Application: 10-01-022
(U 39 E)
Exhibit No.:
Date: September 17, 2010
Witness: Robert S. Gomez
Joseph F. O'Flanagan
Loren D. Sharp
Philippe R. Soenen

PACIFIC GAS AND ELECTRIC COMPANY

DIABLO CANYON POWER PLANT LICENSE RENEWAL

REBUTTAL TESTIMONY

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PACIFIC GAS AND ELECTRIC COMPANY
DIABLO CANYON LICENSE RENEWAL
REBUTTAL TESTIMONY

A. Introduction

Pacific Gas and Electric Company (PG&E) requests that the California Public Utilities Commission (CPUC or Commission) find that it is cost effective and in the best interest of PG&E's customers to preserve the option to operate Diablo Canyon Power Plant (Diablo Canyon or 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. In turn, PG&E requests authority to recover in rates the costs to obtain the state and federal approvals related to renewal of the Diablo Canyon operating licenses (referred to as the "License Renewal project"). PG&E estimates the total cost of the License Renewal project at $85 million. PG&E's economic analysis indicates that, when compared with other possible alternatives, there is a tremendous benefit to PG&E's customers of operating Diablo Canyon an additional 20 years.

The Utility Reform Network (TURN) and the Division of Ratepayer Advocates (DRA) served testimony in response to PG&E's application for approval. DRA and TURN do not oppose PG&E's request to recover the costs of the federal and state processes necessary to preserve the option to operate Diablo Canyon for an additional 20 years beyond expiration of the current operating licenses. However, both parties raise concerns about the assumptions used in PG&E's cost-effectiveness analysis. Additionally, DRA challenges some aspects of PG&E's license renewal project forecast. In this rebuttal testimony, PG&E addresses the concerns and issues raised by these parties.

B. The Commission Need Not Delay Consideration of This Cost Recovery Application Pending Completion of Seismic Studies Recommended by the California Energy Commission (Loren Sharp)

Q 1 Does PG&E agree with the assertion made by DRA and Southern California Edison (SCE) that funding for license renewal can be resolved before the seismic studies recommended by the California Energy Commission (CEC) in its November 2008 Assembly Bill 1632 Report are complete?

A 1 Yes, PG&E agrees that this proceeding requesting authority to preserve PG&E's option to operate Diablo Canyon an additional 20 years can be resolved before the additional seismic studies recommended by the CEC are complete.

Q 2 How does PG&E support its position?

A 2 The CEC-recommended seismic studies should be decoupled from license renewal. Any findings from the CEC recommended seismic studies will be addressed as part of PG&E's *ongoing* Long-Term Seismic Program. If the studies indicate that PG&E should enhance its seismic program, PG&E will take appropriate action at the time in order to ensure the continued safe operation of Diablo Canyon. The seismic studies and their results are not uniquely relevant to license renewal; they are relevant to current operations and will be addressed as part of current operations.

C. PG&E's License Renewal Project Cost Forecast Is Reasonable (Phillipe Soenen)

Q 3 In its testimony, does TURN recommend any specific disallowance with respect to the license renewal costs described in PG&E's application?

A 3 No. TURN does not propose any disallowance to PG&E's $85 million request for the license renewal process.

Q 4 Does DRA recommend the disallowance of any of PG&E's requested license renewal costs?

A 4 Yes. DRA proposes to disallow approximately $8 million of PG&E's $85 million request for funding associated with the license renewal process. The proposed disallowance consists of a reduction of $6.6 million for 3 Full-Time Equivalent (FTE) positions on the License Renewal Project Management Team, and a reduction of $1.4 million in the contingency associated with preparation of PG&E's license renewal application (LRA) at the Nuclear Regulatory Commission (NRC).

Q 5 Does DRA explain why it believes 3 FTE positions should be removed?

A 5 No. DRA provides no explicit justification for its proposed disallowance of the 3 FTE positions.

Q 6 Do you agree with DRA's proposal to remove the Assistant Project Manager (APM) position from the project?

A 6 No. The APM is an integral part of the project team in the implementation and review of the NRC process. The APM supports the Project Manager (PM) in all of the activities required for the project. In particular, the APM is the lead for the extensive NRC safety reviews as well as day-to-day supervision of the project team. The APM also interfaces with subject matter experts at DCPP and with the Strategic Teaming and Resource Sharing Center of Business on technical reviews. The current APM has been a member of the license renewal since its inception.

Q 7 Do you agree with DRA's proposal to remove two additional FTEs from the project?

A 7 No. These costs of 2 FTEs represent the time spent on the License Renewal project by multiple individuals who will support the project as their areas of specialization are required. These individuals are: estimators, financial analysts, budget analysts, cost engineers, contract managers, schedulers, and other project support as required. These individuals perform the project controls function, allowing the PM to assure PG&E management that the project is managed within cost and schedule and that proper contracting policy is enforced. These functions are essential to completing the project on time and on budget.

Q 8 DRA points out that the PM, APM and 2 Project Manager FTEs have the same "compensation value." Can you explain this?

A 8 Yes. PG&E uses a "standard rate" for estimating and project charging. While the estimating standard rate is equivalent for these positions it is not a compensation value. A Standard Rate is the mechanism SAP uses to distribute costs from a Provider Cost Center (PCC)[1] to a project. Each PCC has its own standard rate that it uses to charge for services. The standard rate includes the average hourly salary for all employees in the PCC, supervision and management, payroll taxes, employee benefits, contracts, materials used in the daily operation of the PCC and other costs. All charges by individuals in a PCC are the same.

[1] A Provider Cost Center is an organization that provides services to other organizations or projects.

See Attachment 1, which is PG&E's policy for development of standard rate and Attachment 2, which is the spread sheet that demonstrates the development of the standard rate for the PCC referred to in this application.

Q 9 DRA proposes to reduce the $85 million revenue requirement by the contingency amount applied to the license renewal application activities. Is it appropriate to apply (and therefore reduce) contingencies in this piecemeal fashion?

A 9 No. The total financial costs for most of PG&E's capital projects is normally developed using a single contingency amount applied to escalated direct costs. For the License Renewal project costs, PG&E took a more specific approach and applied contingency percentages to specific activities based on the uncertainty associated with that activity. The range of contingency was from 15 percent to 40 percent. When applied to the combined total estimated direct costs, capital Administrative and General, escalation, and Allowance for Funds Used During Construction, this contingency amounts to 26 percent or $17.579 million overall. Despite the fact that PG&E developed the overall contingency by assigning contingency percentages based on the risk associated with specific activities, it is not appropriate to reduce the contingency as individual activities are completed. In developing the contingency this way, we determined that an overall contingency rate of 26 percent should be applied to the project. That rate does not change based on the passage of time—it is applicable to the entirety of the license renewal project, across all activities.

D. PG&E's Response to DRA's and TURN's Comments on the Cost-Effectiveness Study

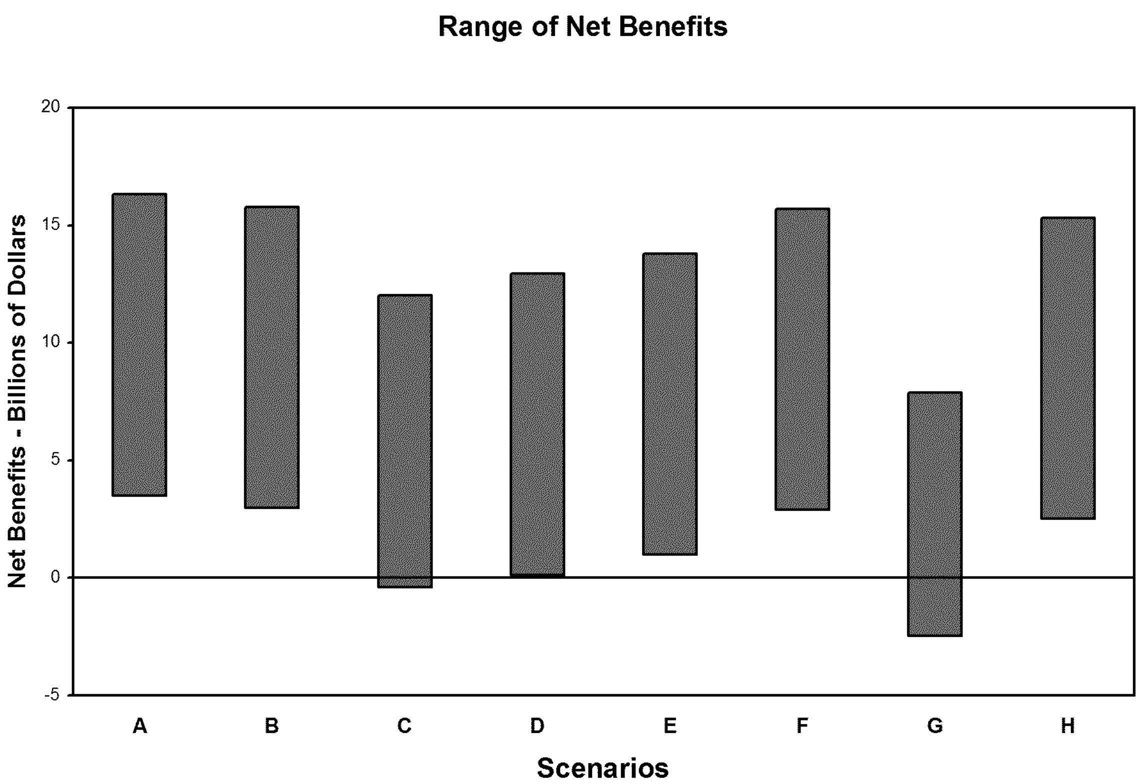
1. PG&E's Economic Analysis Results Are Reasonable (Joseph O'Flanagan)

Q 10 Both TURN and DRA question the results of PG&E's economic analysis presented in this application. How do you respond?

A 10 TURN and DRA point out that, using different assumptions about plant operating parameters and capital and operations and maintenance (O&M) costs can result in scenarios that result in negative net benefits from extended operation of Diablo Canyon. PG&E admits that there is a high degree of uncertainty in any analysis that looks 35 years into the future. However, PG&E believes that it has demonstrated through direct testimony and discovery that over a wide range of assumptions, preserving the option to extend operations of Diablo Canyon is in the best interest of ratepayers.

Figure 1 below shows the range of net benefits for various scenarios. See Attachment 3 for details of all scenarios examined.

FIGURE 1
PACIFIC GAS AND ELECTRIC COMPANY



Scenario	Description
A	Application - 90% Capacity Factor
B	Application - 85% Capacity Factor
C	Cooling Towers - 85% Capacity Factor
D	Cooling Towers - 90% Capacity Factor
E	Cooling Towers - 10 Year Extended Operation
F	Cooling Towers - 25% Higher Capital and O&M
G	CoolingTowers - 10 Year Extended Operation - 25% Higher Capital and O&M
H	Once Through Cooling Mitigation

Q 11 What is DRA's position on PG&E's cost-effectiveness study?

A 11 DRA does not oppose PG&E's cost-effectiveness methodology. However, DRA makes several general comments on PG&E's cost-effectiveness study. In particular, DRA: (1) expresses concern over the use of long-term natural gas forecasts; (2) questions why PG&E does not discuss transformer replacements in testimony; and (3) inquires if PG&E is required by the California State Water Resources Control Board (SWRCB) to install cooling towers at DCPP or provide some form of environmental mitigation.

Q 12 What is TURN's position on PG&E's cost-effectiveness study?

A 12 TURN challenges the assumptions and inputs used by PG&E in its cost-effectiveness study. TURN points out that there is no actual operating experience for any nuclear power plant that has been operating for a full 41 years, with several nuclear power plants barely into their license renewal periods. TURN asserts that the absence of any meaningful operating experience for nuclear plants past 40 years of operation is significant because many nuclear power plants have suffered unpleasant and expensive surprises from problems that have arisen during their operations. As such, TURN states that PG&E should have used a range of future O&M and capital costs, instead of single trajectories, in its economic analysis.

TURN also asserts that there is no evidence that nuclear plants will continue to operate at high capacity factors during the extended license period. TURN suggests that the operating capacity of nuclear power plants could decrease as the plants age and states that PG&E should have used a capacity factor range of 60 percent to 90 percent in its analysis.

Last, TURN asserts that PG&E should have included costs for seismic-related upgrades it expects will result from the additional seismic studies being performed at DCPP.[2]

Q 13 TURN identifies several scenarios that produce negative net present value benefits for PG&E's customers. In other words, TURN presents several scenarios in which extended operation of DCPP would not be the most cost-effective option for PG&E's customers. What is your response to these scenarios?

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[2] The additional seismic studies are the subject of a separate application (A.10-01-014) which was approved in Decision 10-08-003 on August 12, 2010.

A 13 PG&E agrees that TURN has identified several scenarios that result in negative net benefits to customers, but it is important to consider these factors:

- In all of the scenarios presented by TURN, there are a wide range of results in which there are positive and negative net benefits.
- All of the scenarios presented by TURN assume that PG&E will install alternative cooling technology or incur similar costs to comply with the SWRCB policy addressing once through cooling.
- All of the scenarios presented by TURN assume that O&M and capital expenditures are 25 percent above those assumed by PG&E.
- In all of TURN's scenarios, replacement power is assumed to come from gas-fired combined cycle power plants.

TURN has taken plausible, but not likely, assumptions, and combined them to present an unrealistic picture of the benefits of extended operations of DCPP. The Commission should not rely upon this flawed analysis to make its decision on whether it is in the best interest of PG&E's customers to preserve the option to operate Diablo Canyon for an additional 20 years beyond expiration of the current operating licenses.

Q 14 DRA and TURN both question PG&E's failure to include in its cost-effectiveness analysis the cost to retrofit DCPP to new cooling technology. Why did PG&E omit any such costs in its cost-effectiveness analysis?

A 14 PG&E did not include the cost to retrofit Diablo Canyon to new cooling technology in its cost-effectiveness analysis because PG&E's studies indicate that the cost to install cooling towers far exceeds the benefits and installing cooling towers at the Diablo Canyon site would present significant engineering, physical and environmental challenges . As such, PG&E does not intend to comply with the SWRCB Once-Through Cooling policy by installing alternative cooling technology at Diablo Canyon.

Q 15 Has PG&E performed the cost-effectiveness analysis that includes the cost to install cooling towers at Diablo Canyon?

A 15 Yes. While TURN and DRA are correct that PG&E did not include such an analysis in its direct testimony, it did provide that analysis in response to a

DRA data request. The results are shown in Figure 1 and Attachment 3 as Scenarios C and D. As can be seen in Attachment 3, only one alternative in Scenario C results in a negative net benefit.

Q 16 Has PG&E examined any other scenarios regarding the SWRCB policy other than installation of cooling towers?

A 16 Yes. As discussed below, the SWRCB policy allows for alternative compliance requirements at the state's two nuclear facilities if the cost of compliance is wholly out of proportion to the costs identified in Tetra Tech Inc.'s study entitled, "California's Coastal Power Plants: Alternative Cooling System Analysis" (February 2008). PG&E has examined the net benefits of extended operations of Diablo Canyon assuming it incurs mitigation costs equal to the costs used in the Tetra Tech study. The range of net benefits is included in Figure 1 and Attachment 3 as Scenario H. For all replacement power alternatives this scenario has positive net benefits.

Q 17 What is PG&E's response to DRA's request to explain if the SWRCB will require cooling towers for Diablo Canyon or some form of environmental mitigation?

A 17 The policy adopted by the SWRCB on May 4, 2010, does not prohibit the use of once-through cooling at Diablo Canyon. Diablo Canyon must be in compliance with the policy by December 31, 2024, and the policy allows for alternative compliance requirements at the State's two nuclear facilities.

Under Section 3.D of the policy, the Board's executive director must establish a nuclear review committee to review existing cooling tower feasibility studies and determine if additional studies are required. The committee must, within one year of the effective date of the policy, provide the Board with a report outlining any required additional studies and within three years of the effective date of the policy submit a report detailing the results of the additional studies.

The Board, considering the study results, shall establish alternative, site-specific requirements for Diablo Canyon if either: (1) the cost of compliance is wholly out of proportion to the costs identified in Tetra Tech Inc.'s study entitled, "California's Coastal Power Plants: Alternative Cooling System Analysis" (February 2008); or (2) compliance is wholly unreasonable based a consideration of factors including, but not limited to, engineering constraints, space constraints, permitting constraints, public safety, and adverse environmental impacts. Additionally, alternative compliance requirements must be established if installation of cooling towers would conflict with a nuclear safety requirement established by the NRC.

If alternative compliance requirements, including the continued use of once-through cooling, are established, the difference in impacts to marine life must be fully mitigated. Mitigation shall be through funding of projects associated with the State's Marine Protected Areas (MPA) program and in support of an MPA near the facility.

PG&E plans to comply with this requirement by making the necessary showing that the installation of cooling towers is "wholly unreasonable" considering the factors put forth in the policy. PG&E has maintained throughout the rulemaking that the impact on climate change and air quality that would result from compliance far outweigh the benefits of retrofitting to cooling towers. Whether or not this qualitative judgment is reached, the local air district has opined in the instance of another power plant's retrofit that it would not permit cooling towers due to the PM emissions. Additionally, PG&E has maintained during the SWRCB's proceeding that the costs associated with the installation of cooling towers are "wholly out of proportion" to the costs identified in the Tetra Tech study. PG&E previously provided to the SWRCB, and to this Commission, the cooling tower feasibility study prepared by Enercon, Inc.

Q 18 DRA points to discrepancies between the 2010-2024 forecast capital expenditures PG&E presents in this application and those presented in PG&E's 2010 General Rate Case (GRC) Application (A.09-12-020). What is PG&E's response?

A 18 The 2010-2013 capital expenditures used in the cost-effectiveness analysis in this application were incorrect. As explained in testimony in Application 09-12-020, there are two differences between the capital expenditures in that proceeding and those in this:

- Certain projects related to Diablo Canyon, such as Information Technology projects, were not included in the Generation Exhibit which DRA used in its comparison. They were included in other exhibits and sponsored by other witnesses. Since these projects are related to

Diablo Canyon operations, it is appropriate to include them in the economic analysis presented in this proceeding.

- The 2011-2013 capital expenditures used in this Application inadvertently excluded amounts for capitalized pensions.

The correct 2010-2013 capital expenditures are shown below in Table 1:

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
2011-2013 CAPITAL EXPENDITURES
(THOUSANDS OF DOLLARS)

Line No.	2010	2011	2012	2013
1	175,715	157,057	176,887	152,757

DRA's testimony also shows a capital expenditures difference in 2014 between the GRC and this application. This difference is due to the capital cost for the License Renewal Project being requested in this proceeding. The LRA capital was not included in the 2011 GRC figures since it was not being requested in the GRC.

Q 19 What is the impact of correcting the capital forecast in this application?

A 19 Updating the economic analysis to reflect the above capital expenditures has no impact on the results of the economic analysis. Capital expenditures through the timeframe in question were the same in both the current license scenario and the extended operations scenario. Since the benefit of extended operations is the difference between the two scenarios the change in capital expenditures does not affect the result.

2. PG&E's Cost and Operating Assumptions Are Reasonable (Loren Sharp)

Q 20 TURN asserts that PG&E should have forecast higher capital expenditures to reflect the possibility of "unexpected surprises," the dearth of nuclear plant operating experience for longer than 41 years, and the possibility of a prolonged outage at DCPP. Is it appropriate to revise the capital forecast for unexpected surprises?

A 20 No. PG&E has already replaced the large age-limited components at Diablo Canyon, e.g., steam generators, turbines, main generator Unit 1, and reactor vessel heads. The replacement components were engineered for a 50-year life. PG&E's knowledge and experience with the aging mechanisms of the original components along with improved materials and engineering of replacement components adequately address the risk of major equipment failure or degradation. Additionally, PG&E will monitor structures and buildings for deterioration and repair them as necessary. These facilities (containment, auxiliary building, fuel-handling building, turbine building and intake structure) can last indefinitely with a reasonable monitoring and repair program.

Q 21 TURN also asserts that PG&E should have forecast lower operating performance levels (i.e., poorer performance). Is it appropriate to revise the operating performance assumptions to reflect a lower average capacity factor, as TURN suggests?

A 21 No. For performance, unlike other industrial facilities, a nuclear generating station must operate as well on its last day of operation as it did in its first days of operation. This performance is best depicted by looking at the operating performance of plants operating at the end of their current license period. There are seven plants that are in their 40th or 41st year of operation. The operating capacity factors for these facilities over the past seven years has averaged greater than 92 percent and for the past five years greater than 93 percent. To apply TURN's logic, we should see a decrease in performance as plants age—this is not the case.

Q 22 Likewise, TURN asserts that PG&E's non-fuel O&M forecasts should have assumed an older plant will require higher non-fuel O&M expenditures. Is this an appropriate assumption?

A 22 No. To determine cost of operations during the extended license period, PG&E used the "most likely" scenario around which variable options can be analyzed. While no plants have operated beyond 41 years to date, PG&E used reasonable cost assumptions in its cost-effectiveness analysis.

Q 23 Do you agree with TURN's assertion that, "Although PG&E's assumptions that DCPP will continue to operate at high capacity factors and with its assumed O&M costs and capital expenditures through a 20-year license renewal period may turn out to be correct, there is no evidence from other nuclear plants to support these assumptions?"

A 23 No. In order to begin any analysis some base assumptions must be made. PG&E has chosen conservative and probable factors for this analysis as a baseline analysis.

Q 24 Did PG&E include in its capital forecast the cost of seismic upgrades or retrofits that may be dictated by ongoing seismic studies?

A 24 Yes. PG&E included $22.5 million in base capital expenditures for projects resulting from the update to the Long-Term Seismic Plan studies and surveys. Thus, PG&E anticipated there may be some projects resulting from ongoing research into the seismic hazard at Diablo Canyon.

Q 25 Do you agree with TURN's assertion that PG&E's cost-effectiveness study should have included costs for additional seismic-related upgrades to anticipate DCPP being offline for an extended period of time due to a major seismic event?

A 25 No.

Q 26 How do you respond to DRA's observation that PG&E did not include the $50 million transformer replacement project in the list of Plant Betterment Projects in its testimony?

A 26 PG&E inadvertently left the transformer replacement project off list of potential plant betterment projects on page 3-11 of PG&E's testimony. However, the cost of the transformer replacement project is included in the capital expenditures used in the economic analysis. (See Table 3-5, lines 21 and 22 on p. 3-10 of the testimony.)

3. PG&E's Replacement Power Assumptions Are Reasonable (Robert Gomez)

Q 27 What is PG&E's response to DRA's comments that the use of natural gas price forecasts introduces inherent uncertainty into PG&E's cost-effectiveness analysis and that the natural gas price forecasts used by PG&E are dated?

A 27 PG&E agrees with DRA that forecasting natural gas prices is a challenging exercise. This is precisely why PG&E evaluated alternative resource costs based on a wide range of natural gas price forecasts. Since future price forecasts are uncertain, PG&E used low, middle, and high natural gas price forecasts that represent the current and publically available projections used by California state agencies. These same price forecasts are used by the

CPUC and CEC as the basis for similar cost-effective analyses. Additionally, the use of natural gas price forecasts to evaluate resource alternatives to Diablo Canyon in this analysis contributes no more uncertainty than natural gas price forecasts used in any other analysis where gas price forecasts are needed to evaluate costs. In fact, any uncertainty is mitigated because PG&E used a wide spectrum of natural gas price forecasts rather than simply relying on a single forecast.

Q 28 In analyzing PG&E's cost-effectiveness analysis, TURN limits their replacement power options to only the gas-fired combined cycle alternative. How do you respond to this?

A 28 With Diablo Canyon's licenses not expiring for approximately another 15 years, it is not possible to determine exactly what type of replacement power would be used as an alternative should the license not be renewed. The economic, technologic, and regulatory future is so uncertain that limiting the number of alternatives to just one type of resource would be shortsighted and render the cost-effectiveness analysis biased and incomplete. Therefore, PG&E estimated the cost of replacing Diablo Canyon by identifying and evaluating a broad range of alternatives, including: (1) renewables; (2) combined cycles; (3) coal-fueled integrated gasification combined cycles with carbon capture and sequestration; and (4) energy efficiency reductions Considering such a broad range of alternatives, along with various scenarios such as high/low gas prices, renewable mixes, capital costs, etc., is necessary to ensure that the cost-effectiveness analysis is supplied with a sufficient and reasonable spectrum of costs.

In addition to the above uncertainties surrounding the future, since each of these alternative resources have their own significant barriers to overcome in order to be actualized, including integration to the grid, siting, permitting, transmission and carbon dioxide storage availability, etc., it is not prudent to presuppose that one alternative is more credible than another and limit replacement options to only the gas-fired combined cycle as TURN has done. Rather, a robust analysis contemplates the wide set of alternatives such as those developed in PG&E's analysis.

E. PG&E's Ratemaking Proposal Is Reasonable (Joseph O'Flanagan)

Q 29 What is TURN's Ratepayer Protection proposal?

A 29 TURN asserts that PG&E's assumptions regarding Diablo Canyon's operating performance and costs during the 20-year license renewal period are overly optimistic. As such, TURN proposes that the Commission adopt a rebuttable presumption that any O&M and capital costs above those that PG&E now forecasts and any plant operating performance below that which PG&E now projects are unreasonable. If PG&E's actual costs are higher, or performance is lower, than the rebuttable presumption benchmarks, the Commission should consider cost sharing between PG&E's ratepayers and shareholders.

Q 30 What is PG&E's response to this proposal?

A 30 TURN is proposing a radical departure from traditional cost of service ratemaking that is not warranted by the facts in this case. TURN is proposing that the Commission determine now what will be presumed to be a reasonable level of plant performance and spending 15 to 35 years into the future, without regard to any changes in circumstance between now and then. PG&E agrees with TURN that there is a high degree of uncertainty in any set of assumptions when looking out for 35 years. It is not reasonable to use any set of assumptions to set standards to be applied to plant performance or costs under these circumstances. The reasonableness of DCPP's future costs and performance should be reviewed in future GRCs, not determined in this proceeding.

Q 31 DRA would apply a 20-year remaining life to calculate depreciation expense, as compared to the 10-year remaining life PG&E utilized? Which remaining life should be used to calculate depreciation expense and why?

A 31 PG&E does not agree with DRA's proposal. PG&E's 10-year assumption depreciates the License Renewal cost through the current license period. License renewal has not yet been approved. Accordingly, it is premature to establish depreciation rates assuming that the plant will operate past its current license period. The depreciation lives to be applied to Diablo Canyon assets are determined in PG&E's GRC. The appropriate depreciation life for Diablo Canyon will be revisited in a future GRC assuming the license renewal is granted and a decision is made to extend plant operations.

Q 32 What is DRA's proposal regarding the License Renewal Environmental Mitigation Balancing Account (LREMBA)?

A 32 DRA does not oppose the establishment of the LREMBA. DRA agrees that there may be unidentified environmental mitigation costs in the future associated with PG&E's license renewal process. DRA proposes that the environmental and remediation capital and O&M costs be reviewed in the Company's next GRC following issuance of the renewed operating licenses.

Q 33 What is PG&E's response to this proposal?

A 33 PG&E does not object to DRA's proposal.

F. Conclusion

Q 34 What is PG&E's overall response to intervenor testimony?

A 34 As noted in the Introduction, DRA, TURN and SCE do not oppose PG&E's request to recover the costs of obtaining the federal and state approvals necessary to preserve the option to operate Diablo Canyon for an additional 20 years. Additionally, none of the intervenors object to PG&E's cost-effectiveness methodology. While TURN presents several scenarios where license renewal is not the most cost-effective decision for PG&E's customers, those scenarios involve the simultaneous occurrence of improbable circumstances. As such, PG&E urges the Commission to find PG&E's cost-effectiveness analysis and license renewal project cost estimates as reasonable and authorize PG&E to recover $85 million under PG&E's ratemaking proposal.

ATTACHMENT 1

ACTIVITY PRICE POLICY

Date Updated: SEPT2008

Purpose:

This policy defines how activity prices (also known as standard rates, standard costs or activity type rates) are used within PG&E. It also defines terms and establishes accountability for System Level Standard Rates (SLSR), temporary and fixed rates, and standard cost variances.

Policy:

The activity price calculation stated in this policy is applicable to the calculation and use of all activity prices except for special cases approved by the Planning, Forecasting, and Reporting Department. Current examples of special cases include:

- Rates set by contractual agreement
- Fixed rates (Exceptions approved by the Planning, Forecasting, and Reporting Department). Refer to fixed rates on pg. 3.

Activity prices not calculated in accordance with this policy will not properly reflect the best estimate of actual costs. Rates not based on a best estimate of actual costs may expose the company to audit and regulatory risk. In addition, Business Units and Corporate Services will not have reliable or consistent cost information for decision making.

PG&E uses activity prices to move costs from Provider Cost Centers to other cost objects (other PCC or orders) within SAP.

Activity Price Calculation: Activity prices are calculated several times each year in SAP.

Numerator: The numerator consists of all planned annual costs expected to be incurred to support the activity type and should represent the planners' best estimate of actual costs to be incurred. The following costs **must** be included in the standard cost calculation. Exceptions may only be granted by the Planning, Forecasting, and Reporting Department.

- Labor - All productive labor must be planned. Productive labor excludes non-productive time, benefits and payroll taxes. (Non-productive time is planned separately. Benefits and payroll taxes are applied to the cost center as overheads.)
- Non-Productive Time – All non-productive time (e.g., vacation, sick, jury duty, holidays) must be planned.
- Material - All direct material costs required to manage the day-to-day operation of the cost center must be planned. This includes C-card (formerly known as purchasing card) costs. It also includes tools and office supplies that cost less than $5,000. Material burden should also be planned.
- Contracts - All contract costs required to manage the cost center must be planned. This may include items such as copy machine agreements, consulting, agency employees, and coffee service.
- Employee Related - All employee related costs required to manage the cost center must be planned. This includes travel, training, conferences, Learning Center usage, and meals. There are occasions where conferences or training are more appropriately

charged to an order. Contact the Planning, Forecasting, and Reporting Department for authorization to charge to an order.

- PC Devices - All desktop computer support costs related to having PCs on the desktop and all voice (i.e. radio, pager, cell phone and telephone) costs required by the employees that use the equipment must be included in planning.
- Facility Charges - Costs associated with office space must be included in planning. Sometimes it is not practical to divide office space charged for each individual PCC so it is charged to a higher level supervision and management cost center, then allocated down.
- Vehicles - All vehicle costs associated with using company and external fleet must be planned.
- Supervision and Management - These are costs from other cost centers that support and/or direct the cost center. Supervision and Management cost centers (types D and G) are allocated to other PCCs because it is not practical for them to direct charge. Their work hours are not identifiable to unique specific cost objects (e.g., orders). Supervision and Management cost centers should not include significant costs that are not directly attributable to running their cost center such as special project costs or fees in their rate calculation.
- Other - Any other costs related to managing the cost center that are not in the above categories must be planned. This may include items such as reprographic services and late payroll change requests.

Some costs do not directly support the activity type and should be excluded from the numerator. These include:

- Costs that pass through a higher level cost center to be allocated to lower level cost centers as supervision and management costs. An example of this is when facility costs are included in a supervision and management cost center for all the cost centers under that cost center. These costs should not be part of the supervisor's or manager's standard cost.
- Costs in some A&G cost centers that do not directly support an activity type such as corporate donations, and certain contracts.
- For non-labor based activity types depreciation (except for fleet) cannot be included in the rate.

Denominator: **The denominator is the total number of productive hours or other units that are available to be billed—this includes, but is not limited to, planned paid or unpaid overtime, contract employee/staff augmentation billable time, and Hiring Hall employee billable time.** Even those cost centers that do not plan to bill out all of their time (all types except A and E), must calculate the billable hours as if they would be billing out all their time. The denominator does not include non-billable employees' time (e.g., support personnel, employees on paid or unpaid leave) non-productive time (e.g., vacation, sick, jury duty, holidays) or any non-billable time (e.g., breaks, inclement weather, training or staff meetings). Rest periods and overtime meal time are anticipated to only occur during major events and other emergencies, and are therefore considered billable. For non-labor based activity types, billable units should include a non-usage factor (e.g., not all pool cars will be used 100% of the time).

Activity Price Revisions: Activity prices are initially calculated at the end of the year for the upcoming year. It is the responsibility of the Business Units and Corporate Services to ensure that standard cost variances are monitored and that activity prices are adjusted when a standard cost variance is permanent and significant (see Page 5). The

Business Units and Corporate Services are responsible for managing their activity prices to minimize the year-end standard cost variances. A revised activity price is calculated as an annual rate, adjusted to make up for past variances (to target no year-end standard cost variance). The system will be available quarterly for any revisions to activity prices. Significant changes that cannot be implemented during the quarterly scheduled times will be handled on a case-by-case basis.

Consistent Treatment of Costs: The development and application of activity prices must be consistent.

System Level Standard Rate (SLSR)
System Level Standard Rates should follow the same procedures as the activity price calculation stated in this policy. In addition, the request for SLSR should be approved by the Business Finance manager prior to submission to the Planning, Forecasting, and Reporting Department.

Temporary Rates
Temporary rate requests follow the same procedures as the activity price calculation stated in this policy. Both the temporary rate request and rate calculation should be approved by the Business Finance manager prior to submission to the Planning, Forecasting, and Reporting Department. All temporary rate requests should be sent to the Planning, Forecasting, and Reporting Department at least 5 days prior to month end. In addition, the requestor should keep documentation of their temporary rate calculation.

Fixed Rates
Fixed rates are an exception to the activity price calculation as stated in this policy. Both the fixed rate request and rate calculation should be approved by the Business Finance manager prior to submission to the Planning, Forecasting, and Reporting Department. All fixed rate requests should be sent to the Planning, Forecasting, and Reporting Department at least 5 days prior to month end. In addition, the requestor should keep documentation of their fixed rate calculation.

Exceptions: The Planning, Forecasting, and Reporting Department must approve activity prices not based on this policy's requirements.

Year-end Standard Cost Variance Review
If at year-end, the total company capital impact exceeds $5 million in absolute value (including chargeback organizations), a high level adjustment will be made to the income statement. An overhead adjustment to capital will be made in the following year.

Quarterly Standard Cost Variance Review
After each quarter end, the standard cost variance will be reviewed on a company-wide basis to determine if an adjustment is necessary. An adjustment will be considered necessary if the direct capital impact exceeds $5 million in absolute value.

Responsibilities:

- Business Units and Corporate Services - responsible for planning rates and monitoring variances.
- Planning, Forecasting, and Reporting Department - responsible for issuing policy, policy governance, reporting on performance, training, and assistance.

Definitions:

Provider Cost Centers (PCCs): Cost centers that provide services to others (cost centers or orders).

Activity prices: Carefully predetermined costs for the delivery of goods or services, expressed on a per unit basis. Activity prices are based on the identifiable costs which are specific to the output of a provider cost center (numerator), divided by the cost center's billable units of output (denominator):

Activity Price = PCC Costs ÷ Billable hours

Activity prices are used to move costs from the provider of a service to the receiver of a service so that all costs ultimately are charged to the appropriate FERC account and Business Unit Income Statement.

Activity prices are also used to charge affiliates and other third parties. However, other overhead costs must be added to the prices before billing. Activity prices are NOT market rates and should not be directly used in comparison to the external market. Contact the Planning, Forecasting, and Reporting Department before making any market rate comparisons.

Activity Type: A service performed by a PCC (e.g., Fleet Inspection, Emergency Planning, or Construction). A PCC may have more than one activity type (Straight-time, over-time, or double-time are considered the same activity type). An activity price is calculated for each activity type/cost center combination.

System Level Standard Rate (SLSR): SLSR group rates are used to create one rate for a group of similar cost centers. It works by planning to a group cost center which represents all the individual cost centers added together. Then a rate is calculated for the group cost center and that group rate is copied to the individual cost centers. The purpose of group rates is to simplify the planning process, have one rate that is used for similar purposes and to minimize the effects of employee movement between similar cost centers.

Manual Rate: A rate that is not calculated by the system during PCC Planning. There are 2 types of manual rates: Temporary rates and Fixed rates.

Temporary rate: A temporary rate is a rate that is calculated outside of the PCC planning cycle. An example of a temporary rate is a new PCC that will need a new rate. A temporary rate is recalculated in the next PCC planning cycle.

Fixed Rate: A fixed rate is a permanent rate that is not recalculated during PCC planning. An example of a fixed rate is a T-check rate.

Standard Cost Variance: A standard cost variance is the difference between the actual costs incurred in a PCC and the costs charged out. Since SAP calculates activity prices as annual rates, variances are expected on a monthly basis. Standard cost variances are expensed/capitalized each month and are the responsibility of the originating department (Note: Part of T&D and Generation's standard cost variances are capitalized). It is the responsibility of the originating departments to manage their actual costs and activity prices (i.e., charge out rates) to minimize their year-end standard cost variances.

Significant Standard Cost Variance: A PCC's standard cost variance is considered significant when, on a quarterly basis:

- the variance is greater than 10% of PCC costs excluding activity charging credits (i.e., charges out of PCC) and greater than $25,000

or

- any variance that exceeds $250,000

Contact:	David Hatton, Supervisor, Cost Accounting - Planning, Forecasting, and Reporting Department 223-0545
Issued by:	Trung Ha, Director, Planning, Forecasting, & Reporting Department
Approved by:	Barbara Barcon, VP Finance and CFO Utility

ATTACHMENT 2

Estimated Standard Rate 10568
Project Management

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2009
Non-Productive Time	$ 30,891	$ 11,288	$ 3,958	$ 7,824	$ 18,872	$ 14,383	$ 27,914	$ 13,934	$ 29,110	$ 8,415	$ 18,100	$ 14,778	$ 199,470
Labor - Hiring Hall	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Labor - Premium Pay	$ -	$ -	$ 2,500	$ 4,761	$ 3,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,041	$ 13,302
Labor - Hiring Hall Overtime	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Labor - Prod ST BU	$ 48,478	$ 73,957	$ 73,652	$ 78,569	$ 67,298	$ 67,849	$ 55,951	$ 65,332	$ 58,082	$ 96,806	$ 72,289	$ 75,153	$ 833,417
Labor - Prod ST NBU	$ 30,315	$ 31,002	$ 33,449	$ 33,271	$ 26,792	$ 29,584	$ 27,950	$ 32,550	$ 24,623	$ 32,550	$ 29,049	$ 30,956	$ 362,091
Labor - Prod OT and Dbl OT BU	$ 14,964	$ 165,885	$ 52,183	$ 25,012	$ 28,847	$ 22,944	$ 24,662	$ 20,190	$ 11,726	$ 126,741	$ 12,718	$ 5,482	$ 511,353
Labor - Prod OT and Dbl OT NBU	$ 3,060	$ 39,889	$ 11,208	$ (229)	$ 3,827	$ 4,861	$ 1,747	$ 3,737	$ 1,458	$ 35,288	$ (1,809)	$ 502	$ 103,540
Benefits Burden	$ 23,914	$ 31,855	$ 32,505	$ 33,944	$ 28,556	$ 29,571	$ 25,170	$ 29,365	$ 24,812	$ 36,220	$ 24,828	$ 25,997	$ 346,735
Payroll Tax Burd	$ 9,682	$ 31,073	$ 17,299	$ 13,856	$ 12,717	$ 12,273	$ 10,810	$ 11,937	$ 9,397	$ 26,370	$ 8,250	$ 8,462	$ 172,128
Staff Augmentation - Labor	$ (523)	$ 38,828	$ 50,356	$ 15,840	$ 28,050	$ 44,915	$ 11,299	$ 23,648	$ 7,609	$ 2,100	$ 2,200	$ 800	$ 225,121
Staff Augmentation - PM Contract Labor	$ 121,750	$ 121,750	$ 121,750	$ 121,750	$ 121,750	$ 121,750	$ 121,750	$ 121,750	$ 121,750	$ 121,750	$ 121,750	$ 121,750	$ 1,461,000
Contracts	$ 11,008	$ -	$ 165	$ -	$ 389	$ 20,390	$ 2,145	$ 2,463	$ 743	$ 1,980	$ -	$ 825	$ 40,109
Matl Not Othr Class	$ 3,281	$ 740	$ (20,938)	$ 1,077	$ 2,813	$ 2,012	$ (1,391)	$ 17,349	$ 554	$ (3,388)	$ (1,388)	$ 943	$ 1,664
Purchasing Card	$ 145	$ 1,210	$ 1,260	$ 164	$ 4,048	$ 3,067	$ 1,190	$ 2,198	$ 2,074	$ 1,319	$ 327	$ 3,708	$ 20,709
Buysite Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Matl Burd-Plan Only	$ 413	$ 187	$ (2,455)	$ 145	$ 717	$ 492	$ (28)	$ 2,301	$ 223	$ (309)	$ (144)	$ 420	$ 1,963
Tools, First Aid & Supplies	$ -	$ -	$ 53	$ -	$ 395	$ -	$ 383	$ -	$ (87)	$ -	$ -	$ 66	$ 810
Meals Expense	$ 1,061	$ 2,531	$ 5,793	$ 272	$ 4,822	$ 1,067	$ 1,058	$ 614	$ 448	$ 138	$ -	$ -	$ 17,804
Lodging	$ 417	$ 261	$ -	$ 375	$ -	$ 1,109	$ 1,943	$ 864	$ -	$ 374	$ -	$ -	$ 5,343
Employee Travel	$ 350	$ 1,249	$ 3,759	$ 332	$ 68	$ 1,257	$ 2,687	$ 1,638	$ -	$ 54	$ -	$ -	$ 11,394
Emp Temp Living/Relo	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reimbursed Mileage Expense	$ -	$ 391	$ -	$ -	$ -	$ -	$ 251	$ -	$ -	$ -	$ -	$ -	$ 642
In-Lieu of Meals	$ 140	$ 500	$ 100	$ -	$ -	$ -	$ -	$ -	$ -	$ 933	$ -	$ -	$ 1,673
Cash Rewards0PCC Use	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cellular Phone Use	$ 382	$ 360	$ 333	$ 206	$ 105	$ 135	$ 133	$ 131	$ 220	$ 345	$ 215	$ 412	$ 2,976
Other Emply Related	$ 741	$ 1,333	$ 1,256	$ 635	$ 424	$ 691	$ 645	$ 1,160	$ 1,006	$ 865	$ 710	$ 976	$ 10,445
Employee Training	$ -	$ -	$ -	$ 75	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75
Rents	$ -	$ -	$ -	$ -	$ -	$ 146	$ -	$ -	$ -	$ -	$ -	$ -	$ 146
Other Expenses	$ 434	$ 1,239	$ 3,122	$ 620	$ 1,986	$ 3,739	$ 1,305	$ 1,382	$ 2,610	$ 1,732	$ 1,174	$ 1,554	$ 20,896
Activity Types	$ 1,438	$ 2,427	$ 2,064	$ 2,001	$ 4,025	$ 2,000	$ 2,426	$ 2,800	$ 821	$ 6,811	$ 1,800	$ 1,600	$ 30,213
IT-Device Fees	$ 2,194	$ 2,194	$ 2,221	$ 2,249	$ 2,247	$ 2,221	$ 2,314	$ 2,194	$ 2,252	$ 2,194	$ 2,194	$ 2,254	$ 26,728
PCC Direct Cost	$ 304,533	$ 560,150	$ 395,594	$ 342,749	$ 361,751	$ 386,457	$ 322,317	$ 357,534	$ 299,432	$ 499,289	$ 292,263	$ 299,678	$ 4,421,747
Total Supervision & Management	$ 57,413	$ 126,239	$ 106,178	$ 129,458	$ 164,508	$ 185,037	$ 152,495	$ 114,734	$ 95,110	$ 181,256	$ 80,401	$ 127,636	$1,520,465
Total PCC Dollars	$ 361,946	$ 686,389	$ 501,772	$ 472,207	$ 526,258	$ 571,494	$ 474,812	$ 472,268	$ 394,542	$ 680,545	$ 372,664	$ 427,314	**$ 5,942,212**
Total Billable Hours	2,303	3,171	3,528	2,414	2,109	2,618	1,984	2,262	1,848	3,140	2,297	2,036	29,710
PCC Dollars per Productive Hour	**$ 157.20**	**$ 216.44**	**$ 142.23**	**$ 195.61**	**$ 249.53**	**$ 218.29**	**$ 239.32**	**$ 208.78**	**$ 213.50**	**$ 216.73**	**$ 162.24**	**$ 209.88**	**$ 200.01**

A2-1

ATTACHMENT 3

Pacific Gas and Electric Company
Net Benefits of Extended Operations
Various Scenarios

Ln. No.	Description	Scenario							
		A	B	C	D	E	F	G	H
1	EE – Low Cost	5,901	5,370	2,002	2,521	3,391	5,281	(67)	4,896
2	EE – High Cost	9,390	8,858	5,491	6,009	6,880	8,770	3,422	8,385
3	RPS – High DG	9,952	9,420	6,053	6,571	7,441	9,331	3,984	8,947
4	RPS – Reference	11,180	10,648	7,281	7,799	8,669	10,559	5,212	10,175
5	RPS – High Wind	12,028	11,496	8,129	8,647	9,517	11,407	6,060	11,023
6	CC – Low Gas/Low Emission Price	3,503	2,971	(396)	122	993	2,883	(2,465)	2,498
7	CC – MPR Gas/Low Emission Price	4,897	4,365	998	1,516	2,386	4,276	(1,071)	3,892
8	CC – High Gas/Low Emission Price	12,180	11,649	8,281	8,800	9,670	11,560	6,212	11,175
9	CC – Low Gas/MPR Emission Price	4,508	3,976	609	1,127	1,997	3,887	(1,460)	3,503
10	CC – MPR Gas/MPR Emission Price	5,901	5,370	2,002	2,521	3,391	5,281	(67)	4,896
11	CC – High Gas/MPR Emission Price	13,185	12,653	9,286	9,804	10,674	12,565	7,217	12,180
12	CC – Low Gas/High Emission Price	5,055	4,524	1,156	1,675	2,545	4,435	(913)	4,050
13	CC – MPR Gas/High Emission Price	6,449	5,917	2,550	3,068	3,939	5,829	481	5,444
14	CC – High Gas/High Emission Price	13,732	13,201	9,833	10,352	11,222	13,112	7,764	12,727
15	IGCC – Low Fuel Price, Low Capital Cost	4,974	4,442	1,075	1,593	2,464	4,354	(994)	3,969
16	IGCC – High Fuel Price, Low Capital Cost	7,450	6,918	3,551	4,069	4,939	6,829	1,482	6,445
17	IGCC – Low Fuel Price, High Capital Cost	13,836	13,304	9,937	10,455	11,325	13,215	7,868	12,831
18	IGCC – High Fuel Price, High Capital Cost	16,311	15,780	12,413	12,931	13,801	15,691	10,344	15,307

Scenario	Description
A	Application - 90% Capacity Factor
B	Application - 85% Capacity Factor
C	Cooling Towers - 85% Capacity Factor
D	Cooling Towers - 90% Capacity Factor
E	Cooling Towers - 10 Year Extended Operation
F	Cooling Towers - 25% Higher Capital and O&M
G	CoolingTowers - 10 Year Extended Operation - 25% Higher Capital and O&M
H	Once Through Cooling Mitigation

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENT OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF LOREN D. SHARP

Q 1 Please state your name and business address.

A 1 My name is Loren D. Sharp, and my business address is Diablo Canyon Power Plant, P.O. Box 56, Avila Beach, California.

Q 2 Briefly describe your responsibilities at Diablo Canyon Power Plant (Diablo Canyon).

A 2 I am the senior director of Engineering Services at Diablo Canyon. All of Diablo Canyon Engineering, Diablo Canyon Capital Projects management/ subcontractors, Diablo Canyon nuclear fuels department, and Pacific Gas and Electric Company (PG&E) corporate Geo-Sciences expertise team report to me. I report directly to the Diablo Canyon Site Vice President.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in nuclear engineering, master of science degree in nuclear engineering, professional engineer in mechanical engineering, and senior reactor operator certification. I have a total of 35 years of experience with expertise in the following areas: engineering design, plant operation, plant management, and project management.

Q 4 What is the purpose of your testimony?

A 4 I was hired by PG&E based on my plant management and project management expertise to lead the Decommissioning activities at Humboldt Bay Nuclear Plant. After completing fuel loading into storage casks, I was promoted to executive leadership position over engineering and projects at Diablo Canyon. I have held executive leadership positions at plant sites for both Raytheon and Washington Group International. I was a Vice President/Plant General Manager for Raytheon/Washington Group International for 10 years destroying nerve agents or blister agents and provided the senior leadership for plants at Johnston Island in the South Pacific, Umatilla in Oregon, Pueblo in Colorado, Blue Grass in Kentucky, and Tirana in Albania. My experience also includes 12 years in various engineering management roles for Energy Northwest while operating Columbia Nuclear Generating Station. I was a senior nuclear/mechanical engineer at Burns and Roe responsible for analyzing/designing the

Columbia nuclear plant systems/structures. I also supported nuclear plant licensing activities during construction of Columbia Generating Station for five years with Burns and Roe prior to hiring on with the Energy Northwest.

I am sponsoring the following sections:

- Section B, “The Commission Need Not Delay Consideration of This Cost Recovery Application Pending Completion of Seismic Studies Recommended by the California Energy Commission.”
- Section D.2, “PG&E’s Cost and Operating Assumptions Are Reasonable.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.