
<td>(3,692)</td>
</tr>
<tr>
<td>Utility Bundled Sales</td>
<td>67,602</td>
<td>33,907</td>
<td>29,263</td>
</tr>
<tr>
<td>Utility Bundled Load</td>
<td>73,857</td>
<td>37,357</td>
<td>32,361</td>
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<tr>
<td>RPS-Eligible</td>
<td>21,761</td>
<td>18,004</td>
<td>16,435</td>
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<tr>
<td>Large Hydro</td>
<td>11,677</td>
<td>10,232</td>
<td>10,231</td>
</tr>
<tr>
<td>CHP</td>
<td>5,212</td>
<td>3,195</td>
<td>1,809</td>
</tr>
<tr>
<td>Humboldt Local Reliability</td>
<td>420</td>
<td>419</td>
<td>419</td>
</tr>
<tr>
<td>Renewable Integration</td>
<td>3,405</td>
<td>4,778</td>
<td>4,778</td>
</tr>
<tr>
<td>DCPP Need</td>
<td>18,492</td>
<td>4,713</td>
<td>4,312</td>
</tr>
<tr>
<td>Other</td>
<td>12,890</td>
<td>(3,984)</td>
<td>(5,624)</td>
</tr>
</tbody>
</table>

(a) Utility bundled customer load represents the total generation that will be needed to serve utility bundled customer sales based on a 9 percent transmission and distribution system energy line loss factor.

### FIGURE 2-3
**EE, DG CCA AND GENERATION RESOURCE TYPE IN 2017, 2025 AND 2030**

**HIGH LOAD SCENARIO**
TABLE 2-5
EE, DG, CCA AND GENERATION(a) RESOURCE TYPE IN 2017, 2025 AND 2030
HIGH LOAD SCENARIO

<table>
<thead>
<tr>
<th>Generation Requirement</th>
<th>2017</th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>a = g - c - e</td>
<td>Gross Service Territory Sales</td>
<td>96,131</td>
<td>117,665</td>
</tr>
<tr>
<td>b = a + (h - g) - d - f</td>
<td>Gross Service Territory Load</td>
<td>104,954</td>
<td>128,826</td>
</tr>
<tr>
<td>c</td>
<td>Energy Efficiency</td>
<td>(6,482)</td>
<td>(18,870)</td>
</tr>
<tr>
<td>d = (c / 0.91) - c</td>
<td>T&amp;D Line Losses</td>
<td>(583)</td>
<td>(1,698)</td>
</tr>
<tr>
<td>e</td>
<td>Distributed Generation</td>
<td>(7,610)</td>
<td>(16,663)</td>
</tr>
<tr>
<td>f = (e / 0.91) - e</td>
<td>T&amp;D Line Losses</td>
<td>(685)</td>
<td>(1,500)</td>
</tr>
<tr>
<td>g = k - i</td>
<td>Service Territory Sales</td>
<td>82,039</td>
<td>82,132</td>
</tr>
<tr>
<td>h = l - i - f</td>
<td>Service Territory Load</td>
<td>89,594</td>
<td>90,094</td>
</tr>
<tr>
<td>i</td>
<td>CCA / DA Sales</td>
<td>(14,437)</td>
<td>(30,568)</td>
</tr>
<tr>
<td>j = (i / 0.91) - i</td>
<td>T&amp;D Line Losses</td>
<td>(1,299)</td>
<td>(2,751)</td>
</tr>
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<td>k</td>
<td>Utility Bundled Sales</td>
<td>67,602</td>
<td>51,564</td>
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<tr>
<td>l = m_1 + …… + m_7</td>
<td>Utility Bundled Load</td>
<td>73,857</td>
<td>56,775</td>
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<tr>
<td>m_1</td>
<td>RPS-Eligible</td>
<td>21,761</td>
<td>22,168</td>
</tr>
<tr>
<td>.</td>
<td>Large Hydro</td>
<td>11,677</td>
<td>10,232</td>
</tr>
<tr>
<td>.</td>
<td>CHP</td>
<td>5,212</td>
<td>3,195</td>
</tr>
<tr>
<td>.</td>
<td>Humboldt Local Reliability</td>
<td>420</td>
<td>419</td>
</tr>
<tr>
<td>.</td>
<td>Renewable Integration</td>
<td>3,405</td>
<td>4,778</td>
</tr>
<tr>
<td>m_2</td>
<td>DCPP Need</td>
<td>18,492</td>
<td>12,171</td>
</tr>
<tr>
<td>.</td>
<td>Other</td>
<td>12,890</td>
<td>3,812</td>
</tr>
</tbody>
</table>

(a) Utility bundled customer load represents the total generation that will be needed to serve utility bundled customer sales based on a 9 percent transmission and distribution system energy line loss factor.

The needed generation from DCPP in 2030 is 8,139 GWh for the Reference Case. This corresponds to a need of 50 percent of the output of DCPP in 2030, were DCPP to operate in 2030. The need ranges from 4,312 GWh (26 percent) for the Low Load scenario to 11,201 GWh (69 percent) for the High Load scenario.

These results reflect the substantial change in the need for DCPP by bundled electric customers even with the range of uncertainty across the three scenarios. The results indicate that DCPP is only needed when utility bundled customer demand is greater than the total generation from RPS-eligible resources, PG&E’s utility-owned hydro-electric generators, electric storage assets, CHP generation, local reliability generation from Humboldt Bay Generating Station, and renewable integration support from both Colusa and Gateway generating stations.
The need determination also takes into consideration the outage scheduling practices that are necessary to comply with OTC mitigation that would be required for the facility to continue operating beyond its current license periods of 2024 and 2025. Historically, DCPP’s generating units have operated on a 21-month refueling cycle. As part of its OTC mitigation compliance, it is assumed that DCPP would transition from the historical maintenance schedule to an annual two-month spring outage schedule with refueling occurring every other year. This two-month outage schedule in the spring would also help to mitigate over-generation events. Based on this two-month annual outage schedule, post-2025 generation from Diablo Canyon is projected to decline from historical levels to 16,300 GWh.

The segment that is specified as “other” in the figures and tables above refers to annual net purchases, which is the difference between (i) the annual amount of generation that will be purchased in those hours when utility bundled customer load exceeds the total generation from the identified resources (including output from DCPP); and (ii) the total annual amount of generation sold from those same identified resources during hours when their generation exceeds utility bundled customer demand. For years where “other” generation is not shown, there are no additional net purchases for bundled electric customers.

It is important to note that, for the Low Load scenario (Table 2-4), “other” generation is substantially negative in 2025 and 2030. This means that projected annual net purchases are substantially negative; in other words, projected annual net sales are substantial. For the Low Load scenario in 2025, annual net sales (3,984 GWh) are projected to be almost as large as the amount of DCPP generation projected to be needed to supply PG&E’s bundled electric customers (4,713 GWh). For the Low Load scenario in 2030, annual net sales are projected to be larger than the amount of DCPP generation projected to be needed to supply PG&E’s bundled electric customers: 5,624 GWh compared to 4,312 GWh. In short, PG&E’s bundled portfolio is projected to have so

much excess energy that the 4,312 GWh “needed” from DCPP is
actually more appropriately supplied by a resource portfolio better
tailored to fit the electric load of PG&E’s bundled electric customers.
This point is further explored in the next section.

b. DCPP Fit for PG&E’s Utility Bundled Customer Demand

Although DCPP has provided tremendous benefits to the California
electric grid for the past 30 years, as a result of significant changes that
are occurring in California, continued operation of DCPP will likely
exacerbate the prospect of “over-generation”\textsuperscript{17} conditions in the future
as more solar resources continue to come on line. By the end of its
current license period, Diablo Canyon will no longer be a good “fit” for
PG&E’s portfolio. As more solar generation comes on line with output
peaks in the middle of the day, there is less room on the electric system
for energy from baseload resources such as Diablo Canyon. Instead,
what is needed are resources that are flexible and dispatchable, that
can quickly ramp up and down to support integrating renewables onto
the grid and meet the remaining utility bundled demand.

To see how DCPP’s baseload generating profile does not fit the
hourly demand profile associated with PG&E’s bundled electric
customers, Figure 2-4 shows the average hourly need of DCPP in 2030
by month. The dark shaded area represents the total DCPP energy
needed by PG&E’s bundled electric customers for the year.

\textsuperscript{17} Overgeneration occurs when there is more generation in the electric grid than there is
demand from customers, and the output from power plants cannot be reduced to bring
the system back into balance. When overgeneration occurs, actions have to be taken
by the system operator to curtail generation. The curtailed generation is usually solar or
wind resources.
The Bundled Gross Demand (demand of PG&E’s bundled electric customers) is the hourly shape of the 2030 generation consistent with the sales forecast from Table 2-2, which has already been adjusted for the growing DG (hours ending (HE) 1 and 13 are labeled in each month for reference). The hourly Bundled Net Demand is equal to the difference between the hourly Bundled Gross Demand and the hourly generation forecasted from the resources in PG&E’s bundled portfolio before considering the need for DCPP. The light shaded area represents any additional energy that will need to be purchased from the market, either due to the hourly Bundled Net Demand exceeding the generation from DCPP (e.g., January hour HE1) or during the DCPP Spring Outage.\textsuperscript{18}

Figure 2-4 shows how the Bundled Gross Demand and generation supply are impacted by the growth of solar resources, including solar DG, from California’s RPS mandate and DG incentives as the need of DCPP by bundled customers is lowest during the peak solar generating hours. Between March and June, there are hours where no DCPP generation is needed because utility bundled customer demand is fully

\textsuperscript{18} Figure 2.4 is for illustration only as the annual Spring Outage includes half of April and June in addition to May.
met through other resources. If DCPP were to continue operating beyond 2024-2025, it would not be able to reduce its generation during these hours because it is a baseload resource, resulting in a likely need to curtail renewable resources.

**FIGURE 2-5**
PERCENT OF DCPP GENERATION NEEDED BY PG&E’S UTILITY BUNDLED CUSTOMERS IN EACH HOUR IN 2030

REFERENCE CASE

Figure 2-5 shows the percent of DCPP generation that would be needed by PG&E’s bundled electric customers by hour for each season in 2030. Overall, to serve PG&E’s bundled electric customers, need for DCPP generation is significantly below 100 percent on average in almost all hours. Winter and fall are projected to have the greatest average need for DCPP due to higher loads and reduced generation from solar resources, while spring and summer have the lowest average need for DCPP generation and are more likely to experience CAISO system over-generation events. Throughout the year, HE10 through HE16 has the largest decrease in utility bundled customer need, which is consistent with the results shown in Figure 2-4, and reinforces that the generation needed by bundled electric customers will need to be flexible and should be procured over time in order to have the best “fit” given the levels of uncertainty for future projections of EE, DG, and CCA growth.
C. DCPP Would Increase RPS Curtailment as a Result of Over-Generation

RPS requirements on PG&E and other retail sellers in California were increased by SB 350, from 33 percent by 2020 to 50 percent by 2030. An electric grid with significant generation from variable energy resources (i.e., wind and solar) will require a complement of flexible generating facilities to maintain a balance of supply and demand, while also satisfying the state’s renewable energy obligations. The CAISO needs resources with ramping flexibility and the ability to start and stop multiple times per day based on real-time grid conditions. In the absence of this operational flexibility, there is increased potential for “over-generation” conditions, when the supply of power coming onto the grid exceeds customer demand for power. This then forces the need for the curtailment of generating facilities, including wind and solar projects needed for RPS compliance.

Renewal of DCPP’s operating license would directly impact the amount of over-generation and subsequent RPS curtailment that would occur as the RPS targets of 40 percent, 45 percent, and 50 percent are met by 2024, 2027 and 2030, respectively. DCPP’s impact on the amount of RPS curtailment is based on a number of different factors. The primary driver is that DCPP operates as a baseload resource with approximately 2,240 MW of hourly output when both units are online.

D. Reliability Needs Resulting From DCPP’s Retirement

1. The Retirement of DCPP Will Not Affect Local Reliability Needs

DCPP is located in the Los Padres area of PG&E’s service territory, which includes the cities of: San Luis Obispo, Divide, Santa Maria, Mesa, Templeton, Paso Robles, and Atascadero. Under the CAISO’s 2015-2016 Independent System Operator Transmission Plan published on March 28, 2016, most of DCPP’s generation is exported to the north and east of the Los Padres division through 500 kilovolts (kV) bulk transmission lines, which includes a transmission connection between the Diablo Canyon and Midway substations. Los Padres customer demand is served through a network of 115 kV and 70 kV circuits and does not include DCPP as part of the local installed generation capacity as DCPP does not serve load within the

division. As such, DCPP is not needed for local reliability. Unlike San Onofre Nuclear Generating Station, DCPP is considered as a system resource only and is not needed to provide support for local reliability.

2. The Retirement of DCPP Is Not Projected to Require Incremental Capacity Resources Before 2030

Currently, DCPP provides some system capacity benefits to the CAISO, helping maintain a CAISO-wide system capacity supply pool that exceeds the 15 percent planning reserve margin (PRM) requirement on top of meeting the projected annual hourly-peak load. While the discussion in this chapter is largely focused on the need for energy from DCPP, it is important to consider the potential impacts that removing a 2,240 MW resource might have on maintaining reliability for the CAISO system, the potential need for incremental resources to maintain reliability, and uncertainties in the forecasted demand and supply quantities.

a. Projected CAISO System Supply and Demand

Removing 2,240 MW of system capacity from the CAISO system resource supply pool will have an impact on when incremental resources will be needed for RA. However, there is significant uncertainty as to whether incremental resources will be needed before 2030 to provide system RA. To determine when there would be a need for incremental resources to provide system RA, PG&E used the CPUC’s RPS calculator.

The analysis indicates that when DCPP is removed as a RA resource and is not replaced by an incremental system RA resource, it is possible that new resources will be needed beginning in 2030 to maintain the 15 percent PRM. However, there are a number of forecast uncertainties that could move the need year earlier or later than 2030.

Forecasting when the CAISO system will need incremental resources added to the supply portfolio to maintain system reliability is based on a number of different assumptions, each of which carries some uncertainty that could impact the incremental resource need year if changed. These assumptions include the addition of larger
out-of-state system capacity RPS resources, levels of energy storage, and potential CAISO market expansion.

While there are uncertainties for the timing of when incremental RA capacity may be needed, the Joint Proposal’s deliberate and orderly transition ensures that there will be ample time to address any incremental system capacity needs in the CPUC’s IRP proceeding.

E. Costs for Operating DCPP

Another factor contributing to the decision to retire DCPP at the end of the current 2024-2025 license period is the relatively high projected cost to bundled electric customers for DCPP energy output were DCPP to have its operating licenses renewed and DCPP continue to operate in years beyond its current operating licenses.

Extending DCPP’s generating life would require cost recovery for the existing book value of the facility as well as for future capital equipment purchases (CapEx), operations and maintenance (O&M) costs, Administrative and General expenses (A&G), and nuclear fuel expenditures. Table 2-6 shows the projected annual revenue requirement for 2025 and 2030. Table 2-6 also displays projected unit cost (that is, cost per megawatt-hour) for four different levels of useful generation output from DCPP: full output (16,300 GWh), labeled DCPP Total; the Reference Case (8,778 GWh in 2025 and 8,139 GWh in 2030); the High Load scenario (12,171 GWh in 2025 and 11,201 GWh in 2030); and the Low Load scenario (4,713 GWh in 2025 and 4,312 GWh in 2030).

The revenue requirements in Table 2-6 include projected post-2025 costs for OTC mitigation. The “projected market sales benefit” represents revenue
from market sales when bundled electric customers do not need DCPP energy
and is calculated as the sum across hours, of the hourly quantity of DCPP
energy not needed for bundled electric customers multiplied by the projected
wholesale market energy price in that hour. The “gross need unit cost”
represents the cost of DCPP generation to PG&E bundled electric customers if
there are no projected revenues from market sales. The “net need unit cost”
represents the cost of DCPP generation to PG&E bundled electric customers if
there are projected revenues from market sales; it is calculated as revenue
requirement minus “projected market sales benefit,” then divided by the
“needed generation.”

As discussed throughout this chapter, a substantial portion of the energy
produced by DCPP is anticipated to not be needed by PG&E’s bundled electric
customers. If DCPP were to continue operating beyond 2025, PG&E’s bundled
electric customers would pay costs for DCPP generation, even though much of
DCPP’s energy would not be needed to meet the electric load of PG&E’s
bundled electric customers.

F. Conclusion

This chapter presents an analysis describing why a substantial portion of
DCPP’s energy output likely will not be needed to serve PG&E’s bundled electric
customers beyond 2025. Clean energy policy preferences for EE, RPS, CHP,
and other resources have displaced the need for much of DCPP generation.
Increased customer choices for electric supply—including DA, CCA and DG—
are projected to further decrease PG&E’s bundled customer sales, further
eroding the need for all of the power generated by DCPP. Finally, as California
continues to move closer to a cleaner energy future, a large non-dispatchable
unit such as Diablo Canyon no longer “fits” the needed generation profile of the
changing energy landscape. The result is that a substantial portion of DCPP’s
energy output is projected to not be needed to serve PG&E’s bundled electric
customers beyond 2025.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

REPLACEMENT OF DIABLO CANYON POWER PLANT
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A. Introduction

Pacific Gas and Electric Company (PG&E) has joined with the Joint Parties to pursue a different kind of energy future, one that supports California’s goals for greenhouse gas (GHG) emissions reductions and energy policy. Together, the Joint Parties\(^1\) are committed to orderly replacement of Diablo Canyon Power Plant (DCPP or Diablo Canyon) with a portfolio of resources that have no GHG emissions, ensuring California continues on its path toward achieving its GHG emissions reduction goals for 2030 and beyond.

The Joint Proposal includes three tranches of procurement. The first tranche is an “early action” tranche of 2,000 gigawatt-hours (GWh) of energy efficiency (EE) programs or projects to be installed between 2019 and 2024. A competitive solicitation of unprecedented magnitude will be held. New utility EE programs may also be proposed. The result will be innovative additional EE programs to further reduce energy consumption and associated GHG emissions.

The second tranche consists of 2,000 GWh of GHG-free energy and/or EE, procured through a competitive, all-source solicitation resulting in contracts commencing energy deliveries or adding EE projects to the electric power system in the 2025-2030 time period. The third tranche consists of a commitment by PG&E to a 55 percent Renewables Portfolio Standard (RPS) target beginning in 2031—an unprecedented voluntary commitment by a major U.S. investor-owned utility.

A key element of this vision is that it recognizes the value of GHG-free nuclear power as an important bridge over the next eight to nine years. This transition period provides the necessary time to execute multi-year planning, procurement, and development processes associated with orderly replacement

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\(^1\) The Joint Parties include PG&E, Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, and the Alliance for Nuclear Responsibility (A4NR). Although A4NR is a signatory to the Joint Proposal, it is not taking any position on Section 2 of the Joint Proposal which addresses the replacement of Diablo Canyon.
of Diablo Canyon. PG&E’s Application represents the first step along the path that will emerge over the course of the next eight to nine years and involve the participation of multiple parties and government agencies.

PG&E plans to initiate the Tranche #1 solicitation for EE in 2018 and the Tranche #2 solicitation for GHG-free energy and/or EE in 2019. Delays in approval of the Joint Proposal could adversely impact the success of these procurement solicitations.

With the retirement of Diablo Canyon, PG&E’s service territory in northern and central California will lose approximately 18,000 GWh annually of GHG-free energy. The retirement of Diablo Canyon will have a significant impact in a service territory with an approximate system load of 80,000 GWh.

As described in Chapter 1 and Chapter 2, there are significant uncertainties about the scale and timing of additional GHG-free resources (such as RPS, EE and distributed generation (DG)) that will be developed by 2025 under existing California Public Utilities Commission (CPUC or Commission) policies. Additional uncertainty is associated with load departures to Community Choice Aggregation (CCA) and Direct Access (DA) and the resources to supply such load. Still more uncertainty is associated with any GHG emissions reduction policies for procurement which may be adopted to implement Senate Bill (SB) 350. Under these circumstances, load-serving entities (LSE) in northern and central California may understandably be hesitant to procure, now, additional GHG-free resources for year 2025 and beyond.

PG&E and the other Joint Parties believe that it would be short-sighted to wait for the various uncertainties to all be resolved. Waiting would likely undermine the State’s ability to achieve its GHG emissions reduction goals, especially the 2030 GHG emissions target of 40 percent below 1990 levels.

PG&E and the other Joint Parties believe that action is required today. Therefore, the Joint Parties propose to proceed with three tranches of procurement for GHG-free resources, benefitting PG&E’s entire service territory in northern and central California.

The Joint Parties recognize that the three tranches of resource procurement included in the Joint Proposal are not intended to procure everything that will be needed to ensure the orderly replacement of Diablo Canyon with GHG-free resources. The three procurement tranches included in the Joint Proposal are
a reasonable first step to a future such that when Diablo Canyon retires at the 
end of the current license period, there will be sufficient GHG-free resources 
available to provide GHG-free energy at an affordable cost, without jeopardizing 
electric power system reliability. The full solution will emerge over the 
2024-2045 period, in consultation with many parties and with the oversight of 
the Commission, the California Independent System Operator (CAISO), the 
California Air Resources Board, the California Energy Commission, the 
Governor and Legislature, and stakeholders. The Joint Parties envision that 
additional procurement, beyond that specified in the three procurement tranches 
of the Joint Proposal, will be needed on a systemwide basis to replace the 
output of Diablo Canyon and that this issue will primarily be addressed through 
the Commission’s Integrated Resource Planning (IRP) process, which was 
instituted in SB 350 and recently initiated in CPUC Rulemaking (R.) 16-02-007. 
In the IRP proceeding and other appropriate venues, the Joint Parties are 
committed to supporting policies that would result in replacing the output of 
Diablo Canyon with GHG-free resources.

This chapter addresses key considerations in support of the proposed 
three tranches of GHG-free procurement. This chapter discusses the following: 
(1) the extent to which the three tranches address the need for replacement of 
Diablo Canyon energy; (2) projected costs of the three tranches; and (3) GHG 
emissions impact associated with a future including the three tranches, relative 
to current GHG emissions levels. Specific implementation details for each 
procurement tranche are described in Chapters 4 (Tranche #1), 5 (Tranche #2), 
and 6 (Tranche #3).

The remainder of this chapter is organized as follows:

- Section B – Explains why the timing, resources, and quantity of procurement 
  proposed in each of the three tranches together constitute a reasonable and 
  appropriate first step for orderly replacement of Diablo Canyon;
- Section C – Addresses the anticipated costs of the three tranches 
  of procurement;
- Section D – Describes the GHG emissions impacts associated with the 
  three tranches; and
• Section E – Explains that additional procurement needed to address the retirement of Diablo Canyon should be considered in the Commission’s IRP proceeding (R.16-02-007).

B. The Three Tranches of Procurement Constitute a Reasonable and Appropriate First Step

The Joint Proposal describes three tranches of resource procurement. The three tranches are intended as a first step to orderly replacement of Diablo Canyon. Each tranche is associated with a particular time period.

• Tranche #1 is associated with years 2018-2024, during which time Diablo Canyon is planned to be operating.
• Tranche #2 is associated with years 2025-2030, immediately after Diablo Canyon is retired.
• Tranche #3 is associated with years 2031 to 2045, the remaining years Diablo Canyon would operate if its operating licenses were renewed.

1. Timing, Resources, and Quantity for Each Tranche

Resources procured in Tranche #1 are intended to commence deployment before Diablo Canyon retires. Only EE resources will be procured in Tranche #1. If GHG-free energy supply resources were included in Tranche #1, and therefore deployed when Diablo Canyon will still be operating, there is a good possibility that such additional supply-side resources would exacerbate projected overgeneration conditions on the CAISO grid, as discussed in Chapter 2. Restricting Tranche #1 to EE mitigates the possibility that Tranche #1 procurement exacerbates overgeneration conditions while Diablo Canyon continues to operate through the remainder of the current license period. The target amount to be procured in Tranche #1 is 2,000 GWh of EE. This is an unprecedented amount of EE to be procured at one time. PG&E believes it is feasible to obtain this additional 2,000 GWh of EE because of the following: PG&E’s and California’s 40-year historical experience in deploying EE; the potential for further EE; and market forces working in a competitive solicitation.

Tranche #2 addresses the transition period after retirement of Diablo Canyon. (Diablo Canyon Unit #1 is scheduled to retire in 2024, and Diablo Canyon Unit #2 is scheduled to retire during 2025.) The target
for Tranche #2 is 2,000 GWh. Resources procured in Tranche #2 will be either EE or supply resources that provide GHG-free energy. In Tranche #2, PG&E will procure GHG-free resources through a competitive solicitation process. The Tranche #2 commitment aims to provide certainty that GHG-free resources will be available to replace some of Diablo Canyon’s output during the years immediately following Diablo Canyon’s retirement. And as discussed in Chapter 2, some portion of the replacement of Diablo Canyon’s output will be met by increasing amounts of privately-owned DG and by increasing amounts of renewable resources procured by all LSEs complying with California’s RPS standards.2

Finally, Tranche #3 represents an ongoing commitment for years 2031 through 2045—the remaining years Diablo Canyon would be operating if its operating licenses were to be renewed. Tranche #3 is a commitment to an RPS target of 55 percent. Tranche #3 functions as backstop procurement, ensuring that PG&E exceeds the RPS target that exists today for 2031 and beyond. Because Tranche #3 is expressed in terms of an RPS target percentage, the quantity of Tranche #3 procurement is tied to the amount of electricity load from PG&E’s bundled electric customers. As the electricity load of PG&E’s bundled electric customers increases, the quantity of Tranche #3 procurement increases too.

2. The Three Tranches Are a Reasonable First Step in Orderly Replacement of Diablo Canyon With GHG-Free Resources

This section compares the amount of GHG-energy provided by the three tranches to various projected amounts of GHG-free energy needed to replace Diablo Canyon. The comparison suggests that the three tranches are a reasonable first step to orderly replacement of Diablo Canyon with GHG-free energy.

Table 3-1 displays the amount of GHG-free energy that is projected to be provided by the three tranches, with the projected Tranche #3 volume based on the forecasted utility bundled sales for the Reference Case in 2030. For purpose of the projections shown in Table 3-1, Tranche #2 is

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2 See Chapter 2 for a fuller discussion of DCPP displacement by increasing amounts of EE, DG, and RPS, and procurement by CCAs.
assumed to be filled by 1,000 GWh of EE and 1,000 GWh of RPS-eligible resources. (The 1,000 GWh of EE have a generation-equivalent energy amount of 1,099 GWh, due to line losses associated with generation and avoided by EE.) The three tranches are projected to result in 4,586 GWh of GHG-free generation-equivalent energy in 2030.

**TABLE 3-1**
GHG-FREE ENERGY PROVIDED BY THE THREE TRANCHES
REFERENCE CASE IN 2030

<table>
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<th>Line No.</th>
<th>Tranche</th>
<th>Energy (generation-equivalent GWh)</th>
</tr>
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<td>1</td>
<td>Tranche #1&lt;sup&gt;a&lt;/sup&gt;</td>
<td>2,198</td>
</tr>
<tr>
<td>2</td>
<td>Tranche #2&lt;sup&gt;a,b&lt;/sup&gt;</td>
<td>2,099</td>
</tr>
<tr>
<td>3</td>
<td>Tranche #3</td>
<td>289</td>
</tr>
<tr>
<td>5</td>
<td>Total Tranches</td>
<td>4,586</td>
</tr>
</tbody>
</table>

(a) For EE, generation-equivalent energy is greater than the EE volumes due to avoided line losses
(b) Composition of Tranche #2 is assumed to be 50% EE and 50% RPS-eligible resources

In Chapter 2, to assess the need for energy from Diablo Canyon to supply PG&E’s bundled electric customers, PG&E presented a Reference Case, and also two scenarios to illustrate the range of uncertainty. As shown in Table 2-3, the amount of GHG-free energy from Diablo Canyon projected to be needed to supply PG&E’s bundled electric customers under the Reference Case in 2030 is 8,139 GWh. Comparable volumes for the Low Load scenario and High Load Scenario are shown in Tables 2-4 and 2-5: 4,312 GWh and 11,201 GWh, respectively. And as stated in Chapter 2, for the Low Load scenario in 2030, annual net sales are projected to be 5,624 GWh—greater than the amount of “need” for DCPP generation to supply PG&E’s bundled electric customers. Finally, as stated in Chapter 2, the total annual output from Diablo Canyon—were its operating licenses renewed and Diablo Canyon operating in 2030—is projected to be 16,300 GWh.
Now, to compare the amount of energy provided by the three tranches to the need for GHG-free energy to replace Diablo Canyon. The 4,586 GWh from the three tranches is 28 percent of the 16,300 GWh of total annual output of from Diablo Canyon (were its operating licenses renewed and Diablo Canyon operating in 2030). For the Reference Case in 2030, the 4,586 GWh from the three tranches is 56 percent of the 8,139 GWh of GHG-free energy projected to be needed to replace the energy supplied by Diablo Canyon to PG&E’s bundled electric customers. For the High Load case in 2030, 4,586 GWh from the three tranches is 41 percent of the 11,201 GWh of GHG-free energy projected to be needed to replace Diablo Canyon for PG&E’s bundled electric customers. For the Low Load case in 2030, 4,586 GWh from the three tranches is greater than the total “need” of 4,312 GWh of GHG-free energy to replace Diablo Canyon for PG&E’s bundled electric customers.

The procurement that is proposed under Tranche #1 and Tranche #2 benefit all customers in PG&E’s service territory, not just PG&E’s bundled electric customers. For example, the EE programs resulting from Tranche #1 and Tranche #2 must be deployed in PG&E’s service territory. Some of these new EE projects and programs may reduce customer load (resulting in GHG-free generation-equivalent energy) served by an existing CCA or DA provider, or reduce the load of an existing PG&E bundled electric customer that later switches to take service from a CCA. The actual amount of GHG-free generation-equivalent energy to each LSE from Tranche #1 and Tranche #2 EE programs will not be known until years from now. The amount of Tranche #2 GHG-free energy associated with each LSE’s load will depend on: (1) the extent to which selected offers in Tranche #2 are EE or generation resources; (2) whether an LSE chooses to have PG&E procure GHG-free energy resources on behalf of the LSE’s customers or the LSE elects to self-provide its share of Tranche #2 generation resources; and (3) the extent to which existing PG&E bundled electric customers depart for other Energy Service Providers or CCAs.

PG&E and the other Joint Parties believe that the three tranches are sized appropriately, given all the planning uncertainties. Ultimately, the results of the Tranche #1 and Tranche #2 procurement will be reflected in
LSE integrated resource plans in the IRP proceeding at the Commission, and these plans will be the basis for evaluating how much additional procurement will be necessary to replace Diablo Canyon.

3. Reduced Curtailment Will Result in Additional GHG-Free Energy From RPS Resources

One of the factors mentioned in Chapter 2 is the potential impact of Diablo Canyon (were its operating licenses renewed and Diablo Canyon generating in 2025 and beyond) on system overgeneration and curtailment of renewable resources. After Diablo Canyon retires in 2025, some amount of renewable energy is anticipated to be generated, which would not have been generated, but would have been curtailed were Diablo Canyon operating. This amount of renewable energy associated with reduced curtailment should be considered when assessing how much GHG-free energy is needed to replace Diablo Canyon’s energy. This effect is recognized in the Joint Proposal, which identifies “reduced need for periodic curtailment of California’s increasingly abundant solar and wind resources” as a factor in the replacement of Diablo Canyon.3

The amount of reduced curtailment is uncertain. This is driven by a number of factors that include (but are not limited to) the available and allowable amount of exports from the CAISO’s existing California footprint to the rest of the western interconnection, CAISO load, future operating reserve requirements, regional generation requirements, and the technology mix of RPS-eligible resources. Given these factors, the estimated benefit from reduced curtailment is 850 GWh to 3,500 GWh of RPS-eligible generation.4

Here is a revised comparison of the amount of energy provided by the three tranches to the need for GHG-free energy to replace Diablo Canyon, now including the estimated amount of GHG-free energy resulting from reduced curtailment of RPS-eligible generation. The three tranches plus the reduced curtailment sum to an amount between 5,436 GWh and

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3 Joint Proposal, Preamble, Section D.
4 Estimate of 850 GWh is based on PG&E’s analysis using the RPS calculator v.6.2 FINAL and Default 2016 LTPP Assumptions. Estimate of 3,500 GWh is from the CAISO’s 2015-2016 ISO Transmission Plan.
8,086 GWh. This corresponds to between 33 percent and 50 percent of the 16,300 GWh of total annual output of from Diablo Canyon (were its operating licenses renewed and Diablo Canyon operating in 2030). For the Reference Case in 2030, the 5,436 GWh to 8,086 GWh corresponds to between 67 percent and 99 percent of the 8,139 GWh of GHG-free energy projected to be needed to replace the energy supplied by Diablo Canyon to PG&E’s bundled electric customers. For the High Load case in 2030, the 5,436 GWh to 8,086 GWh corresponds to between 49 percent and 72 percent of the 11,201 GWh of GHG-free energy projected to be needed to replace Diablo Canyon for PG&E’s bundled electric customers. For the Low Load case in 2030, even the low-end estimate of 5,436 GWh (from the three tranches plus reduced curtailment) is greater than 100 percent of the 4,312 GWh of “need” for GHG-free energy to replace Diablo Canyon for PG&E’s bundled electric customers; the high-end (3,500 GWh) of the range of potential reduced curtailment is, by itself, 81 percent of the bundled need.

These results further support the belief by PG&E and the other Joint Parties that the three tranches are sized appropriately, given all the planning uncertainties.

C. The Competitive Procurement Process Is Anticipated to Result in Lower Costs for GHG-Free Resources

To procure the three tranches, PG&E will use the procurement processes described in Chapters 4, 5, and 6. The actual costs of the three tranches of GHG-free procurement will not be known until the procurement is completed and the resources are delivering GHG-free energy or EE savings. However, it is possible to estimate an “upper bound” on costs for the three tranches by using a proxy value that is intended to be on the high side of cost.

The proxy value is $98/megawatt-hour (MWh) for 2025. This proxy value represents projected costs associated with renewable resources that might be contracted to come on-line in 2025. This proxy value is based on the following: PG&E’s projections of busbar levelized cost of energy (LCOE) for various RPS-eligible technologies; an energy mix of 80 percent wind (some located in-state and some located in Wyoming) and 20 percent utility-scale solar photovoltaic (PV) resources; extension through 2030 of the production tax credit for wind resources and continuation through 2030 of the investment tax credit for solar
PV resources; and estimated transmission costs associated with energy-only
Wyoming wind, taken from the Commission-approved RPS calculator.

The proxy value is $107/MWh for 2030. This proxy value represents
projected costs associated with renewable resources that might be contracted to
come on-line in 2030. The same projections and assumptions described for the
2025 proxy value hold for the 2030 proxy value.

To each of these two proxy values is added a projection of increased costs
associated with integrating the wind and solar PV resources into the bulk power
system. That projection is $5/MWh for 2025 and $6/MWh for 2030. The result
is $103/MWh in 2025 and $113/MWh in 2030. An “upper bound” estimate for
the three tranches of procurement is $113/MWh.

For comparison, Chapter 2 discusses the projected cost of operating
Diablo Canyon beyond 2025. As indicated by “net need unit cost” in Table 2-6,
the overall cost per MWh for Diablo Canyon is projected to be $149/MWh in
2030 for the Reference Case. Cost may be as low as $127/MWh (High Load
scenario) or as high as $219/MWh (Low Load scenario). If the entire output of
Diablo Canyon were needed by PG&E’s bundled electric customers, the
projected cost would be $107/MWh for each of the 16,300,000 MWh.

The “upper bound” cost for the three tranches of GHG-free replacement is
substantially less than the projected costs for Diablo Canyon in the Reference
Case and in each of the two scenarios. While the final costs of the three
tranches will not be known until the procurement is completed and the resources
are delivering GHG-free energy, PG&E anticipates it is likely that actual
procurement costs for the three tranches of GHG-free resources will be lower
than the “upper bound” cost estimate presented here.

D. Increases in Amounts of GHG-Free Resources and Decreases in
GHG Emissions

California’s electric power system is in the midst of a significant shift as
California is on its way toward achieving ambitious, leading GHG emissions
reduction goals. The Joint Proposal is designed to support these goals with
commitments for GHG-free resources to replace Diablo Canyon. The Joint
Proposal supports California’s policy goals of deep reductions in GHG emissions
and increases in renewables.
1. Outlook for GHG-Free Resources and GHG Emissions

PG&E’s portfolio of electric resources has historically been one of the lowest emitting in the United States. At least one-half of the electricity supplied to PG&E’s bundled electric customers has consistently been GHG-free. Renewable procurement has more than doubled since 2009. In 2014, RPS-eligible generation constituted 27 percent of all delivered energy to PG&E’s bundled electric customers and 56 percent of all delivered energy was GHG-free. As shown in Table 3-2, in 2014 the GHG emissions intensity of PG&E’s bundled electric portfolio was 0.20 metric tons per MWh of generation.

By 2030, after incorporating the three tranches of GHG-free resources in the Joint Proposal and replacing with GHG-free resources the quantity of energy projected to be needed from Diablo Canyon to supply the electricity load bundled electric customers, RPS-eligible generation is projected to constitute at least 55 percent of all delivered energy to PG&E’s bundled electric customers; 80 to 95 percent of all delivered energy is projected to be GHG-free. For the Reference Case, the GHG emissions intensity of PG&E’s bundled resource portfolio is projected to drop to 0.08 metric tons per MWh of generation.

### TABLE 3-2
CHARACTERISTICS OF PG&E’S BUNDLED ELECTRIC PORTFOLIO

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Year</th>
<th>Scenario</th>
<th>RPS Sales Percent</th>
<th>GHG-Free Generation Percent</th>
<th>GHG Emissions Intensity Metric Tons per MWh Generation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2014</td>
<td>Actual</td>
<td>27</td>
<td>56</td>
<td>0.20</td>
</tr>
<tr>
<td>2</td>
<td>2030</td>
<td>Reference Case</td>
<td>55</td>
<td>82</td>
<td>0.07</td>
</tr>
<tr>
<td>3</td>
<td>2030</td>
<td>Low Load Scenario</td>
<td>&gt;55</td>
<td>&gt;95</td>
<td>0.09</td>
</tr>
<tr>
<td>4</td>
<td>2030</td>
<td>High Load Scenario</td>
<td>55</td>
<td>80</td>
<td>0.08</td>
</tr>
</tbody>
</table>

These projections indicate that overall GHG emissions and intensity of GHG emissions, for PG&E’s bundled resource portfolio, will decline significantly from 2014 levels, even with the retirement of Diablo Canyon.
2. Support for California Policy Goals of GHG Reductions and Increased Renewables

The three tranches of GHG-free replacement of Diablo Canyon support greater amounts of EE, higher levels of RPS procurement, and reductions in GHG emissions. In addition, compared to Diablo Canyon, the three tranches are better aligned with California’s policy goals associated with renewables. As discussed Chapter 2, the California electric grid will require more flexible resources in the future to balance supply and demand while accommodating increasing amounts of generation from renewable energy resources.

Diablo Canyon operates as a “baseload” power plant. If its operating licenses were renewed and Diablo Canyon continued to operate as a baseload power plant, Diablo Canyon would contribute to overgeneration events leading to the curtailment of renewable resources. This would make it more difficult to efficiently and cost-effectively meet California’s policy target of 50 percent RPS. Retirement of Diablo Canyon on the timeframe agreed to in the Joint Proposal will allow for increased flexibility for the California electric power system, facilitating the integration of intermittent resources onto the electric grid.

E. Additional Procurement Needs, if Any, Should Be Reviewed in the IRP Proceeding

The Joint Parties recognize that the three tranches of resource procurement included in the Joint Proposal are not intended to procure everything that will be needed to ensure the orderly replacement of Diablo Canyon with GHG-free resources. The Joint Parties share a commitment to ensuring that any additional resources that are needed to replace Diablo Canyon are also GHG-free resources. The Joint Parties envision that additional procurement to replace Diablo Canyon, beyond that specified in the three procurement tranches of the Joint Proposal, will primarily be addressed through the CPUC’s IRP process.

California Public Utilities Code Section 454.52, which was enacted as a part of SB 350, requires the Commission to initiate an IRP process with the following objectives (among others): achieving California’s GHG emissions targets, minimizing impacts on the electric bills of customers, and ensuring system and local reliability. The Commission recently initiated R.16-02-007 to implement the
IRP requirements in SB 350. The IRP proceeding is the appropriate venue to consider the impacts of Diablo Canyon’s retirement on these objectives and what, if any, additional resources—in addition to the resources procured through the three tranches specified in the Joint Proposal—may be needed to meet reliability needs, renewable integration challenges, and GHG emissions targets.

In Section 2.5 of the Joint Proposal, the Joint Parties recognize that there will be significant challenges associated with renewable resource integration, and that these challenges must be reviewed and resolved through the planning process in the IRP and in collaboration with the CAISO. The Joint Parties strongly support the use of cost-effective GHG-free resources, some of which may include additional large pumped storage and utility-owned storage projects, to meet these renewable integration challenges. In addition, the Joint Parties support a change in existing policies that would allow allocation of resource costs for integration and storage to all users of the transmission system through a non-bypassable grid charge.

F. Conclusion

In the absence of orderly planning and up-front commitments to clean energy, the retirement of Diablo Canyon would likely result in increased use of natural-gas-fired, GHG-emitting generating resources. The Joint Proposal is intended to avoid such an outcome. The Joint Proposal uses a three-pronged approach to begin replacement of Diablo Canyon with GHG-free resources.

Load is reduced through procurement of EE in Tranche #1 and Tranche #2; clean supply-side resources are procured in Tranche #2; RPS-eligible resources are procured in Tranche #3. PG&E and the other Joint Parties believe that this three-pronged approach is a prudent, reasonable, and cost-effective first step to facilitate the orderly retirement of Diablo Canyon.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

TRANCHE #1 – ENERGY EFFICIENCY
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A. Introduction

Section 2.1 of the Joint Proposal describes the greenhouse-free (GHG) resources proposed to replace Diablo Canyon Power Plant (DCPP or Diablo Canyon) to help facilitate the achievement of broader statewide goals for deep reductions in GHG emissions, improved reliability, resource integration and other long-term, systemwide benefits. The Joint Parties propose that Pacific Gas and Electric Company (PG&E) be authorized to procure GHG-free replacement resources in three tranches. This chapter describes Tranche #1 of the Joint Proposal, under which PG&E will procure 2,000 gross gigawatt-hours (GWh) of energy efficiency (EE) resources. As stated in Section 2.2.1 of the Joint Proposal, the objective of Tranche #1 is to achieve “early action” energy savings prior to the retirement of Diablo Canyon in order to support flexibility in the timing of resources commitments in Tranche #2 and Tranche #3.

The Tranche #1 energy efficiency commitment is in addition to PG&E’s existing energy efficiency programs. PG&E requests funding authorization in this application to get started with Tranche #1 implementation quickly. Each winning contract or new utility program would be submitted for approval through a Tier 3 advice letter. PG&E proposes to use the existing electric Public Purpose Program (PPP) rate component and balancing account that is approved by the Commission. PG&E will return unspent funds, if any, in an annual electric true-up advice letter, consistent with current practice.

The remainder of this chapter is organized as follows:
1. Section B provides an overview of PG&E’s existing EE portfolio;
2. Section C describes the Tranche #1 target;
3. Section D describes the proposed process for achieving the Tranche #1 target;

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1 Joint Proposal, § 2.2 describes Tranche #1. A copy of the Joint Proposal is included as Attachment A to PG&E’s Application.
4. Section E describes the evaluation, measurement and verification (EM&V) for Tranche #1 EE;
5. Section F provides the requested budget for Tranche #1 procurement;
6. Section G describes PG&E’s proposals for cost recovery, carryover, carryback, and unspent funds;
7. Section H includes PG&E request for a shareholder incentive for EE savings; and
8. Section I addresses PG&E's reporting on progress towards meeting the Tranche #1 target.

B. Energy Efficiency Portfolio Overview

Since the 1970s, PG&E has worked closely with government, nonprofit and private sector partners to design and implement EE programs and policies that allow Californians to do more with less energy to save money and help protect the environment. California has consistently placed EE first in the loading order since the Energy Action Plan of 2003, which was adopted by the California Public Utilities Commission (CPUC or Commission) and the California Energy Commission (CEC). EE continues to be a cornerstone of California’s energy strategy. According to a report by the Natural Resources Defense Council, EE programs have helped California avoid the construction of 10 large power plants and saved 30,000 GWh in electricity savings since 2003. Recent legislation has also affirmed that EE will continue to be an important part of California’s energy policy. Senate Bill 350 created a requirement to establish targets for a cumulative doubling of EE by 2030. Assembly Bill 802 endorses EE programs to bring existing buildings up to current California efficiency codes and standards and to reduce energy use through operational and behavioral improvement, and furthers development of building benchmarking. EE also

2 The “Energy Action Plan” can be found at: http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF.
continues to be instrumental in reducing electricity consumption growth statewide.\(^6\)

PG&E administers an EE portfolio which includes gas and electric efficiency programs with an authorized annual budget of $430.1 million.\(^7\) The EE portfolio annual budget is authorized to continue through year 2025, unless the CPUC issues a superseding decision.\(^8\) PG&E also has a separate gas and electric efficiency program for low-income customers called the Energy Savings Assistance (ESA) Program with an authorized annual budget of $162 million.\(^9\)

The Commission established EE goals for PG&E and the other investor-owned utilities (IOUs) in Decision (D.) 15-10-028 for the years 2016-2024. These goals were incorporated in the CEC’s estimates of additional achievable EE included in the 2015 Integrated Energy Policy Report. PG&E’s current goals are shown in Table 4-1 below, divided between savings from programs and from Codes and Standards. The goals are specified in capacity savings (Megawatts (MW)), energy savings (gigawatt hours (GWh)), and natural gas savings (Millions of Therms (MMth)).

### TABLE 4-1

APPROVED ENERGY EFFICIENCY GOALS FOR 2016-2024

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Year</th>
<th>GWh Programs</th>
<th>C&amp;S Programs</th>
<th>MW Programs</th>
<th>C&amp;S Programs</th>
<th>MMth Programs</th>
<th>C&amp;S Programs</th>
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<tr>
<td>1</td>
<td>2016</td>
<td>625</td>
<td>611</td>
<td>85</td>
<td>141</td>
<td>12.9</td>
<td>5.5</td>
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<tr>
<td>2</td>
<td>2017</td>
<td>637</td>
<td>506</td>
<td>87</td>
<td>105</td>
<td>12.9</td>
<td>5.7</td>
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<td>3</td>
<td>2018</td>
<td>507</td>
<td>408</td>
<td>69</td>
<td>103</td>
<td>14.8</td>
<td>6.1</td>
</tr>
<tr>
<td>4</td>
<td>2019</td>
<td>511</td>
<td>401</td>
<td>70</td>
<td>103</td>
<td>14.9</td>
<td>6.2</td>
</tr>
<tr>
<td>5</td>
<td>2020</td>
<td>519</td>
<td>381</td>
<td>71</td>
<td>101</td>
<td>15.5</td>
<td>6.2</td>
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<td>6</td>
<td>2021</td>
<td>524</td>
<td>326</td>
<td>74</td>
<td>94</td>
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<td>5.9</td>
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<td>2022</td>
<td>541</td>
<td>295</td>
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<td>90</td>
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<td>5.7</td>
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<td>8</td>
<td>2023</td>
<td>558</td>
<td>254</td>
<td>86</td>
<td>84</td>
<td>17.5</td>
<td>5.6</td>
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<td>9</td>
<td>2024</td>
<td>581</td>
<td>240</td>
<td>92</td>
<td>82</td>
<td>18.6</td>
<td>5.3</td>
</tr>
</tbody>
</table>

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\(^7\) D.15-01-023, p. 1. PG&E’s budget includes funding for the Bay Area Regional Energy Network, Marin Clean Energy, and the CPUC’s agreements with contractors for EM&V.

\(^8\) D.14-10-046, Ordering Paragraph 21.

\(^9\) D.12-08-044 established the ESA budget which was subsequently extended to 2015 in D.14-08-030, and subsequently extended through 2016 in D.15-12-024 and D.16-06-018.
The Commission periodically reviews the EE potential in California and revises the IOUs’ EE goals to reflect updated information. The Commission has indicated that it will update the IOUs’ EE goals in the first half of 2017 for 2018 and beyond.\(^{10}\)

**C. Tranche #1 Energy Efficiency Target**

PG&E will procure EE to mitigate the impact of the closure of DCPP on the electric grid and the state’s GHG profile prior to the retirement of DCPP. Consistent with the Energy Action Plan Loading Order, PG&E proposes to first reduce needs for electricity with cost-effective EE resources to reduce electricity consumption and the need for replacement generation.

In Tranche #1, PG&E will obtain 2,000 gross GWh from EE installed\(^ {11}\) in PG&E’s service area by January 1, 2025. Achievement of the Tranche #1 2,000 gross GWh target will be measured by summing the first year gross GWh savings from EE installed in 2018-2024.\(^ {12}\)

PG&E will run and administer a Request for Offers (RFO) as the primary method of procuring the Tranche #1 EE resources. In addition, PG&E may propose, through one or more advice letters, new utility EE programs for the purpose of meeting the Tranche #1 target.

PG&E will hold successive RFOs and/or propose new utility programs until the 2,000 gross GWh target has been obtained. PG&E may also seek CPUC approval for cost-effective EE programs or projects in excess of the 2,000 gross GWh target.

**D. Procurement Process**

This section describes the processes and eligibility rules for PG&E’s Tranche #1 RFO and the process for PG&E to propose new utility EE programs.

\(^{10}\) See D.15-10-028, Appendix 6, “Gantt Chart for Rolling Portfolio Cycle Review Process."

\(^{11}\) The term “installed” is used throughout in reference to EE to indicate the year in which an EE intervention is implemented. “Installed” EE may include replacement or installation of equipment, implementation of operational changes, commencement of behavioral changes, or other activities that reduce energy consumption.

\(^{12}\) First-year savings is defined as the savings in the first full year after the EE project is installed. This is distinct from lifecycle savings (the total savings expected over the life of the project) and cumulative savings (the total savings achieved from installation to a specified future date).
1. **RFO Process**

   PG&E will issue the Tranche #1 RFO on or before June 1, 2018. PG&E will issue successive RFOs and/or propose new utility programs, if needed to fulfill the 2,000 GWh gross savings target. In order to be eligible to compete in the RFOs, the EE must be installed in the 2018-2024 timeframe and no later than January 1, 2025. Some eligibility requirements are specified in this section; additional eligibility requirements may be specified in the solicitation protocol or other appropriate documents when the Tranche #1 RFO is issued.

   A) **Eligibility**: The EE programs or projects must be installed at customer locations in PG&E’s service area where PG&E delivers electricity for which the customer pays PPP charges. Consistent with the rules established by the CPUC for the IOUs’ EE programs, EE savings at a specific customer location cannot exceed the kilowatt-hour (kWh) typically billed to that customer over the course of a year, except if the EE pertains to a new construction project.

   B) **Cost Effectiveness**: For the purposes of bid evaluation, PG&E will assess project or program cost-effectiveness using the Program Administrator Cost (PAC) test in the CPUC Standard Practice Manual. Offers will not be accepted unless they are below a Renewables Portfolio Standard (RPS) eligible resource cost, “RPS cost cap.” Currently, the “RPS Equivalent” cost cap is $98 per MWh in 2025 dollars or $82 per MWh in 2016 dollars, as detailed in Chapter 3. PG&E may update the cost cap prior to the issuance of the RFO. The RPS cost cap ensures that PG&E will not pay more for EE resources than it would pay for RPS resources. The PAC test compares the avoided cost benefits that would result from the proposal to PG&E’s cost (bid price).

   C) **Project or Program Description**: Participants will be required to provide a description of their proposed EE program or projects, which may include the following:

   - Customer(s) or customer segments to be addressed;
   - Geographic location of focus;
   - EE offering(s) – type of audit, technology, operational, or behavioral interventions;
• Program details – description of the approach to identifying customers, contractual or payment arrangement with customers, and other relevant information to explain operation of the program or projects;
• Gross and net GWh to be installed in each year 2018-2024;
• Savings persistence information (detailed in E below);
• Program differentiation information (detailed in F below);
• Evaluation, Measurement and Verification (EM&V) Plan (detailed in G below); and
• Additional requirements may be specified or modified at the time the RFO is issued.

D) Savings Persistence: Participants will be required to provide information as part of their bid package to show that projects are expected to achieve energy savings for at least five years. Offers will be evaluated based on the strength of their showing that EE savings are anticipated to persist for a period of at least five years beyond installation.

E) Differentiation: PG&E plans to require participants to provide information showing how their proposed EE programs or projects would be differentiated from the resources obtained in PG&E’s existing EE portfolio. PG&E may evaluate offers based on the strength of their showing that the proposal:
• Utilizes innovative technologies, for example, technologies that are not currently in PG&E’s EE portfolio;
• Utilizes innovative approaches, for example, approaches that target customer groups not currently targeted in PG&E’s EE programs; and
• Offers greater value or lower cost than PG&E’s EE programs.

PG&E anticipates that there may be multiple offers that target the same location or customer segment. In order to prevent oversubscription of available savings potential, PG&E will group offers by location and segment, and select the highest ranking offers in a location/segment until the potential for that location/segment is saturated.
F) **EM&V Plan:** PG&E plans to require participants to include in their offers an EM&V plan specific and relevant to their program or projects. See Section E for additional EM&V details.

G) **Monthly report:** Winning participants will sign a contract that may include a requirement to provide a monthly report to PG&E that will include a description of active EE projects at customer sites, information to identify each customer site, the type of EE measures and activities at each customer site, anticipated annual savings at each customer site, and verified annual savings for those projects that have completed EM&V activities.

H) **Procurement Review Group (PRG):** PG&E plans to form a PRG to review and provide feedback on the RFO process and selection of offers for Tranche #1. PRG members would be required to have relevant EE experience and be willing to sign non-disclosure agreements and acknowledge that they would be ineligible to participate as a participant or consultant to a participant in RFOs for Tranches #1 or #2.

I) **Independent Evaluator (IE):** PG&E may retain an IE to be actively engaged throughout the RFO process to assist in ensuring a fair and consistent process.

J) **Advice Letter for Contract Approval:** Following the selection of offers, PG&E plans to file a Tier 3 advice letter describing the RFO process and submitting selected contracts for Commission approval.

K) **Independent Verification Consultant:** PG&E plans to hire an independent verification consultant to ensure energy savings is in compliance with agreed upon terms in the contracts.

2. **New Utility EE Programs**

   PG&E may elect to launch new EE programs for the purposes of meeting the 2,000 gross GWh Tranche #1 target. PG&E intends that these new utility EE programs would be evaluated in a manner consistent with the criteria specified for the RFO. For example, PG&E would use a PAC test to evaluate cost-effectiveness (consistent with the approach in the RFO), would describe savings persistence, and would discuss program differentiation.
PG&E would file a Tier 3 advice letter to request authorization of a new program to be implemented as part of Tranche #1, and would include program description details typically required when PG&E seeks to launch new programs by advice letter within the existing EE portfolio. PG&E would hire an independent verification consultant to verify energy savings for the purposes of meeting the 2,000 gross GWh target.

E. Evaluation, Measurement, and Verification

Participants, or PG&E if proposing a new utility program, would provide EM&V plans that are relevant and appropriate to the proposed programs. Where feasible and appropriate, PG&E will encourage estimation of savings based on reduced consumption of electricity relative to existing consumption utilizing normalized meter-based savings estimates. PG&E recognizes the importance of using the appropriate measurement methodology, given the nature of the projects undertaken, and notes that the EM&V plans should be specific to the offers or proposed utility programs. For example, a pay for performance program addressing a small number of large commercial facilities may require different savings estimation and evaluation techniques than a direct install program oriented at replacing specific measures.

Sources for development of an EM&V plan may include: impact evaluation studies, engineering estimates, before-and-after operational data using advanced metering infrastructure and/or sub-metering, follow up inspections and/or engineering assessments, and/or deemed savings.

Participants, or PG&E if proposing a new utility program, would specify in the EM&V plan a specification of how first-year annual gross GWh EE savings will be measured and verified within a maximum of two years post-installation in order that PG&E can document progress toward achievement of the 2,000 gross GWh Tranche #1 target in a timely fashion.

F. Tranche #1 EE Program Budget Request

PG&E requests an additional $1,293.8 million, on a nominal basis, as provided in Table 4-2 below, for the additional EE necessary to meet the Tranche #1 target for the years 2017-2024, subject to return of any unspent funds if this amount exceeds the amount required. The associated annual revenue requirements are presented in Chapter 10. This estimate includes
administrative, direct implementation non-incentive, incentive, EM&V, and marketing costs. It also includes PG&E labor required to administer the RFO(s), select winning offers, design and offer any new utility programs, as well as incentive or performance payments to winning participants or customers. It does not include expenses incurred in 2016.

PG&E’s budget request is calculated based on the RPS cost cap of $0.098 per kWh (levelized, 2025 dollars) or $0.082 per kWh (levelized, 2016 dollars), as outlined in Chapter 3, consistent with the project cost cap in Section D.1.B above. The RPS equivalent cost is an appropriate benchmark for budget development given the goal of procuring early action EE at or below RPS costs. PG&E uses its current weighted average cost of capital of 7 percent and a 10-year average measure life (PG&E’s best estimate of the duration of these resources) and then uses a present value calculation to convert this figure to a cost estimate of the first year savings. PG&E then multiplied the 2,000 GWh gross first year savings target by this figure to produce a budget estimate that is then spread over the course of the Tranche #1 period. Funding is requested in this application before the competitive solicitation to minimize the time necessary to seek approval of the final contracts and avoid the delays inherent in litigating a rate application following an RFO.

Current program costs and savings were also reviewed to confirm that PG&E could reasonably expect to obtain 2,000 GWh of gross savings, measured on a PAC basis, at or below the Tranche #2 “RPS equivalent” cost.

The following table outlines PG&E’s budget request by year for Tranche #1:

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<td>$2.0</td>
<td>$2.0</td>
<td>$204.5</td>
<td>$208.6</td>
<td>$212.7</td>
<td>$217.0</td>
<td>$221.3</td>
<td>$225.7</td>
<td>$1,293.8</td>
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PG&E’s budget request includes modest funding for administrative activities associated with the RFO and potential utility program designs in 2017-2018, with the bulk of the spending in 2019-2024. For the sake of simplicity, PG&E’s revenue requirement request in Chapter 10 specifies a levelized annual revenue requirement to be collected starting in 2019. PG&E will spend a small portion of
the authorized budget in years 2017-2018, prior to collection of the associated
revenue requirements in rates. PG&E will create separate order numbers to
track the costs associated with this Tranche #1 effort separately from other
EE programs.

G. Cost Recovery, Carryover, Carryback, and Unspent Funds

PG&E seeks approval in this Application, as discussed in further detail in
Chapter 10, to recover the budget specified above as an additional revenue
requirement to be collected through the PPP rate component.

PG&E does not know, at this time, how quickly EE programs and projects
will be implemented during the Tranche #1 2019-2024 installation period.
Therefore, PG&E requests authorization for carryover and carryback of the
authorized funds for Tranche #1 across the entire 2017-2024 time period.

Carryover is defined as spending budget authorized in an earlier year in a later
time period. Carryback is defined as spending budget in an earlier year than the
authorized year. Budget authorized in the early years may not be spent until
later, if more time is required for projects to be planned and installed.
Conversely, PG&E will encourage winning participants to implement projects
more quickly to accelerate the benefits to California and PG&E customers.

Hence, PG&E requests permission to spend funds earlier than initially budgeted,
by “borrowing,” or carrying back, budget authorized for later years.

PG&E may underspend on the program relative to the total authorized
budget depending on the prices obtained in the RFO and the progress of
installation of EE projects. In this case, PG&E would return to customers any
unspent funds. PG&E’s cost recovery proposal is provided in greater detail in
Chapter 10.

H. Shareholder Incentive

The Commission approved an energy efficiency shareholder incentive
mechanism in D.13-09-023, entitled the Efficiency Savings and Performance
Incentive (ESPI), to reward the investor-owned utilities for energy efficiency
savings achieved in 2013 and beyond. The mechanism provides a shareholder
incentive for energy savings resulting from the programs in PG&E’s energy
efficiency portfolio, including savings arising from third-party contracts awarded
by PG&E. Pursuant to the process amended by the Commission in
D.15-10-028, PG&E and the other IOUs file annual advice letters by September 1 of each year requesting an incentive award to be included in electric and gas rate adjustments effective January 1. PG&E requests authorization to include savings achieved through the RFO or new utility programs offered to meet the Tranche #1 and Tranche #2 EE commitments through the ESPI mechanism, or such other shareholder incentive mechanism in place for the IOUs’ EE programs when the Tranche #1 or Tranche #2 EE measures are installed.

I. Reporting

PG&E will annually report to the CPUC its progress towards meeting the 2,000 gross GWh target.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

TRANCHE #2 – ALL SOURCE GHG FREE ENERGY

REQUEST FOR OFFERS
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A. Introduction (Strauss)

The Joint Proposal includes three tranches of procurement intended to be a reasonable first step toward replacing the Diablo Canyon Power Plant (Diablo Canyon or DCPP). Section 2.1 of the Joint Proposal describes the objective of Tranche #2 as:

- procure 2,000 GWH of GHG-free energy resources through an all-source solicitation that will commence energy deliveries or add energy efficiency programs or projects to the system in the 2025 to 2030 time period.

This chapter describes the implementation plan for Tranche #2 of the Joint Proposal. Specifically, this chapter describes the types of resources included in Tranche #2 and specifies the proposed compliance obligation of Pacific Gas and Electric Company (PG&E) associated with the Tranche #2 target of 2,000 gigawatt-hours (GWh) per year. This chapter also explains the Request for Offers (RFO) process that PG&E proposes to use to achieve the Tranche #2 commitment. Finally, this chapter explains the cost-recovery proposal for the Tranche #2 procurement, including a provision to recover net costs associated with the Clean Energy Charge.

The Joint Proposal states that this Application is to specify the RFO framework for Tranche #2, including the RFO process, least-cost best-fit (LCBF) evaluation criteria, and the process to obtain approval from the California Public Utilities Commission (CPUC or Commission). This chapter meets this requirement.

The remainder of this chapter is organized as follows:

- Section B – describes the Tranche #2 commitment. Eligible resources are delineated and PG&E’s proposed compliance obligation is specified.

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1 Tranche #2 is specified in the Joint Proposal, §2.3. A copy of the Joint Proposal is included as Attachment A to PG&E’s Application.

2 Joint Proposal, § 2.3.1.
• Section C – describes the process PG&E intends to use to conduct the Tranche #2 RFO.
• Section D – describes the methodology intended to be used to evaluate offers submitted in the Tranche #2 RFO.
• Section E – describes the proposed process for Commission approval of executed contracts resulting from the Tranche #2 RFO.
• Section F – describes the proposal for cost recovery, cost allocation, self-provision option, and reporting.
• Section G – requests a shareholder incentive for Energy Efficiency (EE).
• Section H – requests the Commission to approve the provisions and requirements of Tranche #2 in the Joint Proposal as indicated in this testimony.

B. Tranche #2 Commitment (Strauss)

The Joint Proposal specifies that for Tranche #2 PG&E will issue an all-source RFO for 2,000 GWh per year of greenhouse gas (GHG)-free energy resources or EE. The Tranche #2 RFO is to be issued no later than June 1, 2020. This section describes the resources eligible for procurement in Tranche #2 and specifies PG&E’s proposed compliance obligation to fulfill the Tranche #2 target.

Chapter 4 contains details regarding PG&E’s plan to achieve EE for the Tranche #1 target. Unless otherwise specified, it is PG&E’s intent that the information and details provided in Chapter 4 regarding EE sources are applicable to the EE resources that would be obtained to achieve either the Tranche #1 or Tranche #2 targets.

1. Eligible Resources

To participate in the Tranche #2 RFO, eligible resources must be a source of GHG-free energy or result in energy savings. Specifically, Tranche #2 will be limited to: (1) EE resources; (2) generation resources that do not emit GHGs (carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and nitrogen trifluoride) while generating electricity; or (3) generation resources that are eligible for the Renewables Portfolio Standard (RPS) under California’s RPS

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3 Id.
statutes at the time when a Tranche #2 RFO is issued. An additional condition is that existing out-of-state nuclear generation resources are not eligible for Tranche #2 procurement. An unbundled Renewable Energy Credit (REC) is not a source of energy and therefore is not eligible for Tranche #2 procurement. Energy storage, by itself, is not a source of energy and therefore is not eligible for Tranche #2 procurement unless combined with another resource providing GHG-free energy or energy savings. Regarding geographic sourcing, to be eligible for Tranche #2 procurement a generation resource must have the ability to provide GHG-free energy to customers in PG&E’s service territory.

2. PG&E’s Proposed Compliance Obligation

The Joint Proposal specifies a Tranche #2 target of 2,000 GWh per year. PG&E proposes to implement this target by counting, for each executed Tranche #2 contract that is approved by the Commission and becomes effective, the annual amount of energy specified in the contract averaged over the first five years (60 consecutive months) of the contract. For EE resources obtained in Tranche #2, the sum of the first year gross GWh savings will count toward the 2,000 GWh per year target.

For example, suppose there are three Tranche #2 contracts that are executed, approved by the Commission, and become effective. The three contracts are as follows: an EE project providing 500 GWh of first-year gross GWh savings, a 20-year contract for an RPS-eligible resource coming on-line in 2026 and providing an average of 1,000 GWh per year over the first five years of the contract, and a 25-year contract for an RPS-eligible resource coming on-line in 2027 and providing an average of 500 GWh per year over the first five years of the contract. Together, these three contracts satisfy the compliance obligation to meet the Tranche #2 target of 2,000 GWh per year.

What counts toward the Tranche #2 target for energy resources is the contractually-specified amount of energy, averaged over the first five years (60 consecutive months) of the contract. Actual energy deliveries coming from the contracted resource are not considered when determining whether PG&E has met the Tranche #2 target of 2,000 GWh per year.
If the Tranche #2 RFO yields executed, Commission-approved contracts (and EE resources) that become effective but sum to less than 2,000 GWh, as counted using the methodology described above, PG&E will hold successive RFOs until the 2,000 GWh target is met.4

C. Tranche #2 RFO Process (Strauss)

This section describes the process PG&E intends to use in conducting the Tranche #2 RFO. Some eligibility requirements are specified in this section; additional eligibility requirements may be specified in the solicitation protocol or other appropriate documents when the Tranche #2 RFO is issued.

In Sections C and D of this chapter, PG&E provides an overview of the RFO process and evaluation methodology that it intends to use for the Tranche #2 RFO. The Tranche #2 RFO is anticipated to be issued in 2019. Elements of the RFO process and evaluation methodology may change between now and then, as a result of changes in legal requirements, Commission decisions, changes in electricity resource technology, or market conditions. Consistent with Commission requirements, PG&E will work with the Procurement Review Group (PRG), Cost Allocation Mechanism Group, Independent Evaluator (IE), and the Commission’s Energy Division to draft and finalize RFO bid documents, protocols, and evaluation criteria before the Tranche #2 RFO is issued.5

To ensure a robust response and participation in the Tranche #2 RFO, PG&E plans to: (1) develop a website where information regarding the Tranche #2 RFO will be accessible to the public; (2) provide market e-mail notifications through its distribution list of over 2,000 recipients; and (3) conduct information sessions through forums such as a webinar to provide an overview of the Tranche #2 RFO.

Consistent with its practice in other solicitations, PG&E plans to engage the PRG, Cost Allocation Mechanism Group, and IE throughout the Tranche #2 RFO. PG&E anticipates providing the PRG and Cost Allocation Mechanism Group with the following: an overview of the solicitation, a description of the

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4 See Joint Proposal, § 2.3.2. For purposes of this testimony, the term “Tranche #2 RFO” refers to all RFOs that are conducted to meet the Tranche #2 target of 2,000 GWh per year.

5 See D.07-12-052, p. 150 (providing for consultation with PRG, IE and Energy Division in advance of issuance of an RFO).
evaluation methodology and evaluation process, a proposed shortlist, and any offers PG&E proposes to be executed. An IE will be actively engaged throughout the RFO process to ensure a fair and consistent process.

Eligible offers providing energy deliveries must be from GHG-free energy resources, as described in Section B.1 above. Eligible offers must be for a minimum of five years and commence energy deliveries during the period 2025-2030. Eligible offers must contribute to the 2,000 GWh per year target during this period, as specified in Section B.2 above.

EE proposals must be for projects installed in PG&E’s service territory with a reasonable demonstration that the savings will persist for five or more years. At PG&E’s discretion, EE projects may commence prior to 2025.

While the minimum contract term for eligible energy delivery offers is five years, PG&E may receive offers for longer-term contracts (e.g., 10 years or greater). Such offers may be more competitive or meet another identified need. In those cases, PG&E may execute energy supply contracts with terms exceeding five years.

PG&E intends to require EE offers to meet the relevant eligibility requirements for the Tranche #1 EE resources described in Chapter 4. For EE, PG&E may receive offers for energy savings estimated to persist longer than five years. For EE, the contract is anticipated to cover the period of installation of the projects in the offer as well as the evaluation period, but is not anticipated to cover the entire expected useful life of the EE project.

In addition to the eligibility requirements specified above, as part of the Tranche #2 RFO, PG&E intends to require offers to describe how the project will meet the proposed energy deliveries or savings, and include detailed project information, such as size, location, site control, permitting, and interconnection. Throughout the RFO process and contract term for any executed and approved contracts, PG&E may require participants to post performance assurances, shortlist deposits, or project development or delivery security deposits. EE proposals may be required to include in their proposals an evaluation, measurement and verification (EM&V) plan for assessing performance that is appropriate to the proposed projects.
D. Evaluation Methodology (Strauss)

As part of the Tranche #2 RFO, PG&E will request detailed information for all offers that will include project descriptions (e.g., size, location(s), technology, permitting status, single-line diagrams, EE savings persistence information, EE project differentiation information, EE EM&V Plans, interconnection), developer experience and qualifications, proposed contract costs, and site control. The information provided as part of the offer submission may be utilized during the evaluation process. This evaluation will identify projects with which PG&E may enter into negotiations, that is, “Shortlisted Projects.”

PG&E’s evaluation of offers in the Tranche #2 RFO will apply the principles of PG&E’s LCBF methodology, using quantitative and qualitative criteria based on information contained in the offers. PG&E’s LCBF methodology continues to develop and evolve, in accord with changing Commission rules and guidelines, lessons gleaned from PG&E’s own experiences and best practices elsewhere, and feedback from stakeholders. PG&E’s LCBF methodology in 2019, when the Tranche #2 RFO is intended to be issued, is therefore likely to differ from PG&E’s LCBF methodology today. Accordingly, the evaluation criteria to be used in the Tranche #2 RFO may include, but are not limited to or determined by, the following:

1) **Net Energy Value**: The market value of the energy deliveries or savings for each offer based on time series obtained for the offer over its contract term or, for EE projects, its expected useful life. Any capacity used to meet reliability needs for the transmission or distribution system will be reserved first, to avoid double counting benefits. Since EE benefits are derived from load reduction, the energy benefits may include avoided line losses.

2) **Ancillary Services Value**: The ability to schedule and receive California Independent System Operator (CAISO) market revenues for Ancillary Services (A/S) in accordance with CAISO tariff requirements. The incremental benefit of A/S capability will be captured. The time series for A/S revenues will be jointly determined with energy time series to avoid double counting the value.

   A/S revenues include revenues for providing Regulation Up (RegUp), Regulation Down (RegDn), and Spinning Reserves (Spin).

   Pay-for-Performance revenues associated with providing RegUp and RegDn
may be included. The A/S value of each offer will be assessed based on the
time series of A/S awards obtained for the offer over its delivery term using
the projected market prices for RegUp, RegDn, Spin, and potentially
Pay-for-Performance.6

3) **Capacity Value:** The methodology for valuing Resource Adequacy (RA)
capacity offered in the Tranche #2 RFO is highly dependent on evolving
market products, rules, and structures, as well as the specific attributes of
a particular offer. Evaluation of Capacity Value in the Tranche #2 RFO will
reflect the relevant rules and requirements in place at the time the
Tranche #2 RFO is issued.

4) **Fixed Cost:** Calculated as the sum of projected monthly fixed payments.
Projected monthly fixed payments will be based on the information specified
in an offer. Each offer will also be assigned an annual fixed overhead cost
(independent of the size of the project) representing administrative costs.
For an offer for a Utility-Owned Generation resource, PG&E’s Cost of
Service Model will be used to determine the revenue requirement (mainly
depreciation, return, taxes, and fixed operations and maintenance (O&M))
based on initial capital costs and fixed O&M of the facility. For EE
resources, PG&E will include the projected payments and terms specified in
the offer.

5) **Variable Cost:** Calculated as the sum of variable payments, which will be
based on the variable operations and maintenance (VOM) price multiplied
by the discharge time series obtained for the Offer. Variable cost will also
include the cost of fuel and/or start-up costs, if applicable. The contract
VOM price will affect the energy time series, all other things being equal,
a lower VOM would result in more energy deliveries both in PG&E’s
Evaluation and in actual operation. For EE resources, PG&E will include the
projected payments and terms specified in the offer.

6) **Transmission Network Upgrade Costs:** PG&E may use results from
interconnection studies required of participants. Network upgrades include
all facilities necessary to: (1) reinforce the transmission system after the

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6 PG&E will take into account the limited size of regulation and spin markets when evaluating for A/S values for all offers.
point where a project’s electricity first interconnects with and enters the subject utility’s transmission grid; and (2) transmit or deliver the full amount of generation to or from the project. Transmission cost adders reflect the cost of potential network upgrades borne by customers. Any transmission cost adders attributed to the project will also be considered in ranking offers. Participants will include in their bid price the estimated cost of all the facilities needed to interconnect the project to the first point of interconnection with the transmission system grid. Because these costs are in the bid price and not to be refunded by the customers, they are not included in the calculation of the transmission adder.

7) **Project Viability:** PG&E may review the likelihood that any resource(s) associated with an offer can satisfy the requirements. This assessment may be based on a review of the status and plans for key project activities (e.g., financing, site access, permitting, engineering, procurement, construction, interconnection, start-up and testing, operations, fuel supply, water supply, wastewater discharge, labor agreements, etc.).

The project viability analysis may include an evaluation of the environmental characteristics and environmental impacts of a project. The evaluation may consider environmental permitting (e.g., Participants’ identification of required permits, schedule for acquisition of all necessary permits, and a reasonable demonstration of its ability to comply with all applicable environmental laws and regulations through the contract term) and environmental impacts to air quality, water (including water usage and discharge water quality and quantity), and solid and hazardous waste generation and disposal. The evaluation may also consider environmental leadership, which may include, but is not limited to, community relations, proximity to other emitting and discharging facilities, and the use of (or plans to upgrade to) advanced environmental technology to reduce impacts. The review of an offer may include the technical reliability of an offer to assess how the project’s plant configuration, operating characteristics, and plant operations are likely to meet the contract’s performance requirements.

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7 The term “Participant” refers to parties that submit offers in the Tranche #2 RFO.
For EE projects, PG&E may consider such factors as proposed technology, customer markets, timeframe of implementation, and EM&V plan. PG&E anticipates that there may be multiple offers that target the same location or customer segment. In order to prevent oversubscription of available savings potential, PG&E may group offers by location and segment, and select the highest ranking offers in a location/segment until the potential for that location/segment is saturated. EE proposals may be evaluated based on the strength of their showing that EE savings are anticipated to persist for five or more years following installation.

8) **Credit:** PG&E may consider the Participant’s capability to perform all of its financial and financing obligations under any contracts and PG&E’s overall credit concentration with the Participant or its banks, including any of the Participants’ affiliates.

9) **Contract Modifications:** PG&E may assess the materiality and cost impact of any of Participants’ proposed modifications to any applicable contracts.

10) **Counter-Party Concentration:** PG&E may consider the volume of energy or capacity already under contract from a particular counterparty, as well as offers received in the Tranche #2 RFO.

11) **Safety:** For each offer, PG&E will ask for information from the Participants regarding the safety history and practices of the entities that would construct, operate, own or maintain the projects, and safety information related to the technology for the project.

12) **Supplier Diversity:** It is the policy of PG&E that Diverse Business Enterprises, such as Women-, Minority- or Service-Disabled Veteran-Owned Business Enterprises (WMDVBE) and Lesbian, Gay, Bisexual, and Transgender-owned Business Enterprises shall have the maximum practicable opportunity to participate in the performance of contracts resulting from the Tranche #2 RFO. PG&E encourages Participants to carry out PG&E’s policy and contribute to PG&E’s supplier diversity goal by achieving greater than 30 percent of all procurement with WMDVBEs. The Supplier Diversity evaluation would take into account the Participant’s status as a WMDVBE, intent to subcontract with WMDVBEs, and the Participants’ own Supplier Diversity Program.
13) **Technology Diversity**: PG&E may take into consideration projects utilize innovative technologies that are not currently in PG&E’s portfolio or utilize innovative approaches that target customer groups not currently targeted in PG&E’s EE programs.

**E. Approval Process for Executed Offers (Strauss)**

Following the Tranche #2 RFO, PG&E will file an application to obtain Commission approval of executed EE and supply-side contracts. If successive RFOs are necessary, as described in Section B.2 above, PG&E will similarly file application(s) seeking Commission approval of any EE or supply-side contracts executed in those subsequent RFOs.

**F. Cost Allocation, Cost Recovery, and Reporting (Berman/Strauss)**

The Tranche #2 RFO will result in procurement of EE resources and/or clean (GHG-free or RPS-eligible) supply-side resources. Section 2.6 of the Joint Proposal recognizes that PG&E’s commitment to procure GHG-free energy resources through 2030 and beyond is for the benefit of all customers in PG&E’s service territory. Costs associated with EE in Tranche #2, like those in Tranche #1, would be recovered as a non-bypassable charge through electric Public Purpose Program (PPP) rates, consistent with existing recovery mechanisms for EE costs. Net costs associated with clean supply-side resources will be allocated through the “Clean Energy Charge,” subject to a self-provision option for Community Choice Aggregation (CCA) and direct access (DA) providers. The remainder of this section describes the proposed allocation of costs and cost recovery for EE resources and for clean supply-side resources.

1. **EE Resources (Berman)**

   PG&E’s application seeking Commission approval of agreements resulting from the Tranche #2 RFO will request to recover costs for new EE agreements through the Procurement Energy Efficiency Balancing Account and the associated non-bypassable charge through electric PPP rates. This cost recovery is consistent with California Pub. Util. Code Section 381(a)(1) and the currently-approved rules for cost recovery for PG&E’s EE programs.

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8 See Joint Proposal, § 2.3.3.
In the Tranche #2 RFO application described above in Section E, PG&E will provide detailed information regarding winning EE contracts. If the Commission approves the EE contracts, the resulting costs will then be recovered through the electric PPP rate component. PG&E will annually report progress towards meeting the Tranche #2 EE target, as well as budget and spending on the Tranche #2 EE programs and projects.

2. **Clean Supply-Side Resources (Strauss)**

   Net costs associated with executed Tranche #2 contracts for clean supply-side resources would be recovered through a new non-bypassable charge referred to as the Clean Energy Charge. The Clean Energy Charge would be paid by all electric distribution customers in PG&E’s service territory, including PG&E’s bundled electric customers as well as CCA customers and DA customers, except for those customers supplied by a CCA or DA provider electing to self-provide clean supply-side resources in lieu of having its customers pay the Clean Energy Charge.

   Procurement of clean supply-side resources in Tranche #2 will provide regional and statewide benefits to all electric distribution customers in PG&E’s service territory, by providing GHG-free energy to replace Diablo Canyon when it retires. Therefore, it is reasonable and appears consistent with California law, Legislative intent, and Commission precedent to recover the costs of the clean supply-side resources through the Clean Energy Charge.

   The Legislature has consistently required that all electric distribution customers be allocated a portion of the costs for programs that provide environmental or other benefits. For example, under the Waste Heat and Carbon Emissions Reduction Act (Assembly Bill (AB) 1613), which requires investor-owned utilities to procure efficient combined heat and power (CHP) resources, the Legislature specified that the Commission could allocate procurement costs and benefits to all “benefitting customers,” including

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9 Consistent with current rules, all customers would pay the PPP charge, including customers of CCA and DA providers who elect to self-provide clean supply-side resources as described in Section F.2 below.

10 Cost allocation issues for Tranche #2 are addressed in the Joint Proposal, § 2.6.
bundled electric customers, CCA customers, and DA customers.\textsuperscript{11} Similarly, when it recently enacted SB 350, the Legislature specified that net capacity costs associated with utility procurement to provide for a diverse portfolio of resources and provide “optimal integration of renewable energy in a cost-effective manner” could be included in a non-bypassable charge to be paid by bundled electric customers, CCA customers, and DA customers.\textsuperscript{12} The Legislature has also given the Commission authority to impose nonbypassable charges on CCAs for programs that “provide broader statewide or regional benefits to all customers….\textsuperscript{13} In short, where resource procurement provides regional or statewide benefits, such as the reduction of GHG emissions or other environmental benefits enjoyed by all electric distribution customers, the Legislature has consistently supported the allocation of costs related to this procurement to all of these customers. Tranche #2 procurement provides such benefits and the Clean Energy Charge provides such cost allocation.

The Clean Energy Charge is also consistent with Commission precedent. A decade ago, the Commission determined that “it is imperative that GHG reduction goals and responsibilities be shared as broadly as possible.”\textsuperscript{14} When resource procurement is associated in part with meeting GHG emissions reduction goals or other environmental policies, the Commission has repeatedly approved allocating the associated costs to bundled electric customers, DA customers, and CCA customers.\textsuperscript{15} As the Commission explained with regard to the AB 1613 program:

\begin{quote}
All customers, including CCA and DA customers, will receive environmental benefits from the AB 1613 program. There is no basis for distinguishing among various customer classes in allocating the environmental benefit of reduced GHG emissions. Consequently, there
\end{quote}

\begin{footnotes}
\textsuperscript{14} D.06-02-032 at p. 26; see also D.10-12-035, p. 49, and Finding of Fact 23.
\textsuperscript{15} D.10-12-035 at pp. 49-50 (allocating costs associated with the Qualifying Facility and CHP Settlement to bundled electric customers, DA customers, and CCA customers in part based on GHG emissions reduction benefits); D.09-12-042 at pp. 21-25 (allocating certain GHG-related costs associated with procurement to bundled electric customers, DA customers, and CCA customers); D.10-04-055 at pp. 14, 16-17.
\end{footnotes}
is no basis for distinguishing among various customer classes in allocating the costs associated with this benefit.\(^{16}\)

The Commission also noted that to the extent only bundled electric customers bear the costs for programs that benefit the entire service area, CCA and DA service providers would receive an “unfair advantage” over utilities.\(^{17}\)

PG&E and the other Joint Parties recognize, however, that some CCA and DA providers may want to procure their own clean supply-side resources rather than have their customers be allocated a portion of the benefits and net costs of PG&E procurement through the Clean Energy Charge. For example, a CCA or DA provider may want to procure clean supply-side resources in their local area or consider other factors that are in addition to the Tranche #2 eligibility requirements identified in the Joint Proposal and detailed in Sections B.1 and C above. When it enacted SB 350, the Legislature acknowledged the interest in self-provision and thus included a self-provision option in Public Utilities Code Section 454.51(d) that allows CCA to self-provide renewable integration resources rather than pay for these resources through a non-bypassable charge. PG&E is proposing the same approach for the Clean Energy Charge, giving CCA and DA providers the opportunity to elect to self-provide clean supply-side resources rather than have their customers pay the Clean Energy Charge and have PG&E procure the necessary resources. While some CCA and DA providers may not want to procure additional, clean supply-side resources, others can make a choice to do so and procure clean resources that help achieve California’s GHG goals.

The Clean Energy Charge and the self-provision option are described in more detail below.

a. The Clean Energy Charge

The Clean Energy Charge is intended to equitably allocate net costs and benefits using transparent and readily available market prices to determine the proper amount of the charge. Under the Joint Proposal,

\(^{16}\) D.10-04-055 at p. 14 (citations and footnotes omitted).

\(^{17}\) D.10-12-035, Finding of Fact 13 (regarding the QF/CHP Settlement); D.10-04-055 at p. 17 (regarding the AB 1613 program).
benefits and costs (such as RA and, for RPS-eligible energy resources, benefits associated with RECs) associated with PG&E’s procurement of Tranche #2 supply-side resources would be equitably allocated to responsible Load Serving Entities (LSE) (i.e., to electric distribution customers in PG&E’s service territory, including PG&E’s bundled electric customers, DA customers, and CCA customers). Existing (i.e., on the date of the Commission decision approving this Application) customers of a CCA or DA provider electing to self-provide clean supply-side resources will have the CCA or DA provider perform the procurement in lieu of PG&E, and therefore such customers would not pay the Clean Energy Charge.

RA benefits would be allocated annually using a process similar to the current process used for resources that are eligible for Cost Allocation Methodology (CAM) cost allocation, consistent with the CAM settlement agreement approved by the Commission in Decision (D.) 07-09-044. Under the current CAM mechanism, RA benefits are allocated annually, and then adjusted monthly, based on peak load share, to all LSEs providing service to bundled electric customers, DA customers, or CCA customers. A similar process would apply to allocation of RA benefits associated with clean supply-side resources procured in Tranche #2.

To the extent a clean supply-side resource provides RPS-eligible energy and thus provides RECs, the RECs would be allocated to LSEs based on their load share in the energy delivery year. PG&E will work closely with the Commission to design a process to allocate the RECs for the Clean Energy Charge.

Finally, the “net costs” of the clean supply-side resource would be allocated to all benefitting customers. Net costs include the sum of all contractual fixed and variable costs associated with a clean supply-side resource, less any CAISO market revenues received for energy output and ancillary services, if applicable, for the resource. As described in greater detail in Chapter 10, all costs associated with the clean

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18 Joint Proposal, § 2.6.
supply-side resource would be forecast in PG&E’s annual Energy Resource Recovery Account (ERRA) Forecast Proceeding and actual costs would be recorded in ERRA and a Clean Energy Charge subaccount under the New System Generation Balancing Account, which is in alignment with how the existing CAM costs are forecast and recorded. Because the net costs would be determined using actual market revenues, the calculation of the Clean Energy Charge would be transparent and could be verified by any party with readily available market data.

b. Self-Provision Option

The Clean Energy Charge provides clear allocation of resource benefits and a transparent, market-based determination of net costs. Nonetheless, some CCA and DA providers may want to procure clean supply-side resources on their own. PG&E and the other Joint Parties fully support a self-provision option for clean supply-side resources in Tranche #2.

Each CCA or DA provider that elects to self-provide would commit to: (1) procure a specific GWh amount of clean supply-side resources that satisfy the eligibility criteria described in Sections B and C above; and (2) procure 55% of its retail sales from RPS-eligible resources for the period 2031 to 2045, consistent with the Tranche #3 commitment by PG&E.

CCA and DA providers would make their election to self-provide within thirty days of the Commission decision approving this Application. PG&E’s commitment to provide clean supply-side resources for Tranche #2 will be established when the Commission issues a decision approving this Application, and so should the commitments to self-provide by CCA and DA providers.

If a CCA or DA provider commits to self-provide by providing notice within thirty days of the Commission decision approving this Application, the CCA or DA provider would be allocated a portion of the 2,000 GWh in Tranche #2 based on the CCA or DA provider’s energy load share among all PG&E’s bundled electric customers, CCA customers, and DA customers. PG&E’s 2,000 GWh obligation would be reduced by a
corresponding amount. For example, suppose a CCA commits to self-provide and the CCA serves, as of the date of the Commission decision approving this Application, 5 percent of the total annual energy load of PG&E’s bundled electric customers, CCA customers, and DA customers. Then that CCA would be responsible for procuring 100 GWh of clean supply-side resources consistent with the Tranche #2 eligibility requirements, and PG&E’s Tranche #2 obligation would decrease to 1,900 GWh.

One issue to be addressed is the responsibility of a departing bundled electric customer who switches to take service from a CCA or DA provider that has committed to self-provide. The departing customer would be responsible for the Clean Energy Charge and the CCA or DA provider to which that customer switched would receive the corresponding portion of RA, RECs, and any other benefits of the Tranche #2 procurement made by PG&E on behalf of that customer. The CCA’s initial commitment (100 GWh in the example above) would not change. Because the customer was a bundled electric customer on the date of the Commission decision approving this application, PG&E committed to Tranche #2 procurement on behalf of this customer, and this customer must pay its fair share of the costs of Tranche #2 procurement.

Regarding reporting, a CCA or DA provider that elects to self-provide would need to submit compliance reports to the Commission to verify that it has satisfied the self-provision commitment that it has made and that the resources procured satisfy the Tranche #2 eligibility requirements for clean supply-side resources.

G. EE Shareholder Incentive (Berman)

The Commission approved an energy efficiency shareholder incentive mechanism in D.13-09-023, entitled the Efficiency Savings and Performance Incentive (ESPI), to reward the investor-owned utilities for energy efficiency savings achieved in 2013 and beyond. The mechanism provides a shareholder incentive for energy savings resulting from the programs in PG&E’s energy efficiency portfolio, including savings arising from third-party contracts awarded by PG&E. Pursuant to the process amended in by the Commission in
D.15-10-028, PG&E and the other IOUs file annual advice letters by September 1 of each year requesting an incentive award to be included in electric and gas rate adjustments effective January 1. PG&E requests authorization to include savings achieved through the RFO or new utility programs offered to meet the Tranche #1 and Tranche #2 EE commitments through the ESPI mechanism, or such other shareholder incentive mechanism in place for the IOUs' EE programs when the Tranche #1 or Tranche #2 EE measures are installed.

H. Conclusion (Strauss)

PG&E respectfully requests the Commission approve the provisions and requirements of Tranche #2 in the Joint Proposal and as described in this chapter.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

TRANCHE #3 – VOLUNTARY 55 PERCENT RENEWABLES

PORTFOLIO STANDARD PROCUREMENT COMMITMENT
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A. Introduction

The Joint Proposal includes three tranches of procurement as a reasonable first step toward replacing the Diablo Canyon Power Plant (Diablo Canyon or DCPP) with resources that emit no greenhouse gases (GHG). In Tranche #3, Pacific Gas and Electric Company (PG&E) is voluntarily committing to a 55 percent Renewables Portfolio Standard (RPS) for its bundled electric customers. This chapter describes the proposed requirements for the Tranche #3 procurement, the process that PG&E proposes using to achieve the Tranche #3 commitment, and the proposed cost recovery and cost allocation for costs related to Tranche #3 procurement.  

The remainder of this chapter is organized as follows:

- Section B describes the proposed Tranche #3 requirements;
- Section C describes the proposed process for achieving Tranche #3 commitment; and
- Section D describes the proposal for cost recovery and cost allocation.

B. Tranche #3 Requirements

Under the Joint Proposal, in each of the years beginning in 2031 and ending in 2045, PG&E has committed to meeting 55 percent of its annual bundled retail sales with resources that are eligible for the RPS under California’s RPS statutes applicable at the time of procurement. In determining whether PG&E has met this requirement, all RPS requirements and limits set forth in California’s RPS statutes (California Public Utilities Code (Pub. Util. Code) Section 399.11 et. seq.) applicable at the time of compliance will apply, as interpreted by the California Energy Commission and the California Public Utilities Commission (CPUC or Commission), except that the procurement quantity requirement in each year will be based upon a 55 percent RPS commitment, rather than

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1 Joint Proposal, § 2.4 addresses Tranche #3. A copy of the Joint Proposal is included as Attachment A to PG&E’s Application.

PG&E’s voluntary commitment to 55 percent RPS will terminate on the earlier of 2045 or when superseded through implementation of an RPS requirement that equals or exceeds 55 percent (or equivalent GHG emissions reduction regulation).

**C. Process to Achieve Tranche #3 Commitment**

To meet its commitment of providing 55 percent of bundled retail sales from RPS-eligible resources in each of the years beginning in 2031 and ending in 2045, PG&E plans to utilize the procurement mechanisms (solicitations, bilateral negotiations, etc.) that are approved mechanisms for PG&E’s procurement of RPS-eligible resources at the time the procurement occurs. To ensure deliveries align with the commitment schedule (i.e., deliveries beginning in 2031 and ending in 2045), PG&E may start procuring before 2031, especially if procurement involves new RPS-eligible resources. Because all RPS transactions in the bundled electric portfolio subsequent to the date of a Commission decision approving this Application will facilitate achieving the commitment to 55 percent RPS for PG&E’s bundled electric customers, Tranche #3 procurement is any RPS-eligible procurement for PG&E’s bundled electric portfolio made after the Commission approves this Application.

With regard to verifying that the Tranche #3 commitment has been met, for each applicable year between 2031 and 2045, PG&E will use the RPS Compliance Report spreadsheet applicable for that year and the volumes reported in final, verified compliance reports to demonstrate compliance.

**D. Cost Recovery and Cost Allocation**

The proposed approach to allocation and recovery of Tranche #3 costs differs from the current approach to allocation of RPS procurement costs.

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2 Joint Proposal, § 2.4.1.
3 Joint Proposal, § 2.4.2.
4 Other procurement by PG&E (e.g., some Tranche #2 procurement) may yield, for PG&E’s bundled electric portfolio, RPS-eligible energy or other RPS compliance instruments. Such RPS-eligible energy or other RPS compliance instruments may be used by PG&E to meet its commitment to 55 percent RPS as well as meet any other facet of RPS compliance.
The proposed approach allocates to departing customers a portion of all benefits and all net costs associated with particular RPS contracts, whereas the current approach allocates no benefits and a portion of above-market costs. The proposed approach uses actual, market-based data to determine net costs, whereas the current approach uses forecasted, administratively-determined information to estimate above-market costs. For these reasons, PG&E believes the proposed approach is superior to the current approach.

1. Current Approach

Currently, costs associated with RPS-eligible resources are recovered in two ways. For PG&E’s bundled electric customers, these costs are recovered through PG&E’s generation rate and recorded to the Energy Resource Recovery Account (ERRA), which is a balancing account that is used to pass-through the actual costs of RPS and other procurement. The ERRA portion of PG&E’s generation rates are set based on forecast procurement costs, adjusted for the forecast Power Charge Indifference Adjustment (PCIA) described below, in PG&E’s annual ERRA Forecast proceeding. After the fact, actual procurement costs are reviewed for compliance and authorized in PG&E’s annual ERRA Compliance proceeding, and the difference between actual and forecast procurement costs are recovered in bundled electric rates via the ERRA balancing account in PG&E’s Annual Electric True-Up filing. Unlike the ERRA balancing account, procurement costs are not trued-up for the PCIA.

For customers that have departed from bundled electric service and currently are supplied by a Community Choice Aggregation (CCA) or direct access (DA) provider, the customer is allocated a portion of the forecasted above-market costs associated with RPS-eligible contracts that were executed before a customer’s departure from bundled electric service. These above-market costs are recovered through the PCIA, which is determined in PG&E’s annual ERRA Forecast proceeding. Unlike the procurement costs recorded to ERRA, the PCIA is not subject to balancing account treatment. Instead, the PCIA is set based on a forecast of administratively-determined above-market costs, which are recorded as a credit to the ERRA and reduce bundled customer costs. Moreover,
departing customers do not receive any benefits associated with the RPS-eligible resources for which they are paying through the PCIA.

To determine the above-market contract costs for which a departing customer is responsible, the Commission has developed “vintaging” rules. When a customer departs from a utility’s bundled electric service, that customer is responsible for RPS procurement contracts executed on or before the customer’s date of departure. This is typically referred to as “vintaging” because the date a customer departs is the “vintage” the customer receives for purposes of the PCIA.

2. Proposed Approach

In this Application, PG&E is proposing a different approach by which departing customers would pay for Tranche #3 and future RPS procurement. This section describes the customers to which the proposed approach would apply, for which procurement those customers would be responsible, and the method for determining the procured benefits and costs for which those customers would receive and pay. Finally, the proposed approach is explained to be consistent with existing California law.

First, it is important to be clear about what is proposed to remain unchanged. For PG&E’s bundled electric customers that remain on PG&E’s bundled electric service, costs for past RPS procurement and for Tranche #3 procurement would continue to be recovered in electric rates via the ERRA balancing account. For existing customers of DA and CCA providers (i.e., DA and CCA customers as of the date of the Commission decision approving this Application), costs for past RPS procurement would continue to be recovered via the PCIA and such customers would not be responsible for costs associated with Tranche #3 procurement, unless such a customer someday switches to bundled electric service; once such a customer switches to bundled electric service, the customer would pay for all past RPS procurement and all Tranche #3 procurement in the same manner as any other customer on bundled electric service, and if the customer subsequently departs to DA or CCA service, the customer would be responsible for past RPS procurement and Tranche #3 procurement in the same manner as any other departing customer, as described below. For customers currently on bundled electric service and depart subsequent to
the Commission decision approving this Application, costs for past RPS procurement (i.e., prior to the date of the Commission decision approving this Application) would continue to be recovered via the PCIA, and such customers would not be responsible for costs associated with Tranche #3 procurement made after the customer departs. Furthermore, in this Application PG&E is not proposing any changes to the existing PCIA vintaging rules or the way PCIA is calculated for resources that are not RPS-eligible under current or future California RPS eligibility rules.

In summary, the proposed approach applies only to customers departing bundled electric service on or after the date of the Commission decision approving this Application, and applies only to RPS procurement made on or after the date of the Commission decision approving this Application and on or before the date when the customer departs bundled electric service. These departing customers would be allocated a portion of all benefits and net costs associated with such RPS procurement procured on behalf of these departing customers. In addition, bundled electric customers would pay their share of net costs associated with the Tranche #3 procurement and future RPS procurement through the Clean Energy Charge.

The proposed approach for Tranche #3 procurement allocates benefits and net costs to departing customers in a manner similar to the Clean Energy Charge described in Chapter 5. Net costs associated with Tranche #3 and future RPS procurement (excluding any RPS resources procured as part of a Tranche #2 RFO) would be a Tranche #3 component of the Clean Energy Charge described in Chapter 5. For completeness, the method is described here with a comparable level of detail as it is described in Chapter 5.

RA benefits would be allocated in a manner similar to that described in Chapter 5. RA benefits would be allocated to PG&E for its bundled electric customers and to all LSEs providing service to departing customers. RA benefits would be allocated annually, and then adjusted monthly, based on peak load share among PG&E’s bundled electric customers and the appropriately vintaged departing customers. RECs associated with Tranche #3 and RPS procurement would be allocated to PG&E for its bundled electric customers and to all LSEs providing service to departing
customers, based on the load share among PG&E’s bundled electric
customers and the appropriately vintaged departing customers in the energy
delivery year. PG&E will work closely with the Commission to design a
process to allocate the RECs associated with Tranche #3 and RPS
procurement.

With regard to the allocation of net costs, PG&E is proposing that net
costs be allocated using transparent, market-based prices, rather than
forecasted, administratively-determined inputs. For RPS contracts executed
on or after the date of the Commission decision approving this Application
and on or before the date when the customer departs bundled electric
service, the net costs to be allocated to the departing customer would be
determined by taking the sum of all contractual fixed and variable costs, less
any California Independent System Operator market revenues received for
energy output and ancillary services, if applicable, for the RPS resource.

As described in greater detail in Chapter 10, all net costs associated
with Tranche #3 and future RPS procurement would be forecast in PG&E’s
annual ERRA Forecast proceeding and actual costs would be recorded in a
Clean Energy Charge subaccount under the New System Generation
Balancing Account.

The proposed approach is entirely consistent with California statutory
law. Under California Pub. Util. Code Section 366.2(f), a customer that
elects to depart utility-bundled service for CCA service is responsible for the
share of costs attributable to that customer. Similarly, California Pub. Util.
Code Sections 365.2 and 366.3 provide that bundled electric customers
should not experience cost increases as a result of departing load, and
effectively provide that DA customers and CCA customers are responsible
for costs incurred on their behalf. All RPS transactions subsequent to the
date of the Commission decision approving this Application will facilitate
achieving the commitment to 55 percent RPS; thus, all customers who are
on PG&E’s bundled electric service as of the date of the Commission
decision approving this Application should bear their fair share of these
costs.
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A. Introduction (King)

The purpose of this chapter is to present the details of Pacific Gas and Electric Company’s (PG&E or the Company or the Utility) proposal to retain, re-train, and provide severance benefits to qualified personnel at Diablo Canyon Power Plant (DCPP or Diablo Canyon) Units 1 and 2 through the remainder of plant operations, which will cease in 2024 and 2025, respectively (the Employee Program).

A key element of the Joint Proposal is that it recognizes the value of carbon-free nuclear power as an important bridge strategy over the next eight to nine years. The transition period provides time to plan, procure, and develop greenhouse gas-free energy resources prior to Diablo Canyon’s retirement. The transition will also provide essential time needed for plant employees and the community to effectively plan for the future.

PG&E, and all of California, have benefited from a well-trained, highly skilled, federal and state licensed, dedicated workforce that have contributed to Diablo Canyon’s track record of industry-leading safety and reliability during its 31 years of operations. To continue to deliver these positive results, the Joint Parties agree it is critical to retain this highly-qualified team at Diablo Canyon during the remaining years of operations. The International Brotherhood of Electrical Workers Local 1245 joined in the Joint Proposal and supports approval of the Employee Program. In addition, Engineers and Scientists of California, Local 20 and Service Employees International Union have also reached agreement with PG&E on the retention program.

The Employee Program contains three components: (1) a retention program to maintain staffing levels of qualified employees to ensure the plant’s continued safe and efficient operation (the Employee Retention Program); (2) an employee severance program to provide payments to eligible employees when their positions are eliminated (the Employee Severance Program); and (3) a retraining and development program to facilitate redeployment of a portion of
plant personnel to the decommissioning project and elsewhere within PG&E (the Employee Retraining Program).

The Employee Program described in this chapter provides a fair and equitable set of benefits and incentives to ensure the continuity of the operational excellence that has characterized Diablo Canyon until its last day of generation. This proposal treats employees fairly and benefits customers by mitigating risk of inefficient operation that may result from the loss of experienced and knowledgeable employees.

The remainder of this chapter is organized as follows:

• Section B describes in further detail the rationale and need for all three elements of the Employee Program;
• Section C provides an Employee Retention Program overview and cost forecast;
• Section D provides an Employee Severance Program overview and cost forecast;
• Section E provides an Employee Retraining Program overview and cost forecast;
• Section F provides industry benchmarking data relevant to the Employee Retention Program; and
• Section G describes the mechanisms that PG&E proposes to use to recover costs of the Employee Program.

B. Need for the Employee Program (Halpin)

PG&E’s proposal to retire Diablo Canyon is unique in the industry in several ways. Most relevant to this chapter, PG&E has announced almost a decade in advance that it does not intend to seek license renewal. This creates certain organizational dynamics that will be complex to manage, especially if the situation is exacerbated by shortages in staffing. It would serve PG&E’s customers and California well to appropriately incent the Diablo Canyon team to remain focused on the job of finishing the operating licenses of the plant safely, reliably, and with excellence, while knowing that they will be treated fairly when their current job is complete.

Diablo Canyon plant employees possess highly specialized technical skills, localized knowledge, federal and state licensing, and security clearances that cannot be easily replaced. In the absence of the Employee Retention Program,
existing Diablo Canyon employees could be more likely to retire early or to terminate their employment before the closure of the plant to seek other long-term employment. High levels of attrition could have an impact on the ability of Diablo Canyon to continue effective operations. Accordingly, the goal of the Employee Retention Program is to retain employee staffing levels that existed as of March 2016 to continue excellent operation of the plant until the expiration of the Nuclear Regulatory Commission (NRC) licenses. While some employees will choose to leave DCPP before the end of each retention period due to planned retirements or other job opportunities outside the plant, PG&E’s Employee Program will help to recruit, train, and retain new employees to maintain existing staffing during DCPP’s final years of licensing.

The two-tier approach of the Retention Proposal, as described in Section C below, is designed to address different segments of the Diablo Canyon workforce. The first tier (2016-2020) appropriately incentivizes late-career employees to postpone retirement for four years, allowing an orderly transition and transfer of knowledge. The second tier (2021-2023) is designed to further incentivize the younger workforce to stay through the end-of-generation operations and to be rewarded for their service and commitment. Without the Employee Retention Program, these employees could be motivated to leave PG&E earlier to secure new, more certain employment elsewhere.

The Employee Severance Program and the Employee Retraining Program are similarly critical in retaining and recruiting Diablo Canyon employees through the end of the license period. The Employee Severance Program, which is included in the decommissioning cost estimate, and the Employee Retraining Program are benefits that will incent employees to remain at the plant through the end of the license life and further attract any necessary new recruits as these programs become accessible to eligible employees at or around the time an employee’s position at the plant is officially eliminated.

C. Retention Program Overview and Cost Forecast (King)

PG&E proposes to employ a two-tiered Employee Retention Program to ensure the continued safe and efficient operation of Diablo Canyon.

The Employee Retention Program is a significant employee package that demonstrates PG&E’s commitment to attract and retain employees to operate the plant through the remainder of the license period. Both management and
bargaining unit employees would receive the same opportunity to participate in
the Employee Retention Program.

The first 4-year period (the Tier 1 Employee Retention Payment Period) is
for the period of September 1, 2016 through August 31, 2020 and will provide
a retention payment to each eligible employee at a value of 25 percent of the
employee’s base salary at the end of each of the respective four years.
Employees receiving the retention payments would be required to sign an
agreement with PG&E committing to work at Diablo Canyon until August 31,
2020 in order to receive the retention payments. Any new hires, or PG&E
employees that transfer or bid into DCPP, would be eligible for a prorated
retention incentive. If an employee who signed a retention agreement later
decided to terminate his or her employment at Diablo Canyon prior to the end of
the Tier 1 Retention Payment Period, whether it is because the employee leaves
the Company or accepts another position outside of DCPP, the agreement
would require that employee to refund PG&E all retention funds already paid by
PG&E to the employee during the Tier 1 period. The employee would also lose
his or her eligibility for any additional retention payments after the employee
exits from DCPP.

The second 3-year period (the Tier 2 Retention Payment Period) is for the
period of September 1, 2020 through August 31, 2023 and would provide a
retention payment to each eligible employee at a value of 25 percent of the
employee’s base salary at the end of each of the respective three years.
Employees receiving the retention payments would be required to sign an

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1 “Eligible employees” include active full-time status PG&E employees who work at DCPP or who support DCPP operations and whose job or job functions will be eliminated as a result of the cessation of operations at DCPP. New hires and PG&E employees bidding or transferring into DCPP will also be eligible on a pro-rated basis. Contractors, Hiring Hall, and PG&E employees working at DCPP on a temporary or rotational assignment are not eligible.

2 With regard to new hires, it should be noted that hiring new talent into Diablo Canyon Power Plant has continued to be a challenge, prior to the announcement of the pending closure, as it takes, on average, 110 days to fill any open position. The technical experience needed by employees to work and operate the plant safely is not easily obtainable in the open job market. Many of the new hires are relocating from other nuclear power plants. The announcement of the plant’s retirement will add even more time in DCPP’s recruiting cycles, which highlights the need for a robust Retention Program.
agreement with PG&E committing to continue working at Diablo Canyon through August 31, 2023. Similar to the first retention period, if there is a new hire who joins DCPP or a PG&E employee transfers into DCPP, that employee would be eligible for a prorated retention payment. In addition, if an employee who signed a retention agreement later decided to terminate his or her employment at Diablo Canyon, whether by leaving the Company or accepting another position at PG&E outside of DCPP prior to the end of the Tier 2 Retention Payment Period, the agreement would require that employee to refund PG&E all retention funds already paid by PG&E to the employee during the Tier 2 period. The employee would also lose his or her eligibility for any additional retention payments after the employee exits from DCPP. If an eligible employee completed the Tier 1 Retention Payment Period but terminated his or her employment during the Tier 2 Retention Payment Period, the employee would only be required to refund the retention payments made during the Tier 2 Retention Payment Period as he or she would have met the Tier 1 Payment Period commitment. Table 7-1 shows the retention payment periods.

<table>
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<th>Line No.</th>
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<tbody>
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<td>9/1/2016 – 8/31/2017</td>
<td>12/2017*(a)</td>
</tr>
<tr>
<td>2</td>
<td>9/1/2017 – 8/31/2018</td>
<td>12/2018</td>
</tr>
<tr>
<td>3</td>
<td>9/1/2018 – 8/31/2019</td>
<td>12/2019</td>
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<td>4</td>
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<td>7</td>
<td>9/1/2020 – 8/31/2021</td>
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<td>9/1/2021 – 8/31/2022</td>
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<tr>
<td>9</td>
<td>9/1/2022 – 8/31/2023</td>
<td>12/2023</td>
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</table>

(a) Payment date subject to Commission approval by this date.

1. Retention Program Cost Forecast

As shown in Table 7-2, PG&E estimates the Employee Retention Plan will cost $352.1 million. Of this total, PG&E estimates that the Tier 1
Employee Retention Payment Period will cost $191.6 million and the Tier 2
Employee Retention Payment Period will cost $160.5 million. This estimate
assumes that retention payments for both tiers will be paid to approximately
1,500 employees at Diablo Canyon and that retention of existing staffing
levels at Diablo Canyon is necessary for the continued effective operation of
the plant through the license termination dates. The labor escalation rates
for 2017-2019 are based on those filed as part of PG&E’s 2017 General
Rate Case. The assumed labor escalation rate for 2020-2023 is
3.21 percent, which is the calculated weighted average increase for 2019.

The Employee Retention Program is aimed to keep the entire employee
population retained until August 31, 2023. In order to receive severance,
employees would then need to work through the DCPP closure or to when
their positions are eliminated.

<table>
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<th>Line No.</th>
<th>Tier 1 Retention Payment Period</th>
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<th>2018</th>
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<td>2</td>
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<td>Tier 2 Retention Payment Period</td>
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<td>2023</td>
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<td>Non-Represented Employees</td>
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<td>6</td>
<td>Represented Employees</td>
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<td></td>
<td>$160.5</td>
<td></td>
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3 The cost estimate was created from the end of March 2016 DCPP headcount of 1,461.
4 See Application 15-09-001, PG&E Prepared Testimony, Exhibit (PG&E-19) Update Testimony, Section C, Table 4-1. The rates were applied based on each individual’s employee category and annualized base pay as of March 2016, including 2016 increases for represented employees that had not yet been reflected in PG&E’s Human Resources system.
2. Precedent for Employee Retention Program

The Employee Retention Program proposed in this chapter is consistent with and based in part on another retention program that PG&E proposed during electric industry restructuring. In 1995 PG&E instituted a retention payment program for employees impacted by the selling of PG&E’s fossil-fueled generating facilities. Represented employees were offered a retention payment of 50 percent of their annual pay for the first year, followed by retention payments of 25 percent of their annual pay per year for the following three years. Management employees were provided a retention payment of 60 percent of their base pay for the first year, followed by retention payments of 30 percent of their base pay each year for the following three years.

D. Employee Severance Program Overview and Cost Forecast (King)

PG&E has an established severance program that will also be provided to the employees whose jobs are eliminated at the time of the DCPP closure. At the time of their job elimination, Bargaining Unit employees would receive four weeks of pay plus two weeks of pay for every year of service, as well as a lump sum payment of $5,000. At the time of their job elimination, management employees would receive three weeks’ pay per year, up to a total cap of 78 weeks, as well as a lump sum of $9,000. The severance payments would be at the employee’s current base salary at the time of severance.

The Commission has already found that reasonable employee assistance costs, including an employee severance program, may be included as decommissioning costs for utility employees who become unemployed due to the closure of a nuclear facility.\(^5\) In the same Decision, the Commission accepted PG&E’s 2012 estimate (in 2011 dollars) of severance-related costs at Diablo Canyon totaling approximately $148 million.\(^6\) As provided in PG&E’s 2015 NDCTP, filed on March 1, 2016, PG&E currently forecasts its Employee Severance Program will cost $168 million.

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5 D.14-12-082, p. 19.
6 Id., p. 88.
E. Employee Retraining Program Overview and Cost Forecast (King)

The purpose of the Employee Retraining Program is to support the placement, where feasible and cost-effective, of eligible employees who are interested in transitioning to roles supporting DCPP decommissioning or roles in other parts of the utility. Beginning in 2021, the Company will engage the Diablo Canyon workforce to determine interest in the Employee Retraining Program and conduct a needs analysis. While the employees’ primary roles will continue to be focused on safe operation of DCPP, the Company will develop new training tools and modify the existing training curriculum to support decommissioning needs and utility needs. The technical and professional training may be offered by the DCPP training team, on-line by PG&E Academy, or through external partners. Open positions within the utility may be offered to a qualified Diablo Canyon employee subject to the requirement that the employee completes his or her assignment at DCPP and is released as part of the orderly closure of the plant. Elements of the Employee Retraining Program may include:

- Support for job search – If employee is interested in continuing to work for PG&E after his or her DCPP position is eliminated, the employee would be aligned with a Talent Advocate who would support the employee in navigating PG&E’s internal job openings, advocating for the employee internally, and providing the employee with timely feedback on his or her overall job search.

- Wage protection – If an employee is successful in obtaining another position at PG&E after his or her DCPP position is eliminated, and the position has a lower pay range, the employee will retain the base salary from the DCPP position for a period of up to three years, subject to union negotiations.

- Training – As DCPP gets closer to retirement, additional professional and technical training will be provided to employees who are interested in staying at PG&E and have the appropriate skills to contribute to other departments.

- Relocation assistance – PG&E currently offers relocation assistance for management employees who receive other internal job opportunities, and relocation of represented employees would be administered per existing union agreements.
PG&E currently forecasts the cost of the Employee Retraining Program to be approximately $11.3 million ($2016).

**F. Industry Benchmarking Data Relevant to the Employee Retention Program (Moloney)**

PG&E engaged independent compensation consultant Willis Towers Watson (WTW) to compare the proposed Employee Retention Program against available industry benchmarking data and to provide an expert opinion regarding the reasonableness of the Employee Retention Program in light of Diablo Canyon’s specific circumstances and those data. This section provides the results of WTW’s analysis and our independent opinion.

Based upon our review of the Employee Retention Program as described in Section C, above, WTW used a number of sources to analyze the reasonableness of the Retention Program, including the following:

- 2014 WTW Global Mergers and Acquisitions (M&A) Report database;
- A custom survey of retention plans during business closure that WTW completed for a Fortune 500 client; and

Based on our professional experience servicing our clients, and a review of the aforementioned databases, we conclude that the need to keep critical skilled employees during the years prior to a business (in this case, a plant) closure is the key determining factor in retention plan level and design. Closures differ greatly from typical M&A transactions and require equally different approaches to retention.

Specifically, in closure situations akin to PG&E’s, retention programs tend to be more broad-based; i.e., eligible participants tend to be defined to include all levels of employees. Retention bonus payouts also tend to be at higher levels. Based on our research, we determined that retention bonus payouts increase as employee risk increases (e.g., greater housing re-location costs, more difficulty of job replacement, lower financial payout probability, etc.). The target payout of retention bonuses also increases as to certain jobs that are deemed by management to be more unique and/or critical to the success of the Company prior to the closure. Research indicates that union status, industry sub-sector, business scope, and/or geographic region (within the U.S.) have little material
impact on the variance of practice for retention plans (as a percentage of salary) in business or plant closure. WTW also researched current retention plan practices in union and utility sector.

As shown in Table 7-3, the WTW and Mercer data indicate a middle range of retention plan pay per annum of 25 percent per year of base salary. Therefore, PG&E’s plan is directly in the middle range of current practice.

**TABLE 7-3**
RETENTION PLAN BENCHMARKING DATA

<table>
<thead>
<tr>
<th>Survey/Percentile</th>
<th>25th Percentile</th>
<th>50th Percentile</th>
<th>75th Percentile</th>
</tr>
</thead>
<tbody>
<tr>
<td>Willis Towers Watson</td>
<td>10%</td>
<td>25%</td>
<td>40%</td>
</tr>
<tr>
<td>Mercer</td>
<td>15%</td>
<td>25%</td>
<td>45%</td>
</tr>
</tbody>
</table>

In conclusion, WTW offers the following opinions based on our professional experience and third-party benchmarking:

1. The Retention Plan is economically in the middle range of practice for retention plans for business or plant closure.
2. The Retention Plan effectively addresses retention concerns that fit the circumstances of the closure; specifically:
   - The long length of time that PG&E requires employees to safely operate and maintain the plant prior to the closure;
   - The greater risk of losing employees prematurely than is typical in standard M&A transactions; and
   - The difficulty of replacing the highly-skilled workforce that is employed by PG&E at the Diablo Canyon facility.
3. The Retention Plan had to be customized to address the timing of payouts, additional benefits, and the clawback to address the specific aspects of the closure.
4. The above-referenced customization does not depart from retention plan norms in situations similar to that of PG&E.
G. Cost Recovery (King)

1. Employee Retention Program and Employee Retraining Program

Cost Recovery

PG&E requests the CPUC approve:

1) the Employee Retention Program and associated cost estimate of $352.1 million;

2) the Employee Retraining Program and associated cost estimate of $11.3 million;

3) PG&E’s request to track the actual costs in 2 new two-way expense-only subaccounts within the Diablo Canyon Retirement Balancing Account (DCRBA), the Employee Retention Program Subaccount and the Employee Retraining Program Subaccount; and

4) to recover the associated revenues through the nuclear decommissioning non-bypassable charge. The programs revenue requirements and the proposed DCRBA are presented in Chapter 10. Any refinements to the program cost estimate for the Employee Retraining Program will be presented in the next NDCTP application.

2. Employee Severance Program Cost Recovery

A then-current $148 million ($2012) estimate of Employee Severance Program costs has already been incorporated into PG&E’s decommissioning estimate as part of the 2012 Nuclear Decommissioning Cost Triennial Proceeding. PG&E’s 2015 NDCTP, filed on March 1, 2016, requests approval and recovery of an updated Employee Severance Program estimate of $168 million ($2016). PG&E seeks approval of the Employee Severance Program as part of this Application and will continue to forecast and recover the cost of the Employee Severance Program in each subsequent NDCTP.

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7 D.14-12-082, p. 88.
PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
COMMUNITY IMPACTS MITIGATION PROGRAM

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CHAPTER 8
COMMUNITY IMPACTS MITIGATION PROGRAM

A. Introduction

This chapter describes the Community Impacts Mitigation Program (Community Program), the rationale for the Community Program, and Pacific Gas and Electric Company’s (PG&E) proposal for recovery of the Community Program costs.

Diablo Canyon Power Plant (DCPP or Diablo Canyon) is one of the largest employers, tax payers, and charitable contributors in the San Luis Obispo County (or County) area. Diablo Canyon has been a major part of the San Luis Obispo community for more than three decades. The purpose of the Community Program is to assist the community to transition to a future without Diablo Canyon and to recognize and honor the partnership between the community and Diablo Canyon that has helped the plant achieve operational excellence and high value for PG&E’s customers during its lifetime.

The remainder of this chapter is organized as follows:

- Section B – describes in further detail the rationale for the Community Program;
- Section C – describes and estimates the costs associated with the two components of the Community Program; and
- Section D – describes the proposed cost recovery mechanism for the community impact mitigation payment component of the Community Program.

B. Community Program Rationale

Diablo Canyon has provided reliable, safe, and economic greenhouse gas (GHG)-free electricity for PG&E’s customers for more than 30 years. It has done so with the support and assistance of the local community that has provided a home for DCPP and its employees. Over many years, the local community has both reaped the many benefits and also borne the burdens—both realized and potential—associated with hosting an operating nuclear power plant. Simply put, Diablo Canyon could not have realized its tremendous value to all of
PG&E’s customers without the help and willing partnership of the local community.

While broader State policy objectives and the rapidly changing nature of the electric sector have made it beneficial to retire Diablo Canyon at the end of its current operating license, all of the electricity customers in PG&E’s service area have benefited and will continue to benefit from DCPP’s cost-effective, GHG-free energy. In return for these benefits, customers are responsible to pay for the decommissioning of the facility, including ensuring that the local community has a reasonable opportunity to transition to a new economic and social reality without the operating plant. PG&E and the other Joint Parties believe that this Community Program strikes the right balance between providing appropriate transitional assistance to the community while also recognizing that the community must manage this transition so that it can thrive in the longer term without the historic levels of spending and taxes funded by PG&E customers.

The Community Program is designed to appropriately mitigate some of the adverse economic impacts to the residents of San Luis Obispo County as a result of DCPP’s planned retirement. These impacts will come about due to the loss of the significant stimulus that an operational DCPP provides to the local economy in the revenue it provides to local firms, the jobs it generates for local residents, and the tax revenues it generates to help local governments provide services to local residents.

DCPP’s operation has a profound effect on the economy of the local coastal communities of which it has long been a part, thanks to the large number of stable, highly-skilled jobs it supports. As a result of DCPP, PG&E is the largest private employer in San Luis Obispo County with approximately 1,500 workers and an annual payroll of more than $235 million. Diablo Canyon also spends more than $20 million annually on local goods and services. According to a study performed by the California Polytechnic State University, San Luis Obispo, the total economic impact of DCPP on the local economy in 2011 was about $920 million, including almost $22 million of incremental revenue in other local businesses and $222 million in local household spending by employees of
DCPP, their suppliers and their suppliers’ suppliers.\(^1\) The expenditures by
DCPP, its employees, and vendors in the same year are estimated to have
generated over 3,300 jobs in the local area.\(^2\)

Additionally, PG&E is the largest property taxpayer in San Luis Obispo County. The approximately $22 million that PG&E currently pays in property
taxes for Diablo Canyon to the County helps fund schools, public work projects,
public safety, and health and other vital services. Figure 8-1 shows how PG&E expects these tax payments will diminish as the remaining undepreciated value
of DCPP declines to near zero by 2025. The Community Program will provide
transitional assistance to address this reduction in tax revenues. The retirement
of DCPP will require San Luis Obispo County to transition to a significantly
reduced annual budget or to develop substantial new sources of tax revenue.
The Community Program provides San Luis Obispo County a nearly 10-year period to plan for and manage this major transition.

There is precedent for the type of transitional assistance proposed in the Community Plan. Reacting to similarly rapid changes in DCPP’s depreciation
schedule in the late 1990s due to deregulation, PG&E and the local community
proposed, and the California Public Utilities Commission (CPUC or Commission) approved, $10 million to be paid to the county and local jurisdictions over a
four-year transition period.\(^3\) Faced with even more drastic economic changes
as Diablo Canyon retires, the Commission should again approve the additional
and final transitional plan for the local community proposed in this Application.

### C. Description of the Community Impacts Mitigation Program

The proposed Community Program has two components: (1) community
impact mitigation payments through 2025; and (2) continuing support for
emergency planning, preparedness, and response after the cessation of plant
operations in 2025.

\(^1\) See “Economic Benefits of Diablo Canyon Power Plant: An Economic Impact Study,” June 2013, p. 29 (included as Attachment A to this chapter).
\(^2\) Ibid.
1. **Community Impact Mitigation Payments**

   The Joint Parties agreed to support a stream of mitigation payments totaling approximately $49.5 million between 2017 and 2025 as the primary way to assist the local community to prepare and plan for the long-term loss of economic stimulus that the operating plant provides. While these payments are meant to address the broader economic impacts from Diablo Canyon’s retirement, PG&E calculated the size of the community impact mitigation payments based upon the forecasted reductions in DCPP property tax base over the same period. To be clear, the payments are a proxy number for an appropriate customer contribution to the community transition in preparation for decommissioning and are not meant to represent actual or substitute tax payments. While the community and local economy will continue to benefit from employment and customers will realize the benefit of the electricity produced, the principle change in community benefit is the reduced tax payment during this period. Thus, the Joint Parties based the mitigation payment upon the depreciation schedule shown in Figure 8-1.

   In 2016, PG&E forecasts that DCPP will contribute approximately $22 million in property taxes to the local community. As shown in Figure 8-1, PG&E expects that with the retirement of DCPP, this would decline to nearly zero by the end of 2025.\(^4\) Consistent with the Joint Proposal,\(^5\) PG&E proposes to assist the community to transition and plan for the loss of economic stimulus provided by Diablo Canyon’s operation by making annual payments, as specified in Figure 8-1 below, in each of the years 2017 through 2025 to the County of San Luis Obispo, with the intention that the County will allocate and share these payments with other local entities that have traditionally received a distribution of PG&E’s property tax revenues.\(^6\) The annual payments PG&E proposes to provide to

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\(^4\) The continued operation of the Independent Spent Fuel Storage Installation (ISFSI) and guard station, as well as any additional economic activities like cattle grazing, will continue to generate a relatively small level of economic stimulus and tax revenue.


\(^6\) PG&E is working with the County and other local stakeholders to facilitate the development of an agreement between these entities for an appropriate assessment and allocation methodology.
the County, listed in Figure 8-1 below, are calculated as the difference in each applicable tax year between $22 million (nominal dollars) and the forecasted property taxes attributable to DCPP in each applicable tax year during the period 2017-2025. PG&E proposes to make the payments at the end of each year between 2017 and 2025. As shown in Figure 8-1, the annual payments are forecasted to grow each year as a result of Diablo Canyon’s declining undepreciated value, which, under the proposal in this Application, will reach zero by August 2, 2025.

FIGURE 8-1
FORECASTED UNITARY PROPERTY TAX PAYMENTS TO SAN LUIS OBISPO AND COMMUNITY IMPACTS MITIGATION PAYMENTS

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<th>Year</th>
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<td>0.6</td>
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<tr>
<td>2025</td>
<td></td>
<td>6.1</td>
</tr>
</tbody>
</table>

The community impact mitigation payments will allow the community to prepare for the significant changes in its annual revenues that will take place in the post operational era as local spending, salaries, and tax payments
associated with Diablo Canyon decrease. As provided in Figure 8-1, PG&E proposes to provide a total of $49.5 million (nominal dollars) to the County through the Community Impacts Mitigation Program over the period 2017-2025.

2. Decommissioning Period Emergency Response Program

In addition to the community impact mitigation payments, the Community Program includes continuing PG&E’s emergency planning, preparation, equipment, response activities and financial contributions related to DCPP during, and as part of, decommissioning. PG&E proposes to continue providing and supporting emergency planning and response activities and assets (emergency preparedness activities) that are appropriate to and informed by the reduced risks that remain as decommissioning progresses.

PG&E currently funds emergency preparedness activities at DCPP through both on-site personnel dedicated fully or in part to emergency response activities and through indirect or financial support to federal, state, and local public entities. The recovery of these costs through 2025 is and will be recovered through PG&E’s generation rates, as authorized by legislation, and is not part of the Community Program. Rather, this component of the joint parties’ agreement focuses on the ongoing costs of the emergency preparedness activities during the decommissioning period.

As part of its site-specific decommissioning study in PG&E’s next Nuclear Decommissioning Cost Triennial Proceeding (NDCTP), PG&E proposes to include the forecasted costs for the following emergency preparedness activities as part of decommissioning:

- Establishing emergency preparedness activities for protection of the health and safety of the public during the 10 Code of Federal Regulations (CFR) Part 50 decommissioning phases;
- Formation of a decommissioning advisory panel which could include industry experts, state and local government representatives, community representatives, and affected stakeholders to provide input

7 Joint Proposal, § 5.4.1.
8 See Assembly Bill 361 (2015).
regarding emergency preparedness activities for each decommissioning phase;

- Emergency preparedness activities should consider provisions and protocols that address incidents such as a fire, transportation, spill, or other industrial accidents that could release radioactive material into the environment;

- Decommissioning phases should consider the following decommissioning evolutions, and associated reductions in risk, up until the submittal of the license termination plan to the NRC in accordance with 10 CFR 50.82(a)(9):
  - Permanently defuel the reactor vessels
  - Spent fuel in the spent fuel pools
  - All spent fuel in the Diablo Canyon ISFSI
  - Dismantlement of radioactive systems, structures, and components
  - Submittal of the License Termination Plan to the NRC

- The following should be considered for each decommissioning phase:
  - Reliable and redundant communication capabilities
  - Equipment and training for emergency entities
  - Transmission of emergency response data to appropriate offsite agencies
  - Funding and maintenance of emergency response facilities
  - Maintenance of the early warning system
  - Funding of federal, local, and state government emergency planning functions related to the DCPP Emergency Preparedness Plan

The 2016 funding for the emergency preparedness plan is $8.86 million (2016 dollars). This funding comprises of the following:

- DCPP EP staff – $3.08 million
- Equipment – $1.07 million
- Offsite agencies – $4.71 million

This estimate does not include the approximately 300 PG&E members of the emergency response organization. Those positions support the emergency response organization through a level-of-effort associated with their employment at DCPP.
The post-2025 decommissioning period emergency preparedness costs will be refined with input from the decommissioning advisory panel based on the principles identified above as part of the DCPP site-specific decommissioning study in PG&E’s next NDCTP.

D. Cost Recovery Proposal

PG&E requests the CPUC approve PG&E’s Community Program mitigation payment cost of $49.5 million (nominal dollars) to be recovered through the Nuclear Decommissioning Nonbypassable Charge (ND NBC). The revenue requirement calculation for the Community Impacts Mitigation Program is presented in Chapter 10.

PG&E requests Commission approval in this Application of the decommissioning period emergency response program. The costs of that program, as refined by the work of the proposed decommissioning advisory panel, will be included in the site-specific decommissioning study to be provided in PG&E’s next NDCTP filing and recovered with the rest of the decommissioning cost study forecasted costs through the nuclear decommissioning nonbypassable charge.

The use of the ND NBC is appropriate because the costs of the Community Program should be recovered from all customers who benefited from the reliable operation of DCPP since 1985, including departed load. These benefits have come from energy savings, reliability, and environmental benefits.

Diablo Canyon is one of the most reliable nuclear power plants in the country. DCPP has provided low-cost, carbon-free electricity for more than 3 million northern and central California homes and generates at least 22 percent of the power PG&E provides to the 48 California counties in its service territory. Finally, all customers in PG&E’s service territory have benefited from DCPP’s decades of GHG-free generation and the associated climate benefits. DCPP avoids emitting 6-7 million metric tons of GHGs per year that would otherwise be produced by conventional generation sources, such as fossil fuel plants.

Given that all customers have enjoyed the benefits of DCPP since 1985, it is reasonable to ask all customers to support the community’s transition through the Community Program.
PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

ATTACHMENT A

ECONOMIC BENEFITS OF DIABLO CANYON POWER PLANT:
AN ECONOMIC IMPACT STUDY
Economic Benefits of Diablo Canyon Power Plant

An Economic Impact Study
June 2013

Prepared by:
Patrick Mayeda, Principal
Dr. Kenneth Riener, Principal

In cooperation with:
Pacific Gas & Electric Company

8-AtchA-1
In conjunction with

Produced June 2013
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Executive Summary

The purpose of this study is to examine the economic impacts and other benefits provided by Diablo Canyon Power Plant (DCPP), owned and operated by Pacific Gas and Electric Corporation (PG&E), on San Luis Obispo and northern Santa Barbara counties, as well as on the state of California and the United States. In 2011, DCPP supplied 9.3% of California’s electricity generation and 7% of its total consumed electricity. DCPP has operated at a steadily increasing percentage of capacity over its lifetime due to a practice of constant upgrading and updating of the equipment. The facility also boasts one of the best safety records in the industry according to the Institute of Nuclear Power Operations (INPO).

DCPP produced an estimated 18,566 megawatt hours of electricity in 2011, with a wholesale value of $675.6 million. In conjunction with the utilization of the industry-standard IMPLAN® software version 3.0 to analyze the impact of local expenditures for goods and services exceeding $22 million, a local payroll of $202.5 million, and 714 local retired PG&E employee pensions totaling over $19 million, this created a total 2011 economic impact on San Luis Obispo and Northern Santa Barbara counties of $919.8 million (Figure 1). The indirect and induced impacts totaled $244.3 million, and included positive influences on many local businesses such as restaurants, real estate, wholesale trade, retail shops, financial institutions and healthcare. With 11 and 12 years remaining on the current licenses, it is expected that PG&E would continue to operate DCPP for the duration of those licenses and that the Plant would continue to generate economic benefits similar to those that exist today.

When the study area is expanded to include all of California, the economic impacts grow significantly, due primarily to two factors: larger expenditures for goods and services, and larger multipliers. DCPP purchased an average of $69.7 million in goods and services from vendors in California over the last two years. In addition to the 1,483 employees living on the Central Coast, 60 DCPP employees work and live outside the local market (mostly in San Francisco or Sacramento), which adds $7.0 million to the payroll. These expenditures increase the indirect impact to $90.2 million, and the induced impact to $334.3 million, for a total of $1.1 billion injected by DCPP into the California economy each year.

The total output impact for DCPP nationally is $1.969 billion. To put this number in perspective, DCPP’s production of $675.6 million of wholesale value electricity produced a total U.S. economic impact of nearly three times that number. Large expenditures averaging $291.8 million over the last two years for specialized equipment such as large steam turbines, generators and nuclear fuel (which can only be obtained outside California), causes the economic impact nationwide to increase significantly. As a comparison, San Luis Obispo County’s wine industry, which includes $954.4 million in wine and grape sales and distribution, had a total national economic impact of $1.785 billion in 2007. ¹

Employment

DCPP created 3,358 jobs locally in 2011, including 1,483 jobs at the Plant. The additional 1,874 jobs created by the spending and re-spending of DCPP purchases and payroll expenditures in the local area were in varying industries including food services, hospitals and healthcare, and real estate.

To state this another way, each DCPP job has created more than one additional job in the local economy.

Due to the high-technology nature of nuclear energy production, DCPP employs a large number of highly-trained engineers, scientists, mechanical and electrical tradespeople, plant security, and other operational occupations. DCPP’s location in the largely rural area of California’s Central Coast makes it one of the few providers of a large number of well-paying, head-of-household jobs in the region. In addition, DCPP employment is not seasonal or cyclical, as are agricultural and tourism-related jobs that dominate the local labor scene. Additionally, while the public sector provides many high-paying jobs in the county, they are affected by California’s State budget crisis, while DCPP jobs are not.

Although there are only 60 DCPP employees outside the local study area (statewide), the impact of the total 1,543 jobs created an additional 2,999.5 jobs in California. The skills represent a cross-section of the California labor force, from highly-trained engineers and scientists to security personnel, nurses and physicians and restaurant staff. Total jobs created nationwide is similarly dramatic: a total of 10,372 jobs were created by the operation of DCPP. As with the California analysis, these positions were in a broad spectrum of occupations and industries.
**FIGURE 2: TOTAL JOBS CREATED BY DCPP, 2011**

- **Local**: 3,358 Jobs
- **Total Statewide**: 4,543 Jobs
- **Total Nationwide**: 10,372 Jobs
- **SLO County Wine Industry 2007**: 8,114 Jobs

**Taxes**

DCPP also had a significant impact on tax revenues. Table 1 shows that at the local level, the dominant forms of tax revenue are property taxes, which totaled $30.8 million in 2011. Of this figure, over $25 million represents the Unitary Property Tax bill paid by PG&E to local entities. Most of this money goes to local school districts, County operations and other County entities. This $25 million is equivalent to what would be paid by properties with a combined assessed value of $2.5 billion, or over 5,000 homes assessed at an average $500,000 value. Additionally, at the local level, approximately $5.3 million in sales taxes are generated.
TABLE 1: TAXES GENERATED BY DCPP, 2011

<table>
<thead>
<tr>
<th>Taxes ($ millions)</th>
<th>Local</th>
<th>California</th>
<th>National</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sales Taxes</td>
<td>5.3</td>
<td>7.6</td>
<td>19.4</td>
</tr>
<tr>
<td>Property Taxes</td>
<td>30.8</td>
<td>33.3</td>
<td>44.1</td>
</tr>
<tr>
<td>State &amp; Local Taxes</td>
<td>42.0</td>
<td>51.1</td>
<td>84.8</td>
</tr>
<tr>
<td>Total Federal Taxes</td>
<td></td>
<td></td>
<td>96.5</td>
</tr>
</tbody>
</table>

The total tax paid to the Federal government is substantial: $43.9 million in personal and corporate income tax, $4.5 million in excise taxes and duties and $43.3 million in Social Security taxes. Social Security tax dollars fund future Social Security benefits, and the other two taxes fund various government services.

PG&E has applied for a 20 year license extension, commencing in 2024 for Reactor One and 2025 for Reactor Two. In order to derive a true representation of economic impacts resulting from a potential shutdown of the plant, the year 2027 was used as the point in time in which the Plant would continue to operate with a license extension, or would be idle due to the lack of extension.

If DCPP is granted license extension beyond 2024, the estimated economic impact for the local area in year 2027 will be $1.48 billion (See Figure 3). If license extension is not granted, only cattle grazing and the Independent Spent Fuel Storage Installation (ISFSI) operations would continue at the site. The “No Extension” economic impact on the local area will be $15.2 million, a 98.9% reduction in economic benefit.

Most of the impact of a “No Extension” decision will be to the local area, and therefore is the focus of that section of the analysis. Losses of virtually all DCPP economic activity will occur, including loss of property taxes, sales taxes and direct plant expenditures.

FIGURE 3: ESTIMATED TOTAL ECONOMIC IMPACT ON LOCAL AREA (YEAR 2027), 2011
Additional Benefits

DCPP’s economics benefits to San Luis Obispo and Northern Santa Barbara County are real and measurable. In addition to recognized benchmarks including expenditures, employment, tax revenues, economic output and labor income, PG&E also supports the community with dollars and value not as readily measured.

PG&E takes pride in being a good neighbor. In 2011 the company awarded more than $23 million in charitable grants to recipients throughout its service area. These donations, funded entirely by shareholders, included approximately $1.1 million distributed to more than 90 non-profit organizations in San Luis Obispo and Northern Santa Barbara counties. In addition, PG&E employees donated more than 31,000 hours of volunteer time to a range of local organizations serving youth, education, seniors, fine arts and environmental interests.

Land stewardship is important to PG&E, a value reflected by the company’s ongoing management of the 12,820-acres surrounding DCPP. PG&E’s commitment to stewardship has enabled coastal hiking trails to be opened for public use, including the 3.3-mile Point Buchon Trail through Montaña de Oro State Park and the Pecho Coast Trail that leads to the restored Port San Luis Lighthouse. These trails offer hiker access to spectacular coastal vistas and add to the visitor experience for the county’s important tourism industry. While these resources benefit coastal tourism, they were not valued as part of this study.

PG&E invests in and operates every day with a focus on safety and increased its expenditures for plant safety in the wake of the March 2011 Fukushima accident in Japan. In addition to extensive on site safety equipment and personnel, PG&E allocates $4 million to the San Luis Obispo County Office of Emergency Services, and anticipates spending $50 million over the next three years to meet all of the Nuclear Regulatory Commission’s post-Fukushima requirements. Many local safety systems exist because of DCPP, with emergency response trailers and emergency siren systems available for area emergencies of any kind.
Methodology

The industry-standard IMPLAN 3 software and databases were used for estimating the economic impact of DCPP on local, statewide and national economies. IMPLAN was originally developed at the University of Minnesota, and then became a private firm, the Minnesota IMPLAN Group (MIG). IMPLAN software is based in the pioneering work of Nobel Prize-winning Harvard economist Wassily Leontief, who developed an Input-Output economic model that recognized the interrelationships among industries and between industries and households.

For instance, a dollar spent at a grocery store is divided between the suppliers of the grocery store, the landlord of the grocery store and the owner of the grocery store business. Any dollar spent at the grocery store is parceled out and “re-spent” by the store’s suppliers and landlord (the “indirect effect”), and the employees’ households (the “induced effect”). The “multiplier” effect of the original dollar spent combines the indirect and induced effects, often referred to as the indirect effect.

IMPLAN software and the accompanying databases all depend on the analyst to enter an input such as total employment, expected sales, or payroll in an existing or proposed business. IMPLAN then estimates the effect on revenues, payroll, employment, and taxes paid for every other sector of the economy in the study area. The key to accurate output estimates or predictions is good input estimates: purchased goods and services, number and types of employees, and average “returns to capital” for the industry/sector of the subject business or project. (IMPLAN can be also used to estimate the economic impact of not-for-profit enterprises such as schools, museums, and art shows).

In applying IMPLAN (or any other input-output analytic system) to the specific situation of DCPP, it was important to note that because most of the electricity generated by DCPP is “exported” out of San Luis Obispo County, the county does not benefit from the full retail value of the electricity produced. Derived from Department of Commerce, the Census Bureau, and other government sources, the economic databases used by IMPLAN appear to apply a nationwide retail price for electricity to the output of DCPP. The databases are used in estimating the GDP of San Luis Obispo County so shouldn’t be completely ignored, but to use them as a measure of the “economic impact” of DCPP on San Luis Obispo County would overstate the impact.

In order to avoid overestimating the effect of DCPP on the San Luis Obispo County/Northern Santa Barbara County market area, the authors chose to value the output at wholesale value, rather than the retail value of the electricity sold.

The IMPLAN system is a respected tool, but it does have some limitations in terms of defining an economic sector. IMPLAN relies on the North American Industry Classification System (NAICS) definitions used by the Department of Commerce (and virtually all economics researchers) for calculating the cost structure and interrelationships between a given industry and other indus-
tries in the economy. Relying on the IMPLAN industry/sector for electricity generation requires use of a weighted average of coal, gas, oil and nuclear power plants for determining cost structure. While nuclear power is a significant player in this industry (20% nationwide), it does not dominate the category. When DCPP is analyzed as part of the electricity generation sector, the model projects a large impact on petroleum extraction, mining and rail transportation, which are clearly not appropriate for a nuclear power plant.

In order to create a model that more closely resembled a nuclear power plant, a “custom industry” for DCPP was created within IMPLAN. Using DCPP expenditures provided by PG&E, each expenditure was allocated using more than 100 classes of commodities and services identified within IMPLAN. IMPLAN provides an option to enter actual labor income for use in capturing the effect of employee expenditure. The data is then used to estimate the impact of household expenditures on the various sectors of the economy. In the present case, salary figures were provided, but in order to capture the full impact of employee spending, salary figures were increased by the estimated 40% benefit load of the health plan and retirement plan provided by PG&E to DCPP employees. The resultant impacts created the indirect and induced impacts for the model.

For the direct impact for the model, the wholesale value of the power generated was used. Note, too, that many DCPP employees who moved to the Central Coast to work at DCPP have chosen to stay here after retirement, and therefore spend their PG&E pension checks in the local economy. While a smaller factor than either employee salaries or DCPP purchases of goods and services, it is worth including in the analysis.

IMPLAN applies these inputs to the chosen economic model (local, state and national). In estimating the impact of an industry, IMPLAN takes account of the interactions between industries in the study area, the import/export patterns for goods and services, and the interactions between households and industries.
Section 1: Introduction

The purpose of this study is to examine the economic impacts and other benefits provided by the Diablo Canyon Power Plant (DCPP), owned and operated by Pacific Gas and Electric Company (PG&E), on the Central Coast (San Luis Obispo and Northern Santa Barbara counties), state of California, and the United States. This is the third study, updating two previous reports titled “Economic Benefits of Diablo Canyon Power Plant” authored by the Nuclear Energy Institute (NEI) in 2004 and 2010, local economic impacts of decommissioning the Diablo Canyon Power Plant. Consistent with most standard economic studies, direct impacts such as employment numbers and salaries, plant expenditures, power generation sales and taxes paid are analyzed and then applied to an input/output model to estimate the indirect and induced effects on the economy. This study will quantify DCPP’s economic impacts and how those impacts relate to the overall gross product of this local area.

PG&E, California Polytechnic State University (Cal Poly), NEI and Productive Impact cooperated in the development of this study. PG&E provided detailed data on DCPP employment, expenditures and tax payments, and NEI provided recent nuclear energy trends. The methodology employed in this study utilizes standard economic impact study practices and was modified by experts from Productive Impact to more closely model a nuclear power generation plant.

Finally, faculty and staff of the Orfalea College of Business at Cal Poly peer reviewed the study to ensure that it was conducted in a manner consistent with industry standards and based on reasonable assumptions.

The report is presented in seven sections, which are:

Section 1 provides an introduction
Section 2 offers background on Diablo Canyon that includes Plant history, performance, production costs, taxes paid and local area details such as total employment and earnings
Section 3 examines the economic impacts of the Plant at local, state and national levels
Section 4 provides benefits not captured in a standard input/output analysis
Section 5 examines the net economic impact caused by license extension vs. no license extension beyond 2025
Section 6 discusses nuclear energy trends such as performance, cost competitiveness and industry safety
Section 7 provides a conclusion

A glossary is included at the end of the report
Section 2: Diablo Canyon Power Plant

This section includes a brief history of DCPP as well as information on the facility’s capacity, performance and employment numbers. It also discusses national production costs, local data (such as county demographics), total employment and earnings.

2.1 History and Information

The Diablo Canyon Power Plant is located along the Pacific Coast of California about halfway between Los Angeles and San Francisco near Avila Beach. The plant occupies fewer than approximately 545 acres of the 12,820 acre-property owned by Pacific Gas and Electric Company. The remaining property is maintained as part of the PG&E Land Stewardship Program. Originally owned by the Pecho and Marre families, the outlying property continues to be used for cattle grazing and agriculture under PG&E-managed leases.

DCPP began commercial operation in 1985. The plant is powered by two Westinghouse-designed 4-loop pressurized water reactors (PWR) – Unit 1 and Unit 2. The two reactors have a generation capacity of 2,300 megawatts and produce about 18,000 gigawatt hours (GWh) of electricity annually.

FIGURE 4: LOCATION OF DCPP

Source: www.calpoly.edu
The two PWRs with steam generators are housed in two massive steel-reinforced concrete containment structures centered between a turbine building, spent-fuel handling building and security facilities. Other plant components include water intake system, water discharge structure and the independent spent fuel storage installation (ISFSI) known as dry cask storage. The ISFSI is an interim storage facility built to store spent fuel used to generate electricity at DCPP.

Three 500 kilovolt transmission lines, known as the Diablo Loop, connect the Diablo Canyon Nuclear Power Plant to the electrical grid by providing parallel transmission paths between two substations (Gates and Midway).

The company delivers power to 15 million customers, or one in every 20 Americans.

In 2009, PG&E filed an application with the Nuclear Regulatory Commission (NRC) to extend the operating license for DCPP. The two nuclear reactors are currently licensed until 2024 and 2025, respectively, and will be decommissioned if the Nuclear Regulatory Commission (NRC) does not extend the licenses for an additional 20 years (to 2044 and 2045).

In March 2011, a devastating earthquake struck northern Japan, creating a tsunami that caused extensive damage to the Fukushima Nuclear Power Plant. PG&E voluntarily suspended its license renewal application while it completed advanced seismic studies of earthquake faults in the region.

In addition to its ongoing investments in safe operations, DCPP expects to spend a total of $50 million over the next three years to meet internal goals and all of the NRC’s post-Fukushima requirements.
2.2 Generation

Generating at least 22% of the power PG&E provides to the 48 California counties in its service territory, DCPP provides low-cost, carbon-free electricity for nearly 3 million Northern and Central California homes, and does so without the approximately 6 to 7 million tons per year of greenhouse gases (GHG) that would be emitted by conventional generation sources. Nuclear power plays a major role in meeting the state’s growing energy demand while helping efforts to improve air quality.

The plant has two Westinghouse-designed 4-Loop pressurized-water nuclear reactors (PWR). Together, the twin 1,150 megawatt reactors—known as Unit One and Unit Two—produce about 18,000 gigawatt hours of clean, reliable and affordable electricity annually, sent via three 500-kV lines that connect to this plant to the grid. Unit One went online on May 7, 1985, and is currently licensed to operate through November 2, 2024. In 2011, Unit One generated 9,863,660 megawatt hours of electricity, at a nominal capacity factor of 100.4 percent. Unit Two went online on March 3, 1986, and is licensed to operate through August 20, 2025. In 2011, Unit Two generated 8,702,414 Mwh of electricity, at a capacity factor of 88.9% (See Table 2).

<table>
<thead>
<tr>
<th>Unit Number</th>
<th>Net Capacity (Mw)</th>
<th>Net Generation (Mwh)</th>
<th>Capacity Factor Percent</th>
<th>Commercial Operation Year</th>
<th>License Expiration Year</th>
<th>Reactor Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1,122</td>
<td>9,863,660</td>
<td>100.4</td>
<td>1985</td>
<td>2024</td>
<td>PWR</td>
</tr>
<tr>
<td>2</td>
<td>1,118</td>
<td>8,702,414</td>
<td>88.9</td>
<td>1986</td>
<td>2025</td>
<td>PWR</td>
</tr>
</tbody>
</table>

Mw=megawatts  PWR=pressurized water reactor  Mwh=megawatt hours
Capacity factor (output proportion of their nominal full-power capacity)

2.3 Efficiency

DCPP is a leader in the nuclear energy industry. As shown in Figure 5, DCPP maintained capacity factors at or above the industry average for most of its years of operation. In the three years previous to 2011, DCPP replaced steam generators for both reactors, causing capacity factors to dip slightly during the replacement project outage. Since completing the project, DCPP has outperformed the current national average for capacity by 5.6%.
2.4 U.S. Electricity Generation

Coal and natural gas-powered plants generate more than half of the nation’s electricity. 19% of energy Americans consume comes from nuclear sources (See Figure 6). Although renewable energy is on the rise, it still accounts for only 12.7% of overall generation. Wind power (2.9%) is second to hydroelectric power (8.0%), and continues to grow more quickly than all other renewables.

**FIGURE 6: SOURCES OF U.S. ELECTRICITY GENERATION, 2011**

- Natural Gas 24.3%
- Coal 43.3%
- Petroleum 0.7%
- Renewables 12.7%
- Nuclear Power 19.0%
- Wind 2.9%
- Hydropower 8.0%
- Biomass Wood 0.9%
- Biomass Waste 0.5%
- Geothermal 0.3%
- Solar 0.1%

Source: U.S. Energy Information Administration

California’s in-state electricity generation system produces more than 200,000 gigawatt-hours each year, transported over the state’s 32,000 miles of transmission lines. In 2011, California sources produced 70% of the electricity used in the state. The remaining 30% was imported from the Pacific Northwest (10%) and the U.S. Southwest (20%). Natural gas is the main source for electricity generation at 45% of the total in-state electric generation system power.

Nuclear power provides 18.4% of California’s electricity generation, with DCPP supplying 18,556,074 Mwh, or 9.3% in 2011. According to the California Energy Commission, demand for electricity in California will continue to rise despite the fact that the California industrial sector’s power demands will remain flat. The main drivers for increased electricity demand lie in commercial, agricultural and residential sectors. Rise in demand will be driven by an increase in the number of households and the number of people per household as well as demand for more commercial floor space. Additionally, it is estimated that electric car charging will increase the average household demand 370 kWh by 2022. Each electric vehicle load is the equivalent of adding two new houses to a neighborhood, if those vehicles are charged during peak energy times.

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California’s challenge is to ensure adequate electricity supplies while reducing greenhouse gas emissions as required by Assembly Bill 32: Global Warming Solutions Act. AB32 calls for reductions in greenhouse gas emissions to 1990 levels by the year 2020.

In addition, under the Renewables Portfolio Standard, the State’s goal was to increase the amount of electricity generated from renewable energy resources to 20% by 2010. PG&E is on track to surpass 25% renewable energy resources in 2013. Legislation passed in 2011 pushes that goal to 33% by 2020. Currently, California’s in-state renewable generation is comprised of biomass, geothermal, small hydro, wind and solar generation sites that make up approximately 17% of the total in-state generational output.³

DCPP electricity production costs remain competitive. At 2.78 cents per kilowatt-hour, DCPP’s average production costs are lower than all other forms of electricity, but are higher than the national average of 2.19 cents per kilowatt-hour for nuclear power (See Figure 7). California’s higher taxes, wages, and regulatory/corporate taxes drive up production costs for DCPP by about 20%. Production costs include the operation, maintenance and fuel costs of each type of plant.

It is estimated that $243 billion has already been invested worldwide in renewable electricity sources, with China, Germany and the U.S. leading the way. However, geographical remoteness and high capital costs have caused the use of renewables to be less than expected. A wind farm or a solar park requires a large amount of land compared to a nuclear power plant.

To build the equivalent of a 1,000-Mw nuclear plant, a solar park would require 11,000 acres of PV solar panels and a wind farm would need 50,000 acres of wind turbines. By contrast, Diablo Canyon is able to produce twice as much power (2300 Mw) in a footprint of approximately 545 acres.4

Production costs for renewable electricity sources are currently difficult to estimate. Renewables are comparatively more expensive because of the large scale production needed for significant cost reduction. Experts believe, however, that the costs per kWh will come down over time as economies of scale improve. A cost comparison performed in 2010 of renewable production costs is shown in Figure 9.

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2.5 Employment

DCPP provides a large number of well-paying jobs not only to residents of San Luis Obispo and Northern Santa Barbara counties, but to residents throughout California and the nation as well. With 1,483 employees living in San Luis Obispo and northern Santa Barbara counties, DCPP is the area’s largest private sector employer and the fifth largest overall. Only the County of San Luis Obispo, California Polytechnic State University, Atascadero State Hospital and the California Men’s Colony employ more people than does DCPP. Locally, the payroll of DCPP in 2011 totaled $202.5 million, with an average salary of $136,561 (See Table 3). Because many of the jobs at DCPP are highly skilled, DCPP employees are compensated well above the 2010 county median household income of $57,365.\textsuperscript{5} Technical/maintenance and engineering jobs make up about 35% of all jobs held at DCPP (See Figure 10).

\textbf{FIGURE 10: DCPP JOB CLASSIFICATIONS}

5 U.S. Census Bureau data; California median household income is $60,883
<table>
<thead>
<tr>
<th>Home City</th>
<th>Employees</th>
<th>Average Salary</th>
<th>Total Payroll</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arroyo Grande</td>
<td>243</td>
<td>$135,778</td>
<td>$32,994,071</td>
</tr>
<tr>
<td>Atascadero</td>
<td>216</td>
<td>$138,340</td>
<td>$29,881,338</td>
</tr>
<tr>
<td>Avila Beach</td>
<td>29</td>
<td>$155,404</td>
<td>$4,506,729</td>
</tr>
<tr>
<td>California, not Local</td>
<td>60</td>
<td>$116,819</td>
<td>$7,009,114</td>
</tr>
<tr>
<td>Cayucos/Cambria</td>
<td>5</td>
<td>$164,422</td>
<td>$822,111</td>
</tr>
<tr>
<td>Creston/Shandon/Templeton</td>
<td>71</td>
<td>$136,710</td>
<td>$9,706,438</td>
</tr>
<tr>
<td>Grover Beach</td>
<td>109</td>
<td>$130,734</td>
<td>$14,250,046</td>
</tr>
<tr>
<td>Guadalupe/Lompoc/Orcutt</td>
<td>8</td>
<td>$112,036</td>
<td>$896,286</td>
</tr>
<tr>
<td>Los Osos/Morro Bay</td>
<td>76</td>
<td>$131,055</td>
<td>$9,960,143</td>
</tr>
<tr>
<td>Nipomo</td>
<td>117</td>
<td>$136,311</td>
<td>$15,948,444</td>
</tr>
<tr>
<td>Oceano</td>
<td>29</td>
<td>$143,471</td>
<td>$4,160,648</td>
</tr>
<tr>
<td>Paso Robles/San Miguel</td>
<td>128</td>
<td>$137,006</td>
<td>$17,536,712</td>
</tr>
<tr>
<td>Pismo Beach/Shell Beach</td>
<td>73</td>
<td>$145,101</td>
<td>$10,592,375</td>
</tr>
<tr>
<td>San Luis Obispo</td>
<td>238</td>
<td>$141,912</td>
<td>$33,775,156</td>
</tr>
<tr>
<td>Santa Margarita</td>
<td>15</td>
<td>$130,819</td>
<td>$1,962,282</td>
</tr>
<tr>
<td>Santa Maria</td>
<td>126</td>
<td>$123,234</td>
<td>$15,527,528</td>
</tr>
<tr>
<td>U.S., not CA</td>
<td>16</td>
<td>$140,753</td>
<td>$2,252,041</td>
</tr>
</tbody>
</table>

**Subtotals**

<p>| | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Local</td>
<td>1483</td>
<td>$136,561</td>
<td>$202,520,307</td>
</tr>
<tr>
<td>State</td>
<td>1543</td>
<td>$135,794</td>
<td>$209,529,421</td>
</tr>
<tr>
<td>National</td>
<td>1559</td>
<td>$135,844</td>
<td>$211,781,462</td>
</tr>
</tbody>
</table>
In addition to their base salaries, PG&E employees enjoy a higher-than-average benefit load of approximately 40%. PG&E’s business requires finding and retaining highly qualified employees to ensure that the company continues to deliver high-quality, cost effective, uninterrupted service to all of its customers.

An added benefit of DCPP salaries is that total employment numbers, salaries and benefit costs are not seasonal, subject to national economic cycles or State budget woes. In that sense, DCPP is a significant financial stabilizer to the local economy which has been buffeted in recent years by a number of factors such as fluctuations in crop values in the agriculture sector, reduced tourist spending due to the economic recession and wide fluctuations in government payroll. All have all affected local economic stability.

There are 714 retired PG&E employees who reside in San Luis Obispo and Santa Barbara counties, most of whom were likely employed at DCPP. Total 2011 pension cost for the local retirees was estimated at $19,049,361. Since PG&E and its employees pay into Social Security, DCPP retirees also qualify for Social Security benefits. And since retirees continue to receive medical coverage from PG&E, they will likely not utilize Medi-Cal or other publicly-funded medical insurance programs.

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6 Benefit load typically includes health benefits, 401k type plans, and retirement/pension plans.
2.6 Expenditures for Goods and Services

DCPP is a major purchaser of goods and services from local, state and national sources, averaging over $374.6 million per year nationally. Purchases include procurement of parts, tools and services from a wide variety of businesses. Expenditures vary from year to year as shown in Table 4.

Local expenditures in San Luis Obispo and Northern Santa Barbara counties in 2011 totaled about $21.8 million, owing in part to PG&E’s policy of sourcing goods and services locally wherever feasible. When specialty parts or expertise are unavailable locally, DCPP goes out of area to purchase goods and services. PG&E’s state and nationwide spending in 2011 totaled $78.8 million and $298.7 million, respectively. The jump in nationwide expenditures from 2010 to 2011 reflects increased fuel costs, capital expenditures and upgrades, and purchase of specialty services that cannot be found in California.

<table>
<thead>
<tr>
<th>TABLE 4: DCPP EXPENDITURES BY STUDY AREA</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
</tr>
<tr>
<td>Local*</td>
</tr>
<tr>
<td>California</td>
</tr>
<tr>
<td>Nationwide</td>
</tr>
</tbody>
</table>

*San Luis Obispo and Northern Santa Barbara counties

| FIGURE 11: DCPP EXPENDITURES 2008–2011 |
DCPP benefits the community in a number of ways, including sourcing local goods and services whenever possible. San Luis Obispo and Santa Barbara counties have enjoyed—on average—$21.8 million of direct spending in the community from the operations of DCPP. The specialized nature of a nuclear plant requires that purchase, maintenance and repair of power generation equipment and parts are priorities (See Figure 12 for the top 25 impacted sectors). There are many qualified service companies in the local area that DCPP uses whenever possible.

**FIGURE 12: TOP 25 EXPENDITURES IN SAN LUIS OBISPO AND SANTA BARBARA COUNTIES**

TOTAL 2011 LOCAL EXPENDITURES $21,769,134

<table>
<thead>
<tr>
<th>Expenditure Category</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wholesale purchase of goods and parts</td>
<td>10,323,555</td>
</tr>
<tr>
<td>Maintenance and cleaning services to building</td>
<td>5,988,172</td>
</tr>
<tr>
<td>Maintenance and repair construction</td>
<td>3,353,208</td>
</tr>
<tr>
<td>Power generation equipment and parts</td>
<td>2,453,893</td>
</tr>
<tr>
<td>Miscellaneous professional and technical services</td>
<td>2,237,163</td>
</tr>
<tr>
<td>Specialized design services</td>
<td>1,925,277</td>
</tr>
<tr>
<td>Environmental and other technical consulting services</td>
<td>1,656,594</td>
</tr>
<tr>
<td>Machinery and equipment rental and leasing</td>
<td>1,386,588</td>
</tr>
<tr>
<td>Maintenance and repair of nonresidential buildings</td>
<td>1,241,921</td>
</tr>
<tr>
<td>Security services</td>
<td>835,239</td>
</tr>
<tr>
<td>Building materials</td>
<td>623,372</td>
</tr>
<tr>
<td>Waste management services</td>
<td>528,508</td>
</tr>
<tr>
<td>Food services</td>
<td>413,035</td>
</tr>
<tr>
<td>Engineering services</td>
<td>348,002</td>
</tr>
<tr>
<td>Miscellaneous store retailers</td>
<td>336,404</td>
</tr>
<tr>
<td>Other support services</td>
<td>316,539</td>
</tr>
<tr>
<td>Industrial building construction</td>
<td>273,453</td>
</tr>
<tr>
<td>Automotive repair and maintenance</td>
<td>270,317</td>
</tr>
<tr>
<td>Advertising and related services</td>
<td>252,327</td>
</tr>
<tr>
<td>Switchgear and switchboard apparatus manufacturing</td>
<td>227,522</td>
</tr>
<tr>
<td>Other new construction</td>
<td>224,547</td>
</tr>
<tr>
<td>State and local non-education</td>
<td>223,210</td>
</tr>
<tr>
<td>Electronics stores</td>
<td>215,660</td>
</tr>
<tr>
<td>Telecommunications</td>
<td>172,369</td>
</tr>
<tr>
<td>Management and consulting services</td>
<td>159,097</td>
</tr>
<tr>
<td>All other sectors</td>
<td>422,154</td>
</tr>
</tbody>
</table>
2.7 Property Taxes (Unitary)

Public utility assets, including generating facilities like DCPP, are subject to the same taxation as other property. By State law (Article XIII, Section 19 of the California State Constitution), public utilities pay property taxes directly to the State Board of Equalization (BOE) which in turn, distributes taxes back to the local taxing jurisdictions.

The BOE establishes property taxes for utility companies based on the value of all utility-operated property and assets throughout the state. This is called a single “unitary” value, and is used instead of separately assigning a value to each component part. The BOE allocates the unitary value of public utility assets among taxing jurisdictions in proportion to the replacement cost new, less depreciation, value of each item of unitary property. The amount of the tax revenues distributed back to each county is based on the ratio of the total unitary value to the proportion of total PG&E property located in a particular county.

Without Proposition 13 protection and as DCPP performs plant capital improvements for safety or in preparation for potential relicensing, PG&E’s unitary tax liability continues to increase each year. As shown in Figure 13, unitary tax distributions have a significant effect on numerous local entities, especially schools and other county and city operations.

As a result of multibillion-dollar investment made by PG&E in DCPP, the Power Plant has a very large property assessment. PG&E’s 2011/2012 Unitary Property Tax payment for San Luis Obispo County was $25,373,098. This is the equivalent of a one % property tax on over 5,070 single-family residences (assuming an average assessed value of $500,000 per residence). And given that DCPP provides its own water, sewer, and roads, and most of its own security and fire protection, the plant places a very low burden on County public services.

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7 Proposition 13 was passed in California in 1978 and established a fixed property tax rate of 1% of assessed value (plus amounts required to repay any assessment bonds approved by the voters). Source: California State Board of Equalization, 2013

8 Data obtained from actual 2011 San Luis Obispo County tax records for PG&E. Although 88% of the actual unitary taxes paid are directly attributable to DCPP, it could be argued that without the existence of DCPP, much of the other PG&E property would not be in existence (i.e. power transmission lines, etc.)
FIGURE 13: PG&E 2011/2012 UNITARY TAX REVENUE ALLOCATION

- San Luis Coastal Unified $9,241,539
- General Fund $6,784,180
- Roads $295,145
- $25,000–$249,000*
- $1–$24,900**
- Education Resource Augmentation Fund (ERAF-State Transfer) $2,276,290
- SLO Co Community College $1,916,636
- County School Service $1,136,971
- Lucia Mar Unified $544,903
- Atascadero Unified $389,190
- Port San Luis Harbor $382,246
- Paso Robles Unified $356,045
- County Library $489,972
- Roads $295,145

*There are 17 governmental entities that receive between $25,000 to $249,999
**There are 63 governmental entities that receive between $1 to $24,999
To help understand the substantial effect that annual DCPP unitary tax payments have on the Central Coast, a sampling of three jurisdictions that receive unitary taxes is reviewed below.

**San Luis Obispo County General Fund:**
The total 2011-2012 budget for San Luis Obispo County is $464,428,463, with $383,347,164 earmarked for the General Fund. The General Fund receives 26.7% of the DCPP unitary tax payment each year. In 2011, the County of San Luis Obispo received $6,784,180 from PG&E’s tax payment, which accounts for 1.8% of the County’s General Fund. These monies help fund public work projects, probation and sheriff offices and health and other vital services. This $6.8 million could fund both the Animal Shelter ($1.58 million) and Child Support Services ($4.87 million) in their entirety.

As the County budget is subject to shortfalls, DCPP’s steadily-growing property tax payment helps mitigate potential cuts to funds for roads, libraries and employees’ jobs and benefits. PG&E pays more property taxes than any other entity in the county because of the method of assessment and lack of Proposition 13 property tax protection. As long as Diablo Canyon operates, payments will continue.

**San Luis Coastal Unified School District:**
In the 2010/2011 tax year, San Luis Coastal Unified School District received $9,241,539, or 36.4% of the unitary taxes paid by PG&E. The overall school district budget for 2012/2013 is estimated at $79.9 million. PG&E’s unitary tax payment supports approximately 11.6% of the school district’s entire budget. The amount of annual property tax dollars received by the school district from PG&E has led to the district becoming a “basic aid” or “community funded” district.

Basic aid districts do not receive funding based on enrollment. Rather, districts rely on a large, steady property tax base that creates a stable revenue source for the districts, mitigating the effects of State budget shortfalls. Despite its status as a basic aid school district, San Luis Coastal Unified School District is experiencing budgetary challenges and has made cuts in personnel and programs including music, adult education, special education and professional development. Cuts would have been more severe and much earlier if not for the unitary taxes paid by PG&E.
Port San Luis Harbor District:

In 1954, the citizens of southern San Luis Obispo County voted to create and fund a Harbor District for the Port San Luis area. The district was created to help refurbish and maintain the Harbor District’s old facilities and increase commerce for the South County. Five harbor commissioners were elected and, in 1955, the State Legislature granted the Harbor District the area’s tidelands in trust. The State of California owns and manages the waters extending to the three-mile mark. The Harbor District owns the Harford Pier and surrounding property.

In 2011/2012, the Harbor District’s $4,166,400 budget was used to repair District facilities and tend to environmental responsibilities while maintaining funds needed to serve the boating and general public. PG&E’s unitary tax payment allotment to the Harbor District for 2011/2012 is $383,246, or 9.2% of the Harbor District’s total budget. In 2011/2012, the Harbor District budgeted $50,000 for Harford Pier and Canopy design and permits in preparation for a $1.5 million Pier and Canopy upgrade. Without the tax dollars paid by PG&E, that project could have been delayed or postponed indefinitely. Many additional projects - such as land craft mechanized repairs, parking lot repaving or dredging pump replacements - could be at risk without this tax revenue stream.
Section 3: Economic and Fiscal Impacts

Most of DCPP’s employees live in San Luis Obispo County or Northern Santa Barbara County. Wages employees receive are mainly spent in their area of residence. DCPP strives to source local vendors for its expenditures; however, a significant amount of goods and services are procured from outside the local area and much of the specialized equipment and technical expertise must be purchased outside California.

Terminology

In economic parlance, the direct impact of a business or project is the total value of the good or service generated by the business or activity being analyzed. For a private business, direct impact would generally be the sales generated by the firm. For a public service, such as a homeless shelter, it would be the value of the services delivered. For certain types of activities, such as retail or wholesale trade, the total output direct impact is the difference between the price of the goods purchased for sale, and the revenues received from the sale. The logic of this difference is that the wholesale price of the goods is already captured in the output of the producers of the goods.

The indirect impact of a business is the revenue generated by other firms as a result of the business' operation. For example, if a supermarket buys lettuce from a local farm, the farm's sale to the supermarket is classified as indirect impact.

The induced impact of a business/activity is the change in household expenditures, owing to the business operation. For instance, spending by employees of the supermarket as well as employees of the farm and other suppliers generate induced impact.

The distinction between indirect impact and induced impact is very important to economists but may not have as much interest to the public. Economic impact reports often combine indirect impact and induced impact, and report the total as indirect impact. This report maintains the distinction between the two for readers interested in seeing the information.

Another term which needs some explanation is imputed rental activity [or IRA Value] for owner-occupied dwellings. IRA value methods were developed by national accounting economists to determine the economic effect of household expenditures used for purchasing and maintaining a home. IRA assumes that homeowners are their own landlords, and that while homeowners are not paying rent to landlords, payments for mortgages, landscaping and maintenance stimulate the economy in the same way that a landlord's expenditures for these same expenses do and are accounted for in the national accounting totals. Even while “imputed rental value” is not as concrete an expenditure as are purchases of food and furniture, it is a legitimate contributor to the economy.
Tax Effects

In addition to the local expenditures directly or indirectly attributable to the presence of DCPP, another significant benefit is the increased tax revenue from these activities. Tax revenues take several forms: personal and business income taxes, property taxes, sales taxes, building permits, auto license fees and many other taxes. Since many of these taxes are used to cover the cost of providing a related service, they are reported separately.

Value of Electricity Produced

When modeling the economic activity of DCPP, the direct impact is the value of the electricity generated at DCPP. Using production figures and daily spot wholesale rates, the value of this electricity is estimated at $675.6 million in 2011. When comparing this value to the $1.226 billion total value of all electricity generated in San Luis Obispo County as reported by the Department of Commerce, it reinforces the conservative nature of this study.

The $1.226 billion represents approximately 10% of San Luis Obispo County’s total Gross Regional Product, but it has little direct effect on the people of San Luis Obispo County, since most of the power is exported to other areas of PG&E’s market. And although Department of Commerce does not report DCPP’s electricity output separately, there are no other significant sources of electricity generation in San Luis Obispo County other than the Morro Bay Power Plant, which is only put into service during times of very high demand, and two Carrizo Plains solar projects that have not yet come online. Therefore, it is safe to assume that the entire $1.226 billion estimation represents only the electricity generated by DCPP.

Model Inputs

DCPP’s spending lifts economic activity. This effect is experienced by the private sector through increased sales and employment, and by the public sector through increased tax revenue to support public services. The economic and fiscal impacts of DCPP’s operations go well beyond spending on employee and retiree benefits, purchases, salaries, and taxes. They also reflect the strong stimulus that plant operations provide to key measures of economic activity—the value of electricity production, employment, and labor income—in the economy. More important to local residents are the effects of money flowing into the local economy as a result of DCPP’s presence here. This cash stimulus comes in three main forms: local expenditures by DCPP employees, which is based upon their salaries and benefits, purchases of goods and services from local vendors and local expenditures by retired DCPP employees who have stayed in the area after retirement.
Employee Expenditures

The number of employees working at DCPP and residing on the Central Coast at the end of 2011 was 1,483. Total payroll during 2011 was $202,520,307. In addition to salaries, DCPP employees receive competitive benefits in the form of healthcare, dental care and retirement benefits, generally about a 40% additional value. DCPP employees have a guaranteed benefit retirement plan similar to Cal Poly or municipal employees. This means that they have to set aside less in tax-deferred retirement plans and have more discretionary income to spend locally. More of their wages can be used to purchase homes, groceries, cars, meals and movie tickets. As a result, the induced impact of these wages is about the same as the direct wages—$203.2 million.

Purchases of Goods and Services

The next largest source of financial stimulus to the local economy results from DCPP’s purchases of goods and services from local businesses and tradespeople. The list of local vendors includes office supply stores, plumbers, fence builders, roofers, welders, painters, parts and hardware stores. The actual mix varies significantly from year to year, so 2010 and 2011 expenditures were averaged to obtain a representative mix. The average annual expenditure (or “spend”) was $18,209,014.

Retiree Expenditures

The third source of financial stimulus is money spent locally by DCPP retirees. There were 714 PG&E retirees living in San Luis Obispo and Northern Santa Barbara counties at the end of 2011, with estimated pensions of $19,049,361 for the year.

### TABLE 5: DCPP VITAL STATISTICS 2011

<table>
<thead>
<tr>
<th>Study Area</th>
<th>Local (San Luis Obispo and Santa Barbara counties)</th>
<th>State (California)</th>
<th>National (USA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Employees</td>
<td>1,483</td>
<td>1,543</td>
<td>1,559</td>
</tr>
<tr>
<td>Payroll</td>
<td>$202,520,307</td>
<td>$209,529,421</td>
<td>$211,781,462</td>
</tr>
<tr>
<td>Annual Expenditures for Goods and Services</td>
<td>$18,209,014</td>
<td>$69,735,934</td>
<td>$293,585,539</td>
</tr>
<tr>
<td>PG&amp;E retirees living in San Luis Obispo/Santa Barbara counties</td>
<td>$19,049,361</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$239,780,165</strong></td>
<td><strong>$279,266,898</strong></td>
<td><strong>$505,581,900</strong></td>
</tr>
</tbody>
</table>

8-AtchA-29
3.1 Local Economic Impact

Economic Impact in the Local Economy

The largest economic impact of DCPP on San Luis Obispo and Santa Barbara Counties is in the **imputed rental activity** for owner-occupied dwellings. As described earlier, this variable is the “rent” that homeowners would pay to rent their own homes. It reflects DCPP employees and suppliers stimulus to the local economy by building and maintaining homes. Homes are seen as both an investment as well as a “consumer durable good.” Seven of the remaining top ten categories listed on Table 6 reflect the consumption, healthcare, and investment expenditures of DCPP employees, and employees of DCPP vendors. The only exception, wholesale business, ranks high because of DCPP’s policy of purchasing goods from local vendors where feasible. Many commodity-type goods, such as petroleum products and some office supplies, can be purchased in wholesale quantities.

### TABLE 6: DCPP LOCAL TOTAL ECONOMIC IMPACT, 2011

<table>
<thead>
<tr>
<th>Rank</th>
<th>Description</th>
<th>Direct*</th>
<th>Indirect*</th>
<th>Induced*</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Electric power generation, transmission, and distribution</td>
<td>$675,572,354</td>
<td>$113,870</td>
<td>$3,988,787</td>
<td>$679,675,011</td>
</tr>
<tr>
<td>2</td>
<td>Imputed rental activity for owner-occupied dwellings</td>
<td>0</td>
<td>$31,864,664</td>
<td></td>
<td>$31,864,664</td>
</tr>
<tr>
<td>3</td>
<td>Offices of physicians, dentists, and other health practitioners</td>
<td>$362</td>
<td>$14,312,112</td>
<td></td>
<td>$14,312,474</td>
</tr>
<tr>
<td>4</td>
<td>Real estate establishments</td>
<td>$213,473</td>
<td>$12,318,973</td>
<td>$12,532,446</td>
<td>$559,324,882</td>
</tr>
<tr>
<td>5</td>
<td>Food services (i.e. restaurants)</td>
<td>$139,381</td>
<td>$12,245,125</td>
<td></td>
<td>$12,384,506</td>
</tr>
<tr>
<td>6</td>
<td>Private hospitals</td>
<td>$35</td>
<td>$10,282,620</td>
<td></td>
<td>$10,282,971</td>
</tr>
<tr>
<td>7</td>
<td>Wholesale trade businesses</td>
<td>$299,395</td>
<td>$8,020,818</td>
<td></td>
<td>$8,320,213</td>
</tr>
<tr>
<td>8</td>
<td>Monetary authorities and depository credit intermediation activities</td>
<td>$159,237</td>
<td>$7,486,983</td>
<td></td>
<td>$7,646,220</td>
</tr>
<tr>
<td>9</td>
<td>Petroleum refineries</td>
<td>$194,874</td>
<td>$6,809,443</td>
<td></td>
<td>$7,004,318</td>
</tr>
<tr>
<td>10</td>
<td>Securities, commodity contracts, investments, and related activities</td>
<td>$73,168</td>
<td>$6,289,903</td>
<td></td>
<td>$6,363,071</td>
</tr>
<tr>
<td>11</td>
<td>Nondepository credit intermediation and related activities</td>
<td>$112,482</td>
<td>$4,717,455</td>
<td></td>
<td>$4,829,937</td>
</tr>
<tr>
<td>12</td>
<td>Medical and diagnostic labs and outpatient and other ambulatory care</td>
<td>$16,396</td>
<td>$4,453,737</td>
<td></td>
<td>$4,470,133</td>
</tr>
<tr>
<td>13</td>
<td>Retail Stores - Food and beverage</td>
<td>$4,920</td>
<td>$4,184,188</td>
<td></td>
<td>$4,189,108</td>
</tr>
<tr>
<td>14</td>
<td>Other state and local government enterprises</td>
<td>$37,264</td>
<td>$3,422,775</td>
<td></td>
<td>$3,460,039</td>
</tr>
<tr>
<td>15</td>
<td>Retail Stores - Motor vehicle and parts</td>
<td>$6,253</td>
<td>$3,167,321</td>
<td></td>
<td>$3,173,574</td>
</tr>
<tr>
<td>16</td>
<td>Nursing and residential care facilities</td>
<td>0</td>
<td>$3,141,147</td>
<td></td>
<td>$3,141,147</td>
</tr>
<tr>
<td>17</td>
<td>Telecommunications</td>
<td>$118,315</td>
<td>$2,825,343</td>
<td></td>
<td>$2,943,658</td>
</tr>
<tr>
<td>18</td>
<td>Retail Stores - General merchandise</td>
<td>$3,423</td>
<td>$2,930,800</td>
<td></td>
<td>$2,934,223</td>
</tr>
<tr>
<td>19</td>
<td>Facilities support services</td>
<td>$2,667,004</td>
<td>$60,379</td>
<td></td>
<td>$2,727,383</td>
</tr>
<tr>
<td>20</td>
<td>Legal services</td>
<td>$101,803</td>
<td>$2,509,997</td>
<td></td>
<td>$2,611,800</td>
</tr>
<tr>
<td>21</td>
<td>Management, scientific, and technical consulting services</td>
<td>$1,442,994</td>
<td>$1,085,823</td>
<td></td>
<td>$2,528,817</td>
</tr>
<tr>
<td>22</td>
<td>Retail Nonstores - Direct and electronic sales</td>
<td>$2,197</td>
<td>$2,328,031</td>
<td></td>
<td>$2,330,228</td>
</tr>
<tr>
<td>23</td>
<td>Civic, social, professional, and similar organizations</td>
<td>$20,235</td>
<td>$2,218,715</td>
<td></td>
<td>$2,238,950</td>
</tr>
<tr>
<td>24</td>
<td>Retail Stores - Clothing and clothing accessories</td>
<td>$2,379</td>
<td>$2,207,133</td>
<td></td>
<td>$2,209,511</td>
</tr>
<tr>
<td>25</td>
<td>Maintenance and repair construction of nonresidential structures</td>
<td>$658,288</td>
<td>$1,337,986</td>
<td></td>
<td>$1,996,273</td>
</tr>
<tr>
<td></td>
<td>Total all other categories</td>
<td>$15,608,731</td>
<td>$68,043,653</td>
<td></td>
<td>$83,652,384</td>
</tr>
</tbody>
</table>

*Direct:* Total value of the good or service generated by the business or activity being analyzed. **Indirect:** Revenue generated by other firms. **Induced:** Change in household expenditures.

Source: © 2012 Minnesota IMPLAN Group, Inc.
The Total Economic Impact of DCPP on the local economy in 2011 was $919,823,060 (See Table 6). This includes almost $22 million of incremental revenue in other local businesses and $222.3 million in local household spending by employees of DCPP, their suppliers and their suppliers’ suppliers. As shown in Figure 14, this impact is spread across a wide spectrum of the local economy, including medical services, restaurants and bars, real estate firms, investment management firms, etc.

**FIGURE 14: TOP TEN IMPACTED SECTORS, LOCAL TOTAL ECONOMIC IMPACT $866.2M**

The perceptive reader might notice that the direct impact of energy output, $675.57 million, is slightly less than the estimated value of electricity produced, $679.7 million. In the present case, a custom IMPLAN industry for DCPP was created, since the closest existing industry in IMPLAN sector plan is electricity production, which includes all forms of fossil-fuel electricity, nuclear and renewable energy production. Our input weighting was based upon actual DCPP “spend,” as described earlier. The most significant contributor to the discrepancy is purchases through wholesale trade. IMPLAN considers the direct output impact of wholesalers to be the difference between the cost of goods sold, and the sale price of the goods. This avoids double-counting the purchase price of the goods purchased, and resold, by the wholesaler.

**Job Creation in the Local Economy**

In 2011, expenditures by DCPP, its employees and vendors generated over 3,300 jobs in the area which means that each DCPP job has created more than one additional job in the local economy. Additional detail on job creation is provided in the table and graph that follow. Table 7 shows the jobs generated in the local economy cover the full spectrum of skill levels and job types, from accountants to nurses to grocery store clerks.
FIGURE 15: ECONOMIC IMPACTS OF DCPP EMPLOYMENT

- Expenditures 174.5 (5.2%)
- Pensions 107.0 (3.2%)
- Employee Wages 1,593.0 (47.4%)
- Direct Jobs of DCPP 1,483.0 (44.2%)

TABLE 7: JOBS CREATED IN SAN LUIS OBISPO AND SANTA BARBARA COUNTIES BY DCPP, 2011

<table>
<thead>
<tr>
<th>Rank</th>
<th>Description</th>
<th>Direct*</th>
<th>Indirect*</th>
<th>Induced*</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Electric power generation, transmission, and distribution</td>
<td>1,483.0</td>
<td>0.1</td>
<td>5.0</td>
<td>1,488.1</td>
</tr>
<tr>
<td>2</td>
<td>Food services (restaurants)</td>
<td>0.0</td>
<td>2.3</td>
<td>199.9</td>
<td>202.2</td>
</tr>
<tr>
<td>3</td>
<td>Offices of physicians, dentists, and other health practitioners</td>
<td>0.0</td>
<td>0.0</td>
<td>120.4</td>
<td>120.4</td>
</tr>
<tr>
<td>4</td>
<td>Private hospitals</td>
<td>0.0</td>
<td>0.0</td>
<td>68.6</td>
<td>68.6</td>
</tr>
<tr>
<td>5</td>
<td>Real estate establishments</td>
<td>0.0</td>
<td>1.2</td>
<td>66.5</td>
<td>67.7</td>
</tr>
<tr>
<td>6</td>
<td>Retail Stores - Food and beverage</td>
<td>0.0</td>
<td>0.1</td>
<td>64.5</td>
<td>64.5</td>
</tr>
<tr>
<td>7</td>
<td>Securities, commodity contracts, investments, and related activities</td>
<td>0.0</td>
<td>0.6</td>
<td>53.8</td>
<td>54.4</td>
</tr>
<tr>
<td>8</td>
<td>Private household operations</td>
<td>0.0</td>
<td>0.0</td>
<td>53.7</td>
<td>53.7</td>
</tr>
<tr>
<td>9</td>
<td>Wholesale trade businesses</td>
<td>0.0</td>
<td>1.9</td>
<td>50.7</td>
<td>52.6</td>
</tr>
<tr>
<td>10</td>
<td>Nursing and residential care facilities</td>
<td>0.0</td>
<td>0.0</td>
<td>51.5</td>
<td>51.5</td>
</tr>
<tr>
<td>11</td>
<td>Retail Stores - General merchandise</td>
<td>0.0</td>
<td>0.1</td>
<td>49.5</td>
<td>49.5</td>
</tr>
<tr>
<td>12</td>
<td>Retail Nonstores - Direct and electronic sales</td>
<td>0.0</td>
<td>0.0</td>
<td>40.5</td>
<td>40.5</td>
</tr>
<tr>
<td>13</td>
<td>Individual and family services</td>
<td>0.0</td>
<td>0.0</td>
<td>40.5</td>
<td>40.5</td>
</tr>
<tr>
<td>14</td>
<td>Retail Stores - Clothing and clothing accessories</td>
<td>0.0</td>
<td>0.0</td>
<td>35.4</td>
<td>35.4</td>
</tr>
<tr>
<td>15</td>
<td>Nondepository credit intermediation and related activities</td>
<td>0.0</td>
<td>0.8</td>
<td>34.5</td>
<td>35.4</td>
</tr>
<tr>
<td>16</td>
<td>Employment services</td>
<td>0.0</td>
<td>4.4</td>
<td>28.4</td>
<td>32.8</td>
</tr>
<tr>
<td>17</td>
<td>Retail Stores - Miscellaneous</td>
<td>0.0</td>
<td>0.0</td>
<td>32.4</td>
<td>32.4</td>
</tr>
<tr>
<td>18</td>
<td>Retail Stores - Motor vehicle and parts</td>
<td>0.0</td>
<td>0.1</td>
<td>32.0</td>
<td>32.0</td>
</tr>
<tr>
<td>19</td>
<td>Civic, social, professional, and similar organizations</td>
<td>0.0</td>
<td>0.3</td>
<td>30.5</td>
<td>30.8</td>
</tr>
<tr>
<td>20</td>
<td>Medical and diagnostic labs and outpatient and other ambulatory care services</td>
<td>0.0</td>
<td>0.1</td>
<td>27.0</td>
<td>27.1</td>
</tr>
<tr>
<td>21</td>
<td>Services to buildings and dwellings</td>
<td>0.0</td>
<td>4.1</td>
<td>22.3</td>
<td>26.5</td>
</tr>
<tr>
<td>22</td>
<td>Home health care services</td>
<td>0.0</td>
<td>0.0</td>
<td>24.8</td>
<td>24.8</td>
</tr>
<tr>
<td>23</td>
<td>Retail Stores - Health and personal care</td>
<td>0.0</td>
<td>0.0</td>
<td>24.0</td>
<td>24.1</td>
</tr>
<tr>
<td>24</td>
<td>Management, scientific, and technical consulting services</td>
<td>0.0</td>
<td>13.1</td>
<td>9.8</td>
<td>22.9</td>
</tr>
<tr>
<td>25</td>
<td>Private elementary and secondary schools</td>
<td>0.0</td>
<td>0.0</td>
<td>21.3</td>
<td>21.3</td>
</tr>
<tr>
<td></td>
<td>Total all other categories</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

*Direct: Total value of the good or service generated by the business or activity being analyzed. Indirect: Revenue generated by other firms. Induced: Change in household expenditures.

Source: © 2012 Minnesota IMPLAN Group, Inc.
Tax Impact at the Local Level

As seen in Table 8, DCPP generated over $38 million in state and local taxes. The largest single item, $30.8 million in property tax payment, includes the $25 million paid directly by PG&E, as well as additional property taxes paid by DCPP vendors and employees. Over $5 million of sales taxes are paid annually by DCPP and their vendors and employees, which helps county and municipal governments balance their budgets.

<table>
<thead>
<tr>
<th>Description</th>
<th>Indirect Business Tax</th>
<th>Households</th>
<th>Corporations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Social Ins Tax- Employee Contribution</td>
<td>$124,326</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Social Ins Tax- Employer Contribution</td>
<td>$288,051</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Business Tax: Sales Tax</td>
<td>$5,328,432</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Business Tax: Property Tax</td>
<td>$30,810,022</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Business Tax: Motor Vehicle Lic</td>
<td>$121,431</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Business Tax: Other Taxes</td>
<td>$1,531,435</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Corporate Profits Tax</td>
<td></td>
<td>$1,070,926</td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Income Tax</td>
<td>$2,005,062</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: (Fines- Fees)</td>
<td>$541,156</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Motor Vehicle License</td>
<td>$87,398</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Property Taxes</td>
<td>$40,083</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Other Tax (Fish/Hunt)</td>
<td>$20,964</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total State and Local Tax</td>
<td>$38,079,371</td>
<td>$2,818,989</td>
<td>$1,070,926</td>
</tr>
</tbody>
</table>

Source: © 2012 Minnesota IMPLAN Group, Inc.

In addition to the size of tax revenue estimates, it is worth noting that underlying expenditures remain constant and tax revenues stable, regardless of the state of the local or State economy, and unlike revenues from more cyclical businesses and sectors that have fallen significantly from historic high peaks, such as the housing and real estate market.

A tangential question which arises when discussing property taxes is the effect DCPP closure would have on the local housing market if DCPP were to close and its employees move away. While an analysis would be highly speculative, this study examines several statistics for indicators. If most of the 1,483 local DCPP employees are members of different households, approximately 1,450 homes would be vacated over a relatively short time period if the plant closed and DCPP employees relocated to another area. By comparison, San Luis Obispo County has averaged 1,291 new housing starts per year since 1990.
A large number of homes for sale has the potential to significantly depress property values, in turn causing a large drop in new housing starts. If new housing starts decreased by half, it would take about 2.5 years to absorb excess inventory. A drop in local housing prices could draw a significant number of retirees and other mobile households with moderate income and net worth into the area. It appears likely that there would be, at least temporarily, a drop in housing prices, followed by corrections and eventual recovery. In the meantime the precipitous drop in new home construction, a major local source of employment, and the drop in home prices would cause major disruptions in the local economy.

Overall, this analysis shows that DCPP provides a significant stimulus to the local economy in the revenue it provides to local firms, the jobs it generates for local residents, and the tax revenues it generates to help local governments provide services to local residents. And as a non-seasonal, non-cyclical operation, DCPP is a significant stabilizer to the local economy.
3.2 California Economic Impact

Economic Impact on California

The total Economic Impact of DCPP on the State of California is $1.1 billion in 2011. In addition to this financial boost to the California economy, DCPP generated 4,542 jobs in California, with over 1,000 of them outside San Luis Obispo and Santa Barbara counties.

The Economic Impact of DCPP on the State of California is larger than the impact on the local market for three reasons. First, since many of the goods and services that DCPP needs are not available locally but are available elsewhere in California, total statewide purchases of goods and services are larger than the local number. Second, because dollars spent in California recirculate more times within California before “leaking out” to other states or countries, the multiplier is larger. Third, there are 60 DCPP employees who work and live in California, but outside the local DCPP area. These factors result in an across-the-board increase in the total dollar impact of DCPP on the California economy.

The $1.1 billion total Economic Impact of DCPP on the state of California (pacing far ahead of the local impact), is due in part to the greater amount of purchases of sophisticated equipment and increased fees paid for specialized engineering consulting outside the local area. The economic sectors of engineering consulting and wholesale trade, rank very high in the statewide analysis.

On the other side, those sectors most influenced by household spending, such as restaurants and bars, ranked lower. The direct impact is slightly greater because of the small number (60) of DCPP-related employees whose work location and residence are outside the local area. Total impact is greater because of the larger multiplier effect. For instance, in the local market, a payroll of $202,520,300 produced a total output impact of $203,211,941 for a multiplier of 1.003. The reason that the impact is not larger is that a significant proportion of an employee’s wages goes to income taxes and Social Security withholding, which reduces spendable income. At the statewide level, the net spendable income is recirculated several times throughout California before “leaking out” to the rest of the world. Therefore, the statewide ratio of wages to total output impact is $277,968,322 / $209,529,421, which equals 1.33.
Figure 16 and Table 9 show that other than the value of the electricity itself, the largest economic impact is in the **imputed rental activity** for owner-occupied dwellings. As mentioned earlier, this is the rent that homeowners would pay to rent their own homes. It reflects the fact that employees of DCPP and DCPP suppliers stimulate the California economy by building and maintaining their homes. It is worth noting that after housing cost, the sector most significantly affected is medical care—the combined impact of doctors and dentists, and private hospitals is $31.2 million.
### TABLE 9: DCPP CALIFORNIA TOTAL ECONOMIC OUTPUT, 2011

<table>
<thead>
<tr>
<th>Rank</th>
<th>Description</th>
<th>Direct</th>
<th>Indirect</th>
<th>Induced</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total</td>
<td>$675,572,354</td>
<td>$90,162,430</td>
<td>$334,332,031</td>
<td>$1,100,066,815</td>
</tr>
<tr>
<td>1</td>
<td>Electric power generation, transmission, and distribution</td>
<td>$675,572,354</td>
<td>$207,144</td>
<td>$2,982,044</td>
<td>$678,761,542</td>
</tr>
<tr>
<td>2</td>
<td>Imputed rental activity for owner-occupied dwellings</td>
<td>0</td>
<td>$41,107,325</td>
<td>$41,107,325</td>
<td>$41,107,325</td>
</tr>
<tr>
<td>3</td>
<td>Wholesale trade businesses</td>
<td>$1,137,205</td>
<td>$15,862,428</td>
<td>$16,999,634</td>
<td>$16,999,634</td>
</tr>
<tr>
<td>4</td>
<td>Offices of physicians, dentists, and other health practitioners</td>
<td>$317</td>
<td>$16,690,915</td>
<td>$16,691,232</td>
<td>$16,691,232</td>
</tr>
<tr>
<td>5</td>
<td>Management, scientific, and technical consulting services</td>
<td>$14,805,832</td>
<td>$1,747,185</td>
<td>$16,553,017</td>
<td>$16,553,017</td>
</tr>
<tr>
<td>6</td>
<td>Real estate establishments</td>
<td>$940,264</td>
<td>$15,261,471</td>
<td>$16,201,735</td>
<td>$16,201,735</td>
</tr>
<tr>
<td>7</td>
<td>Food services (Restaurants)</td>
<td>$711,256</td>
<td>$15,431,963</td>
<td>$16,143,219</td>
<td>$16,143,219</td>
</tr>
<tr>
<td>8</td>
<td>Private hospitals</td>
<td>$2,554</td>
<td>$14,542,177</td>
<td>$14,544,731</td>
<td>$14,544,731</td>
</tr>
<tr>
<td>9</td>
<td>Facilities support services</td>
<td>$12,724,919</td>
<td>$81,546</td>
<td>$12,806,466</td>
<td>$12,806,466</td>
</tr>
<tr>
<td>10</td>
<td>Monetary authorities and depository credit intermediation activities</td>
<td>$758,991</td>
<td>$9,335,119</td>
<td>$10,094,110</td>
<td>$10,094,110</td>
</tr>
<tr>
<td>11</td>
<td>Insurance carriers</td>
<td>$391,704</td>
<td>$9,257,917</td>
<td>$9,649,622</td>
<td>$9,649,622</td>
</tr>
<tr>
<td>12</td>
<td>Petroleum refineries</td>
<td>$479,392</td>
<td>$8,965,220</td>
<td>$9,444,612</td>
<td>$9,444,612</td>
</tr>
<tr>
<td>13</td>
<td>Securities, commodity contracts, investments, and related activities</td>
<td>$280,882</td>
<td>$8,113,495</td>
<td>$8,394,377</td>
<td>$8,394,377</td>
</tr>
<tr>
<td>14</td>
<td>Employment services</td>
<td>$6,516,550</td>
<td>$1,442,495</td>
<td>$7,959,045</td>
<td>$7,959,045</td>
</tr>
<tr>
<td>15</td>
<td>Nondepository credit intermediation and related activities</td>
<td>$455,927</td>
<td>$7,408,454</td>
<td>$7,864,381</td>
<td>$7,864,381</td>
</tr>
<tr>
<td>16</td>
<td>Pharmaceutical preparation manufacturing</td>
<td>$2,737</td>
<td>$6,878,461</td>
<td>$6,881,198</td>
<td>$6,881,198</td>
</tr>
<tr>
<td>17</td>
<td>Medical and diagnostic labs and outpatient and other ambulatory care services</td>
<td>$20,658</td>
<td>$5,723,846</td>
<td>$5,744,504</td>
<td>$5,744,504</td>
</tr>
<tr>
<td>18</td>
<td>Legal services</td>
<td>$782,549</td>
<td>$4,819,467</td>
<td>$5,602,016</td>
<td>$5,602,016</td>
</tr>
<tr>
<td>19</td>
<td>Retail Stores - Food and beverage</td>
<td>$15,423</td>
<td>$5,357,010</td>
<td>$5,372,432</td>
<td>$5,372,432</td>
</tr>
<tr>
<td>20</td>
<td>Telecommunications</td>
<td>$627,792</td>
<td>$4,394,548</td>
<td>$5,022,340</td>
<td>$5,022,340</td>
</tr>
<tr>
<td>21</td>
<td>Other state and local government enterprises</td>
<td>$151,835</td>
<td>$4,714,653</td>
<td>$4,866,488</td>
<td>$4,866,488</td>
</tr>
<tr>
<td>22</td>
<td>Retail Stores - Motor vehicle and parts</td>
<td>$21,386</td>
<td>$4,550,862</td>
<td>$4,572,248</td>
<td>$4,572,248</td>
</tr>
<tr>
<td>23</td>
<td>Retail Stores - General merchandise</td>
<td>$12,429</td>
<td>$4,467,282</td>
<td>$4,479,711</td>
<td>$4,479,711</td>
</tr>
<tr>
<td>24</td>
<td>Industrial process variable instruments manufacturing</td>
<td>$4,397,048</td>
<td>$33,247</td>
<td>$4,430,295</td>
<td>$4,430,295</td>
</tr>
<tr>
<td>25</td>
<td>Management of companies and enterprises</td>
<td>$1,066,748</td>
<td>$3,067,555</td>
<td>$4,134,303</td>
<td>$4,134,303</td>
</tr>
<tr>
<td></td>
<td>All other sources</td>
<td>$43,650,889</td>
<td>$122,095,345</td>
<td>$165,746,234</td>
<td>$165,746,234</td>
</tr>
</tbody>
</table>

Source: © 2012 Minnesota IMPLAN Group, Inc.
The sector with the second largest impact is managerial and technical consulting services, which reflects the significant amount of engineering and design work that PG&E contracts out to leading consulting firms in California. In addition, the wholesale trade business sector receives a great deal of business from selling goods such as fuels, lubricants, office supplies, paint, and nuts and bolts to DCPP. Other high-ranking sectors reflect purchases by households of employees of DCPP and their suppliers—real estate firms, food service and banking institutions, for example.

**Job Creation in the California Economy**

The jobs created in California by DCPP, beyond those directly employed by DCPP, reflect the DCPP’s purchases of goods and services. The ratio of total jobs created to DCPP employees is 4,542.5/1,543=2.94. This high ratio is due to the fact that DCPP employees are relatively well-paid—with an average salary of over $135,000 per year—but the jobs created by their spending are often less-well paid.

**FIGURE 17: ECONOMIC IMPACT OF EMPLOYMENT IN CALIFORNIA**

- Expenditures: 20%
- Pensions: 3%
- Direct Jobs of DCPP: 34%
- Employee Wages: 43%
### TABLE 10: CALIFORNIA JOBS CREATED, 2011

<table>
<thead>
<tr>
<th>Rank</th>
<th>Description</th>
<th>Direct</th>
<th>Indirect</th>
<th>Induced</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total</td>
<td>1,543.0</td>
<td>668.8</td>
<td>2,330.7</td>
<td>4,542.5</td>
</tr>
<tr>
<td>1</td>
<td>Electric power generation, transmission, and distribution</td>
<td>1,543.0</td>
<td>0.3</td>
<td>3.7</td>
<td>1,547.0</td>
</tr>
<tr>
<td>2</td>
<td>Food services (Restaurants)</td>
<td>11.5</td>
<td>248.7</td>
<td>260.1</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Employment services</td>
<td>156.2</td>
<td>34.6</td>
<td>190.8</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Offices of physicians, dentists, and other health practitioners</td>
<td>0.0</td>
<td>136.7</td>
<td>136.7</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Management, scientific, and technical consulting services</td>
<td>111.2</td>
<td>13.1</td>
<td>124.3</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Wholesale trade businesses</td>
<td>6.6</td>
<td>92.0</td>
<td>98.6</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Facilities support services</td>
<td>97.1</td>
<td>0.6</td>
<td>97.7</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Private hospitals</td>
<td>0.0</td>
<td>94.0</td>
<td>94.0</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Private household operations</td>
<td>0.0</td>
<td>85.5</td>
<td>85.5</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Real estate establishments</td>
<td>4.9</td>
<td>79.8</td>
<td>84.7</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Retail Stores - Food and beverage</td>
<td>0.2</td>
<td>78.9</td>
<td>79.2</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Retail Stores - General merchandise</td>
<td>0.2</td>
<td>73.3</td>
<td>73.5</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Nursing and residential care facilities</td>
<td>0.0</td>
<td>65.8</td>
<td>65.8</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Securities, commodity contracts, investments, and related activities</td>
<td>2.1</td>
<td>59.7</td>
<td>61.8</td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>Nondepository credit intermediation and related activities</td>
<td>2.9</td>
<td>47.6</td>
<td>50.5</td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>Individual and family services</td>
<td>0.0</td>
<td>47.9</td>
<td>47.9</td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>Retail Stores - Clothing and clothing accessories</td>
<td>0.1</td>
<td>44.5</td>
<td>44.6</td>
<td></td>
</tr>
<tr>
<td>18</td>
<td>Retail Stores - Motor vehicle and parts</td>
<td>0.2</td>
<td>44.1</td>
<td>44.3</td>
<td></td>
</tr>
<tr>
<td>19</td>
<td>Retail Nonstores - Direct and electronic sales</td>
<td>0.1</td>
<td>43.2</td>
<td>43.3</td>
<td></td>
</tr>
<tr>
<td>20</td>
<td>Business support services</td>
<td>30.4</td>
<td>8.2</td>
<td>38.6</td>
<td></td>
</tr>
<tr>
<td>21</td>
<td>Services to buildings and dwellings</td>
<td>9.0</td>
<td>28.6</td>
<td>37.6</td>
<td></td>
</tr>
<tr>
<td>22</td>
<td>Retail Stores - Miscellaneous</td>
<td>0.1</td>
<td>37.2</td>
<td>37.3</td>
<td></td>
</tr>
<tr>
<td>23</td>
<td>Medical and diagnostic labs and outpatient and other ambulatory care services</td>
<td>0.1</td>
<td>32.9</td>
<td>33.0</td>
<td></td>
</tr>
<tr>
<td>24</td>
<td>Private junior colleges, colleges, universities, and professional schools</td>
<td>0.0</td>
<td>32.8</td>
<td>32.8</td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>Legal services</td>
<td>4.4</td>
<td>27.0</td>
<td>31.4</td>
<td></td>
</tr>
</tbody>
</table>

Source: © 2012 Minnesota IMPLAN Group, Inc.

As seen in Table 10, the sector with the largest number of jobs created is food services. This illustrates the fact that jobs at both lower and higher skill levels have been created by DCPP expenditures, both to vendors and to their employees. By way of clarification, the employment services sector can include temporary employment services, which may specialize in anything from security guards to engineering and scientific talent. In addition, this sector can include union trades, where the union (electrician, plumbing) serves as a clearing house for its members.
Tax Impact at the State Level

The statewide number, $33,255,105, is $2 million more than the local impact, which indicates that counties outside the local market have benefited from DCPP’s activities. The State Corporate Income Tax, $1,650,893, would include the portion of PG&E income taxes attributable to DCPP operations, as well as taxes paid by DCPP vendors, and companies that provide goods and services to PG&E employees. The State Personal Income Tax exceeds $4.1 million, which is substantial.

TABLE 11: STATE AND LOCAL TAX IMPACT, CALIFORNIA, 2011

<table>
<thead>
<tr>
<th>Description</th>
<th>Indirect Business Tax</th>
<th>Households</th>
<th>Corporations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Social Ins Tax- Employee Contribution</td>
<td>$185,358</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Social Ins Tax- Employer Contribution</td>
<td>$429,457</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Bus Tax: Sales Tax</td>
<td>$7,570,844</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Bus Tax: Property Tax</td>
<td>$33,255,105</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Bus Tax: Motor Vehicle Lic</td>
<td>$172,534</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Bus Tax: Other Taxes</td>
<td>$2,175,923</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Corporate Profits Tax</td>
<td>$1,650,893</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Income Tax</td>
<td>$4,169,876</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: NonTaxes (Fines- Fees)</td>
<td>$1,166,362</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Motor Vehicle License</td>
<td>$189,064</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Property Taxes</td>
<td>$83,182</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Other Tax (Fish/Hunt)</td>
<td>$45,777</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total State and Local Tax</td>
<td>$43,603,863</td>
<td>$5,839,619</td>
<td>$1,650,893</td>
</tr>
</tbody>
</table>

Source: © 2012 Minnesota IMPLAN Group, Inc.

DCPP impacts the California economy in many ways, raising the question: if DCPP were to shut down, what would be the net impact on California? There are many possible scenarios. Based on current State policy, it is highly unlikely that another nuclear plant would be built in California. DCPP generation could be replaced with new fossil units, renewable power, or a combination thereof. However important policy implications, like those of AB32 are outside the scope of this report. A fossil fuel plant outside California, whether in a neighboring state or Mexico, is a possibility. However, citizens of these areas are expressing increasing resistance to power plants and their accompanying pollution being built in their backyards, while the power is exported to help support the California economy. While PG&E is working diligently to comply with AB32 and bring renewable sources into its energy portfolio, renewable sources of energy are more expensive than nuclear or fossil fuel electricity and would increase the cost of doing business or living in California. Based on these scenarios, it would be extremely difficult and expensive to replace DCPP’s electric generation.
If DCPP were replaced by a “generic” power plant producing the same amount of power, valued at $678.74 million, the IMPLAN model can be used to estimate the impact of replacing DCPP with a variety of existing power plant technologies. Briefly, the total jobs generated statewide would be 2,280, versus 4,542 for DCPP. This is due to the fact that most of the power would be generated by fossil fuels, which cost more than nuclear, and because the plants require fewer personnel. So, changing over the power plant would induce a net loss of 2,262 jobs statewide. The total economic impact statewide would be $896 million, versus $1.1 billion, which would represent a loss of $204 million in GDP. And this does not take into account the fact that, since the replacement power would be more expensive than DCPP power, there would be further depression of economic activity statewide.
3.3 National Economic Impact

Economic Impact on the National Level

On the national level, there is a dramatic increase in the amount of “spend” for goods and services. Much of the generating equipment such as turbine heat-exchangers are produced by two or three manufacturers nationally, none in California. In addition, the nuclear fuel, which averages over $75 million per year, is sourced totally from outside California. Adding the increased “multiplier” resulting from the larger market to these expenditures results in a greatly increased total impact number: over $1.8 billion in 2011. The largest item, other than the value of the electricity itself, is the nuclear fuel component labeled “All other basic inorganic chemical manufacturing” (Table 12), also known as “Nuclear Fuel Manufacturing” [Figure 18].

FIGURE 18: TOP TEN IMPACTED SECTORS, NATIONAL TOTAL ECONOMIC IMPACT $1.845 BILLION

- Power Generation, Transmission, & Distribution $691.9M
- Nuclear Fuel Manufacturing $64.5M
- Next 8 $336.0M
  - Rental Value $62.8M
  - Real Estate Firms $48.5M
  - Management / Technical Consulting $47.3M
  - Employment Services $40.6M
  - Wholesale Businesses $36.7M
  - Business Support Services $36.0M
  - Financial Institutions $32.1M
  - Food Services (Restaurants) $32.0M
<table>
<thead>
<tr>
<th>Rank</th>
<th>Description</th>
<th>Direct</th>
<th>Indirect</th>
<th>Induced</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total</td>
<td>$675,572,354</td>
<td>$495,895,790</td>
<td>$673,582,189</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>1</td>
<td>Electric power generation, transmission, and distribution</td>
<td>$675,572,354</td>
<td>$6,191,423</td>
<td>$10,098,322</td>
<td>$691,862,099</td>
</tr>
<tr>
<td>2</td>
<td>All other basic inorganic chemical manufacturing</td>
<td>$64,183,247</td>
<td>$361,027</td>
<td>$64,544,275</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>3</td>
<td>Imputed rental activity for owner-occupied dwellings</td>
<td>$0</td>
<td>$62,771,661</td>
<td>$62,771,661</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>4</td>
<td>Real estate establishments</td>
<td>$6,302,072</td>
<td>$42,230,609</td>
<td>$48,532,681</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>5</td>
<td>Management, scientific, and technical consulting services</td>
<td>$42,246,743</td>
<td>$5,023,269</td>
<td>$47,270,011</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>6</td>
<td>Employment services</td>
<td>$36,303,049</td>
<td>$4,322,269</td>
<td>$40,625,307</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>7</td>
<td>Wholesale trade businesses</td>
<td>$7,388,484</td>
<td>$29,346,872</td>
<td>$36,735,356</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>8</td>
<td>Other support services</td>
<td>$34,842,600</td>
<td>$1,120,723</td>
<td>$35,963,323</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>9</td>
<td>Monetary authorities and depository credit intermediation activities</td>
<td>$5,533,481</td>
<td>$26,598,423</td>
<td>$32,131,903</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>10</td>
<td>Food services (Restaurants)</td>
<td>$3,763,636</td>
<td>$28,191,332</td>
<td>$31,954,968</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>11</td>
<td>Private hospitals</td>
<td>$4,412</td>
<td>$30,801,014</td>
<td>$30,805,426</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>12</td>
<td>Offices of physicians, dentists, and other health practitioners</td>
<td>$1,833</td>
<td>$30,346,648</td>
<td>$30,348,481</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>13</td>
<td>Insurance carriers</td>
<td>$2,517,829</td>
<td>$23,623,268</td>
<td>$26,141,097</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>14</td>
<td>Securities, commodity contracts, investments, and related activities</td>
<td>$2,351,244</td>
<td>$22,055,089</td>
<td>$24,406,333</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>15</td>
<td>Petroleum refineries</td>
<td>$6,377,427</td>
<td>$16,470,586</td>
<td>$22,848,013</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>16</td>
<td>Telecommunications</td>
<td>$5,928,656</td>
<td>$16,689,432</td>
<td>$22,618,088</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>17</td>
<td>Nondepository credit intermediation and related activities</td>
<td>$3,104,094</td>
<td>$19,177,681</td>
<td>$22,281,775</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>18</td>
<td>Other general purpose machinery manufacturing</td>
<td>$20,155,500</td>
<td>$12,156</td>
<td>$20,167,657</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>19</td>
<td>Management of companies and enterprises</td>
<td>$8,007,353</td>
<td>$9,988,447</td>
<td>$17,995,800</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>20</td>
<td>Legal services</td>
<td>$3,808,740</td>
<td>$10,214,219</td>
<td>$14,022,959</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>21</td>
<td>Facilities support services</td>
<td>$13,507,506</td>
<td>$357,985</td>
<td>$13,865,491</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>22</td>
<td>Pharmaceutical preparation manufacturing</td>
<td>$9,519</td>
<td>$12,043,260</td>
<td>$12,052,779</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>23</td>
<td>Architectural, engineering, and related services</td>
<td>$8,677,216</td>
<td>$2,473,363</td>
<td>$11,150,578</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>24</td>
<td>Industrial process variable instruments manufacturing</td>
<td>$10,532,456</td>
<td>$145,358</td>
<td>$10,677,815</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td>25</td>
<td>Other state and local government enterprises</td>
<td>$1,262,177</td>
<td>$9,282,669</td>
<td>$10,544,846</td>
<td>$1,845,050,334</td>
</tr>
<tr>
<td><strong>Total all other sources</strong></td>
<td><strong>$202,895,095</strong></td>
<td><strong>$383,600,752</strong></td>
<td><strong>$586,295,847</strong></td>
<td><strong>$1,845,050,334</strong></td>
<td></td>
</tr>
</tbody>
</table>

Source: © 2012 Minnesota IMPLAN Group, Inc.
Jobs Created at the National Level

The number of jobs created nationally is proportionally larger: over 10,372 jobs have been created by DCPP nationally, in a broad spectrum of skill levels and career paths. Each of the 1,559 direct DCPP jobs has generated over five additional jobs in other businesses serving DCPP or their employees, or their employees’ employees. This is due to the nearly self-contained nature of the US economy, where a dollar spent locally will circulate within the economy several times before “leaking out.”

**FIGURE 19: NATIONAL ECONOMIC IMPACTS OF DCPP EMPLOYMENT**

- Expenditures 50.4%
- Employee Wages 32.5%
- Direct Jobs of DCPP 15.0%
- Pensions 2.1%
### TABLE 13: NATIONAL JOBS CREATED, 2011: 9477.1 JOBS

<table>
<thead>
<tr>
<th>Rank</th>
<th>Description</th>
<th>Direct</th>
<th>Indirect</th>
<th>Induced</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total</td>
<td>1,559.0</td>
<td>3,215.0</td>
<td>5,598.3</td>
<td>10,372.3</td>
</tr>
<tr>
<td>1</td>
<td>Electric power generation, transmission, and distribution</td>
<td>1,559.0</td>
<td>9.8</td>
<td>16.0</td>
<td>1,584.9</td>
</tr>
<tr>
<td>2</td>
<td>Employment services</td>
<td>926.5</td>
<td>110.3</td>
<td>1,036.8</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Food services (Restaurants)</td>
<td>67.2</td>
<td>503.1</td>
<td>570.2</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Management, scientific, and technical consulting services</td>
<td>312.4</td>
<td>37.1</td>
<td>349.6</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Other support services</td>
<td>330.6</td>
<td>10.6</td>
<td>341.2</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Real estate establishments</td>
<td>41.8</td>
<td>280.0</td>
<td>321.8</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Offices of physicians, dentists, and other health practitioners</td>
<td>0.0</td>
<td>239.8</td>
<td>239.9</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Private hospitals</td>
<td>0.0</td>
<td>233.0</td>
<td>233.0</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Wholesale trade businesses</td>
<td>43.6</td>
<td>173.2</td>
<td>216.8</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Nursing and residential care facilities</td>
<td>0.0</td>
<td>162.2</td>
<td>162.2</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Securities, commodity contracts, investments, and related activities</td>
<td>15.3</td>
<td>143.2</td>
<td>158.5</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Retail Stores - General merchandise</td>
<td>1.1</td>
<td>154.2</td>
<td>155.3</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Retail Stores - Food and beverage</td>
<td>1.1</td>
<td>154.1</td>
<td>155.2</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Nondepository credit intermediation and related activities</td>
<td>21.0</td>
<td>129.9</td>
<td>150.9</td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>Business support services</td>
<td>108.6</td>
<td>34.0</td>
<td>142.6</td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>Services to buildings and dwellings</td>
<td>49.8</td>
<td>84.4</td>
<td>134.2</td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>Private household operations</td>
<td>0.0</td>
<td>120.4</td>
<td>120.4</td>
<td></td>
</tr>
<tr>
<td>18</td>
<td>Facilities support services</td>
<td>115.2</td>
<td>3.1</td>
<td>118.3</td>
<td></td>
</tr>
<tr>
<td>19</td>
<td>Civic, social, professional, and similar organizations</td>
<td>8.5</td>
<td>90.4</td>
<td>98.9</td>
<td></td>
</tr>
<tr>
<td>20</td>
<td>Retail Stores - Motor vehicle and parts</td>
<td>1.1</td>
<td>92.4</td>
<td>93.5</td>
<td></td>
</tr>
<tr>
<td>21</td>
<td>Individual and family services</td>
<td>0.0</td>
<td>91.9</td>
<td>91.9</td>
<td></td>
</tr>
<tr>
<td>22</td>
<td>Architectural, engineering, and related services</td>
<td>70.8</td>
<td>20.2</td>
<td>91.0</td>
<td></td>
</tr>
<tr>
<td>23</td>
<td>Management of companies and enterprises</td>
<td>39.5</td>
<td>49.2</td>
<td>88.7</td>
<td></td>
</tr>
<tr>
<td>24</td>
<td>Monetary authorities and depository credit intermediation activities</td>
<td>14.8</td>
<td>71.3</td>
<td>86.1</td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>All other basic inorganic chemical manufacturing</td>
<td>84.8</td>
<td>0.5</td>
<td>85.3</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total all other industries</td>
<td>951.4</td>
<td>2,593.8</td>
<td>3,545.2</td>
<td></td>
</tr>
</tbody>
</table>
Tax Impact at the National Level

DCPP’s expenditures (in the process of generating electricity) generate a substantial amount of federal tax revenue. Unlike state and local tax revenues, which are dominated by property taxes, sales taxes and various fees, the federal government relies very heavily on personal and corporate income taxes to fund its operations. DCPP generates over $16 million in federal corporate income tax, $27.5 million in Federal Personal Income Taxes, $43.3 million in Social Security taxes, and $6.6 million in excise taxes, customs duties and other fees (See Table 14).

**TABLE 14: FEDERAL TAX IMPACT, NATIONAL, 2011**

<table>
<thead>
<tr>
<th>Description</th>
<th>Employee Compensation</th>
<th>Proprietor Income</th>
<th>Indirect Business Tax</th>
<th>Households</th>
<th>Corporations</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Social Insurance Tax:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Employee Contribution</td>
<td>$21,808,360</td>
<td>$2,662,715</td>
<td></td>
<td></td>
<td></td>
<td>$24,471,075</td>
</tr>
<tr>
<td>Social Insurance Tax:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Employer Contribution</td>
<td>$21,498,620</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$21,498,620</td>
</tr>
<tr>
<td>Indirect Business Tax:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Excise Taxes</td>
<td></td>
<td></td>
<td>$3,230,467</td>
<td></td>
<td></td>
<td>$3,230,467</td>
</tr>
<tr>
<td>Indirect Business Tax:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Custom Duty</td>
<td></td>
<td></td>
<td>$1,267,371</td>
<td></td>
<td></td>
<td>$1,267,371</td>
</tr>
<tr>
<td>Indirect Business Tax:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fed NonTaxes</td>
<td></td>
<td></td>
<td>$2,158,076</td>
<td></td>
<td></td>
<td>$2,158,076</td>
</tr>
<tr>
<td>Corporate Profits Tax</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$16,398,957</td>
<td>$16,398,957</td>
</tr>
<tr>
<td>Personal Tax: Income Tax</td>
<td></td>
<td></td>
<td></td>
<td>$27,487,792</td>
<td></td>
<td>$27,487,792</td>
</tr>
<tr>
<td>Total Federal Tax</td>
<td>$43,306,980</td>
<td>$2,662,715</td>
<td>$6,655,914</td>
<td>$27,487,792</td>
<td>$16,398,957</td>
<td>$96,512,358</td>
</tr>
</tbody>
</table>

In addition to the taxes collected by the federal government, out-of-state DCPP vendors and consulting firms generate tax revenues for their respective states. As shown in Table 15, these revenues are dominated by property taxes and sales taxes, but state corporate and personal income taxes are also significant.
### TABLE 15: STATE AND LOCAL TAX IMPACT, NATIONAL

<table>
<thead>
<tr>
<th>Description</th>
<th>Indirect Business Tax</th>
<th>Households</th>
<th>Corporations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Social Security Insurance Tax- Employee Contribution</td>
<td>$295,462</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Social Security Insurance Tax- Employer Contribution</td>
<td>$684,558</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Business Tax: Sales Tax</td>
<td>$19,424,322</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Business Tax: Property Tax</td>
<td>$44,082,572</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Business Tax: Motor Vehicle Lic</td>
<td>$403,166</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indirect Business Tax: Other Taxes</td>
<td>$5,528,352</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Corporate Profits Tax</td>
<td></td>
<td>$3,006,542</td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Income Tax</td>
<td>$8,184,395</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: NonTaxes (Fines- Fees)</td>
<td>$2,273,385</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Motor Vehicle License</td>
<td>$492,076</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Property Taxes</td>
<td>$232,929</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Personal Tax: Other Tax (Fishing/Hunting Licenses)</td>
<td>$213,855</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total State and Local Tax</strong></td>
<td><strong>$70,122,970</strong></td>
<td><strong>$11,692,102</strong></td>
<td><strong>$3,006,542</strong></td>
</tr>
</tbody>
</table>
3.4 Value of Environmental Benefits

Greenhouse gas emission levels are reported in terms of metric tons of carbon dioxide equivalents. The 1990 U.S. baseline was 6,133 million metric tons. By 2009 that figure had grown to 6,576 metric tons, an increase of 443 million metric tons. The use of nuclear-generated electricity helped avoid 613 metric tons of carbon dioxide in 2011 (see figure 20), or the equivalent of carbon dioxide released from 118 million passenger cars (60% of all U.S. cars currently on the road).

Without the emission avoidances of nuclear generation, required U.S. reductions would increase by more than 50% to achieve targets agreed to under the Kyoto Protocol.9


Source: Nuclear Energy Institute (NEI)

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9 The Kyoto Protocol refers to an international agreement linked to the United Nations Framework Convention on Climate Change. The agreement, signed in Kyoto, Japan in 1997, includes the U.S. among participants who committed to internationally binding emission reduction targets.
According to testimony by PG&E\textsuperscript{10}, DCPP avoids the emission of seven to eight million tons per year of greenhouse gases (GHG) that would otherwise be produced by conventional generation sources such as fossil fuel plants. The cost to purchase equivalent carbon credits on the Intercontinental Exchange (ICE) for six to seven million tons of GHG ranges from $3,129,000 and $18,375,000 per year.\textsuperscript{11} A total of 1.34 million acres of pine forest would be needed to sequester carbon emitted at those levels, and 1.25 million passenger vehicles would have to be removed from service to avoid seven million tons of GHG.

Additionally, nuclear energy avoids the annual production in the U.S. of more than half a million tons of nitrogen oxide\textsuperscript{12} and 1.4 million tons of sulfur dioxide. As part of the U.S. EPA Acid Rain Program from 1990-1995, results from 21 states showed that a 16.4% increase in nuclear generation avoided release of 480,000 tons of sulfur dioxide (37% of the required emissions reduction). Under the 1990 Clean Air Act Amendments, no credit was allocated to nuclear plants, but based on the average value of publicly traded sulfur dioxide credits, the savings would have a value of about $50 million.

\textsuperscript{10} Pacific Gas & Electric Company 2014 General Rate Case Prepared Testimony Exhibit (PG&E-6) Energy Supply, November 15, 2012
\textsuperscript{11} Estimate based on futures price range of $1.49–$8.75 metric ton contract on the ICE market between September 2011 and September 2012. One lot = 1000 metric tons of carbon = 3,326 metric tons of CO2
\textsuperscript{12} Equivalent to NO released by 28 million cars
Section 4: License Extension vs. No License Extension

Presently, there are two nuclear reactors in operation at DCPP, with one licensed to operate until 2024 and the second to 2025. If the Nuclear Regulatory Commission (NRC) does not extend the licenses for an additional 20 years (2044 and 2045), as requested by PG&E, the reactors would be decommissioned. As a centerpiece of the economies of San Luis Obispo and Northern Santa Barbara counties, DCPP produced an estimated $675.6 million of electricity in 2011, contributing at least $1 million to 46 different sectors of the local economy. If DCPP is granted extension to licenses, the plant would continue to generate economic benefits similar to those produced today. However, if license extensions are not granted, DCPP would be required to cease operations and begin to shut down the Plant.

The year 2027 was used as the reference point for analyzing economic impacts that would result from an NRC decision to not extend licenses. This is a point in time when either full operation would continue with license extension, or the plant would be idle during the decommissioning and removal process. In either case, the Independent Spent Fuel Storage Installation (ISFSI), known as the Dry Cask Storage Facility, would continue to operate, so economic benefits associated with the ISFSI is included in all scenarios. According to the March 2010 report entitled “The Local Economic Impacts of Decommissioning the Diablo Canyon Nuclear Power Plant,” the most reasonable alternative use of the site after decommissioning is cattle grazing, a use that has been included in the economic analysis of no license extension.

4.1 Economic Impact on the Economy

In 2011, DCPP contributed $919.8 million of total economic impact (direct, indirect and induced) to San Luis Obispo and Northern Santa Barbara counties. The state and nation also benefited economically from the operations of DCPP, receiving $1,100 billion and $1,969 billion in total economic impact, respectively. By 2027, if DCPP is granted license extension, the total economic impact for the local area is expected to grow to $1.48 billion per year, assuming a 3-percent-per-year growth rate and no change in employment (see Figure 3). State and national economic impacts are substantial as well, respectively yielding $1.76 billion and $3.16 billion in 2027.

13 According to the US Energy Information Administration, DCPP produced 18,566 MWH in 2011 and the California weighted average wholesale price (SP-15 Gen DA LMP Peak) for 2011 was $36.39 per MWH, for a total of $675,572,354 electricity produced.
In the case of no license extension, there will be limited activity on the site. The Independent Spent Fuel Storage Installation (ISFSI) and guard station will continue to operate until the Department of Energy has taken custody of all the spent fuel. Since there is no specific date for this to occur, this report assumes operations of the ISFSI will continue well after the decommissioning of DCPP has been completed. According to PG&E, the operation of the ISFSI facility requires 41 employees with a combined payroll of $6.7 million. Because these employees will live in the local communities, they will contribute to the local economic impact. Besides employee expenditures, it is estimated that only about $203,142 local expenditures will result from ISFSI continued operations. Based on these figures, the total economic activity of the ISFSI facility is estimated to be $13.68 million in 2027.

Additionally, assuming the best alternate usage of the nearly 10,000 acre property after decommissioning would be cattle grazing, the total direct economic impact created by this activity in the local area is $1.5 million in 2027. A total of $15.2 million of economic impact would continue to occur even after denial of DCPP relicensing. Therefore, the denial would result in a net loss of 1.46 billion (99.1% decline) to the local area in year 2027 alone. An estimated $42.5 billion would be lost over the entire re-licensing period if the extension request is denied.\(^\text{14}\)

DCPP’s economic impact is not only large in size, but it has a stabilizing effect on the local economy. Refueling takes place every 18 to 22 months for each reactor and occurs during the tourism industry’s off-season. Refueling brings in several hundred workers from outside the local area who stay in motels, hotels or short-term rentals and often eat at local restaurants. Each reactor alternates its refueling schedule, usually resulting in at least one refueling or significant equipment installation per year, typically during a slack period of the tourist season. The economic impacts of these planned outages will be discussed in a future publication.

\(^{14}\) Source of all ISFSI and Cattle Ranching impact estimates: The Local Economic Impacts of Decommissioning the Diablo Canyon Power Plant, March 2010
4.2 Loss of Jobs

In 2011, DCPP employed 1,483 direct employees in San Luis Obispo and Northern Santa Barbara counties, which created an additional 1,875 jobs for a total of 3,358 jobs in the local economy. DCPP also employs 60 additional employees in California who do not reside in the local economy, and 16 other employees live outside California. DCPP’s out-of-area impact causes a ripple effect, creating an additional 2,999.5 and 8,813 jobs, respectively. It is not expected that the number of direct jobs would increase because of license extension, but rather would stay the same or slightly reduce in number. By 2027, the total number of jobs created is estimated to be the same as the year 2011 (See Figure 22).

A report to the California Public Utilities Commission determined the best alternate usage of the nearly 12,000 acre property after decommissioning would be cattle grazing. The total direct jobs created for cattle grazing is estimated at three. Because of the ripple effect throughout the economy, an additional 27.1 indirect and induced jobs would be created, where a total of 71.1 total jobs would be created in the local economy in the case of no license extension in 2027. Therefore, the loss of this stimulus would result in the elimination of more than 3,286 jobs from virtually every sector of the economy.

FIGURE 22: ESTIMATED TOTAL JOBS (DIRECT AND INDIRECT) FOR YEAR 2027
4.3 Loss of Taxes Generated

In 2011, PG&E paid over $25 million in Unitary Taxes to San Luis Obispo County related to DCPP operations. An additional $5.8 million of property taxes are generated from other indirect and induced sources, resulting in property taxes of $30.8 million paid in 2011. By 2027, it is estimated that these property taxes will grow to $49.4 million. California will receive an estimated $12.1 million in sales taxes in 2027 from DCPP operators, while combined sales taxes and property taxes generated in the local area will total $58.0 million (See Figure 23).

In the case of no license extension, the ISFSI and guard station will continue to operate, as well as the nearly 12,000-acre property would be used for grazing cattle. These activities would generate $1.253 million in local area property and sales tax; however, funds garnered will be nothing close to the scale of that which the continued operations of DCPP would produce.

It is estimated that Unitary Property Taxes paid to San Luis Obispo County would decline by 97.3% if license extension does not occur.

This decline would adversely affect the entire region. Almost all of the $12.1 million California sales tax revenue in 2027 alone would be lost.
Section 5: Nuclear Industry Trends

Currently, 14% of the world’s electricity is provided by nuclear power, including 436 plants operating in 30 different countries. Thirteen countries rely on nuclear power for over one-quarter of their electricity generation. The U.S. ranks number one in total worldwide nuclear power generation at 31.4% (See Figure 24).

![FIGURE 24: TOP TEN NUCLEAR POWER GENERATING COUNTRIES (2011)]

<table>
<thead>
<tr>
<th>Country</th>
<th>Percentage</th>
<th>Generation (Billion Kwh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>U.S.</td>
<td>31.4%</td>
<td>790.2</td>
</tr>
<tr>
<td>France</td>
<td>16.7%</td>
<td>421.1</td>
</tr>
<tr>
<td>Russia</td>
<td>6.4%</td>
<td>161.7</td>
</tr>
<tr>
<td>Japan</td>
<td>6.2%</td>
<td>156.2</td>
</tr>
<tr>
<td>Korea</td>
<td>5.9%</td>
<td>147.7</td>
</tr>
<tr>
<td>Germany</td>
<td>4.1%</td>
<td>102.3</td>
</tr>
<tr>
<td>Canada</td>
<td>3.6%</td>
<td>90.0</td>
</tr>
<tr>
<td>China</td>
<td>3.5%</td>
<td>87.4</td>
</tr>
<tr>
<td>Ukraine</td>
<td>3.4%</td>
<td>84.8</td>
</tr>
<tr>
<td>Sweden</td>
<td>2.4%</td>
<td>59.3</td>
</tr>
</tbody>
</table>

Although the U.S. generates the most electricity worldwide, nuclear falls to the middle of the pack as a percentage of national power generation. In 2011, the U.S. generated 19.2% of its entire electricity portfolio through nuclear power. France generated 77.7% of its electricity through nuclear power, and at the other extreme, China generated most of its power through fossil fuels (mainly coal), with only 1.8% through nuclear generation (See Figure 25).
In the aftermath of the Fukushima accident, several countries—including Germany and Switzerland—have indicated that they do not plan further nuclear expansion, but many more plan to proceed with nuclear power development. Fourteen countries are moving ahead with 66 new plants under construction; others have longer-term plans for new nuclear development. China has 51 reactors currently planned out of 120 total proposed, and India plans to build 16 reactors of a proposed 40 to keep up with demand.\textsuperscript{15} The U.S. Department of Energy projects that U.S. electricity demand will rise 24\% by 2035, about one percent each year. Therefore, U.S. energy companies have proposed to build up to 19 new nuclear plants, and has 11 reactors currently planned to start construction including three under construction at Vogtle in Georgia, Summer in South Carolina and Watts Bar in Tennessee.

In 2011, nuclear energy provided 19.2\% of the United States’ electricity, or 790.2 billion kilowatthours (bkWh) out of a total U.S. electricity generation of 4,105 bkWh (See Figure 26). There are currently 104 licensed reactors operating in 31 different states, of which 35 are boiling water reactors and 69 are pressurized water reactors. To put the scale of this energy generation into perspective, the amount of electricity generated by just an average sized 1,000-MWe reactor at 90\% capacity factor in one year is 7.9 billion kWh—enough to supply electricity for 690,000 households. If generated by other fuel sources, power of this magnitude would require 13.7 million barrels of oil, 3.4 million short tons of coal and 65.8 billion cubic feet of natural gas.

Although there are a number of new domestic reactors in the pipeline, additional nuclear capacity is not expected to be online until 2017, at the earliest. As the demand for electricity continues to climb, the U.S. will struggle to meet demand without new power plants. The nuclear industry has been able to generate more electricity as older reactors go offline due to increased operational efficiency (section 5.1), but license renewal for many plants is crucial to maintain current production [See Figure 27].
5.1 Nuclear Industry Performance

A significant achievement of the U.S. nuclear power industry over the last 20 years has been the increase in operating efficiency due to improved maintenance and technology. This has resulted in an upward trend in capacity factor (output proportion of their nominal full-power capacity), which has gone from 56.3% in 1980 and 66% in 1990 to 89.0% in 2011.16 A major component of this upward trend is the length of refueling outages. In 1990 refueling outages averaged 107 days, but dropped to 40 days by 2,000, with the record being 15 days. Typical refueling outages happen every 18 to 24 months and create a significant decrease in capacity factor. Additionally, overall generation has increased because of improved thermal efficiency. The average thermal efficiency rose from 32.49% in 1980 to 33.85% in 1999. Nuclear power generation capacity factors are the highest of all fuel types since power can be generated 24 hours a day, seven days per week (See Table 16).

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Average Capacity Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>89.0%</td>
</tr>
<tr>
<td>Geothermal</td>
<td>69.5%</td>
</tr>
<tr>
<td>Biomass</td>
<td>64.6%</td>
</tr>
<tr>
<td>Coal (Steam Turbine)</td>
<td>61.1%</td>
</tr>
<tr>
<td>Hydro</td>
<td>48.3%</td>
</tr>
<tr>
<td>Gas (Combined Cycle)</td>
<td>45.6%</td>
</tr>
<tr>
<td>Wind</td>
<td>31.8%</td>
</tr>
<tr>
<td>Solar</td>
<td>24.0%</td>
</tr>
<tr>
<td>Gas (Steam Turbine)</td>
<td>13.4%</td>
</tr>
<tr>
<td>Oil (Steam Turbine)</td>
<td>8.1%</td>
</tr>
</tbody>
</table>

Source: Nuclear Energy Institute (NEI)

Another way to increase overall generation is through uprate, which is the process of increasing the maximum power level at which a commercial nuclear power plant operates. Power uprates at nuclear plants are very common and require additional capital investment. More than 120 uprates have been approved by the NRC and implemented, generating approximately 6,211 mWe of power or equivalent to adding another six nuclear reactors. Sixty-seven more uprate projects are currently in sight, with capital costs of $250 to $500 million each. A nationwide capacity increase of 2,637 mWe by 2016 is currently under review and expected. In addition to increasing generating capacity, these uprate projects also improve the reliability of the units and support operating license extensions, which require extensive review of plant equipment condition.

Through a reduction in reactor downtime, improved thermal efficiency, and uprate projects, nuclear power generation has increased from 577 bkWh hours in 1990 to 790.2 bkWh in 2011, a 36.9% improvement, or capacity addition equivalent to approximately 29 new 1,000 MWe reactors.

16 Source: Nuclear Energy Institute (NEI)
5.2 Cost Competitiveness: Production Costs and Fuel Costs

The cost of nuclear power generation has remained flat over the last decade. Although efficiency improvements have occurred, fuel costs (including enrichment), and operating and maintenance (O&M) costs have increased. In general, the construction costs of nuclear power plants are significantly higher than for coal or gas-fired plants because of the requirements for special materials, the incorporation of sophisticated safety features and back-up control equipment. These contribute to much of the nuclear generation cost, but once the plant is built the cost variations are minor.

Production Costs

Production costs include O&M and fuel costs at a power plant. Since 2001, nuclear power plants have achieved the lowest production costs compared to coal, natural gas and oil. For nuclear power plants, spent fuel management, plant decommissioning, and final waste disposal are included in the production costs. These costs, while usually external for other technologies, are internal for nuclear power (See Figure 28).

**FIGURE 28: U.S. ELECTRICITY PRODUCTION COSTS**

This figure shows the annual cost associated with the operation, maintenance, administration, and support of a nuclear power plant. Included are costs related to labor, material and supplies, contractor services, licensing fees and miscellaneous costs such as employee expenses and regulatory fees. The average non-fuel O&M cost for a U.S. nuclear power plant in 2011 was 1.51 cents per kWh and the overall production cost was 2.19 cents per kWh. Because nuclear plants refuel every 18 to 24 months, they are not subject to fuel price volatility like natural gas and oil power plants.
**Fuel Costs**

This is the total annual cost associated with the consumption of nuclear fuel resulting from the operation of the unit. This cost is based upon the amortized costs associated with the purchasing of uranium, conversion, enrichment, and fabrication services along with storage and shipment costs and inventory (including interest) charges less any expected salvage value. The average fuel cost at a U.S. nuclear power plant in 2011 was 0.68 cents per kWh. Nuclear fuel costs were at a low of 0.51 cents per kWh in 2005, and since then, fuel costs for nuclear power plants have increased 33.3 percent.

![Figure 29: Fuel as a Percentage of Electric Power Production Costs, 2011](source)

Fuel costs make up 31% of the overall production costs of nuclear power plants. Fuel costs for coal and natural gas and oil, however, make up more than 78% of the production costs (See Figure 29) and all subject to rapid market fluctuation.
Section 6: Community Benefits Provided by DCPP

In addition to the economic benefits that DCPP contributes to San Luis Obispo and Northern Santa Barbara counties, the state and nation in the form of jobs, income, and taxes, the plant also enhances the local community in ways that are often intangible and unquantifiable. PG&E strives to be a good corporate citizen by engaging, supporting and improving the neighborhoods where their customers and employees live and work. PG&E’s community investment program is completely funded by shareholders and has no impact on customers’ utility rates. This section of the report includes a discussion of benefits beyond the IMPLAN economic model previously presented. Although actual quantified results of these programs are not estimated, it should be noted that each has economic value.

6.1 Local Charitable Grants and Volunteerism

Charitable Grants

PG&E has been part of California for over 100 years and believes in its responsibility to contribute to the growth and vitality of the communities PG&E serves. In 2011, through PG&E’s nationally recognized giving program, the company donated over $23 million in charitable, shareholder-funded investments.

In San Luis Obispo and northern Santa Barbara counties in 2011, more than 90 local nonprofit organizations shared a total of $1.1 million of PG&E’s charitable funds. A contribution of $250,000 to the Lucia Mar School District helped create Central Coast New Tech High, a new school offering an innovative approach to 21st century education. PG&E’s $25,000 grant to the Prado Day Center in San Luis Obispo helped reduce the homeless services center’s energy costs using weatherization, energy improvements and building repairs. PG&E employees bolstered the effort in an afternoon spent painting and refurbishing the center’s dining area and bathrooms. PG&E’s partnership with Habitat for Humanity provided a $37,500 grant to fund solar panels on three newly built homes. Not only do the solar panels help save families $500 a year on energy costs, but each panel also helps avoid the release of more than 132,000 pounds of carbon dioxide over the 30-year life of the system, or the equivalent greenhouse gas savings realized by recycling 20.9 tons of waste.
PG&E actively supports DCPP’s local area through various specially targeted community investments programs, including:

**PG&E Bright Ideas Grants:** Teaching students about solar energy and conservation through a $10,000 grant for Arroyo Grande High School’s solar education project.

**Cal Poly Journalism:** Enabling students to develop key employment skills through a $38,000 grant for state-of-the-art audio visual equipment.

**Port San Luis Marine Institute:** Advancing education for underserved students in San Luis Obispo and Santa Barbara counties through a $15,000 donation to ongoing environmental education efforts.

**PG&E Ambassadors:** Training 40 PG&E employee ambassadors to support community events and offer public speaking presentations throughout the region.

**REACH (Relief for Energy Assistance through Community Help):** Relieving families in need with $25,000 of assistance to help pay energy bills.

**California Mid State Fair Heritage Foundation:** Assisting the fairgrounds to save money and energy through a $25,000 donation to replace outdated lighting fixtures at the fairgrounds.

**Food Bank Coalition of San Luis Obispo County:** Funding energy efficiency upgrades and volunteering for the group’s annual Hope for the Holidays and Hunger Awareness campaigns.

More online at: www.pge.com/myhome/edusafety

**Volunteerism**

PG&E recognizes that its employees are an integral part of the company’s community outreach and improvement efforts. Collectively, employees volunteered 32,585 hours in 2011, assisting in a range of charitable efforts throughout Northern and Central California. In December of 2011, over 100 PG&E employees from across DCPP’s local area worked with the non-profit Kaboom! and other community volunteers, collaborating to build a new playground at the Boys and Girls Club in Oceano. Over the course of a single day, the club’s barren asphalt was transformed into an impressive playground, complete with a rock-climbing wall and a twisty slide. The project also included shade structures, murals and an outdoor classroom. The work required mixing 18,000 pounds of concrete and moving 105 yards of mulch – all done by hand with the help of PG&E volunteers. The day culminated with a ceremony in which PG&E’s chief nuclear officer presented the group a $73,000 check in support of the project.

**Employee Giving**

In keeping with the company’s goal to engage, support and improve the neighborhoods where its customers and employees live and work, San Luis Obispo and Northern Santa Barbara county employees pledged more than $429,000 to local organizations through PG&E’s annual employee giving campaign.
6.2 Environmental Preservation/Land Stewardship

PG&E is proud of its long history of managing lands and waters in a responsible and environmentally sensitive manner. That commitment is exemplified by PG&E’s preservation of the 12,820 acres that make up the land upon which Diablo Canyon sits. The land is comprised of 14 miles of pristine coastline extending from Port San Luis Harbor to Montaña de Oro State Park and stretches inland about a mile and a half to the peaks of the Irish Hills.

Diablo Canyon is located in a unique and sensitive biome, home to fauna like American peregrine falcon, brown pelican, southern sea otter and northern elephant seal. As DCPP has a vast network of pipes and wires traversing this habitat, PG&E has an obligation to protect these resources while performing operations to meet customers’ expectations for reliability and service. Diablo Canyon’s Land Stewardship Program was initiated to manage and protect natural and cultural resources, share these resources with communities and educational organizations, provide opportunities for sustainable agricultural practices and develop managed access to promote environmental appreciation. The Land Stewardship team consists of professionals from many disciplines including archaeologists, biologists, engineers, land planners and foresters who closely monitor the land.

PG&E’s active stewardship of this natural resource includes livestock grazing, resulting in a healthier rangeland habitat that sustains native plant species while reducing invasive plant species. PG&E also allows researchers to explore the area’s habitat and ecology. This includes archaeology students from nearby Cal Poly who, in partnership with PG&E, are engaged in a multi-year research project focused on the prehistory of the Pecho Coast, and State Parks, Cal Poly and CALFIRE personnel who partner with PG&E to conduct prescribed burns to restore a closed-cone Bishop Pine grove.

The property also includes two scenic trails open to the public for hiking opportunities—the 3.3-mile Point Buchon Trail (round trip is 7.5 miles), and 3.75-mile Pecho Coast Trail (round trip is 8 miles). As part of PG&E’s broader effort to promote environmental education, docent naturalists, who include plant employees, lead groups along Pecho Coast Trail and provide information about the location’s history, cultural resources and biological diversity. The Point Buchon Trail is located on the northern end of the property, and in an effort to preserve the landscape, has a daily limit of 275 hikers. This 3.3-mile trail is accessed through Montaña de Oro State Park and allows hikers to enjoy the area’s pristine coastline. PG&E has partnered with the California Coastal Commission, California Conservation Corps, and Cal Poly San Luis Obispo to protect resources from hiker impact and to conduct trail maintenance. Interpretive signage has been developed to provide the public an opportunity to appreciate the natural resources of the Point Buchon Trail and build awareness of the stewardship programs (such as rotational grazing programs and prescribed burns), that the Stewardship team has developed.
Additionally, the Pecho Coast Trail, which has been open since 1993, offers a hike to the beautiful 1890’s Victorian Lighthouse located on the south end of the DCPP property. This docent-guided trail is available by reservation only, passing through a pathway close to the entrance of the plant’s employee access road. This 1.75-mile hike affords access to beautiful rugged cliffs and broad coastal terraces as well as the newly restored Point San Luis Lighthouse. The trail continues another 2 miles up the coast to an ancient oak grotto.

PG&E has partnered with the California Coastal Commission, California Conservation Corps, Port San Luis Harbor District and Point San Luis Lighthouse Keepers (non-profit that maintains the Lighthouse) and many volunteers to conduct trail maintenance such as eradicating noxious weeds, and develop educational programs for underserved youth. Through its Land Stewardship Program, PG&E has preserved these areas that offer examples of the Central Coast in its natural, open space context.

For more information, please visit www.pge.com/myhome/environment/commitment
6.3 Air Quality

One of the most important aspects of environmental stewardship is the improvement of air quality. The Clean Air Act of 1970 set standards to improve the nation’s air quality by establishing limits on the emission of nitrogen oxides (NOx), a precursor of ground-level ozone and smog; sulfur dioxide, which produces acid rain; particulate matter, such as smoke and dust; and mercury. In 1990, the U.S. Environmental Protection Agency amended the Clean Air Act by developing extensive regulations to reduce nitrogen oxides through creation of the Ozone Transport Commission and the NOx Budget Program to help reduce ground-level ozone in the Northeast and Mid-Atlantic states.

In 2009, the California Air Resources Board (ARB) established California’s Global Warming Solutions Act (AB32), setting the goal of reducing GHG emissions to 1990 levels by 2020. Greenhouse gas reporting regulations were enacted, requiring regulated entities such as PG&E to prepare and submit annual greenhouse gas emissions inventories to the California Air Resources Board. December 2010, ARB adopted a cap-and-trade program to place an upper limit on statewide greenhouse gas emissions. This is the first state-level cap and trade program in the U.S. and took effect beginning 2012, with a limit that reduces by 15% over the life of the program (by 2020). It should be noted that the cap levels decrease by 2-3% per year even as the demand for electricity grows. As per AB32 requirements, PG&E began reporting greenhouse gas emissions from some of its facilities and operations to the U.S. EPA in 2011.

Nuclear energy is the world’s largest source of nearly emission-free power generation. Nuclear power plants emit absolutely no carbon dioxide, nitrogen oxides or sulphur dioxides. Heat generates from fission rather than burning fuel, therefore producing no greenhouse gases or emissions associated with acid rain or urban smog. Using additional nuclear energy gives states increased flexibility in complying with clean-air requirements. For the year 2006, the Nuclear Energy Institute reported that U.S. nuclear plants prevented the emissions of almost 681.2 million metric tons of carbon dioxide. This is equivalent to removing 131 million U.S. passenger cars from service. In 2005, the 136 million U.S. passenger cars on the road generated an estimated 709.3 million metric tons of CO₂ [See Figure 30]. According to the World Nuclear Association (WNA), “For every 22 tons of uranium used, one million tons of CO₂ emissions is averted.”
Nuclear power plants like DCPP emit virtually no greenhouse gases (GHGs) during the production of electricity. According to testimony by PG&E, DCPP avoids emitting seven to eight million tons of GHGs per year that would otherwise be produced by conventional generation sources, such as fossil fuel plants. PG&E’s most recent independently verified CO₂ emissions rate of 575 pounds of CO₂ per MWh is about half the national average among utilities. As a charter member of the California Climate Action Registry, PG&E was the first investor-owned utility in California to complete a third-party-verified inventory of carbon dioxide (CO₂) emissions in 2003. In 2009, PG&E began voluntary reporting to The Climate Registry, a non-profit organization that sets consistent and transparent reporting standards for North American businesses and governments. PG&E is a founding member of The Climate Registry. In addition, PG&E has participated in the Carbon Disclosure Project since 2005. PG&E’s annual submission provides additional detail on our actions related to climate change and our greenhouse gas emissions profile.

Source: Nuclear Energy Institute (NEI)
6.4 Emergency Planning and Preparedness

Diablo Canyon Power Plant is one of the safest and most secure industrial work environments in the country. Multiple layers of physical security, together with high levels of operations performance, protect plant workers, the public, and the environment. However, natural and man made disasters can strike, leaving devastation in their wake, such as the tsunami that hit Japan in March 2011. The timing and location of disaster events cannot accurately be predicated, but preparations can help mitigate their consequences.

PG&E strives to ensure DCPP’s local counties have the resources they need to discharge the serious responsibility of emergency preparedness, planning and response in the event of radiological incident and/or the many other types of emergencies that could occur. PG&E has gone well beyond the scope of what is required by then Assemblyman Sam Blakeslee’s AB 292: “Nuclear Emergency Preparedness Funding, San Luis Obispo County” regulation. The law requires that local governments located near operating nuclear power plants develop and maintain emergency response plans with the utility, with all associated costs of plans reimbursed by the utility to the local government.

PG&E’s 2012 budget forecast of expenses related to DCPP’s offsite emergency preparedness exceeds $4 million. The State of California Nuclear Power Preparedness Fund, which supports State, County and local emergency response organizations, receives approximately $2.9 million dollars. Approximately $628,000 goes to support the Federal Emergency Management Agency (FEMA) exercise evaluation and program at DCPP.

Nearly $330,000 is spent annually on a number of programs meant to educate the public on emergency preparedness: PG&E places full-page advertisements in local telephone directories as the primary means for providing updated emergency preparedness information to the public; PG&E produced an emergency preparedness information calendar distributed throughout the DCPP Emergency Planning Zone (EPZ) as a handbook for planning special needs and protective actions; PG&E distributes siren information stickers for local businesses, parks and recreational areas within the DCPP EPZ; and PG&E assists in the funding of “No Assistance Required,” a San Luis Obispo County Office of Emergency Services program that focuses on special needs population. This program helps special needs individuals to notify emergency responders that they have safely evacuated following an emergency.
Other Offsite Emergency Expenses:

- Evacuation Time Estimate (funded under EP Rulemaking Project) - $250K
- Offsite meteorological equipment maintenance support contract - $250K
- Radiological monitoring equipment calibrations and dosimetry replacements - $45K
- American Red Cross, local hospital and EMS support agreements - $30K
- Contractor / staff augmentation for offsite exercise development - $20K
- Joint Information Center video, mock media and spokesperson training - $20K
- Annual siren test volunteer support agreement - $10K
- State of CA / National Radiological Emergency Preparedness conference support - $7.5K

According to Victor Dricks, senior public affairs officer for NRC Region IV, the Commission conducted a nationwide review of nuclear power plants for their capacity to respond to earthquakes, power outages and other catastrophic events, and Diablo was found to have “a high level of preparedness and strong capability in terms of equipment and procedures to respond to severe events.”

Aside from the strong financial relationship between DCPP and the local emergency service offices, PG&E champions public education of emergency preparedness by sponsoring fun and exciting events for the community, such as a recent Preparedness Expo with the American Red Cross (ARC).

PG&E provided the ARC with $2.5 million to support their Ready Neighborhoods program, which improves disaster readiness throughout the utility’s territory.

On March 20, 2012, more than 1,000 people received information on how to prepare for a natural disaster at the San Luis Obispo Veterans Hall, which provided a one-stop, public forum that touched on everything from CPR to seismic safety. About 20 local businesses, public safety agencies and service organizations also participated, including The Listos Program.

The Listos Program is a Spanish language disaster preparedness curriculum based in CERT (Community Emergency Response Team). PG&E is a proud supporter of Listos, which means “ready” in Spanish, and is a series of emergency preparedness courses that encourages the Spanish-speaking community to prepare for disasters and prepares residents to develop family communication plans, build specialized emergency kits, and teaches use of fire extinguishers and home utilities shut off in case of a disaster. In 2012, PG&E helped to expand the Listos Program beyond Santa Barbara County into San Luis Obispo with a $25,000 charitable grant.

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6.5 Housing Values

DCPP is an economic mainstay of San Luis Obispo and Santa Barbara counties, providing more than 1,483 high-paying head-of-household jobs, well above the average county wage. Unitary taxes paid by DCPP fund a large part of local school districts budgets and provide levels of public and educational services that are far above those in surrounding counties. Despite the positive indicators of the economic benefits of DCPP, some opponents believe nuclear facilities have a negative impact on real estate and property values and public and social services. However, a study published in 2006 by Roger H. Bezdek and Robert M. Wendling concluded that in areas close to nuclear power plants, total property values, assessed valuations and median housing prices were often increased at rates above the national and state averages. The study found that in each of its seven study regions, housing prices were several times higher than prior to the opening of the nuclear facilities. Furthermore, the study concluded that the presence of a nuclear facility actually protected property values during periods of relative economic decline by providing stability and steady employment. It is impossible to quantify housing price increases resulting from DCPP due to the complexity of factors affecting prices.

Currently, the median house price in San Luis Obispo County is $365,000. An increase in new home inventory increases the prospect of owning a home (as opposed to renting), encouraging buyers to enter the housing market and creating the opportunity for the market to correct itself. The average rent for a three bedroom house is $1,456, whereas the payment for the median house is $1,455 (3.5% for 30 years). With an average salary of $136,500 and a current interest rate of 3.5 percent, a DCPP employee could qualify for a loan in excess of $736,000. The question of whether someone would purchase a home versus rent is personal, and doesn’t always follow the ability to afford. Therefore, it is inconclusive whether the presence of DCPP actually increases home prices or not.

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Section 7: Conclusion

As an integral part of San Luis Obispo and Northern Santa Barbara counties, the economic impacts of Diablo Canyon Power Plant are real. Expenditures, jobs, tax revenues, economic impact, labor income, and contributions to the local economy make DCPP one of the most valued economic assets on the Central Coast of California.

Capturing all the economic activity generated by DCPP is difficult. This study does manage to capture the majority of it, although because of our analysis methodology, it does tend to produce conservative results. To more closely estimate the impacts, future studies could be performed for a detailed look at the economics of plant upgrades/modifications and unit refuelings. During these events, many out-of-town contractors descend on the local area, spending money in local hotels/motels, rentals, retail goods, food services and gasoline. Although there is generally a reduction in electricity generated during these activities, local economic activity increases dramatically.

Depending on outcome of future re-licensing activities, the opportunity costs for the local area are great. Non-license renewal will not only affect 2024 and beyond, it will also affect the near future, as plant modifications/upgrades to extend the life of the plant will no longer be necessary. Quantifying and understanding the economic impacts of DCPP is an important piece of the puzzle for the future of DCPP and the local area.
Glossary

**AB292**: Assembly Bill 292-Nuclear Emergency Preparedness Funding, San Luis Obispo County

**Assembly Bill 32-California Global Warming Solutions Act (AB32)**: Specified greenhouse gas reduction goals for the State of California. Passed in 2006

**ARB**: California Air Resources Board

**BLS**: Bureau of Labor Statistics

**BOE**: State Board of Equalization

**Capacity Factor**: Output proportion of nominal full-power capacity

**Diablo Canyon Power Plant Emergency Planning Zone (DCPP EPZ)**: An approximate 10 mile area around a nuclear power plant determined by the Nuclear Regulatory Commission and Environmental Protection Agency

**Direct Impact**: Total value of the good or service generated by the business or activity being analyzed (value of electricity generated at DCPP)

**FEMA**: Federal Emergency Management Agency

**GDP**: Gross Domestic Product

**Greenhouse Gases (GHG)**: Atmospheric gases that contribute to the greenhouse effect. Greenhouse gases absorb and emit infrared radiation and include: water vapor, carbon dioxide, methane, nitrous oxide and ozone

**GRP**: Gross Regional Product

**GWh**: Gigawatt hours

**ICE**: Intercontinental Exchange

**IMPLAN**: Economic modeling software developed at the University of Minnesota and was later spun off as a private firm, the MIG

**Indirect Impact**: Revenue generated by other firms

**Induced Impact**: Change in household expenditures

**Institute of Nuclear Power Operations (INPO)**: Formalized group to provide safety and reliability assistance to the nuclear power industry. Services include: plant evaluations, training and accreditation, events and analysis information exchange and operations assistance

**IRA Value**: Imputed Rental Activity
ISAR: Industrial Safety Accident Rate
ISFSI: Independent Spent Fuel Storage Installation
KV: Kilovolt
MIG: Minnesota IMPLAN Group
MW: Megawatt
MWh: Megawatt hours
NAICS: Northern American Industry Classification System
NEI: Nuclear Energy Institute
NoX: Nitrogen oxides
NRC: Nuclear Regulatory Commission
NREP: National Radiological Emergency Preparedness
San Luis Obispo OES: San Luis Obispo County Office of Emergency Services
OSHA: Occupational Safety and Health Administration
O&M: Operating and Maintenance
Proposition 13: Passed in California in 1978 and established a fixed property tax rate of 1% of assessed value (plus amounts required to repay any assessment bonds approved by the voters)
PWR: Pressurized water reactors
RCLD: Replacement Cost New Less Depreciation
ROP: Reactor Oversight Process
Unitary Taxes: State corporate taxes on a corporation’s global income
U.S. EPA: United States Environmental Protection Agency
Watt-Hour (Wh): Unit of measurement for electrical energy used in a circuit by a load of one watt of power for one hour
WANO: World Association of Nuclear Operators
WNA: World Nuclear Association
PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
DCPP LICENSE RENEWAL PROJECT COSTS
2009-2016
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A. Introduction

In Section 5.2 of the Joint Proposal, the Joint Parties\(^1\) agreed that it was reasonable and prudent for Pacific Gas and Electric Company (PG&E) to incur the costs related to the federal and state license renewal (LR) processes which are largely comprised of technical and environmental studies and permitting and licensing costs paid to the Nuclear Regulatory Commission (NRC). The Joint Proposal recognizes that PG&E incurred these costs to preserve all options, including LR, during the period of resource planning uncertainty that ultimately resulted in the decision not to proceed with LR and to instead replace Diablo Canyon Power Plant (Diablo Canyon or DCPP) with a portfolio of greenhouse gas (GHG)-free resources.

As one element of the overall compromise that resulted in the Joint Proposal, PG&E seeks to recover $52.688 million in reasonable and prudent costs incurred in support of LR for Diablo Canyon. PG&E filed a license renewal application (LRA) with the NRC on November 23, 2009, in order to preserve the option to operate DCPP for an additional 20 years beyond the expiration of the current operating licenses for Units 1 and 2, which are 2024 and 2025, respectively. The activities performed and costs incurred in support of LR were for activities necessary to ensure the availability of adequate generation beyond 2024.

DCPP has been a vitally important piece of PG&E’s generation resource portfolio since it began operation because of both its reliability, and its GHG-free emissions. Since 1985, DCPP has operated safely and reliably, earning high performance and safety ratings from the NRC and the Institute of Nuclear Power Operations (INPO). Over its lifetime, DCPP has run more than 80 percent of the time, compared with the national average of 70 percent for the nuclear industry.

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\(^1\) The Alliance for Nuclear Responsibility (A4NR) did not join in this section of the Joint Proposal.
DCPP provides approximately 6 percent of the energy generated in California annually, enough to meet the energy needs of more than three million northern and central Californians. DCPP’s low carbon energy also has contributed to meeting California’s GHG emission reduction goals. DCPP avoids 6-7 million metric tons per year of GHG emissions that would otherwise be produced by conventional generation resources. Pursuing LR therefore preserved the option for PG&E to continue operating DCPP as a safe, reliable, clean energy generation resource beyond 2024.

There were multiple advantages to initiating the LR process in 2009. The time frame for NRC LR reviews is uncertain and may take many years to complete. If the operating licenses were not renewed, PG&E, the California Public Utilities Commission (CPUC or Commission), the California Independent System Operator, and the state of California would need sufficient time to plan for Diablo Canyon replacement power. Applying for LR in 2009 therefore supported long-term resource planning efforts by PG&E and the state. Applying for LR also allowed PG&E to address any changes to plant Systems, Structures, and Components (SSC) or programs necessary to support longer-term operation in a systemic and logical fashion prior to the start of the renewal period.

In addition, PG&E is a member of Strategic Teaming and Resource Sharing (STARS), a consortium of single-station utilities that together work to gain cost efficiencies enjoyed by utilities that operate a fleet of nuclear power stations. The NRC Staff had budgeted and allocated resources to review an LRA according to a pre-determined “slot” for a STARS plant. PG&E’s identified slot for filing a LRA was late-2009. Had PG&E not used its designated slot, it would have been unable to file the LRA until a much later date, which would have adversely affected long-term resource planning.

Although PG&E concluded that incurring costs to support DCPP LR was reasonable and prudent under the circumstances that existed that time, PG&E re-evaluated that position throughout the LR process. For example, PG&E requested that the NRC delay issuance of a final decision on LR while it performed California Energy Commission (CEC)-recommended seismic studies, substantially reducing—but not eliminating—LR costs during that time. PG&E also continually re-assessed key strategic factors, including customer economic benefits, load requirements, GHG compliance, renewable integration challenges,
and shareholder risks. Due to the dramatic changes currently taking place in California’s energy landscape, including recent mandates regarding a 50 percent Renewables Portfolio Standard (RPS) requirement by 2030 and substantial proposed increases in Energy Efficiency (EE), PG&E determined that LR was no longer in the best interests of PG&E’s customers and that DCPP would be retired in 2025. PG&E prudently kept open the option to renew the DCPP operating licenses. External circumstances—including substantial increases in RPS-eligible resources and EE—ultimately contributed to the decision to retire DCPP as of 2025. PG&E requests that the CPUC authorize recovery in customer rates the reasonable and prudent costs expended to support the federal and state processes that were necessary to preserve the option to operate Diablo Canyon through 2045. As described in more detail below, these expenditures include the fees and costs of the NRC LR process, including the NRC’s safety, technical, and environmental reviews, and the fees and costs associated with State review and approvals related to the NRC LRA (e.g., coastal consistency and Coastal Development Permit (CDP) reviews). The costs described below also include project management costs, which reflect the cost of PG&E employees and outside consultants dedicated to completing the required tasks associated with processing the federal and state applications, as well the costs to perform certain studies requested by the CPUC in response to CEC recommendations.

B. Background

1. Overview of LR

The Atomic Energy Act of 1954 (AEA), as amended, authorizes the United States NRC to issue operating licenses for nuclear power reactors. These licenses may be issued for a period of up to 40 years, and may be renewed upon expiration for an additional 20-year term. The safety and technical review requirements for LR are set forth in Part 54 of Title 10 of the Code of Federal Regulations (CFR). The NRC’s regulatory scheme specifically addresses plant maintenance and equipment aging issues and evaluates whether SSCs will continue to perform safely.
beyond the original 40-year term. The objective of the NRC’s LR process is to ensure that the detrimental effects of aging, which could adversely affect the functionality of SSCs that serve or could impact safety functions during the period of extended operation, are adequately managed. The intended function of SSCs must be maintained throughout the renewal term the same as during the term of its current license. As a result, the LR review does not revisit the basis for the initial licensing of the plant or reconsider the full range of ongoing regulatory and operational issues that arise during operations.

The NRC’s safety and technical requirements are supplemented by the requirements in Part 51 of Title 10 of the CFR for evaluation of environmental impacts of continued plant operation. That regulation codifies the NRC’s generic determinations of environmental impacts of LR and specifies a number of issues for further, plant-specific review.


In 2009, PG&E’s Board of Directors approved the submission of an application to seek a 20-year extension of Diablo Canyon’s operating licenses. PG&E prepared the DCPP LRA and entered the federal LR process by filing the LRA with the NRC on November 23, 2009. Shortly thereafter, on January 29, 2010, PG&E submitted an application to the CPUC to authorize recovery in customer rates of the costs to proceed with the federal and state processes necessary to preserve the option to operate Diablo Canyon following expiration of the current operating licenses and through the period 2025-2045.³ PG&E estimated $85.02 million for the DCPP LR Project, assuming a completion date of December 31, 2014.

The NRC performed a detailed review of the technical portion of the application supporting continued operation of DCPP. PG&E supported the NRC technical review by responding to Requests for Additional Information (RAI), preparing for and participating in on-site audits and inspections, and performing annual updates of the LRA, as required by regulation. The NRC completed and issued a Safety Evaluation Report (SER) in June 2011.

The SER documents the NRC Staff’s safety review of the LRA and

³ A.10-01-022.
described the technical details considered in evaluating the safety aspects of operation for an additional 20 years beyond the term of the current operating licenses. The NRC concluded that the LRA met the standards for issuance of a renewed license under the NRC’s LR regulations.

In addition to the SER, the NRC is required to complete an environmental evaluation of PG&E’s LR application before issuing a renewed license. The NRC performed a detailed review of the Environmental Report (ER) PG&E submitted with the application, but did not issue a draft Environmental Impact Statement (EIS) prior to suspension of NRC review. PG&E supported the NRC environmental review by responding to RAIIs and preparing for and participating in an on-site audit.

Under the AEA, the NRC must also offer interested parties an opportunity to request a hearing on issues related to an LRA. As part of that adjudicatory process, the NRC’s Atomic Safety and Licensing Board (ASLB) considered a number of issues raised by San Luis Obispo Mothers for Peace. NRC regulations require PG&E, as the applicant, to participate in the adjudicatory process for the LRA.

The NRC also requires a consistency determination from the state agency with the responsibility for enforcing the provisions of the federal Coastal Zone Management Act (CZMA) and related California statutes and regulations, prior to issuance of a renewed operating license. PG&E filed an application for a coastal consistency determination with the California Coastal Commission (CCC) on November 23, 2009. The CCC concluded that it could not proceed with the federal coastal consistency determination without having reviewed the results of the advanced seismic studies recommended by the CEC. The CCC also concluded that LR constitutes “development” under the California Coastal Act and therefore requires PG&E to apply for a separate CDP. In response, PG&E shifted its focus to completing the CEC-recommended seismic studies by filing an application for approval of the studies’ scope and recovery in customer rates the costs of those seismic studies and by initiating and pursuing the numerous permitting actions required to perform those seismic studies.

In March 2011, as PG&E was in the midst of the permitting process for the seismic studies, an earthquake and subsequent tsunami occurred
in Japan, with the tsunami causing an accident at the Fukushima Daiichi nuclear power plant. On April 10, 2011, PG&E requested that the LR process be delayed until after completion of additional seismic studies requested by the CEC. PG&E’s request to delay the NRC LR process also addressed significant community and political support for completing the seismic research prior to concluding the federal LR process.


Although the NRC LR review process was suspended, PG&E maintained the application up-to-date in accordance with federal regulations by submitting annual updates to the NRC. The annual updates obligated PG&E to perform detailed licensing and engineering reviews of all plant configuration and design changes, revised calculations, and NRC correspondence to determine whether there were any impacts to the LRA. The NRC’s adjudicatory processes also continued during this period.


The economic and political landscapes significantly changed between 2009 and 2016. During that time, natural gas prices and the cost of large-scale photovoltaic renewable power generation declined significantly. Additionally, as California enacted legislation in 2011 to move to a 33 percent RPS by 2020, concerns about resource integration and the potential for over-generation and negative pricing increased. This phenomenon diminished the value of baseload, non-flexible generation.

In letters dated May 2, 2014 and July 3, 2014, the NRC acknowledged completion of the advanced seismic studies and requested additional safety and environmental information from PG&E. The NRC also requested that PG&E provide a schedule for continuing the state process for the CZMA consistency review. PG&E Letter DCL-14-103, dated December 22, 2014, and DCL-15-027, dated February 25, 2015, updated the LR application to provide the requested additional information. In DCL-15-027, PG&E stated that it would notify the NRC of the Coastal Consistency Certification schedule upon determining whether to proceed with LR. In a letter dated April 28, 2015, the NRC stated that although PG&E had not yet established a schedule to complete the DCPP CZMA consistency review, the NRC
would move forward with its review of the DCPP LRA. Anticipating resumption of the state consistency process, PG&E prepared a draft CDP.

Though PG&E concurred with moving forward with the NRC review in order to preserve the option of LR, as discussed in Chapter 2, PG&E continued to assess a number of key strategic factors, such as the customer economic benefits, load requirements, GHG compliance, renewable integration challenges, and shareholder risks. As stated in Section C of the Joint Proposal, after considering factors, including, but not limited to: (1) the increase of the RPS to 50 percent by 2030 under Senate Bill (SB) 350 (2015); (2) the doubling of EE goals under SB 350; (3) the challenge of managing over-generation and intermittency conditions under a resource portfolio increasingly influenced by solar and wind production; (4) the growth rate of distributed energy resources; and (5) the accelerating departure of PG&E’s bundled load customers to distributed generation and Community Choice Aggregation, PG&E, in consultation with the Joint Parties, concluded that the most effective and efficient path forward for achieving California’s goal for deep reductions of GHG emissions was to retire DCPP in 2025 and replace it with a portfolio of other GHG-free resources.

C. LR Project Activities

In this section, PG&E describes the costs incurred to support the DCPP LR Project since June 2009. PG&E presents costs incurred for work performed from June 2009 through June 2016 including associated Allowance for Funds Used During Construction (AFUDC) in Table 9-1.
### TABLE 9-1

**TOTAL COSTS INCURRED**

(THOUSANDS OF DOLLARS)

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Cost(a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Project Team</td>
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<tr>
<td>2</td>
<td>LRA Preparation</td>
<td>2,542</td>
</tr>
<tr>
<td>3</td>
<td>Safety/Technical Review</td>
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</tr>
<tr>
<td>4</td>
<td>Environmental Review</td>
<td>374</td>
</tr>
<tr>
<td>5</td>
<td>Severe Accident Mitigation Alternatives (SAMA)</td>
<td>519</td>
</tr>
<tr>
<td>6</td>
<td>Adjudicatory Process</td>
<td>2,183</td>
</tr>
<tr>
<td>7</td>
<td>NRC Staff Review Fees</td>
<td>7,072</td>
</tr>
<tr>
<td>8</td>
<td>Advisory Committee on Reactor Safeguards (ACRS)</td>
<td>222</td>
</tr>
<tr>
<td>9</td>
<td>CZMA Consistency/CDP</td>
<td>1,954</td>
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<tr>
<td>10</td>
<td>Other State Processes</td>
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<td>Capital Administrative and General</td>
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<tr>
<td>12</td>
<td>AFUDC</td>
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</tr>
<tr>
<td>13</td>
<td>Other Expenses</td>
<td>479</td>
</tr>
<tr>
<td>14</td>
<td>Total</td>
<td>$52,688</td>
</tr>
</tbody>
</table>

(a) Due to rounding, the total does not equal the sum of the costs incurred.

1. **Federal Process**

   PG&E incurred costs associated with the following activities:

   (1) Preparation of the LRA; (2) NRC Safety/Technical Review; (3) ACRS Review; (4) Environmental Review and Historic Properties Management Plan; (5) SAMA; and (6) Adjudicatory Process. In addition to specific activities, there are project management costs, which include NRC review fees and maintenance of a project team.

   **Preparation of LRA, Including ER**

   Section 54.21(a)(3) requires that for each structure and component determined to be within the scope of Part 54, the applicant must demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis (CLB) for the period of extended operation.

   In accordance with these Part 54 regulations, PG&E’s LRA included general administrative information, an integrated plant assessment (IPA),

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4 Unless otherwise stated, a reference to “Section” in this testimony refers to Title 10 of the CFR.

5 Unless otherwise stated, a reference to a “Part” in this testimony refers to Title 10 of the CFR.
an evaluation of time limited aging analyses (TLAA), a supplement to the
Updated Final Safety Analysis Report for Diablo Canyon, changes to the
Technical Specification for Diablo Canyon to manage the effects of aging
during the period of extended operation, and an ER that complies with
Subpart A of Part 51.

The IPA is a detailed technical assessment required by the NRC
identifying the scope of SSCs at the plant subject to LR review and requiring
an aging management review (AMR) in accordance with Section 54.21(a).
An AMR must identify applicable aging mechanisms and demonstrate that
aging effects from those mechanisms will be adequately managed to
maintain the CLB and to assure that there will be an acceptable level of
safety during the period of extended operation. The AMR includes a review
of plant and industry operating experience to identify potential aging effects
applicable to the SSCs, and evaluates existing Aging Management
programs (AMP) at the plant to assure that all in-scope equipment and
all relevant aging effects will be adequately managed. The AMR may
also demonstrate the need for additional equipment inspections or
additional AMPs.

TLAAs are defined as any calculations or engineering evaluations for
SSCs within the scope of LR that involve assumptions based on the original
40-year operating terms. The LRA must: (1) verify that TLAAs remain valid
during the renewal term; (2) re-analyze/evaluate TLAAs to bound the
renewal term; or (3) manage aging effects encompassed by the TLAA.

The LRA must also include an environmental evaluation documented
in an ER for plant-specific issues specified in NRC regulations.
The regulations include a requirement that the applicant identify and
evaluate any “new and significant” environmental information developed
since the plant began operation.

The LR Project cost estimate includes costs required for PG&E to
prepare and review the LRA prior to its submittal to the NRC. These costs
include those necessary to:

• Finalize draft LRA;
• Conduct supporting technical analyses;
- Perform plant and peer technical reviews of the draft LRA and resolve comments provided during those review; and
- Complete management reviews and obtain approval to submit the LRA.

The LR Project incurred $2.542 million in direct costs for these activities. This includes the cost for Worley Parsons, the primary engineering contractor supporting the STARS Center of Business (COB), to resolve technical comments and develop the draft LRA, fatigue analyses by Structural Integrity Associates (SIA) and Westinghouse, supplemental technical reviews by Advanced Concepts Incorporated (ACI), and civil structural aging evaluations by consulting engineers.

Project costs also include those associated with preparation of the ER by PG&E technical staff and consulting engineers, resolution of management review comments on the draft ER, and resolution of management and technical comments on the SAMA evaluation by ERIN Engineering.

Safety/Technical Review

Once the NRC determined the LRA was complete and acceptable for docketing, the NRC Staff began its technical review of the application’s content. The NRC Staff review process is rigorous and requires active support and input from the applicant. For example, the NRC Staff routinely requests additional information from the applicant in areas where it requires additional data or analyses to support the findings the NRC must make in order to authorize LR. PG&E received 384 RAI from the NRC, which is consistent with the number of RAIs received by other plants going through the NRC LR process. When PG&E received an RAI, PG&E reviewed the request, performed any technical analysis required to develop the response, prepared a draft response, performed a technical review of the response, and submitted the final response to the NRC. The level of effort needed to respond to an RAI varied from as little as a few hours for one person or several months’ worth of effort by a team of people (e.g., where the RAI required a major engineering analysis). RAI responses were developed and/or reviewed by plant technical staff and contractors, depending on the nature of the request. Worley Parsons, SIA, Westinghouse, ACI, and
Enercon each supported development of the RAI responses at different
times and for different technical topics.

NRC staff also conducted on-site audits and inspections to review
plant operating experience and the documentation, implementation,
and effectiveness of the AMPs and activities associated with the LRA.
In connection with its safety and technical review, NRC staff conducted
a Scoping and Screening Audit and an AMP Audit. Based on its Scoping
and Screening Audit, the NRC concluded that the inspection results
supported a conclusion of reasonable assurance that actions have been
identified and have been taken or planned to manage the effects of aging
in the SSCs identified in the application and that the intended functions of
these SSCs would be maintained in the period of extended operation.
The NRC’s 8-day, on-site AMP Audit consisted of NRC Staff examination of
DCPP LRA Program bases documents and related references, interviews
with various DCPP representatives, and walkdowns of multiple plant areas.
In total, the NRC reviewed 36 AMPs and held several breakout (discussion)
sessions with applicant representatives. The NRC’s Region IV office also
conducted a safety and technical inspection. To prepare for and support
these audits and inspections, PG&E provided refresher training to plant staff
and contractors on the underlying documents supporting the LRA. PG&E
also required these individuals to be available during the audits and
inspection to answer questions or document comments from the NRC
reviewers.

With the information provided in PG&E’s LRA, included in responses
to RAIs, and obtained through its audits and inspections, the NRC Staff
prepared Inspection Reports and documented its reviews in the SER.
Along with the Supplemental Environmental Impact Statement (SEIS)
discussed below, the SER provides the technical and legal basis for the
NRC’s decision to grant or deny license renewal. In January 2011, the NRC
Staff issued a draft SER, requiring PG&E to perform a technical review of
the document to confirm that commitments and plant and program
descriptions have been presented consistent with the plant’s understanding
of commitments made in the LRA and during the review process with NRC
staff. Plant staff as well as contractors, supported this technical review. In June 2011, the NRC staff issued the final SER.

In letters dated May 2, 2014 and July 3, 2014, the NRC requested PG&E to update the safety and technical information in the DCPP LRA to address newly-issued guidance since suspension of the NRC review process. PG&E Letter DCL-14-103, dated December 22, 2014, and DCL-15-027, dated February 25, 2015, updated the LRA to provide the requested information.

While the NRC did not perform any on-site safety or technical audits associated with the LRA update, the NRC issued RAIs to PG&E. PG&E responded to these RAIs in 2015 and 2016.

In total, the direct costs charged to the LR Project for safety/technical review were $4.651 million.

Advisory Committee on Reactor Safeguards

The ACRS is an advisory committee established by the AEA under the Federal Advisory Committee Act. The ACRS has three primary purposes: (1) to review and report on safety studies and reactor facility license and LRAs; (2) to advise the NRC on the hazards of proposed and existing reactor facilities and the adequacy of proposed reactor safety standards; and (3) to initiate reviews of issues applicable at all nuclear reactors (generic issues). The ACRS is independent of the NRC Staff and reports directly to the NRC, which appoints its members. The ACRS is comprised of recognized technical experts and is structured so that experts representing many technical perspectives can provide independent advice to be factored into the NRC decision-making process.

As with all NRC LRAs, the ACRS reviews the DCPP SER prepared by NRC Staff in its role as an independent, third-party oversight committee on the nuclear safety aspects of LR. The DCPP ACRS Sub-Committee meeting was held on February 9, 2011. Preparation for the full ACRS was underway when PG&E requested suspension of the NRC LR review in April 2011.

The LR Project costs incurred is $0.222 million in direct costs for these activities.
Environmental Review

The NRC considers the issuance of a renewed license to be a major federal action under the National Environmental Policy Act that requires preparation of an EIS before issuing a renewed license. The NRC’s LR environmental review involves a Generic Environmental Impact Statement (GEIS) and a site-specific supplement addressing those issues identified in Part 51, Table B-1, that require site-specific analysis.

The GEIS examines the possible environmental impacts that could occur as a result of renewing any commercial nuclear power plant license and, to the extent possible, establishes the bounds and significance of these potential impacts. The GEIS makes maximum use of environmental and safety documentation from original licensing proceedings and information from state and federal environmental agencies, the nuclear utility industry, and operational experience, among others. For each type of environmental impact, the GEIS establishes generic findings to the extent possible.

The GEIS addresses 92 environmental issues on a generic basis. The NRC found that 68 of the 92 issues were adequately analyzed in the GEIS. These were deemed “Category 1” issues. LR applicants are not required to address Category 1 environmental issues in their ER, absent any new and significant information indicating that the analysis in the GEIS is not inapplicable. For Category 1 issues, the GEIS describes that the environmental impacts in an impact category and assigns a single significance level to the impact (small/moderate/large) for all plants. No additional plant-specific mitigation measures are considered to be warranted, absent new and significant information.

Issues that must be addressed on a plant-specific basis are deemed “Category 2” issues. These issues must be addressed by the applicant in the ER submitted as part of the LRA to the extent the issue is applicable to a plant. As required by Part 51, PG&E submitted an ER with its LRA that contained, among other things: (1) a description of the proposed action, including any plans to modify the facility or its administrative control procedures and any modifications directly affecting the environment or affecting plant effluents that—in turn—affect the environment; (2) an analysis of the environmental impacts of alternatives to LR; (3) an analysis
of the environmental impacts of LR and the impacts of operation during the
extended period for the applicable Category 2 issues, as well as alternatives
for reducing adverse impacts associated with Category 2 issues; and (4) an
analysis of environmental justice issues.

The NRC environmental review is conducted on a separate, parallel
track from the NRC safety/technical review. In January 2010, the NRC
published a Notice of Intent to Prepare a SEIS in the Federal Register.
As with the safety/technical reviews, the NRC Staff conducted an on-site
environmental audit in order to gather information for the scoping process.
The environmental audit was conducted in April 2010 and lasted one week.

As with the safety and technical audits, PG&E required plant
environmental personnel and technical consultants to support the
environmental audit process by helping develop RAI responses and by
being present at the audit to answer NRC Staff questions.

By NRC letters dated May 2, 2014, and July 3, 2014, the NRC
requested PG&E update the ER to incorporate recent information and
address the revised GEIS issued in 2011. PG&E Letters DCL-14-103, dated
the ER to provide the requested information.

In October 2015, the NRC held another one-week on-site environmental
audit to address the ER update. Subsequent to the on-site audit, the NRC
issued RAIs to which PG&E subsequently provided responses.

In March 2016, the NRC issued an Environmental Scoping Report
that addressed public comments related to the environmental review of
the DCPP LRA.

The LR Project costs incurred is $0.374 million in direct costs for the ER
Review activities.

SAMA Analysis

Part 51 requires that LR applicants provide an analysis of alternatives to
mitigate severe accidents if the NRC has not previously evaluated SAMA for
the applicant’s plant in an EIS or related supplement or in an environmental
assessment. Like nearly all plants seeking LR, DCPP has not previously
performed a SAMA analysis.
Pursuant to this requirement, PG&E developed and submitted a SAMA report along with its ER in November 2009. The report included the following elements and processes:

- Characterized overall plant risk from a severe accident;
- Identified potential mitigation alternatives (SAMAs);
- Evaluated potential risk reduction and cost to implement each SAMA;
- Determined whether each SAMA was cost-beneficial based on a NRC-approved model; and
- Determined whether implementation of any SAMA was cost-beneficial.

As required by Part 51, the SAMA analysis used a plant-specific model as input to an NRC-approved model that calculates potential radiation dose to the public and economic impacts from hypothesized accidents involving radioactive releases from the containment structure into the environment. Then, using regulatory analysis techniques, the SAMA analysis calculated the monetary value of the base risk of radiation dose to the public and workers, off-site and on-site economic impacts, and replacement power. This value becomes a cost/benefit screening tool against which to analyze potential SAMAs. If the cost to implement a SAMA exceeded the base risk value, it could be rejected as failing a cost/benefit test.

The NRC collected information regarding the SAMA report during its environmental audit and through RAIs. In letters dated May 2, 2014 and July 3, 2014, the NRC requested PG&E update the ER, including the SAMA analysis. PG&E Letters DCL-15-027, dated February 25, 2015, and DCL-15-080, dated July 1, 2015, updated the SAMA analysis, including by incorporated the latest seismic information. In September 2015, the NRC conducted a one week on-site SAMA audit to address the SAMA update. Subsequent to the on-site audit, the NRC issued RAIs on the SAMA evaluation, to which PG&E subsequently provided a response.

The LR Project costs incurred $0.519 million in direct costs for the SAMA activities.

Adjudicatory Process

The NRC’s rules of practice in Part 2 govern the adjudicatory (or public hearing) process for the DCPP LR proceeding. NRC hearings are led by a panel of judges from the NRC’s ASLB. Numerous contentions were
submitted to the NRC as part of the NRC’s LR proceeding. The NRC’s adjudicatory process for LR involves the following major steps:

- Proposed contentions filed by interested stakeholders;
- Responses to proposed contentions on the issue of their admissibility for further hearing;
- A prehearing conference and oral argument on intervention and the contention admissibility;
- Mandatory disclosures on admitted contentions;
- Motions for summary disposition, seeking to dismiss or narrow admitted contentions;
- Filing of written direct and rebuttal testimony on admitted contentions;
- Oral evidentiary hearing on admitted contentions;
- An initial ASLB decision on admitted contentions; and
- Appeals of initial ASLB decisions to the full NRC.

Between 2010 and 2016, PG&E was actively involved in the NRC’s hearing process. In 2015, the ASLB found in favor of PG&E on all admitted contentions on the DCPP LR docket. In 2016, the Commission denied the last remaining appeal, effectively ending the NRC adjudicatory process for DCPP LR.

In addition to the LR-related adjudicatory process, intervenors were active in submitting contentions attempting to link LR to issues involving current operations. The following are two examples that were submitted to the DCPP LR docket and that required a PG&E response:

- San Luis Obispo Mothers for Peace submitted a contention alleging that the NRC’s failure to include specific “safety” findings in the NRC’s continued storage rule, which addresses the feasibility and capacity for eventual spent fuel disposal, means that the NRC must make site-specific findings for each LRA. Mothers for Peace also petitioned the NRC to suspend issuance of LRAs until the NRC makes valid findings that spent fuel generated during any reactor’s license term can be safely disposed of in a repository.
- Based upon PG&E’s completion of the CEC-recommended seismic studies completed in September 2014, Friends of the Earth filed a petition seeking a hearing on the adequacy of the DCPP seismic...
design and licensing basis. The petition raised three specific safety contentions that attempted to link current seismic issues to LR.

The LR Project costs incurred is $2.183 million in direct costs for the adjudicatory process.

**NRC Staff Review Fees**

Under federal law, the NRC must recover the costs associated with NRC Staff reviews of license applications. Hourly rates for licensing and inspection work performed by NRC professional staff are established by regulation in Part 170. The NRC tabulates the hours worked by NRC Staff on the DCPP LR application and requires PG&E to reimburse the agency for the cost of performing that work.

As discussed above, due to the suspension of the NRC LR review, minimal NRC review fees were incurred between mid-2011 and mid-2015. The LR Project costs incurred is $7.072 million in direct costs for the NRC review fees.

**LR Project Team**

PG&E created a full-time project team consisting of project management personnel, financial support, administrative support, and technical personnel to develop and support all of the LRA-related activities described in this testimony. PG&E benchmarked other LR projects and staffed a project team based on this benchmarking. The team included a Project Manager, Assistant Project Manager, PG&E representative at the STARS COB, two Full-Time Equivalent (FTE) staff members for project support, six FTE Project Engineers, and one Administrative and Technical Assistant. The project team consisted of both PG&E personnel and contract employees. The project team received support from PG&E’s Law, Government Relations, and Communications departments.

Due to the suspension of the NRC LR proceeding, project team costs decreased between mid-2011 and mid-2014. Activities completed during the NRC LR review suspension period included revising plant documents to maintain configuration control, performing technical reviews to update the LRA annually as required by Section 54.21(b), and conducting limited implementation planning efforts in order to preserve the option of LR.

In addition, monthly mandatory disclosures in the adjudicatory process
continued during suspension of the technical and environmental review. Specifically, during the suspension period, PG&E remained obligated to provide all documents relevant to admitted contentions to intervenors and NRC staff. PG&E was also required to provide monthly status updates and participate in infrequent status calls with the parties and the ASLB, both remotely and in person.

The LR Project costs incurred is $14.531 million in direct costs for the project team.

The NRC LR process is shown in Figure 9-1 below. Highlighted activities are those that were completed during the DCPP LR review process.

2. **State Process**

The state LR process costs incurred 2009-2016 are associated with the following activities: (1) CZMA Consistency Certification/CDP; and (2) Other State Processes.

**CZMA/CDP**

The NRC renewal of the Diablo Canyon operating licenses for Units 1 and 2 constitutes issuance of a discretionary permit by a federal agency and
triggers consistency review under the CZMA. The CCC and the Bay Conservation and Development Commission are the two designated coastal management agencies in California that have been delegated authority to certify consistency with pursuant to the federal CZMA. In the case of DCPP, the CCC has the relevant CZMA consistency jurisdiction. PG&E submitted a Coastal Consistency Certification Application (CCCA) to the CCC simultaneously with PG&E’s filing of the LRA on November 23, 2009. PG&E engaged plant environmental personnel and technical consultants to support development of the CCCA in 2009.

The CCC found the CCCA lacked sufficient information for the CCC to complete its review, stating that it could not proceed with its analysis without having reviewed the results of the advanced seismic studies recommended by the CEC. The CCC also asserted that LR constitutes “development” under the California Coastal Act, which required PG&E to apply for a separate CDP. In response, PG&E shifted its focus to performing the seismic studies, including filing an application for approval of scope and recovery in customer rates the costs of those seismic studies and initiating and pursuing the numerous permitting actions required to implement those seismic studies. Although the NRC review was on hold 2011-2014, PG&E continued to develop its CZMA consistency/CDP strategy while the seismic studies were in progress to avoid delays in the process once NRC review was reinitiated.

In 2014 and 2015, following completion of the advanced seismic studies requested by the CEC, PG&E developed a draft CDP application to re-start the state LR process. The LR Project team developed the draft CDP application consistent with the California Environmental Quality Act and the California Coastal Act.

The LR Project costs incurred is $1.954 million in direct costs for the CZMA consistency/CDP activities.

**Other State Processes**

By letter dated June 25, 2009, then-CPUC President Peevey requested that PG&E provide to the CPUC information responsive to certain CEC recommendations related to LR. The LR Project team prepared the information responsive to the request. Specifically, the LR Project team
prepared the following: (1) a Balance of Plant (BOP) seismic reliability study; (2) an evaluation of Kashiwazaki-Kariwa Nuclear Power Plant (KKNPP) lessons learned; (3) a study addressing the local economic impact of Diablo Canyon; and (4) a study of alternate power generation options.

**BOP Seismic Reliability Study.** The CEC recommended that PG&E address the possibility of a prolonged outage of the Diablo Canyon due to damage to non-safety-related SSCs following a postulated severe earthquake. PG&E developed and submitted a report to the CPUC that compared the as-built codes for non-safety SSCs to current building codes and seismic design standards for non-nuclear power plants. The report also evaluated the seismic vulnerability and reliability of non-safety-related SSCs and described component repair and replacement plans for components that could cause a prolonged outage.

**KKNPP Lessons Learned.** The CEC recommended that Diablo Canyon evaluate the lessons learned from the KKNPP earthquake in Japan. The lessons learned are addressed in a Significant Event Notification issued by the INPO issued on October 24, 2007 and included: (1) an integrated emergency response strategy and alternate methods of communication can improve the response to site-wide events with multiple challenges; (2) on-site fire protection systems and local fire department response may be challenged during natural disasters; (3) unexpected radiological liquid and gaseous releases can occur following natural disasters; (4) seismic events can impact the integrity of radioactive waste storage drums or other items that are stacked without restraints; and (5) alternate means of personnel contamination monitoring may need to be established following a natural disaster. A report documenting PG&E’s review and recommendations with regard to KKNPP lessons learned was submitted to the CPUC in 2010, along with PG&E’s LR cost recovery application.

**Local Economic Impacts of Shut Down.** In 2009 and 2010, PG&E contracted with Cal Poly to oversee a study of the local economic impact of Diablo Canyon. This study was submitted to the CPUC in 2010, along with PG&E’s LR cost recovery application. In 2013, PG&E completed an updated local economic impact study.
Study Alternate Power Generation Options. To respond to the CEC recommendation, as well as to develop and support the economic analysis presented in the DCPP LR Testimony, PG&E contracted with Energy and Environmental Economics, Inc. (E3). E3 assisted with development and review of alternative energy prices.

The LR Project costs incurred is $1.628 million in direct costs for the other state-mandated activities associated with LR.

D. The LR Project Implemented and Followed Processes to Monitor and Control Costs

1. Budgeting Process

The DCPP LR Project budget was overseen and approved on an ongoing basis by the DCPP Executive Oversight Board (EOB). On a monthly basis meetings were conducted with DCPP senior leadership to provide updates on the scope of work, approved budget, future cost projections, and actual monthly spends.

2. Project Management Oversight Process

Project management oversight of the DCPP LR Project was conducted at two levels: DCPP and PG&E Corporate. Both DCPP and PG&E corporate procedures were used to ensure the project adhered to PG&E project management best practices, collectively referred to as the Project Management Standard.

On a monthly basis, reports were submitted to DCPP and PG&E corporate including such information as:

- Actual Expenditure To-Date;
- Project Status;
- Significant Achievements and Upcoming Deliverables;
- Scope, Schedule, and Resources; and
- Issues, Risk, and Opportunities.

In addition, monthly DCPP EOB meetings were conducted with DCPP senior leadership to provide updates on the scope of work, approved budget, future cost projections, and actual monthly spends.

The DCPP LR Project also conducted periodic independent third-party audits or assessments. Industry peers and experts reviewed a variety of
project-related items, including processes being employed, project
documentation, and plans for addressing technical subjects.

3. Contractor Support

PG&E took adequate steps to ensure that its contractor and technical
support costs were reasonable and prudent. PG&E negotiated favorable
contract terms under the current market conditions and circumstances.

E. Cost Recovery

PG&E requests the CPUC authorize PG&E to recover the $52.7 million in
costs incurred for its relicensing activities through the generation rate component
paid by bundled customers. The revenue requirement for recovery of these
costs is presented in Chapter 10.

F. Conclusion

PG&E incurred $52.688 million during 2009-2016 in order to preserve the
option to operate Diablo Canyon through 2045. Throughout that time frame,
PG&E continually re-assessed whether 20 additional years of DCPP operation
was in the best interest of PG&E’s customers. Although major shifts in
California energy policy ultimately led to PG&E’s decision not to relicense
Diablo Canyon, PG&E’s actions to initiate the relicensing process in 2009—and
its management of that process since that time—were reasonable, given the
long-term planning horizon for generation resources and the uncertainties in
California energy policy that PG&E had to manage. The costs were prudently
incurred and are appropriately recovered in customer rates.
CHAPTER 10

ACCOUNTING, COST RECOVERY, AND REVENUE REQUIREMENTS
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A. Introduction (Hoglund)

The Joint Proposal was entered into with a diverse group of stakeholders to govern the closure of the Diablo Canyon Power Plant (DCPP or Diablo Canyon) at the expiration of its existing Nuclear Regulatory Commission (NRC) operating license and provide for the orderly replacement of Diablo Canyon with a portfolio of greenhouse gas-free (GHG-free) resources. Several portions of the Joint Proposal require approval by the California Public Utilities Commission (CPUC or Commission) and adoption of rate making mechanisms and revenue requirements to implement and recover the costs of the CPUC-related portions of the Joint Proposal.

As described in the previous chapters of testimony, there are four sections of the Joint Proposal that PG&E proposes to implement through the application filed in this proceeding: (1) the procurement of GHG-free replacement resources in Section 2 of the Joint Proposal; (2) the employee retention, retraining and severance programs in Section 3 of the Joint Proposal; (3) the community benefits program in Section 4 of the Joint Proposal; and (4) the ratemaking and cost recovery proposals associated with Diablo Canyon in Section 5 of the Joint Proposal. The purpose of this chapter is to present Pacific Gas and Electric Company’s (PG&E) cost recovery proposals and revenue requirement requests associated with these four topics in the Joint Proposal.

Specifically, PG&E requests the Commission authorize the following:

- Establishment of a new 2-way balancing account, the Diablo Canyon Retirement Balancing Account (DCRBA), effective January 1, 2017, with three 2-way subaccounts to: (1) recover DCPP’s full book value by the time the units cease operations in 2024 and 2025;\(^1\) (2) account for the difference between actual and adopted expenses related to PG&E’s proposed Employee Retention Program for Diablo Canyon employees; and

\(^1\) Joint Proposal Section 5.1.
(3) account for the difference between actual and adopted expenses related to PG&E’s proposed Employee Retraining Program for Diablo Canyon employees.²

- Recovery of DCPP Unit 1’s and Unit 2’s undepreciated plant as of December 2016 and future capital additions, as described in Section B below, by the end of each unit’s license life, which will terminate in 2024 and 2025, respectively.³

- Authorization to update the Diablo Canyon capital depreciation expense revenue requirement annually to reflect the forecast annual gross additions as provided in PG&E’s General Rate Case (GRC). Authorization to true-up the previous year’s authorized revenues with actual capital depreciation expense through a Tier 3 advice letter to be filed in May of each year through the remainder of the plant’s license life.⁴

- Recovery of $352.1 million in costs associated with retaining approximately 1,500 employees at Diablo Canyon, as described in Chapter 7.⁵ The recovery would occur over a 7-year period through an annual expense-only revenue requirement of $50.9 million from January 1, 2018 through December 31, 2024 via the Nuclear Decommissioning (ND) Non-bypassable Charge (NBC).

- Recovery of $11.3 million in costs associated with retraining eligible employees at Diablo Canyon, as described in Chapter 7.⁶ The recovery would occur over a 5-year period through an annual expense-only revenue requirement of $2.3 million from January 1, 2021 through December 31, 2025 via the ND NBC.

- Tracking of the difference between actual and adopted Tranche #1 Energy Efficiency (EE) Program costs, as described in Chapter 4, in the Procurement Energy Efficiency Balancing Account (PEEBA) beginning January 1, 2017.⁷

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² Joint Proposal Section 3.2.
³ Joint Proposal Section 5.1.
⁴ Joint Proposal Section 5.1.
⁵ Joint Proposal Section 3.2.
⁶ Joint Proposal Section 3.2.
⁷ Joint Proposal Section 2.2.
• Recovery of $1.3 billion for the new Tranche #1 EE Programs, as described in Chapter 4, over a 7-year period through an annual expense-only revenue requirement of $186.9 million. Recovery would be from January 1, 2019 through December 31, 2025 via the electric Public Purpose Program (PPP) NBC.\(^8\)

• Recovery of costs associated with executed Tranche #2 contracts for clean supply-side resources through the Energy Resource Recovery Account (ERRA) and the Clean Energy Charge which would be recovered through a new subaccount in the New System Generation Balancing Account (NSGBA).\(^9\)

• Recovery of costs associated with executed Tranche #3 contracts for Renewables Portfolio Standard (RPS)-eligible resources through the ERRA and the Clean Energy Charge from utility bundled customers, including utility bundled customers that depart from bundled service after the Commission issues a decision approving this Application through the date of departure, as described in more detail in Chapter 6.\(^10\)

• Recovery of $49.5 million, as described in Chapter 8, to be paid to San Luis Obispo County to assist the local community to prepare and plan for the long-term loss of economic stimulus that the operating plant provides.\(^11\) The recovery would occur over an 8-year period through an annual expense-only revenue requirement of $6.3 million from January 1, 2018 through December 31, 2025 via the ND NBC.

• Recovery of $52.7 million in costs associated with Diablo Canyon license renewal activities, as described in Chapter 9, through an annual expense-only revenue requirement of $6.7 million. The recovery would occur over an 8-year period from January 1, 2018 through December 31, 2025 via the electric generation rate.\(^12\)

\(^8\) Joint Proposal Section 2.2.
\(^9\) Joint Proposal Section 2.3, 2.6.
\(^10\) Joint Proposal Section 2.4, 2.6.
\(^11\) Joint Proposal Section 4.
\(^12\) Joint Proposal Section 5.2.
B. Revenue Requirements and Cost Recovery Mechanisms for PG&E’s Proposals (Marre/Hoglund)

1. Establishment of the Diablo Canyon Retirement Balancing Account (Marre/Hoglund)

a. Diablo Canyon Book Value Amortization Proposal (Marre)

The Joint Proposal Section 5.1 states that, consistent with CPUC cost recovery principles for long-life capital assets, the Joint Parties support full cost recovery of PG&E’s investment and return on Diablo Canyon, fully amortized/depreciated to a zero book value by the end of 2024 for Unit 1 and the end of 2025 for Unit 2. This treatment reflects the status quo cost recovery mechanism in place for Diablo Canyon; generation rates are based on a depreciation schedule that assumes Diablo Canyon will be retired at the end of its NRC operating licenses. Current generation rates are therefore set to fully recover PG&E’s investment in Diablo Canyon at the end of the existing NRC operating licenses. The Joint Proposal does not change this assumption. However, PG&E does propose to fine tune the existing process by adding an annual true-up to reflect actual depreciation and capital spending.

In this Application, PG&E proposes to implement a cost recovery mechanism, as described below, to fully recover its investment in DCPP including: (1) the direct assigned net plant investment as of December 2016; (2) all post-2016 gross capital additions¹³ installed during the remainder of Diablo Canyon’s license life; (3) depreciation of Diablo Canyon; (4) cancelled project costs, if any; and (5) any residual materials and supplies (M&S) balance at the end of the license life. The current license life for Unit 1 and Unit 2 are scheduled to terminate in November 2024 and August 2025, respectively. However, as specified in Section 5.1 of the Joint Proposal, should the State Water Resources Control Board not grant PG&E’s request to continue once through cooling operations for Unit 2 beyond December 31, 2024, then PG&E

¹³ Gross capital additions is intended to represent both capital additions and cost of removal spend. Both increase rate base and are also considered a capital expenditure.
alternatively proposes to fully recover its capital investment for Unit 1 and Unit 2 by the end of December 2024.

1) **Net Plant Costs as of 2016**

DCPP rate base is made up of both direct assigned and allocated common plant. Direct assigned plant generally represents the capital investments to the facilities and equipment at the DCPP site. Allocated plant generally represents the cost of facilities shared by all Lines of Business (LOB). Examples include PG&E’s utility headquarters buildings located at 77 Beale Street and 245 Market Street in San Francisco. The allocated common plant amounts are assigned to all LOBs as determined in PG&E’s GRC. In this application PG&E proposes only to recover the direct assigned plant. Once DCPP is retired, the allocated common plant will be reassigned to the remaining LOB assets.\(^\text{14}\)

PG&E proposes to use the 2016 direct assigned net plant forecast amount of $1.805 billion as presented in its 2017 GRC Application. This net plant amount, representing the unrecovered balance as of the end of 2016, will be amortized over the remaining life of DCPP—8.5 years, assuming Unit 2 operates until August 2025. Subsequent to closing the 2016 accounting books, PG&E will update the 2016 net plant balance and amortization schedule.

2) **Plant Additions Subsequent to 2016**

PG&E will continue to make capital investments at DCPP to support its ongoing operations until the end of the license life. To simplify the recovery over the remaining eight to nine years of plant life, PG&E proposes to calculate a remaining life depreciation rate that is based on the vintage of the gross additions. For example, gross plant additions occurring in 2017 would have a depreciation rate of 1/8.5 years, gross plant additions occurring in 2016 would

\(^{14}\) PG&E is not proposing any change to the allocation factors in this application. PG&E proposes to address the allocation factors in the GRC Application prior to DCPP retirement. Under the current GRC cycles this would be the 2023 GRC.
have a depreciation rate of 1/7.5 years, and continuing this
methodology through 2024. In 2025, any gross capital additions
would be treated as expense. This amortization method will ensure
that all post-2016 capital additions are fully recovered by the end of
DCPP’s license life.

For the period 2017-2019, PG&E proposes to use the adopted
2017 GRC gross capital additions for DCPP in determining the
incremental depreciation expense. For post 2019 capital
additions, in its next GRC (currently 2020) PG&E will provide a
capital expenditure and additions forecast for DCPP through 2025 to be considered and adopted by the Commission. Capital additions
will remain subject to reasonableness review in PG&E’s GRC.

3) Amortization (Depreciation) of Plant

Beginning in 2017, PG&E will begin depreciating its embedded
plant as of 2016 and post 2016 capital additions as described in
Sections 1 and 2 above. To ensure there is no double recovery of
the costs, the GRC adopted level of depreciation will be netted
against this “modified” DCPP depreciation calculation such that only
the incremental amount of depreciation is collected from customers.

4) Cancelled Project Cost Recovery

As PG&E designs, engineers and constructs a project to
install/replace an asset, the costs are charged to Construction Work

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15 For the 2018 and 2019 Attrition years the gross capital additions will be based on the
approved 2017 GRC Decision. Should the Commission approve a third attrition year in
PG&E’s 2017 GRC, PG&E will then determine DCPP’s 2020 gross capital additions
based on the approved 2017 GRC Decision.

16 In a GRC only the Test Year plus two Attrition Years are forecast. For DCPP only,
PG&E will provide the forecast from the expected 2020 Test Year through 2025 so that
the Commission will have PG&E’s best estimate of the capital costs expected to be
incurred through the end of its license life.

17 In PG&E’s 2017 GRC, both The Utility Reform Network and Alliance for Nuclear
Responsibility have challenged the reasonableness of PG&E’s proposed Unit 2
generation stator project. If PG&E proceeds with the Unit 2 Stator project, these parties
have reserved the right to challenge the reasonableness of this project in the
2020 GRC. PG&E will incorporate the Commission’s decision on this and any other
Diablo Canyon-related capital addition as part of its proposed mechanism for recovery
of Diablo Canyon capital additions.
in Progress (CWIP) until the asset being installed is considered used and useful. During the CWIP stage of the project PG&E may assess a project based on multiple criteria to determine if the project should continue or if it should be cancelled. As part of its assessment process PG&E may, prior to the end of DCPP’s license, determine the most prudent action is to cancel a capital project recorded in CWIP.

In those instances in which PG&E may determine the best alternative is to cancel a project, PG&E proposes that the total project costs incurred at the time the decision is made to cancel the project be recovered from customers. PG&E proposes to recover these costs through an annual expense only revenue requirement from the year the cancellation decision is made through December 31, 2024, to be recovered as part of the Annual Electric True-Up (AET) advice letter through its existing generation rate component. Tracking of the actual revenues, including Franchise Fees and Uncollectibles (FF&U), collected through the generation rate component would occur through the Utility Generation Balancing Account (UGBA). These costs would not be included in DCPP’s rate base.

PG&E will submit a report in the AET advice letter filing that addresses the following factors: (1) whether the initial decision to build the project was reasonable; (2) whether the costs incurred to date were prudent and reasonable; (3) whether the project was reasonable throughout the project’s duration in light of both the relevant uncertainties that then existed and of the alternatives for meeting the needs of the customers; and (4) whether the project was canceled promptly when conditions warranted.

5) **Materials and Supplies Cost Recovery**

PG&E maintains an M&S inventory balance for DCPP used in the normal operation to repair or replace equipment at the site. Depending on the usage of the material, M&S may be either

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18 Cancelled project costs are not considered part of rate base and receive no return.
expensed or capitalized. PG&E does not currently propose any immediate adjustment to the M&S balance. Rather, PG&E proposes that in the 2020 GRC (or subsequent GRC following the 2017 GRC Decision), PG&E presents the cost recovery proposal which will evaluate the M&S balance of the 2020 GRC Test Year, the forecasted usage through 2025, less an estimated salvage value. PG&E’s request is to fully recover its M&S balance by the end of the license life.

b. DCRBA Cost Recovery Mechanism (Marre/ Hoglund)

1) Diablo Canyon Capital Depreciation Subaccount Cost Recovery and Tier 3 Advice Letter Proposal (Marre)

PG&E proposes to establish a new 2-way subaccount within the proposed DCRBA, the Diablo Canyon Capital Depreciation Subaccount, for the purpose to track and adjust the capital revenue requirements\(^\text{19}\) associated with DCPP direct assigned plant to reflect: (1) the full depreciation of DCPP’s full net book value as of December 31, 2016 and (2) the full depreciation of the gross capital additions that are installed over the remainder of the plant’s license life by vintage by the end of each unit’s operational license life in 2024 and 2025, respectively.

To accomplish this, beginning in 2017, PG&E proposes to file in May of each year a Tier 3 advice letter to: (1) forecast the next year’s capital related revenues incorporating the gross capital additions, as provided in PG&E’s GRC, to ensure a more-accurate depreciation expense revenue collection for the next year; (2) to true-up authorized capital related revenues, reflecting the actual gross plant additions for the previous year; and (3) show the depreciation by vintage of gross additions.

PG&E proposes that this annual Tier 3 advice letter receive disposition by the CPUC no later than the first December CPUC Business Meeting of the year of the advice letter submittal to ensure

\(^{19}\) Capital revenue requirements include depreciation, return on rate base, and income taxes.
that the updated revenues for the next year are able to be included in electric rates on January 1 of the next year through the AET advice letter. For the 2018 Diablo Canyon depreciation expense revenue requirement, if a final decision for this proceeding is not issued in time to complete the Tier 3 advice letter process before 2017 year-end PG&E will use the 2017 GRC authorized revenue requirement for the year 2018 and will commence with the new method of setting the annual revenue requirement with the May 2018 Tier 3 advice letter. Additionally, for the capital additions forecast, PG&E will provide information at a project level and note any material changes to PG&E’s GRC forecast of planned capital improvements.

2) **Employee Retention Program Subaccount and the Employee Retraining Program Subaccount Cost Recovery (Hoglund)**

   PG&E proposes to recover the Employee Retention Program and Employee Retraining Program costs of $352.1 million and $11.3 million, respectively. Recovery of the Employee Retention Program would be through an annual expense-only revenue requirement of $50.9 million over a 7-year period from January 1, 2018 through December 31, 2024. Recovery of the Employee Retraining Program would be through an annual expense-only revenue requirement of $2.3 million over a 5-year period from January 1, 2021 through December 31, 2025. Any refinements to the cost estimate for the Employee Retraining Program will be presented in the next Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) application.

   As provided in Chapter 7, the retention program will help PG&E retain the approximately 1,500 employees necessary to ensure the continued safe and efficient operation of the plant throughout the remainder of its licenses. Also as provided in Chapter 7, the Employee Retraining Program will support the placement, where feasible and cost-effective, of eligible employees who are interested in transitioning to roles supporting DCPP decommissioning or roles in other parts of the utility.
PG&E proposes to create two new 2-way subaccounts within the proposed DCRBA, the Employee Retention Program Subaccount and the Employee Retraining Program Subaccount, to track the actual expenses incurred compared to each of the adopted program costs. The Employee Retention Program and Employee Retraining Program revenue requirements, including FF&U, would be recovered in rates through the ND NBC in the AET advice letter. Once the Employee Retention Program and Employee Retraining Program conclude, the balance in the DCRBA subaccounts (including interest and FF&U expense) would be transferred to the Nuclear Decommissioning Adjustment Mechanism (NDAM) for refund to or recovery from customers through the next available AET advice letter.

True up of the difference between actual revenue collected through the ND NBC and adopted revenue requirements, including FF&U, would occur annually in the NDAM through the AET advice letter.20

While cost forecasts for the Employee Severance Program are provided in Chapter 7 for informational purposes, PG&E is only seeking approval at this time of the reasonableness of the program. PG&E will continue to include updates of its forecast of the costs of the approved program in its site-specific decommissioning plan in the NDCTP. Cost recovery of the severance program will ultimately be through the decommissioning trust.

2. Recovery of Energy Efficiency Tranche #1 Program Costs (Hoglund)

PG&E proposes additional EE to mitigate the impact of the closure of the DCPP on the electric grid and the state’s GHG profile prior to the retirement of DCPP. As described in Chapter 4, PG&E forecasts it will require $1.3 billion to fund the Tranche #1 programs. PG&E’s expense forecast for Tranche #1 includes a modest expense forecast in 2017 and 2018 and, as such, requests authority to begin recording actual Tranche #1

20 The NDAM was established in D.99-10-057 and tracks the recovery of the various ND revenue requirements.
expenditures to the PEEBA beginning January 1, 2017. To more closely
align the forecasted Tranche #1 revenues with the bulk of Tranche #1
expenditures, PG&E proposes to recover the forecasted $1.3 billion program
costs for Tranche #1 through the electric PPP rate component over
a 7-year period. Recovery would be through an annual expense-only
revenue requirement of $186.9 million from January 1, 2019 through
December 31, 2025.

The recovery and balancing account treatment of the electric PPP rate
was addressed in Decision (D.) 11-12-038. Consistent with that decision,
PG&E proposes to track, in the PEEBA, the actual electric EE expenditures
for Tranche #1 compared to the adopted program cost forecast. PG&E
does not know, at this time, how quickly EE programs and projects will be
implemented during the Tranche #1 2019-2024 installation period.
Therefore, PG&E requests authorization for carryover and carryback of the
authorized program costs for Tranche #1 across the entire 2017-2024 time
period. In the event that PG&E’s expenditures for Tranche #1 EE are less
than the authorized forecast, PG&E will return to customers any unspent
funds at the conclusion of PG&E’s fulfillment of the Tranche #1 commitment.
Any balance in the PEEBA (including interest) would be transferred to the
Procurement Energy Efficiency Revenue Adjustment Mechanism (PEERAM)
for refund to customers through the AET process. FF&U expense would be
added as appropriate to the PEERAM.

The electric procurement EE revenue requirement, including FF&U,
would be recovered as a non-bypassable charge through electric PPP rates
in the AET advice letter. The electric procurement EE adopted revenue
requirements and billed revenues would be trued up annually through the
PEERAM consistent with Pub. Util. Code Section 381(a)(1) and the
currently-approved rules for cost recovery for EE programs. PG&E’s electric
EE procurement funding would be included in the electric PPP rate
component effective January 1, 2019 or as soon thereafter as possible,
based on the then current revenue allocation and rate design methods
adopted for procurement EE funding.

21 See Chapter 4 for forecast of EE costs associated with Tranche #1.

a. Tranche #2 Contracts

In Tranche #2, winning projects could be an EE project or a GHG-free energy resource. If the winning project is an EE project, then PG&E will forecast the revenue requirement for the project and recover it subject to the same balancing account proposed for Tranche #1. If the winning project is a GHG-free energy resource, then costs associated with executed Tranche #2 contracts for clean supply-side resources are proposed to be recovered through the ERRA and a new NBC referred to in this testimony as the Clean Energy Charge. Costs recorded to the ERRA would be actual costs for the resources less net costs associated with the Clean Energy Charge. Net costs for the Clean Energy Charge would be the sum of all contractual fixed and variable costs of the resources less any California Independent System Operator (CAISO) market revenues received for energy output and ancillary services, if applicable, for the resource. The net Clean Energy Charge costs would be allocated to all benefiting customers, which would include electric distribution customers in PG&E’s service territory, including utility bundled, Community Choice Aggregation (CCA) and direct access (DA) customers, but excluding departing load customers taking electric service from a load serving entity (LSE) that has elected to self-provide, as described in Chapter 5.22

PG&E proposes that the net Clean Energy Charge costs be recorded to a Clean Energy Charge subaccount in the NSGBA. As is done for the other procurement related costs currently recorded in the NSGBA, the net costs associated with the Clean Energy Charge would be consolidated under the distribution rate and thus, would be paid by all electric distribution customers in PG&E’s service territory, including utility bundled, CCA, and DA customers, subject to an exclusion for customers of an LSE that self-provides. The development of the Clean Energy Charge cost forecast would be included in the annual ERRA.

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22 Cost allocation issues for Tranche #2 are addressed in the Joint Proposal Section 2.6.
forecast proceeding, or a similar proceeding designated by the Commission. The ERRA forecast proceeding is the logical place to develop and present the rate forecast as other costs recorded to the NSGBA are also presented to the Commission for review and approval in this annual proceeding.

The Clean Energy Charge associated with Tranche #2 costs, including the proposed approach for determining and allocating costs and benefits, is described in more detail in Chapter 5 of PG&E’s Prepared Testimony.

b. **Tranche #3 Contracts**

Costs associated with executed renewable resources are proposed to be recovered through the ERRA and the Clean Energy Charge as described in Chapter 6. As explained above, the Clean Energy Charge would be recovered through a new subaccount in the NSGBA from utility bundled customers that depart PG&E bundled service on or after the date of a final decision in this proceeding. Costs recorded to the ERRA would be actual costs for the resources less net costs associated with the Clean Energy Charge. Net costs for the Clean Energy Charge would be the sum of all contractual fixed and variable costs of the resources less any CAISO market revenues received for energy output and ancillary services, if applicable, for the resource. The Clean Energy Charge costs related to Tranche #3 and future RPS would be allocated: (1) to all utility bundled customers as of the date the Commission issues a decision approving this Application; and (2) to customers who depart after the decision date, through the date of their departure.

The Clean Energy Charge associated with RPS and Tranche #3 resource costs, including the proposed approach for determining and allocating costs and benefits, is described in more detail in Chapter 6 of PG&E’s Prepared Testimony.

4. **Recovery of Community Benefits Costs (Hoglund)**

PG&E proposes to recover the community impact mitigation payments, proposed as part of the Community Impact Mitigation Program, of $49.5 million over an 8-year period. Recovery would be through an annual
expense-only revenue requirement of $6.3 million from January 1, 2018 through December 31, 2025, to be recovered as part of the AET advice letter through the ND NBC. Tracking of the actual revenues, including FF&U, collected through the ND NBC rate component would occur through the NDAM.

As provided in Chapter 8, the purpose of this program would be to mitigate the loss of economic stimulus in the local community from the discontinuation of Diablo Canyon operations during the transition period to retirement. The proposed community impact mitigation payments appropriately recognize the benefits that Diablo Canyon, with the support of its local community, have provided to all customers over the decades of its successful operation.

While cost forecasts for emergency response costs during decommissioning are provided in Chapter 8 for informational purposes, PG&E is only seeking approval at this time to include updates of these costs in its site-specific decommissioning plan in the next NDCTP and to recover those costs ultimately through the decommissioning trust.

5. Recovery of Relicensing Costs (Hoglund)

PG&E proposes to recover $52.7 million in costs associated with Diablo Canyon license renewal activities. PG&E proposes to recover these costs through an annual expense only revenue requirement of $6.7 million over an 8-year period from January 1, 2018 through December 31, 2025, to be recovered as part of the AET advice letter through the generation rate component. Tracking of the actual revenues, including FF&U, collected through the generation rate component would occur through the UGBA.

A summary of the revenue requirements requested through this application are shown in Table 10-1 below.
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PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX A
STATEMENTS OF QUALIFICATIONS
PACIFIC GAS AND ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS OF JANICE S. BERMAN

Q 1 Please state your name and business address.
A 1 My name is Janice S. Berman, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).
A 2 I am Senior Director in the Customer Energy Solutions organization. From 2008-2015, I was responsible for various aspects of energy efficiency including strategy.

Q 3 Please summarize your educational and professional background.
A 3 I received a Bachelor of Arts degree in Mathematics from Whitman College in 1986. I received a Master of Science degree in Operations Research from Stanford University in 1987. In 1998, I received a Master of Business Administration degree from the Haas School of Business at the University of California, Berkeley.

I began my employment at PG&E in 1987. I was an Analyst, Senior Analyst, and Manager in PG&E’s Electric Resource Planning Department, where I focused on long- and short-term planning of generation and demand-side management programs. In 1994 and 1995, I was a Manager in the Rates Department, with a focus on customer segmentation and contribution to margin. In 1995 and 1996, I worked at PG&E Enterprises, supervising the activities of PG&E’s unregulated subsidiaries, as Chief of Staff to the Senior Vice President and Vice President. In 1996 through 1998, I was Manager of New Revenue Development, with a focus on non-tariffed products and services. In 1998 and 1999, I was Director of Regulatory Strategy, where I focused on the reliability must-run contracts with power generation facilities and associated case at the Federal Energy Regulatory Commission. In 1999 and 2000, I was Director of Gas System Operations, where I was responsible for the 24-hour operation of PG&E’s gas transmission pipeline, expansion planning, scheduling gas flows through California, developing, and maintaining the scheduling system, and negotiations with interconnected pipelines and power plants. In 2000
through 2002, I was Director of New Revenue Development, where I
focused on negotiating agreements with telecommunications companies for
installation of their equipment on PG&E’s infrastructure. In 2002
through 2004, as Director of Operations Revenue Requirements, I was
responsible for developing and managing PG&E’s General Rate Case and
other regulatory cases. In 2004 through 2007, as Director of Rates and
Tariffs, I was responsible for determining PG&E’s gas and electric rates, and
for administering PG&E’s tariffs. In 2007, as Director of Pricing and
Emerging Products, I was responsible for development of new pricing
options and products. In 2008 through 2009, as Senior Director of
Customer Energy Efficiency, Generation, and Revenue Development, I was
responsible for determining PG&E’s customer energy efficiency programs,
distributed generation programs, and the development of non-tariffed
product and service opportunities. In 2010-2012, I was Senior Director of
Policy and Integrated Planning, where I was responsible for strategy,
regulatory, and budget planning for the Customer Energy Solutions
organization. In 2012-2015, I was Senior Director of Strategy Research and
Analytics, with a focus on energy efficiency strategy, data analytics and
governance, and evaluation, measurement and verification.

Q 4 What is the purpose of your testimony?
A 4 I am sponsoring the following testimony in PG&E’s Retirement of Diablo
Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of
Associated Costs Through Proposed Ratemaking Mechanisms:

- Chapter 4, “Tranche #1 – Energy Efficiency.”
- Workpapers supporting Chapter 4, “Tranche #1 - Energy Efficiency.”
- Chapter 5, “Tranche #2 – All Source GHG Free Energy Request for
  Offers”:
  - Section F.1, “EE Resources”; and
  - Section G, “EE Shareholder Incentive.”

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.
Q 1 Please state your name and business address.
A 1 My name is Janice Y. Frazier-Hampton, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).
A 2 I am Director of Integrated Resource Planning within the Energy Policy, Planning and Analysis Department of PG&E’s Energy Policy and Procurement organization. My department is responsible for long-term planning for energy procurement and forecasting electric generation costs for use in various regulatory proceedings.

Q 3 Please summarize your educational and professional background.
A 3 I have a Bachelor of Business Administration degree in Finance from Northeast Louisiana University, Monroe, Louisiana, and a Master of Business Administration degree with a concentration in Finance from Golden Gate University, San Francisco.

I joined PG&E in 1982 and have held various positions of increasing responsibility in the Finance, Regulatory Relations and Energy Policy and Procurement organizations. I was promoted to Director in 2001. I assumed my current position in March 2010.

Q 4 What is the purpose of your testimony?
A 4 I am sponsoring the following testimony in PG&E’s Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms:
- Chapter 2, “Diablo Canyon Power Plant Need Analysis.”
- Workpapers supporting Chapter 2, “Diablo Canyon Power Plant Need Analysis.”

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.
Q 1 Please state your name and business address.
A 1 My name is Edward D. Halpin, and my business address is Pacific Gas and Electric Company, Diablo Canyon Power Plant.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).
A 2 I am the Senior Vice President, Generation and Chief Nuclear Officer responsible for PG&E’s utility owned-generation facilities portfolio of nuclear, hydro, fossil and renewables. As Chief Nuclear Officer, I am responsible for the long-term safe, reliable, and cost-effective performance of the Diablo Canyon Power Plant and the decommissioning of Humboldt Bay Unit 3 nuclear facility as well as the planning and execution of the decommissioning of Diablo Canyon Units 1 and 2.

Q 3 Please summarize your educational and professional background.
A 3 I received a Bachelor’s degree in Ocean Engineering from the U.S. Naval Academy in 1983. I also received the following Master’s degrees: Strategic Communication and Leadership from Seton Hall University in 2002 and Human Development from Fielding Graduate University in 2010. Prior to joining PG&E, I held several positions at the South Texas Project (STP) Nuclear Operating Company where I served as President, Chief Executive Officer, and Chief Nuclear Officer responsible for the overall strategic direction of STP and the operation of the STP’s Units 1 and 2. I joined PG&E on April 2, 2012. I am currently the Senior Vice President, Generation and Chief Nuclear Officer.

Q 4 What is the purpose of your testimony?
A 4 I am sponsoring the following testimony in PG&E’s Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms:
   • Chapter 7, “Employee Program”:
     – Section B, “Need for the Employee Program.”

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.
PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF TERESA J. HOGLUND

Q 1 Please state your name and business address.
A 1 My name is Teresa J. Hoglund, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).
A 2 I am a Director in the Revenue Requirements and Tariffs Department, which is a group within Regulatory Affairs. I oversee work related to short- and long-term revenue requirement and rate forecasts, cost of service and balancing account recovery.

Q 3 Please summarize your educational and professional background.
A 3 I received a Bachelor of Business Administration degree with an Accounting concentration from the Pacific Lutheran University in 1983. After my undergraduate program, I worked in the Tacoma office of Ernst & Whinney as a consultant in the Tacoma Telecommunications Practice. I received a Certified Public Accountant certificate in the state of Washington in 1986. I moved to California in 1987 and joined CPNational/Alltel as Manager of Cost Separations and Settlements. At CPNational/Alltel, over the next five years, I held various positions, including Western Region Budget Director, Western Region Controller and Southwest Region Controller.

In 1992, I joined PG&E as a Senior Analyst in the Plant and Depreciation Accounting group within the Capital Accounting Department. Subsequently, I held the position of the Plant and Depreciation Manager.

In 1995, I moved to the Corporate Accounting Department and held various positions or combinations of such positions over nine years including Energy Accounting Manager, Technical Accounting Manager, and External Financial Reporting Manager.

In 2004, I left PG&E for personal reasons. In 2009, I returned to PG&E as a Senior Regulatory Specialist in the Analysis and Rates Department. In 2010, I was promoted to Manager of Regulatory Analysis and Forecasting, which is a group within the Analysis and Rates Department. I did governance work related to balancing accounts and monthly revenue
requirement and rate forecasting. In 2011, I moved into my current position as Director of Revenue Requirements and Tariffs.

I have sponsored testimony before the California Public Utilities Commission, for PG&E’s recovery of Expenditures, in 1997 and 1998, to Enhance Transmission and Distribution System Safety and Reliability Pursuant to Section 368(e) (A.99-03-039), the 2009 Market Redesign and Technology Upgrade Cost Recovery (A.10-02-012), the 2011 General Rate Case – Phase 3 Cost Recovery (A.10-03-014), the 2014 General Rate Case – Phase 1 Cost Recovery (A.12-11-009), SmartMeter™ Program Modifications Cost Recovery (A.11-03-014), Smart Grid Pilot Deployment Project Cost Recovery (A.11-11-017), Mobile Home Park Service Transfer Cost Recovery (R.11-02-018), Default Residential Rate Programs (A.10-08-005), and the 2015 Gas Transmission and Storage Cost Recovery (A.13-12-012).

I am also sponsoring cost recovery testimony in the Joint Utility Market Redesign and Technology Upgrade Cost Recovery (A.12-01-014), the 2011 Market Redesign and Technology Upgrade Cost Recovery (A.12-04-009), and the 2017 General Rate Case – Phase 1 Balancing Accounts (A.15-09-001).

Q A

What is the purpose of your testimony?

I am sponsoring the following testimony in PG&E’s Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms:

- Chapter 10, “Accounting, Cost Recovery, and Revenue Requirements”:
  - Section A, “Introduction”;
  - Section B.1.b.2, “Employee Retention Program Subaccount and the Employee Retraining Program Subaccount Cost Recovery”;
  - Section B.2, “Recovery of Energy Efficiency Tranche #1 Program Costs”; and
  - Section B.4, “Recovery of Community Benefits Costs”; and
  - Section B.5, “Recovery of Relicensing Costs.”
• Workpapers supporting Chapter 10, “Accounting, Cost Recovery, and Revenue Requirements”:
  – “Revenue Requirement Calculation.”
Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.
Please state your name and business address.

My name is Thomas P. Jones, and my business address is Pacific Gas and Electric Company, 735 Tank Farm Road, San Luis Obispo, California.

Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

I am the Director of Strategic Initiatives at Diablo Canyon Power Plant (DCPP), where I oversee the license renewal projects for DCPP, dry cask storage licenses at both Humboldt Bay and Diablo Canyon, the DCPP land stewardship program, and other initiatives related to DCPP.

Please summarize your educational and professional background.

I have a Bachelor of Arts in Political Science degree from the University of California at Santa Barbara and have been actively engaged in California public policy since 1994. I worked for the California State Legislature for seven years covering matters related to utilities, unitary tax, public education and emergency preparedness, including nuclear-related legislation and DCPP property tax impacts associated with rapid depreciation related to the proposed electrical deregulation in 1997-1998.

I joined PG&E’s government relations department in 2001. In my various capacities at PG&E, I have received extensive training in emergency planning from the utility, the Nuclear Energy Institute and the Harvard School of Public Health and have served on the emergency response organization for 15 years. I have also served on various economic-development community boards, including the Economic Vitality Corporation in San Luis Obispo, for nearly a decade.

What is the purpose of your testimony?

I am sponsoring the following testimony in PG&E’s Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms:

- Chapter 8, “Community Impacts Mitigation Program”:
• Workpapers supporting Chapter 8, “Community Impacts Mitigation Program.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.
PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARY K. KING

Q 1 Please state your name and business address.
A 1 My name is Mary K. King, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E or the Utility).
A 2 I currently lead the PG&E Human Resources (HR) Labor Relations and Business Partner function. My responsibilities include negotiating and administering PG&E’s bargaining unit contracts and providing strategic HR support to the lines of business (LOB) to ensure PG&E’s HR programs and strategies are implemented consistent with LOB strategies and needs.

Q 3 Please summarize your educational and professional background.
A 3 I hold a Bachelor of Science degree from the United States (U.S.) Military Academy at West Point and a Juris Doctorate degree from Indiana University at Indianapolis. Before joining PG&E, I held positions at Calpine in Middletown, California and Indianapolis Power and Light in Indiana. I began my career in the U.S. Army as Platoon Leader, Executive Officer and Captain. I joined PG&E in 2009 as Principal Negotiator and have held numerous leadership positions in Human Resources (HR), including leading recruiting and as Senior Director of HR Delivery. I was Chief of Staff for the Utility President prior to assuming my current role in February 2015. I was promoted to Vice President, Human Resources in June 2015.

Q 4 What is the purpose of your testimony?
A 4 I am sponsoring the following testimony in PG&E’s Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms:
- Chapter 7, “Employee Program”:
  - Section A, “Introduction”;
  - Section C, “Retention Program Overview and Cost Forecast”;
  - Section D, “Employee Severance Program Overview and Cost Forecast”;

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– Section E, “Employee Retraining Program Overview and Cost Forecast”; 
– Section G, “Cost Recovery;” and 
  • Workpapers supporting Chapter 7, “Employee Program.”
Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.
PACIFIC GAS AND ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS OF STEVEN E. MALNIGHT

Q 1 Please state your name and business address.
A 1 My name is Steven E. Malnight, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).
A 2 I hold the position of Senior Vice President, Regulatory Affairs, for Pacific Gas and Electric Company. I am responsible for developing, coordinating and managing policy with state and federal regulatory agencies, including the California Public Utilities Commission (CPUC), the California Energy Commission and the Federal Energy Regulatory Commission. I am also responsible for developing and filing rate proposals with the CPUC, and for oversight of the company’s gas and electric tariffs.

Q 3 Please summarize your educational and professional background.
A 3 I hold a Bachelor of Science degree in Chemical Engineering from the University of Notre Dame and a Master’s degree in Business Administration from the Tuck School of Business at Dartmouth. I joined PG&E in 2002 and have held various leadership positions within the company, including Vice President of Renewable Energy and Vice President of Customer Energy Solutions. I was appointed to my current role as Senior Vice President, Regulatory Affairs in September 2014.

Q 4 What is the purpose of your testimony?
A 4 I am sponsoring the following testimony in PG&E’s Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms:
   • Chapter 1, “Policy and Overview”:

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.
PACIFIC GAS AND ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS OF CHARLES M. MARRE

Q 1 Please state your name and business address.

A 1 My name is Charles M. Marre, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Senior Director of Capital Accounting and am responsible for the capital policies and accounting.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Commerce, majoring in Accounting, from Santa Clara University in 1982 and a Master of Business Administration degree in Finance from Golden Gate University in 1989.

I also earned the Certified Management Accountant Professional Designation in 1991.

Prior to assuming my current position, I held the positions of Senior Director of Regulatory Relations, Operations Proceedings; Director of Finance, Utility Operations Business Planning; Director of Finance, Capital Accounting & Payment Services; Director of Finance, Capital Accounting; Manager of Finance, Plant Accounting; Manager of Finance on the System Applications & Products Implementation Project; Supervisor of Finance, Job Accounting; and various Senior Analyst and Analyst positions in the Finance organization’s Corporate Accounting, Capital Accounting and Budget Departments.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E’s Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms:

- Chapter 10, “Accounting, Cost Recovery, and Revenue Requirements”:
  - Section B.1.a, “Diablo Canyon Book Value Amortization Proposal”;
  - and
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PACIFIC GAS AND ELECTRIC COMPANY

STATEMENT OF QUALIFICATIONS OF PATRICK MOLONEY

Q 1 Please state your name and business address.
A 1 My name is Patrick Moloney, and my business address is Suite 2000, 345 California Street, San Francisco, California.

Q 2 Please state your current employer and position.
A 2 I am employed by Willis Towers Watson (WTW) as the Regional Leader for Executive Compensation.

Q 3 Briefly describe your responsibilities at WTW.
A 3 I have been in my current position for 5 years and have been involved in human resources (HR) consulting for approximately 25 years. I work with boards of directors and managers to design and implement pay programs that reinforce business goals. I have experience helping companies address specific business events including: initial public offerings, business closures, bankruptcy, negative say-on-pay votes, and mergers and acquisitions.

Q 4 Please describe WTW’s business more generally.
A 4 WTW is a global leader in HR and risk consulting. More specifically, WTW has the largest executive compensation practice in the world and works with 75 percent of the Fortune 500 companies.

Q 5 What prior experience do you have consulting on compensation and HR projects that are relevant to the retirement of Diablo Canyon Power Plant (DCPP)?
A 5 My practice includes HR and compensation consulting for a broad range of firms, large and small, in a variety of industries. Although the names of my clients are confidential, a representative sample of my relevant experience includes:

- Fortune 500 Utility – Retention plan development for closure of geographic business unit
- Fortune 500 Utility – Retention and long-term incentive plans for a new business unity
- Fortune 100 Company – Retention plan development for acquired business unit
• Fortune 500 Industrial – Retention plan development for employees of a geographically dispersed business unit identified for potential closure
• Global 1000 Company – Retention and long-term incentive plan development for employees of an acquired company

Q 6 Please describe what research you have conducted or authored that is relevant to the retirement of DCPP?

A 6 I have participated in or managed the following research projects that are relevant to the retirement of DCPP:
• Managed: Towers Watson 2015 Mergers and Acquisitions Practices Survey
• Managed: Towers Watson 2015 Digital Companies Incentive Practices Survey
• Participated: WTW Utility Compensation Trends Update 2016
• Managed: Venture Pay Group Compensation for Incubators/Accelerators
• Managed: Venture Pay Group Compensation for Digital Financial Services Companies

Q 7 What relevant occupational experience do you have prior to your current work at WTW?

A 7 Before joining Towers Watson, I founded and managed the Seattle office of the Venture Pay Group, a boutique consulting firm serving private equity and growth organizations worldwide. Prior to that, I was a Managing Consultant in Towers Perrin’s San Francisco executive compensation practice.

Q 8 Please summarize your educational background.

A 8 I earned a Bachelor’s degree from the University of Washington, Seattle and an M. Phil. from Oxford University, England.

Q 9 What is the purpose of your testimony?


Q 10 Does this conclude your statement of qualifications?

A 10 Yes, it does.
Please state your name and business address.

My name is Todd Strauss, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

I hold the position of Senior Director of Energy Policy, Planning, and Analysis. I support energy procurement activities by providing guidance and oversight for policy formulation, long-term planning, valuation analysis and portfolio analysis.

Please summarize your educational and professional background.

I received my Bachelor of Science degree in Mathematics from the Massachusetts Institute of Technology. I hold a Ph.D. in Industrial Engineering and Operations Research from University of California, Berkeley.

I have worked as an Assistant Professor at the Yale School of Management, a Principal at the consulting firm PHB Hagler Bailly, and Director of Quantitative Analysis at an affiliate company of PG&E.

In 2003, I joined PG&E as Director of Quantitative Analysis. I was appointed to my current position in 2006.

What is the purpose of your testimony?

I am sponsoring the following testimony in PG&E’s Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms:

- Chapter 3, “Replacement of Diablo Canyon Power Plant.”
- Chapter 5, “Tranche #2 – All Source GHG Free Energy Request for Offers”:
  - Section A, “Introduction”;
  - Section B, “Tranche #2 Commitment”;
  - Section C, “Tranche #2 RFO Process”;
  - Section D, “Evaluation Methodology”;
  - Section E, “Approval Process for Executed Offers”;
Section F.2, “Clean Supply-Side Resources”; and Section H, “Conclusion.”

- Chapter 6, “Tranche #3 – Voluntary 55 Percent Renewables Portfolio Standard Procurement Commitment.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.
PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF L. JEARL STRICKLAND

Q 1 Please state your name and business address.
A 1 My name is L. Jearl Strickland, P.E., and my business address is Pacific Gas and Electric Company, Diablo Canyon Power Plant.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).
A 2 I have the lead responsibilities for the Generation Technical Services Department within PG&E. The department is responsible for: Compliance and Business planning; Geosciences; Seismic Projects; Regulatory Projects; Probabilistic Risk Assessment; Corrective Action Program; Strategic Initiatives (including License Renewal); Nuclear Fuels procurement; and Spent Nuclear Fuel Storage Program.

Q 3 Please summarize your educational and professional background.
A 3 I have a Bachelor of Science degree in Civil Engineering from California State University, Chico; a Master’s of Business Administration degree in Project and Construction Management from Golden Gate University; and completed graduate studies in Civil and Geotechnical Engineering at University of California, Berkeley. I have 36 years of experience with PG&E, including: Design Engineering; Chief Civil Engineer; developer of Diablo Canyon's Spent Nuclear Fuel Storage Program; Manager of Strategic Projects and Senior Region Manager in Government Relations; and Director of Nuclear and Regulatory Projects.

Q 4 What is the purpose of your testimony?
A 4 I am sponsoring the following testimony in PG&E's Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms:
   • Chapter 9, “DCPP License Renewal Project Costs 2009-2016.”

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.