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PACIFIC GAS AND ELECTRIC COMPANY

APPLICATION FOR APPROVAL OF 2008 LONG-TERM REQUEST FOR OFFER RESULTS AND FOR ADOPTION OF COST RECOVERY AND RATEMAKING MECHANISMS

REPLY TESTIMONY

CONFIDENTIAL INFORMATION PROTECTABLE UNDER DECISION 06-06-066, APPENDIX 1, AND SUBMITTED UNDER PUBLIC UTILITIES CODE SECTION 583

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A. Introduction

Pacific Gas and Electric Company (PG&E) seeks the approval of four agreements resulting from its 2008 Long-Term Request for Offers (LTRFO). First, PG&E seeks approval of a Power Purchase Agreement (PPA) with Mirant Marsh Landing, LLC (Marsh Landing) for the net output of the Marsh Landing Generating Station (Marsh Landing Project), a new, natural gas-fired combustion turbine facility that is expected to produce 719 megawatts (MW) at peak July conditions beginning May 2013.

Second, PG&E seeks approval of a Purchase and Sale Agreement (PSA) with Contra Costa Generating Station LLC (Contra Costa LLC) for the Contra Costa Generating Station (also referred to as the Redacte Generating Station) (Contra Costa Project), a new, natural gas-fired combined cycle facility that is expected to produce 586 MW of generation at July peak conditions beginning June 2014.

Third, PG&E seeks approval of a PPA with Midway Sunset Cogeneration Company (Midway Sunset) for the output of an existing natural gas-fired, combined heat and power qualifying facility that will deliver, at July peak conditions, 129 MW for five years and 61 MW for an additional two years.

Finally, PG&E seeks approval of an intermediate term PPA with Mirant Delta for Mirant Delta's Contra Costa Units 6 and 7 (CC 6 and 7 PPA) that requires these aging units to be retired in April 2013, subject to necessary regulatory and governmental approvals.

These agreements arose out of PG&E's 2008 LTRFO, which the Independent Evaluator concluded was a "fair and rigorous solicitation for resources that will help [PG&E] meet its LTPP authorized capacity needs."[1] The following parties served testimony in response to PG&E's application: Pacific Environment; The Utility Reform Network (TURN); Division of Ratepayer Advocates (DRA); CAlifornians for Renewable Energy (CARE); and the Coalition of California Utility Employees and California Unions for Reliable Energy. In this

[1] PG&E Initial Testimony, Appendix 5.1, at p. 25.

reply testimony, PG&E addresses the concerns and issues raised by these parties and demonstrates that the four agreements proposed in this proceeding are just, reasonable and in PG&E's customers' interests.

B. The New Resources Proposed by PG&E Are Consistent With the Need Level Established in the 2006 Long-Term Procurement Plan Proceeding (Antonio J. Alvarez)

Q 1 Please state the purpose of this portion of PG&E's reply testimony.

A 1 This portion of the reply testimony responds to the testimony of the Pacific Environment, DRA, TURN and CARE concerning the appropriate amount of procurement within the 1,112 MW to 1,512 MW range of need authorized by the California Public Utilities Commission (CPUC or Commission) in the 2006 Long-Term Procurement Plan (LTPP) Decision (*i.e.*, Decision (D.) 07-12-052).**[2]**

This section explains the basis for the need range and why it is appropriate for the Commission to use the high end of the procurement authorization in this proceeding. The section also addresses the alleged "new and/or relevant" information that parties identified in their testimony, which they assert informs the specific question of how much of the procurement authority of 1,112 MW to 1,512 MW should PG&E be allowed to procure in this proceeding. The specific items addressed include:

- The new California Energy Commission (CEC) expected peak demand forecast.
- Higher levels of energy efficiency (EE) included in the new CEC forecast.
- Export assumptions.
- Retirement schedules.

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[2] The need authorized in the 2006 LTPP Decision was 800 MW to 1,200 MW plus any remaining MW from the 2004 LTRFO associated with terminated contracts. It is undisputed that 312 MW of contracts that were authorized in the 2004 LTRFO were subsequently terminated. Thus, in this testimony, PG&E will refer to a need determination of 1,112 MW to 1,512 MW.

1. The Commission Should Use the High End of the 2006 LTPP Decision Need Authorization in This Proceeding

Q 2 Please explain why there is a range of new resource need authorized in the 2006 LTPP Decision.

A 2 In Decision 07-12-052, the Commission determined a range of new resource need for PG&E's service area of 1,112 MW to 1,512 MW. This new resource need represents the amount of new dispatchable resources needed in 2015 to meet a reliability requirement equal to PG&E's service area expected peak plus a planning reserve margin (PRM) requirement of 15 to 17 percent. The low end of the range (1,112 MW) uses a 15 percent PRM and the high end of the range (1,512 MW) uses a 17 percent PRM requirement.

Q 3 Please explain why the Commission should apply the high end of the 2006 LTPP decision need range in this proceeding.

A 3 There are two primary reasons why the high end of the need authorization range (*i.e.*, 1,512 MW) is appropriate for the Commission to use when approving the proposed agreements for new capacity in this proceeding. First, the 15 percent PRM provides the minimum level of planning reserves that the Commission determined is necessary to provide reliable service. If any of the new generation resources anticipated in the 2006 LTPP Decision fail to materialize, PG&E's PRM will fall below 15 percent in 2015. The 2 percent range (between 15 and 17 percent) provides an additional margin of safety, given the uncertainties associated with the expected peak demand and the resources that are available to serve that peak in 2015. Second, there is the inherent "lumpiness" of resource additions, which result in reserves levels above the minimum 15 percent level. That is, the amount of MW and on-line dates of any given set of projects selected in a solicitation is unlikely to match the authorized procurement amount exactly. Therefore, for the initial years, following the commercial operation of the selected projects, reserves could exceed the minimum 15 percent PRM. Furthermore, Pacific Environment, DRA and CARE in particular argue that the Commission should authorize contracts at the low end of the authorized procurement range, focusing their arguments on a small subset of the broad range of need factors the Commission evaluated in Decision 07-12-052.[3] PG&E will address below the flawed conclusions that Pacific Environment, DRA and CARE draw about this small subset of factors. Just as important, however, the Commission should recognize that the need range found in Decision 07-12-052 was based on numerous factors and the dynamic conditions between them, and it would be unwise for the Commission to amend that need based solely on any one changed condition.

2. The New CEC Expected Peak Demand Forecast

Q 4 Pacific Environment witness Rory Cox asserts that the current demand forecasts are "markedly" lower than the forecasts used in the 2006 LTPP proceeding.[4] Do you have any concerns about his testimony?

A 4 Yes. Mr. Cox cites the CEC's 2009 Integrated Energy Policy Report (IEPR) and notes that the projected electricity growth rate for 2010-2018 is 1.2 percent, and that forecasts of consumption are "markedly lower" than forecasts included in the 2007 IEPR. Mr. Cox also states that electricity consumption by 2018 is forecast to be "down by more than 5 percent and peak demand by around 3.5 percent compared to the CED 2007 forecast."[5]

However, the electricity consumption rates and peak demand numbers cited by Mr. Cox are projected for the state of California, not PG&E's service area. In the CEC's California Energy Demand (CED) 2010-2020 Adopted Forecast (2009 CED Adopted Forecast), adopted in December 2009, the CEC broke down the statewide demand by utility planning area, and by service area. Mr. Cox's testimony overstates the impact of the 2009 CEC demand forecasts by focusing on statewide demand forecasts, rather than demand forecasts for PG&E's planning and service area. Changes in electricity consumption and peak demand forecasts for PG&E's planning area and service area were significantly different than the numbers cited by

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[3] In its testimony, DRA states that "[i]f PG&E's need determination was amended to account for **only** this new information, its current authorized need would be 915 MW, rather than 1,512 MW." (DRA, Testimony at p. 9; emphasis added.)

[4] Pacific Environment, Testimony of Rory Cox, at p. 3.

[5] *Id.*

Mr. Cox. For example, the 2009 CED Adopted Forecast shows electricity consumption in PG&E's planning area down by only 1.69 percent in 2018 compared to the CED 2007 forecast, rather than the more than 5 percent noted by Mr. Cox. Also, the average annual growth rate in electricity consumption for the period 2010-2018 forecast by the CEC in 2007 was 1.23 percent. In the 2009 CED Adopted Forecast, the average annual electricity consumption growth rate was forecast to be 1.27 percent for PG&E's planning area, which is a higher electricity consumption growth rate over the 2010-2018 period than was forecast in 2007.[6] This is also higher than the statewide growth rate forecast of 1.2 percent.

Similarly, the average annual growth rate for peak demand forecast by the CEC for PG&E's planning area was 1.34 percent in 2007, which is identical to the forecast the CEC adopted in 2009. Thus, there is no change in the CEC peak demand annual growth rate forecast in the 2007 and the 2009 forecasts.[7]

Finally, with regard to forecasted expected peak demand for PG&E's planning area, the CEC reduced its forecast for 2018 by 2.35 percent, from 26,754 MW forecast in 2007 to 26,125 MW forecast in 2009, which is below the 3.5 percent cited by Mr. Cox.

Q 5 What is the relevant change in expected peak demand forecast that the Commission should consider in this proceeding?

A 5 The relevant change between the 2007 and 2009 CEC demand forecasts is: (1) the difference in PG&E service area peak demand, rather than planning area peak demand; and (2) the difference in peak net of EE savings which are reasonably expected to occur.

Q 6 Can you explain the difference between PG&E's planning area and service area?

A 6 The PG&E planning area as defined by the CEC includes, in addition to PG&E's bundled and direct access customer peak demand, the peak

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[6] Kavalec, Chris and Tom Gorin, 2009. *California Energy Demand 2010-2020, Adopted Forecast*. California Energy Commission. CEC-200-2009-012-CMF, at p. 55, Table 10. This document is available at: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF.

[7] *Id.*

demand of more than a dozen municipal entities. Roughly speaking, the PG&E service area, which only includes bundled and direct access customer load, amounts to about 85 percent of the PG&E planning area.[8]

Q 7 Is the PG&E service area need consistent with the Commission determination in the 2006 LTPP Decision?

A 7 Yes. In the 2006 LTPP Decision, the Commission determined that PG&E's service area need was 1,112 MW to 1,512 MW.[9] To be consistent, only the PG&E service area need portion of the 2009 CED Adopted Forecast should be considered when the Commission is deciding whether to adopt the low or high end of the 1,112 MW to 1,512 MW range.

Q 8 Please explain why the peak demand <u>net</u> of EE savings which are reasonably expected to occur is the right peak demand to consider when reviewing the need for new resources using the 2009 CED Adopted Forecast.

A 8 In reviewing the need for new resources, the Commission should only consider EE savings that are reasonably expected to occur because counting on higher EE savings would result in supply deficiencies if the assumed EE savings fail to materialize. In the 2006 LTPP proceeding, the Commission determined that 80 percent of the future EE savings associated with PG&E's EE goals were already embedded in the 2007 CEC peak demand forecast.[10] Based on the CEC's recommendation, the Commission also decided that the other portion of the utilities' EE goals (*i.e*, the remaining 20 percent) should be treated as a resource in the 2006 LTPP, reducing the utilities' new resource procurement authority.[11] By 2015, the impact of the additional EE savings not included in the CEC peak forecast was 430 MW.[12]

Q 9 How should EE be considered when the Commission reviews the 2009 CED Adopted Forecast?

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[8] *Id*. at pp. 50, 53.

[9] D.07-12-052, p. 116, Table PGE-1, n. 2 (looking at service area need).

[10] D.07-12-052, Finding of Fact 25.

[11] D.07-12-052, Finding of Fact 20.

[12] D.07-12-052, Table PGE-1, line 16.

A 9 Because the 2009 CED Adopted Forecast has already been reduced to account for the EE savings that are reasonably expected to occur, the Commission should compare the 2009 CED Adopted Forecast with the 2007 peak demand forecast reduced by the reasonably expected to occur EE savings used by the Commission in the 2006 LTPP Decision. As indicated by Mr. Cox, the 2009 CED Adopted Forecast is lower than the 2007 CEC forecast in part because the 2009 CED Adopted Forecast has higher EE savings than the 2007 CEC forecast.[13]

Q 10 Considering the PG&E service area peak and the effect of EE savings which are reasonably expected to occur, what is the net change in the peak demand forecast from the 2007 to the 2009 CEC demand forecast?

A 10 Considering the peak demand for PG&E's service area net of EE savings which are reasonably expected to occur, the difference between the two CEC forecasts (*i.e.*, 2007 and 2009) is approximately 300 MW in 2015.[14] When other changes that have occurred since the 2006 LTPP Decision was issued are taken into consideration, this relatively small change in CEC demand forecast does not support the Commission adopting the low end of the 1,112 MW to 1,512 MW need determination range.

Q 11 Is a 300 MW difference in the expected peak demand forecast a good reason to use the low end of the procurement range authorized in the 2006 LTPP Decision?

A 11 No. A 300 MW decrease in a 22,000 MW peak demand expected in 2015 for PG&E's service area is not a good reason to use the low end of the range. First, the current CEC forecast reflects the current pessimistic outlook after a major economic downturn. As noted before, according to the CEC's 2009 forecast report, the expected growth in PG&E's planning area from 2010 to 2018 is 1.34 percent. Compared to past historic 8-year growth rates, a 1.34 percent is at the low end of the range (from 1.02 percent to 2.8 percent annual compounded 8-year historic growth rates). It is important

[13] Pacific Environment, Testimony of Rory Cox, at p. 4.

[14] 22,078 MW (PG&E's service area 2015 peak, Table PGE-1, line 2), less 430 MW (Uncommitted Energy Efficiency, Table PGE-1, line 16), less 21,318 MW (CEC's 2009 IEPR peak forecast for PG&E's service area, Form 1.5b.)

to understand that even a relatively modest growth rate of about 1.5 percent (rather than the 2009 CEC growth rate of 1.34 percent) will offset the reduction projected by the new CEC peak forecast.

Second, there is a great deal of uncertainty about economic and demographic factors affecting the peak demand that can be expected eight years from now. Finally, the consequences of being short of resources outweigh the costs of having adequate resources needed to ensure reliable service to PG&E's customers.

Q 12 Does Mr. Cox rely on any other materials to support his claim that demand has been reduced since the 2006 LTPP Decision was issued?

A 12 Yes. Mr. Cox relies on the *2008 California Gas Report* (2008 Gas Report) prepared by six California utilities, including PG&E.[15]

Q 13 Do you have any concerns about how Mr. Cox uses the 2008 Gas Report?

A 13 Yes. First, the purpose of the 2008 Gas Report was to present an "outlook for natural gas requirements and supplies for California though the year 2030."[16] The purpose of the report was not to provide a forecast of electric demand. Thus, Mr. Cox appears to be taking the report out of context.

Second, as he did with his quotations from the 2009 IEPR, Mr. Cox refers to statewide numbers, rather than the PG&E-specific numbers that are contained in the report. While Mr. Cox is correct that statewide natural gas demand was only expected to grow by 0.1 percent per year between 2008 and 2030, demand in PG&E's service area was expected to be double that, growing by an average of 0.2 percent per year over the 2008 to 2030 period.[17]

Third, contrary to the implication in Mr. Cox's testimony, the relatively "flat" growth in natural gas demand statewide between 2008 and 2030 does not directly correspond to a decrease in electric consumption, and more importantly it provides little useful information about the peak demand for

[15] Pacific Environment, Testimony of Rory Cox, at pp. 3-4.

[16] California Gas and Electric Utilities, *2008 California Gas Report*, at p. 3. This document is available at: http://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf.

[17] *Id.* at p. 32.

electricity. Instead, the report concludes that "[g]as demand for electric power generation is expected to be moderated by CPUC-mandated goals for electric energy efficiency programs and renewable power."[18] The 2006 LTPP Decision need determination took both energy efficiency and renewable resource development into account when the Commission determined the need for 1,112 MW to 1,512 MW of new generation resources in PG&E's service area. Thus, the 2008 Gas Report referenced by Mr. Cox neither demonstrates that the peak demand for electricity has been reduced nor supports modifying the 2006 LTPP Decision need authorization.

Finally, Mr. Cox fails to quote one portion of the 2008 Gas Report that is relevant to this proceeding. In that report, the utilities conclude that "[f]or the purposes of load following and backstopping intermittent renewable resource generation, gas-fired generation will continue to be the technology of choice to meet the ever-growing demand for electric power."[19]

Q 14 Pacific Environment witness Bill Powers also argues that the current demand forecasts are lower than the demand forecasts adopted by the CEC in 2007.[20] Can you address Mr. Powers' testimony?

A 14 Yes. First, Mr. Powers relies on the same 2009 CED Adopted Forecast relied on by Mr. Cox. For the reasons explained above, the 2009 CED Adopted Forecast is not "markedly lower" than the 2007 CEC forecast. Second, unlike Mr. Cox, Mr. Powers appears to argue that the 2009 CED Adopted Forecast itself is incorrect. For example, Mr. Powers cites the draft forecast issued by the CEC in June 2009, which had a lower demand forecast. Mr. Powers asserts that the 2009 CED Adopted Forecast "was modified in favor of the PG&E and SCE point-of-view" and that PG&E had a vested interest in ensuring that the final demand forecast adopted by the CEC was higher.[21] Mr. Powers also asserts that the CEC did not properly consider distributed solar photovoltaics and distributed generation.[22]

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[18] *Id*. at p. 8.

[19] *Id*. at p. 7.

[20] Pacific Environment, Testimony of Bill Powers, pp. 1-3.

[21] *Id*. at pp. 2-3.

[22] *Id*. at pp. 2-3, 9-12.

Q 15 Do you have any concerns about Mr. Powers' testimony?

A 15 Yes. First, the appropriate place to litigate the CEC demand forecasts is at the CEC, not in this proceeding. Mr. Powers appears to disagree with the final demand forecasts adopted by the CEC in the 2009 CED Adopted Forecast. Again, the appropriate place to raise his concerns was at the CEC. Second, Mr. Powers implies that somehow the utilities (*i.e.*, PG&E and Southern California Edison (SCE)) influenced the CEC to increase the demand forecast. Numerous parties actively participated in the CEC process, including PG&E and SCE. Mr. Powers offers no evidence to question the impartiality of the CEC or to provide any basis for his implication that the CEC's decision to change its final demand forecast was incorrect. If Mr. Powers believed the 2009 CED Adopted Forecast was flawed, he should have raised that issue with the CEC in 2009.

Q 16 Does Mr. Powers dispute specific aspects of the 2009 CED Adopted Forecast?

A 16 Yes. Mr. Powers spends several pages of his testimony disputing the CEC's population growth scenarios and the impact of EE.[23] Again, these are issues that Mr. Powers or Pacific Environment should have raised at the CEC. These parties should not be allowed to re-litigate the 2009 CED Adopted Forecast in this proceeding.

Q 17 DRA claims that according to the new CEC forecast, PG&E's resource need in 2015 is now forecasted to be 597 MW less than anticipated in the 2006 LTPP Decision.[24] CARE also relies on CEC demand forecasts and makes similar claims.[25] Can you comment on DRA's and CARE's estimated reduction?

A 17 Yes. DRA's and CARE's estimates suffer from the same problem as Pacific Environment's estimated reduction. DRA and CARE used the PG&E <u>planning area</u>, rather than the PG&E <u>service area</u> expected peak forecast, as previously discussed in Answer 6, and did not account for the EE impacts

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[23] *Id*. at pp. 4-7.

[24] DRA Testimony, at p. 9.

[25] CARE Testimony, at p. 3.

that are reasonably expected to occur. As shown above, the correct change in expected peak demand net of EE impacts is approximately 300 MW.

3. Increased Energy Efficiency

Q 18 Mr. Cox also states that increased energy efficiency reduces the need for new resources.[26] Pacific Environment witness Bill Powers and CARE make a similar point.[27] Can you respond to their testimony on this point?

A 18 Yes. First, Mr. Cox states that PG&E is forecasting that "half of the anticipated growth in electric energy demand will be mitigated through energy efficiency and customer-owned solar."[28] This statement is correct. However, the impact of EE and customer-owned solar was already factored into the 2006 LTPP Decision need determination. Thus, the fact that PG&E is aggressively pursuing EE and customer-owned solar power does not mitigate the need for additional new generation resources that the Commission authorized in the 2006 LTPP Decision.

Second, Mr. Cox refers to the increased EE impacts the CEC included in its 2009 forecast, compared to what was included in the 2007 forecast, as another reason to reduce the need for new capacity.[29] However, the CEC's increased EE savings have already been factored into the CEC's 2009 peak demand forecast discussed above, and it is simply one of the reasons why the CEC's 2009 forecast is lower than its 2007 forecast.

Third, Mr. Cox and CARE also indicates that a new CEC report ("*Incremental Impacts of Energy Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast*" (CEC Incremental Impacts Staff Report)) shows an additional 5,000 GWh/yr load reduction in PG&E's service area by 2020 since the last forecast in 2006.[30] However, Mr. Cox fails to mention that the CEC's Incremental Impacts Staff Report he quotes explains that these incremental EE impacts are not firm, and because of that reason, these incremental EE savings

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[26] Pacific Environment, Testimony of Rory Cox, at pp. 4-5; CARE Testimony, at p. 3.

[27] Pacific Environment, Testimony of Bill Powers, at pp. 3, 6-7.

[28] Pacific Environment, Testimony of Rory Cox, at p. 4.

[29] *Id*. at p. 4.

[30] *Id*. at p. 4; CARE Testimony, at p. 3.

were not included in the 2009 CED Adopted Forecast. As the Incremental Impacts Staff Report notes, relying on these incremental EE estimates could result in serious reliability (and customer costs) consequences due to possible supply shortfalls.[31]

Finally, Mr. Cox refers to Assembly Bill (AB) 2021, enacted in 2006, that sets a statewide goal of reducing total forecasted electricity consumption by 10 percent over the next 10 years. In the 2006 LTPP process, PG&E incorporated a significant amount of EE and, specifically, CEC forecasts that included EE and PG&E's EE goals.[32] Thus, the fact that AB 2021 established statewide goals does not change the need authorization in the 2006 LTPP Decision.

4. Export Assumptions

Q 19 Mr. Cox asserts that the export assumptions in the 2006 LTPP Decision are incorrect.[33] DRA and CARE also mention export assumptions in their respective testimony.[34] Can you comment on this issue?

A 19 Yes. Mr. Cox notes that the 2006 LTPP Decision assumed 3,000 MW flow from Northern to Southern California and that a CEC report ("*Revisiting Path 26 Power Flow Assumptions"* (Path 26 CEC Staff Report)) has found such an assumption to be no longer valid.[35] However, in the 2006 LTPP Decision, the Commission already considered the CEC's viewpoint on the assumed export level.[36] In addition, as indicated in the Path 26 Staff Report, a number of factors impacted the past power flows in either direction on Path 26, including imports by non-California Independent System Operator (CAISO) parties who were entering into economic transactions at the time. The period considered by the Path 26 Staff Report referenced by

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[31] Jaske, Mike and Kavalec, Chris, 2009. *Incremental Impacts of Energy Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast*, CEC-200-2010-001, at p. 52. This document is available at: http://www.energy.ca.gov/2010publications/CEC-200-2010-001/CEC-200-2010-001-D.PDF.

[32] D.07-12-052, at p. 48.

[33] Pacific Environment, Testimony of Rory Cox, at p. 5.

[34] DRA Testimony, at p. 9; CARE Testimony, at pp. 3-4.

[35] Pacific Environment, Testimony of Rory Cox, at pp. 5-6.

[36] D.07-12-052, at p. 105.

Mr. Cox reflects a period of surplus, rather than stress conditions, which can be used to inform the support an area provides to the other area in peak or stress conditions. As proposed by the Path 26 Staff Report, the PRM proceeding (CPUC Docket R.08-04-012) is a key place to review this Path 26 flow assumption, or determine a new methodology that is reflective of peak or stress conditions.[37]

5. Retirement Schedules

Q 20 Pacific Environment witness Rory Cox asserts that the retirement schedules assumed in the 2006 LTPP Decision have not been accurate.[38] Can you comment on Mr. Cox's testimony?

A 20 Yes. In its 2006 LTPP Decision, the Commission directed the utilities to contract for new dispatchable generation to replace aging units. Proposed regulations issued by the State Water Resources Control Board (State Water Board) have set deadlines for retrofitting, repowering, or retiring units that rely on once-through cooling (OTC) technology. The precise timing of the retirement of the aging units remains uncertain. The schedule of retirements will likely be driven by when a unit breaks down and requires major repairs, or when it is no longer economic to operate an aging facility, with final decision made by the unit owners.

To support his argument, Mr. Cox relies on a recent draft report issued by the State Water Board ("*Draft Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*" (Draft State Water Board Staff Report) and asserts that the retirement dates for the Pittsburg and Moss Landing Generating Stations have been pushed back to 2017.[39] However, the Draft State Water Board Staff Report relied on by Mr. Cox assumed a 2017 retirement date because the State Water Board recognized that: (1) OTC would be addressed in the Commission's 2010 LTPP proceeding; (2) it generally takes seven years to develop a new

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[37] Brown, Denny, *Revisiting Path 26 Power Flow Assumptions*, October 2008. CEC-200-2008-006, at p. 7. This document is available at: http://www.energy.ca.gov/2008publications/CEC-200-2008-006/CEC-200-2008-006.PDF.

[38] Pacific Environment, Testimony of Rory Cox, at pp. 5-6.

[39] *Id.*

generation resource facility (including regulatory approval, permitting, and construction); and (3) 2017 was an appropriate assumption for a retirement given that it would be seven years from the date the 2010 LTPP proceeding was initiated.[40] The State Water Board did not preclude these plants from retiring earlier and expressly recognized that retirements are based largely on "competitive procurement and forward contracting mechanisms implemented by the CPUC."[41] To the extent the Commission approves the new generation resources proposed in this proceeding, the Pittsburg and Moss Landing Generation Stations can retire earlier than the 2017 deadline referred to in the Draft State Water Board Staff Report.

Q 21 Mr. Cox also asserts that all 4,200 MW of aging OTC facilities in PG&E's service area that were included in the 2006 LTPP Decision can be retired without requiring PG&E to procure any additional capacity.[42] Is this correct?

A 21 No. Even a cursory review of the 2006 LTPP Decision need determination demonstrates that if 4,200 MW of aging power plants retire by 2015, and this capacity is not replaced, PG&E's service area PRM would be well below the Commission-mandated PRM of 15 percent. Moreover, the "*2008 Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California*" report relied on by Mr. Cox in his testimony stated that its conclusions were "optimistic" and that "the modeling effort conducted for this study was limited in scope, capable of only taking a snapshot of the big picture, due to time constraints."[43] The report concluded that "the key recommendation arising from this study is that the industry must continue

[40] *Draft Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (November 23, 2009), at p. 3. This document is available at: http://www.swrcb.ca.gov/water_issues/programs/npdes/docs/cwa316/otcpolicy112309_clean.pdf.

[41] *Id*. at p. 2.

[42] Pacific Environment, Testimony of Rory Cox, at p. 6.

[43] California Ocean Protection Council & State Water Resources Control Board, *Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California* (ICF Jones & Stokes, April 2008) at p. 6. This document is available at: http://www.swrcb.ca.gov/water_issues/programs/tmdl/docs/power_plant_cooling/reliability_study.pdf.

comprehensive study of the issue, examining the reliability implications of retirement of each plant individually and in combinations with all other plants…."[44] The report relied on by Mr. Cox also assumed that "planned power plants through the Western U.S. and Canada will be on-line" in concluding that only transmission upgrades will be necessary to address the retirements of aging OTC facilities.[45] However, it is unclear if these plants have or will be built, and if any of the transmission projects alluded to in the study are currently being planned or proposed.

6. Other Arguments Raised by the Intervenors Concerning the Need Authorization Are Equally Misplaced

Q 22 Pacific Environment witness Rory Cox notes that neither the Marsh Landing nor the Contra Costa Generating Station facilities are needed.[46] Can you comment on this assertion?

A 22 The Scoping Memo issued in this proceeding clearly stated that the Commission would not revisit the 1,112 MW to 1,512 MW range established in the 2006 LTPP Decision.[47] If Mr. Cox's proposal not to approve either new generation resource is adopted, only 184 MW of new resources would have been procured in the 2008 LTRFO process, well below even the low-end range of the Commission's need authorization. Mr. Cox's proposal is clearly outside the scope of this proceeding and contrary to the clear direction in the Scoping Memo and 2006 LTPP Decision.

C. The Marsh Landing and Contra Costa Generating Stations Will Support the Integration of Intermittent Renewable Resources (Marino Monardi and Redacted

Q 23 Why are operationally flexible resources important to maintaining electric reliability?

A 23 In order to maintain system reliability, the output of the generation available to CAISO must match the wholesale load at all times. Given that load and variable generation like solar or wind, vary continually (seasonally, daily,

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[44] *Id.*

[45] *Id.* at p. 2.

[46] Pacific Environment, Testimony of Rory Cox, at p. 2.

[47] *Assigned Commissioner's Ruling and Scoping Memo* (Scoping Memo) at p. 7.

hourly and intra-hourly), and are difficult to forecast for operating purposes, the generation system needs to have sufficient flexibility to respond to load and variable generation changes. Further, the system must be ready to respond to unplanned outages. In the future, because of the expected reliance on variable generation to meet higher renewable targets, the system will increasingly be required to be more flexible than it is today to accommodate the increased variability and forecast uncertainty of more renewable resources.

The CAISO, which is responsible for maintaining a reliable supply of electricity for much of California, has pointed out the following challenges that need to be addressed in order to effectively integrate renewable resources:

> Variability – Output changes according to availability of primary fuel, resulting in fluctuations in all time scales.
>
> Uncertainty – Magnitude and timing of variable output is less predictable, over supply, under supply.
>
> System Security – Ability of the system to withstand disturbances is compromised by lack of inertia of many renewable resource technologies.[48]

According to the CAISO, a 33 percent renewable generation requirement will result in the addition of approximately 20,000 MW of intermittent capacity, of which almost half will be wind generation.[49] To integrate these resources, the CAISO has identified a need for flexible gas-fired resources possessing "quick start and significant ramping capability to integrate renewable resources and maintain grid reliability."[50]

Q 24 Has the Commission addressed the need for operationally flexible resources?

A 24 Yes. In the 2006 LTPP Decision, the Commission directed PG&E to "procure dispatchable ramping resources that can be used to adjust for the

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[48] "CAISO Presentation to the California Cogeneration Council Annual Meeting," on October 21, 2009 by Jim Detmers and Don Fuller.

[49] CAISO Letter to the CPUC dated February 1, 2010, regarding Applications 09-10-022 and 09-10-034 for approval of contracts with GWF Energy LLC and Calpine Corporation.

[50] *Id*.

morning and evening ramps created by intermittent types of renewable resources."[51]

Q 25 How did PG&E design its 2008 LTRFO to achieve the Commission's objectives?

A 25 Recognizing this need for operationally flexible resources, PG&E's 2008 LTRFO sought 1,112 MW to 1,512 MW of new dispatchable and operationally flexible resources to fill PG&E's service area need identified by the Commission. The LTRFO then selected and executed agreements for new resources with those units that scored highest, when considering the mix of market value, operational flexibility and viability. As stated previously, operationally flexible resources are of paramount importance now and in the future since they are the tools the CAISO will use to respond to changing conditions, on very short notice, to meet the reliability needs of the system. In addition to their energy and RA capacity value, operationally flexible resources offer the CAISO reliability products commonly referred to as ancillary services. The CAISO tariff[52] defines the following ancillary services:

(i) Regulation Up and Regulation Down
(ii) Spinning Reserve
(iii) Non-Spinning Reserve
(iv) Voltage Support
(v) Black Start capability

The Redacted and Contra Costa Projects are capable of providing all of these ancillary services, except black start, which is primarily provided by PG&E's hydro resources.

Traditionally, many old gas-fired steam plants had a fair amount of flexibility, which allowed them to follow load when economic, or ramp up when other plants became unavailable, or to meet other reliability needs. However, those traditional resources will retire in the near future. As such, the system must have flexible resources, capable of providing ancillary services, to allow the CAISO to continue to manage the system reliably.

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[51] D.07-12-052, at p. 106.

[52] CAISO Tariff Article 1 – General Provisions, Section 8 – Ancillary Services (http://www.caiso.com/2495/249591eb6d3d0.pdf).

The Marsh Landing and Contra Costa Projects are consistent with the Commission's direction in the 2006 LTPP Decision and the 2008 LTRFO Solicitation Protocol and will allow the CAISO to manage the system reliably. The Marsh Landing and Contra Costa Projects are dispatchable and operationally flexible generation resources that can provide most ancillary service products and quickly adjust to changing conditions. The key characteristics of the Projects that provide this operating flexibility are:

(a) <u>Non-spinning reserves[53] are the ability to start-up on extremely short notice on any given day</u> – The Projects are able to turn on and provide part of their output within 10 minutes, which is an ancillary service product required by the CAISO to manage the system called non-spinning reserves. This quick start capability is essential for responding to rapidly changing system conditions that might occur due to wind or solar resources dropping off very quickly or to help manage situations like a forced outage at another facility.

(b) <u>Spinning reserves[54] over a large range</u> – The Projects also have the ability to quickly ramp production up and down from their respective minimum to maximum operating levels providing a range of over 1,000 MW of flexibility. Both non-spinning and spinning reserves give the CAISO the ability to respond to system disturbances, such as the sudden loss of solar production because cloud cover develops or the sudden drop off of wind. Such ancillary services will become increasingly important as more resources with little operating flexibility and variable and unpredictable production are added to the system to meet renewable goals. Further, while start speed and flexibility are very important, the ability to shut down is also essential to respond to times when wind or solar production spikes upward quickly.

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[53] Non-spinning reserves are defined as generating capacity that is capable of being synchronized and ramping to a specified load in 10 minutes.

[54] Spinning reserve is defined as unloaded synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in 10 minutes, and that is capable of running for at least two hours.

(c) Regulation Up or Down[55] – These units also can provide regulation up or down under Automatic Generation Control (AGC). AGC puts the unit's operation under the CAISO's control so it can balance the system and follow load on and instantaneous basis.

(d) Short minimum run times – A further benefit is that these plants have reasonably short minimum up-times, and therefore will not be constrained from coming up to meet emergency needs and then shutting back down when no longer needed, like when loads may be low during mild spring weather. This beneficial element is lacking in some of the large older plants that will retire, those units typically have longer minimum run times once brought on-line.

The operational flexibility of these two facilities will be greatly superior to the operational characteristics of the old steam units on which the CAISO currently relies to adjust for changes in system conditions. In particular, the start times for the new facilities are in minutes, rather than the hours required to start up the old steam units. The ramp rates for the new facilities are at least an order of magnitude faster than the ramp rates of the old steam units, and approach the ramping capability of a unit at PG&E's Helms Pumped Storage facility.

Q 26 Mr. Cox asserts that new natural gas-fired facilities are not needed to integrate the increasing amount of renewable resources in PG&E's electric portfolio.[56] Can you comment on Mr. Cox's assertion?

A 26 Yes. First, Mr. Cox's assertion is contrary to the 2006 LTPP Decision. In that decision, the Commission recognized that PG&E needed to procure dispatchable ramping resources that can be adjusted for the intermittent renewable resources. Wind and solar resources produce variable and difficult to forecast generation. To manage the increased variability and forecast uncertainty, additional operating reserves are needed in the form of

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[55] Regulation provided by a resource that can increase (regulation up) or decrease (regulation down) its actual operating level in response to a direct electronic signal from the CAISO to maintain standard frequency in accordance with established Reliability Criteria. This capability can only be provided by units with AGC.

[56] Pacific Environment, Testimony of Rory Cox, at pp. 7-11.

flexible operational resources that can provide regulation, load following, ramping, and day-ahead commitment services.

Second, as indicated in response to Question 23, the CAISO, which operates the transmission system in much of California, has expressly stated the need for new, gas-fired generating resources that can integrate the increasing number of renewable resources being developed inside and outside of California. Results from the CAISO's preliminary Phase I integration study will provide estimates of the amount, and operating characteristics of the required additional generation resources necessary to support the 33 percent renewable goal.

Q 27 Do you have any other concerns about Mr. Cox's claim that no new gas-fired resources are needed to integrate renewable resources?

A 27 Yes. One of the primary reports relied on by Mr. Cox to reach his conclusion is a CEC report from June 2009 ("*Impact of Assembly Bill 32 Scoping Plan Electricity Resource Goals on New Natural Gas-Fired Generation*" (CEC AB 32 Impact Report).**[57]** However, Mr. Cox selectively picks sections of this report to draw his conclusions. For example, the AB 32 Impact Report concludes that renewable integration can be accomplished primarily with transmission upgrades <u>after</u> 7,758 MW of new, efficient gas-fired units are added in California to replace retiring OTC gas-fired units.**[58]** The CEC's AB 32 Impact Report also relies on the development of a significant amount of Combined Heat and Power (CHP) technology, which even the authors of the report acknowledge is a key assumption that is subject to "a great deal of uncertainty."**[59]** Moreover, CHP is largely not dispatchable because it needs to provide constant thermal output to its steam host and therefore is not typically helpful to integrate renewable resources.

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[57] Pacific Environment, Testimony of Rory Cox, at p. 7.

[58] Tanghetti, Angela, Karen Griffin, 2009. *Impact of Assembly Bill 32 Scoping Plan Electricity Resource Goals on New Natural Gas-Fired Generation.* California Energy Commission. CEC-200-2009-011 at p. 2. This document is available at: http://www.energy.ca.gov/2009publications/CEC-200-2009-011/CEC-200-2009-011.PDF.

[59] *Id*. at p. 15.

Q 28 Has the CAISO provided any additional information regarding the need for operationally flexible resources such as the facilities proposed in this proceeding?

A 28 Yes. In November 2007, the CAISO estimated that to manage a 20 percent renewable portfolio standard (RPS) it needed:

- Additional 100 MW to 500 MW for Regulation-Down reserves, and 170 MW to 250 MW for Regulation-Up reserves.
- Additional capacity for intra-hour load following comparable to the amount needed to cover hour-ahead load forecast error (standard deviation is 600 MW to 900 MW).

Significantly more flexible capacity is needed for a portfolio with 33 percent rather than 20 percent renewable resources. The CAISO is currently studying the integration needs for different 33 percent RPS scenarios.[60]

Q 29 Mr. Cox also asserts that energy storage can replace the need for new, gas-fired generation to integrate renewable resources, relying primarily on the CEC's 2009 IEPR. Please comment on Mr. Cox's argument.

A 29 As Mr. Cox notes, the CEC's 2009 IEPR identified energy storage as a potential new resource for integrating renewable generation. However, Mr. Cox failed to discuss a number of the challenges identified in the 2009 IEPR concerning energy storage. For example, one of the storage technologies referenced by Mr. Cox, pumped storage, is, according to the CEC, "extremely difficult" to develop in California given siting and water issues.[61] Moreover, much of the energy storage technology referred to by Mr. Cox is very expensive and "paying for these technologies is a significant barrier to increasing the amount of utility-scale storage in California."[62]

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[60] CAISO Renewable *Resources and the California Electric Power Industry: System Operations, Wholesale Markets and Grid Planning*, July 20, 2009, at p. 7. This document is available at: http://www.caiso.com/23f1/23f19422741b0.pdf.

[61] California Energy Commission, *2009 Integrated Energy Policy Report*, Final Commission Report, December 2009, CEC-100-2009-003-CMF, at p. 194. This document is available at: http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF.

[62] *Id*. at p. 195.

Indeed, even the optimistic forecast in the 2009 IEPR concluded that much of the installation of energy storage, if it occurs, would not occur until 2015 to 2020, which is after the new resources are needed.[63]

Q 30 Pacific Environment and CARE assert that the Redacted and Contra Costa Projects do not have sufficient operational flexibility to integrate renewable resources based on a comparison between PG&E's 2008 LTRFO Solicitation Protocol and applications for certification (AFC) submitted to the CEC for each of these facilities.[64] Please respond to this issue.

A 30 PG&E described above the contractual operating characteristics of the Redacted and Contra Costa Projects and explained how these facilities would be beneficial in integrating renewable resources. Section D below addresses the difference between the contractual requirements in the PPA and PSA and the CEC AFCs submitted by Mirant Marsh Landing and Contra Costa LLC.

D. PG&E's 2008 Long-Term Request for Offers Was Conducted Consistent With the Solicitation Protocols Redacted and Jon L. Maring)

1. The Redacted and Contra Costa Projects Will Operate Consistently With the Requirements in PG&E's 2008 LTRFO Solicitation Protocol

Q 31 CARE points out that PG&E's LTRFO Protocol requires that peaking facilities be available 4,000 operating hours per year, and that this is well above the operating hour limits Redacted is proposing to operate in its permit applications.[65] Is this a concern?

A 31 No. The 4,000 operating hour requirement in the LTRFO Protocol document was for peaking facilities that PG&E would own. No similar requirement was established for PPAs with peaking facilities owned by independent generators, such as Redacted PG&E prefers to have the ability to

[63] *Id.*

[64] Pacific Environment, Testimony of Rory Cox, at pp. 13-14; CARE Testimony, at pp. 2, 4-5, 7-8.

[65] CARE Testimony, at p. 7.

operate its utility-owned generation (UOG) facilities over a wide range of system conditions.

Q 32 Pacific Environment states that the Redacted Project is being permitted to run at a maximum annual capacity factor of 20 percent.[66] CARE claims this operational constraint, which equals 1,752 hours of operation per year, makes the project unattractive at the current negotiated price.[67] What is your response to these concerns?

A 32 It is correct that the Redacted Project is being permitted to run at a maximum capacity factor of 20 percent, equal to 1,752 hours of operation per year. PG&E was aware of this operating constraint at the time it entered into the Redacted PPA with Mirant. This constraint was factored into the economic evaluation of Marsh Landing and the ultimate selection of Redacted as a winning offer. As a peaking facility with a full load heat rate of approximately 10,000 Btu/kWh, Redacted will generally operate at low capacity factors and operating hours, responding to peak load requirements and system needs for services such as renewable resource integration. PG&E anticipates that Redacted will have an expected capacity factor of about Redacted or Redacted of operation per year, which is well below the limits Mirant is seeking in its permits. Because this constraint was included in the economic evaluation of Marsh Landing, CARE's claim that the constraint makes the project unattractive is incorrect.

Q 33 Pacific Environment and CARE assert that Contra Costa Project does not have sufficient operational flexibility to integrate renewable resources based on a comparison between PG&E's 2008 LTRFO Solicitation Protocol and its AFC.[68] Can you respond to this concern?

A 33 Yes. The contractual operating requirements for the Contra Costa Project are fully consistent with PG&E's 2008 LTRFO Solicitation Protocol. Contra Costa LLC has contractual obligations within the PSA that meet or exceed all of the operational requirements set forth in PG&E's All Source Request for Offers issued in April 2008. There are severe penalties within

[66] Pacific Environment, Testimony of Rory Cox, at p. 14.

[67] CARE Testimony, at pp. 7-8.

[68] Pacific Environment, Testimony of Rory Cox, at p. 13-14; CARE Testimony, at pp. 4-5.

the PSA for failure to comply with these requirements. In addition, Contra Costa LLC has indicated that it intends to amend its CEC AFC to provide for levels of operation that meet or exceed the operational requirements set forth in PG&E's LTRFO Protocol. Contra Costa LLC has prepared a declaration included as Attachment A to this reply testimony that more fully addresses these issues.

2. PG&E Followed Its Environmental Leadership Protocol in the 2008 LTRFO Solicitation Process

Q 34 CARE claims that PG&E did not follow its own Environmental Leadership Protocol when it conducted the 2008 LTRFO.[69] Pacific Environment voices similar concerns.[70] What is your response?

A 34 PG&E fully followed its Environmental Leadership protocol which provided for, among other things, assessments of cumulative impacts and local community outreach plans. These assessments contributed to an overall Environmental Leadership score for each offer and, in certain cases as outlined below, led to follow-on actions by PG&E to eliminate offers or improve the environmental profile of the offer.

The Environmental Leadership protocol helped guide PG&E's analysis of the environmental impacts of the proposed offers, resulting in a score which PG&E used to help develop its short list of offers. The Environmental Leadership evaluation was part of PG&E's offer evaluation methodology, which also considered seven other quantitative and qualitative criteria that measure other facets of the expected value of a proposed project to PG&E's ratepayers. As a result of the Environmental Leadership analysis, PG&E disqualified offers from consideration for short listing based on potential significant environmental concerns raised by the project offer.

The scoring of the offers was completed in October 2008. The scores for the eight evaluation criteria were used to produce an initial ranking of the 2008 LTRFO offers. Based on the scores, PG&E developed a short-list of the most attractive offers. PG&E entered into negotiations with the short-listed participants.

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[69] CARE Testimony, at p. 10.

[70] Pacific Environment, Testimony of Rory Cox, at pp. 15-22.

During negotiations with short-listed offers, PG&E continued to refine its evaluation of the offers in order to select the best combination of projects from the short-list to fill the Commission's need authorization. PG&E was concerned about the potential local environmental impacts of selecting two offers in close geographic proximity in Contra Costa County. While PG&E recognized that ultimately the CEC is responsible for assessing the environmental impacts of the projects and establishing the appropriate controls, limits and mitigation, PG&E's negotiators took affirmative steps to reduce the impact of the two new gas-fired facilities on the residents of Contra Costa County.

It was noted in the Environmental Leadership assessment at the short-listing stage that cumulative impacts were a concern in Contra Costa County, and that Redacted would score higher if Mirant agreed to shut down old units. PG&E subsequently negotiated an agreement with Mirant Delta LLC to retire its Contra Costa 6 and 7 units, which rely on OTC technology and are located next to the proposed Mirant Redacted facility. PG&E thus negotiated the early closure of these old units to reduce the concentration of generating facilities in Contra Costa County. This is an example of how PG&E's Environmental Leadership criterion was implemented in the offer evaluation process after short-listing was complete in addition to disqualifying projects from the short list.

As a further example of how the Environmental Leadership criterion influenced the negotiations after the short listing process, in the negotiations for the Contra Costa Project, PG&E and the developer agreed significantly to enhance the design of the project by incorporating General Electric (GE) 7FA.05 combustion turbine generators, GE's most recent technology enhancement. This new equipment will result in a facility with more output at high efficiency, reduced emissions and improved operational flexibility compared to the current model of the 7FA. The new units will be capable of much quicker starting times than the current technology. This will result in higher efficiency operations and substantial environmental benefits. The new combined cycle technology will significantly reduce the time required for start-ups over current combined cycle technologies, resulting in significantly reduced air emissions on an annual basis.

Q 35 Pacific Environment claims that the Commission has directed the utilities to provide greater weight to environmental siting issues.[71] Is this correct?

A 35 Yes and no. Mr. Cox is correct that in the 2006 LTPP Decision, the Commission identified environmental impacts and related siting issues as one factor to consider in the LTRFO evaluation process. However, the Commission also identified a number of other factors, such as customer costs and risk, resource diversity, portfolio fit, local and system reliability and viability.[72] In designing the 2008 LTRFO, PG&E included all of these factors in the evaluation process, including environmental impacts.

Q 36 Did PG&E review its evaluation criteria with the Procurement Review Group (PRG) and the Commission's Energy Division before it started the 2008 LTRFO evaluation process?

A 36 Yes. As PG&E explained in its initial testimony, the PRG and Energy Division reviewed PG&E's evaluation criteria before PG&E started reviewing the 2008 LTRFO offers.[73]

Q 37 Were all of the criteria including Environmental Leadership considered in the 2008 LTRFO evaluation process?

A 37 Yes. As PG&E explained in its initial testimony, each of the evaluation criteria was considered.[74] Moreover, as explained in more detail above, Environmental Leadership was considered not only in the evaluation process, but also in negotiations to ensure that the winning offers achieved this goal.

E. The Contra Costa 6 and 7 Tolling Agreement Is Just and Reasonable and Should Be Approved (Marino Monardi)

Q 38 Why has PG&E contracted for the output of Contra Costa 6 and 7?

A 38 The Contra Costa 6 and 7 PPA serves several purposes. First, the Contra Costa 6 and 7 PPA provides an important environmental benefit in

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[71] Pacific Environment, Testimony of Rory Cox, at p. 15.

[72] D.07-12-052, at pp. 156-157.

[73] PG&E Initial Testimony, at p. 3-2.

[74] *Id*. at pp. 3-9 to 3-11.

that it requires the Seller, subject to CAISO and governmental approvals, unless the CAISO intervenes, to shut down these two aging units, which rely on OTC, at the end of the contract term. Without this contract, it is uncertain when these facilities would have retired. Second, until adequate replacement capacity comes on-line, the Contra Costa 6 and 7 PPA provides PG&E and its customers several important and valuable attributes, including a source of local Bay Area Resource Adequacy capacity, a product that PG&E is required to procure. It also provides a resource that PG&E can dispatch economically when market energy prices are high. Under the PPA, PG&E would pay for the gas and receive the energy at a contractually guaranteed heat rate and therefore PG&E can avoid market purchases. This type of product is especially important during summer peak periods when demand for power is high and the power market is constrained, resulting in relatively expensive cost for power from the market.

F. The Contra Costa Generating Station Was Appropriately Valued in the 2008 LTRFO Evaluation Process (Charles E. Riedhauser)

Q 39 TURN questions whether the value for Resource Adequacy (RA) that PG&E employs in its calculation of market value is plausible.[75] Do you understand its objection?

A 39 No. Kevin Woodruff, TURN's witness, finds no fault with PG&E's market valuation methodology for the Contra Costa PSA and does not mention any specific objection to the RA methodology. TURN claims that if future RA values were lower than PG&E assumed, then the value of the Contra Costa PSA would be adversely impacted. Mr. Woodruff, however, offers no alternative estimate of its RA values. The RA values adopted by PG&E reflect PG&E's best estimate of market conditions and the use of well-known modeling techniques. The RA values are consistently used for all contract valuations, including long and short-term offers received in the LTRFO, intermediate term requests for offers, and RPS solicitations. Both the model and RA values have been vetted by several Independent Evaluators. The RA values were provided to PG&E's PRG as part of discussions regarding PG&E's competitive solicitation process.

[75] TURN Testimony, at pp. 17-22.

G. CARE's Concerns About the Hybrid Market Should Be Rejected (Roy M. Kuga)

Q 40 CARE argues that until a review of the hybrid market in California can be completed, "additional utility owned generation should not be approved."[76] Do you agree with this position?

A 40 No. In fact, CARE's argument has been rejected by the Commission. In the 2006 LTPP proceeding, certain parties argued that the Commission should eliminate the hybrid market and preclude additional UOG. The Commission determined that:

> The PD disallowed any form of UOG bidding into competitive solicitations until a functional, transparent methodology for comparing the bids on a level playing field has been established. This prohibition was supported in comments by the IPP community, CLECA, SCE, and several other parties. However, a number of parties reference in their comments recent RFOs in which robust mechanisms for comparing PSA and PPA bids were developed and implemented, and the processes were deemed fairly and successfully administered by the PRGs, IEs, and this Commission.
>
> We are sufficiently convinced by these arguments—and particularly by the positions articulated by TURN and DRA—that, recognizing the additional safeguards adopted in this decision regarding IE, PRG and ED oversight of the RFO development process, we will relax for the moment the proposed restriction to exclude head-to-head competition between PPAs and PSAs (and in appropriate circumstances, EPCs). However, we reiterate that, as a precondition for conducting an RFO seeking utility ownership options, the IOU, in conjunction with its IE, PRG, and ED staff shall develop a strict code of conduct—to be signed by any and all IOU personnel involved in the RFO process—to prevent sharing of sensitive information between staff involved in developing utility bids and staff who create the bid evaluation criteria and select winning bids.[77]

PG&E allowed utility-ownership proposals in the 2008 LTRFO consistent with the Commission's directives and followed the Commission's requirements regarding the development of a code of conduct. Because utility-ownership proposals are expressly allowed in an RFO, subject to the Commission's requirements for conducting the RFO, there is no basis for CARE's argument that there should be a blanket prohibition of utility-owned projects. Furthermore, utility ownership of generating facilities is a policy issue that is outside the scope of this proceeding.

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[76] CARE Testimony, at p. 5-6.

[77] D.07-12-052 at p. 206 (footnotes omitted).

Q 41 CARE asserts that "[t]he majority of recent power plant additions have been utility owned generation."[78] Is this correct?

A 41 No. While CARE is correct that the Redacted Colusa and Humboldt Generating Stations are utility-owned projects, there are also a number of new generation resources that have been built or are in the process of development that are not utility-owned. For example, non-utility-owned facilities arising out of PG&E's 2004 LTRFO that either have been built or are in the process of being permitted for construction include: the Russell City Project (601 MW); Panoche Energy Center (399 MW); and Starwood Power (118 MW). In addition, winning non-utility-owned offers selected in the 2008 LTRFO include the Mariposa Project (184 MW) and the proposed Redacted Project (719 MW). PG&E has also proposed entering into PPAs for the upgraded GWF Tracy facility (incremental 145 MW) and the Calpine Los Esteros Facility Critical Energy Facility (LECEF) (incremental 109 MW). These PPAs are currently being considered by the Commission in consolidated Applications 09-10-022 and 09-10-034 (the novation proceeding). All of these proposed and developed projects demonstrate that the hybrid market is functioning exactly as the Commission intended, with robust development of both Independent Power Producer-owned facilities and utility-owned facilities. Finally, PG&E has contracted for more than 5,300 MW of new renewable generation from third parties.

H. TURN's Concerns About PG&E's GWF Tracy and Calpine LECEF Applications Are Outside the Scope of This Proceeding Redacted a Delay in Approval Is Misplaced Redacted and Marino Monardi)

Q 42 TURN claims PG&E acted inappropriately by seeking approval of the Tracy and LECEF upgrades in the DWR novation process rather than the LTRFO process.[79] Do you agree?

A 42 No. PG&E chose the winning LTRFO projects to fill the resource need adopted in the 2006 LTPP Decision. In the novation proceeding, PG&E is

[78] CARE Testimony, at p. 5-6.

[79] TURN Testimony, at pp. 22-26.

asking the Commission to approve the Tracy and LECEF Upgrade contracts on their own merits, not to satisfy the 2006 LTPP need authorization.[80] PG&E has proposed the upgrade contracts as part of an overall effort to novate existing contracts between GWF and Calpine and the California Department of Water Resources (DWR).

TURN cites PRG presentations and PG&E management documents such as the Utility Risk Management Committee and Corporation Risk Policy Committee papers as evidence that PG&E switched the upgrades from the LTRFO process to the novation process. Notably, PG&E already expressly acknowledged this change in its January 22, 2010 Reply Testimony in the novation proceeding.[81]

Q 43 TURN suggests that the Commission can delay approval of the Contra Costa Project PSA until September 30, 2010 without a risk that the seller can cancel the PSA.[82] Would approval of the PSA as late as September 30, 2010 potentially delay the on-line date of the facility?

A 43 Yes. Redacted

Redacted

Q 44 DRA suggests that the Commission deny without prejudice PG&E's request to approve the PSA, and allow PG&E to re-apply for approval of the

[80] PG&E Post-Hearing Reply Brief, filed February 5, 2010 in Applications 09-10-022 and 09-10-034, at pp. 22-24.

[81] PG&E Reply Testimony, submitted in Applications 09-10-022 and 09-10-034 on January 22, 2010, at p. 14.

[82] TURN Testimony, at pp. 11-12.

agreement if the PPAs for GWF Tracy and Calpine LECEF are rejected.[83] How would such a delay in Commission approval affect the viability of the PSA?

A 44 As TURN witness Mr. Woodruff notes in his testimony at p. 11, Redacted Redacted Redacted Accordingly, there is no guarantee that this opportunity would be available to PG&E's customers if the Commission rejects the PSA in this proceeding.

Q 45 Should the Commission delay a decision in this proceeding until after July 2010 as suggested by TURN?

A 45 It is important for the Commission to act within the contractual timelines specified in the LTRFO PPAs. Delaying a decision beyond these timelines would lead to contract implications for the LTRFO PPAs, which could lead to project viability issues that could be avoided if the Commission acts consistent with the schedule currently in place for this proceeding. Unnecessary delay, such as that proposed by TURN and DRA, will only serve to further chill future developers' interest in participating in the California wholesale market ultimately increasing prices that consumers will need to pay.

I. TURN's Market Valuation Analysis Requires Clarification (Charles E. Riedhauser)

Q 46 Table 2 in the testimony of Mr. Woodruff for TURN shows the market values supplied by PG&E for four contracts. Do you have any comment on this table?

A 46 Yes. The market values given in TURN's Table 2 are correct but do not tell the entire story as they do not account for the different capacities and tenors of the contracts. PG&E's methodology compares the levelized market values, which accounts for the different capacities and tenors of the contracts, and therefore is a more meaningful view. These are provided in the table below.

[83] DRA Testimony, at p. 6.

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
LEVELIZED MARKET VALUES

Line No.	Project	Incremental Capacity (MW)	Market Value ($MM)	Levelized Market Value ($/kW-yr)
1	Redacted Project	Redacted		
2	Contra Costa Project			
3	GWF Tracy Upgrade			
4	LECEF Upgrade			

In addition, the Market Value column in TURN's Table 2 could be misinterpreted to mean that there is relatively little difference in the cost to customers between the portfolio comprised of the Redacted PPA and the Contra Costa PSA, on the one hand, and the portfolio comprised of the Marsh Landing PPA plus the GWF Tracy and LECEF Upgrade PPAs. In fact, there is a significant difference in the levelized market value between these two portfolios. The market value numbers in TURN's Table 2 represent the above-market payments for each of the four contracts summed over the entire term of each agreement. By focusing only on the above-market dollar outlay for each portfolio over the life of the contracts/assets, the TURN assessment fails to emphasize how many MW of capacity will be acquired for the benefit of customers under each portfolio. Although the total market values between the two portfolios are relatively close Redacted Redacted the amount of capacity that PG&E's customers receive under the Redacted PPA and the Contra Costa PSA portfolio is 34 percent larger. Thus, for a small incremental additional above-market cost, PG&E's customers receive 332 MW more capacity from the Redacted PPA and the Contra Costa PSA portfolio at a price of Redacted for the incremental capacity. It strains credibility to suggest that the economic benefit to customers of the Redacted GWF, LECEF Upgrade portfolio is even close to the Redacted and Contra Costa portfolio.

J. Lowering the Need Determination or Selecting Other Resources to Satisfy the 2006 LTPP Need Would Reduce Competition in Future Solicitations (Marino Monardi)

Q 47 TURN proposes as an alternative that the Commission approve the Tracy and LECEF Upgrades proposed in the novation proceedings and reject one of the winning projects from PG&E's 2008 LTRFO.[84] Do you agree with this proposal?

A 47 No. Approving the Tracy and LECEF Upgrades to fill the LTRFO need, over the Redacted and Contra Costa Projects, would harm the competitive solicitation process. All these projects competed fairly in the 2008 LTRFO on an equal basis and the winners were selected based upon the uniform application of cost effectiveness and other evaluation criteria. The benefits of the competitive process, which depend greatly on robust seller participation, would be lost if LTRFO winners were displaced by non-winners.

If the Commission were to authorize non-winning projects to replace the LTRFO winners, this will damage the credibility of the process and discourage future participation in the utility procurement process. The Tracy Upgrade and the LECEF Upgrade are projects that merit approval, not to fill the LTRFO needs, but instead to achieve the benefits on novation of the DWR contracts. In particular, as PG&E explained in its opening brief in Applications 09-10-022 and 09-10-034, the GWF and LECEF Upgrade PPAs provide benefits including novation of DWR contracts, operational benefits, and environmental benefits.[85] While the GWF and LECEF Upgrade PPAs should not be approved to satisfy the PG&E service area need identified in the 2006 LTPP Decision, because of the other benefits of these agreements, PG&E recommends the approval of the Upgrade PPAs in addition to the Redacted PPA and the Contra Costa PSA, which should be approved as a part of the 2008 LTRFO process.

Q 48 Pacific Environment asserts that the Redacted and Contra Costa Projects are not needed because of changes that have occurred since the

[84] TURN Testimony, at p. 4.

[85] PG&E Opening Brief, filed in Applications 09-10-022 and 09-10-034 filed on January 29, 2010, at pp. 3-4.

2006 LTPP Decision was issued.[86] The need issue has been addressed above in Section A above. Can you describe the impact of the Commission adopting Pacific Environment's argument would have from a commercial perspective on future RFOs?

A 48 Yes. 2008 LTRFO participants spent a considerable amount of time and money preparing their initial offers. Many of these offers included hundreds of pages of materials, draft contracts and detailed information. All of these offers were prepared at the participants' expense. For short-listed participants, there were substantial additional expenses including additional information that was provided to PG&E and the expense and time of the lengthy negotiation process. For the winning participants, there was even more expense finalizing the PPAs or PSAs and starting the process of permitting and developing their facilities, such as submitting AFCs to the CEC.

If, after all of this time and expense, the Commission revisited its previous need determination and decided that the winning projects may not be needed after all (which PG&E strongly disputes), parties may be hesitant to participate in future RFOs. One of the key elements of developing new generation resources in California, which has been a challenge in recent years, is a stable regulatory environment. If parties are able to force a reconsideration of previous Commission need authorizations, developers may simply decide that there is too much regulatory uncertainty in California and elect not to participate in future RFOs. Ultimately, this is detrimental for customers as there will be a smaller pool of offers in future RFOs and likely higher prices.

Q 49 Have market participants expressed concerns about the Commission revisiting the 2006 LTPP Decision need determination in this proceeding?

A 49 Yes. In their Prehearing Conference Statement, the Independent Power Producers Association, a trade group representing numerous independent developers, expressed exactly this concern:

> In this case, PG&E and four counterparties (including the turnkey contractor for the Oakley facility) have invested considerable time and money into a lengthy process that only now is culminating in a request

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[86] Pacific Environment, Testimony of Rory Cox, at p. 6.

> for the Commission's approval. All of this investment was made in a good-faith reliance on the Commission's decision and in the reasonable belief that the Commission meant what it said when it established PG&E procurement authority in D.07-12-052. If the need determination is revised at this late stage in the process to eliminate one or more projects, potential investors in California's energy infrastructure will have little reason to place any reliance on the Commission's procurement decisions.[87]

K. The Midway Sunset Agreement Should Be Approved (Dennis L. Sullivan)

Q 50 CARE's states that the Midway Sunset PPA "violates PG&E's stated requirements in its All Source Requests for Offers" because the offer is from a partial, not complete unit.[88] Is this accurate?

A 50 No. The Redacted facility is comprised of three units, two of which would sell to PG&E under the proposed agreement. Therefore, PG&E is acquiring the output of two complete units, not partial units.

Q 51 Did any other party serve testimony objecting to the Redacted PPA?

A 51 No.

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[87] IEP Prehearing Conference Statement, filed November 30, 2009, at p. 3.

[88] CARE Testimony, at p. 9.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT A

DECLARATION OF GREG LAMBERG

SENIOR VICE PRESIDENT, RADBACK ENERGY

ATTACHMENT A

Declaration of Greg Lamberg

DECLARATION OF GREG LAMBERG

I, Greg Lamberg, a Senior Vice President with Radback Energy, provide the following declaration in support of Pacific Gas and Electric Company's (PG&E) Application 09-09-021 pending currently at the California Public Utilities Commission (CPUC or Commission). I make this declaration based on my own personal knowledge and, if called to do so, could and would competently testify as to the matters set forth in this declaration.

CONTRACTUAL OBLIGATIONS

Contra Costa Generating Station LLC (CCGS LLC) is contractually obligated under the PSA to ensure that the Contra Costa Generating Station (Contra Costa Project) meets or exceeds the operational requirements set forth in PG&E's All Source Request for Offers issued in April of 2008. There are severe penalties within the PSA for failure to comply with these requirements. There are three dispatch scenarios which the Contra Costa Project is required to address in the permitting of the project, set forth in Table 1 below. The first dispatch scenario represents the requirement (300 starts, 25 of which are cold) specified in PG&E's 2008 All Source Request for Offers. The second and third dispatch scenarios were developed by CCGS LLC to provide even greater dispatch flexibility and enhanced value to PG&E and its customers.

TABLE 1
Combustion Turbine Dispatch

Case No.	1	2	3
Dispatch	**PG&E Spec. 275 Hot Starts 25 Cold Starts [1]**	**6x16 1,500 hrs at Peak July [2]**	**6x24/1x18 1,500 hrs at Peak July [3]**
Combustion Turbines/HRSGs			
Number of Turbines/HRSGs	2	2	2
Minimum Load Hours - Natural Gas	-	-	-
Base Load ISO Hours - Natural Gas	3,657	3,933	6,924
Base Load Peak July Hours - Natural Gas	1,500	1,500	1,500
Total Hot Starts - Natural Gas	275	260	51

SB_GT&S_0488803

TABLE 1
Combustion Turbine Dispatch

Total Warm Starts - Natural Gas	-	51	-
Total Cold Starts - Natural Gas	25	1	1
Total Shutdowns - Natural Gas	300	312	52

Notes:

1. The Case 1 dispatch profile was created based on PG&E's 4/1/08 All-Source Long-Term Request for Offers, which requires 300 starts per year, of which, 25 are cold starts.
2. The Case 2 dispatch profile assumes a typical 6x16 dispatch wherein the plant would be shutdown every night for 8 hours as well as all day on Sundays.
3. The Case 3 dispatch profile was created for the purpose of developing a worst-case scenario for air permitting wherein the plant would operate at base load for 24 hours per day 6 days per week and 18 hours on Sundays. This case provides conservative estimates for those pollutants that are more heavily influenced by run hours, versus starts and stops.

PERMIT REQUIREMENTS

CCGS LLC is also required under the PSA to obtain permits that provide for levels of operation that meet or exceed the operational requirements set forth in PG&E's LTRFO Protocol. Contra Costa LLC recently responded in its Data Responses to the CEC (See Data Response 3, dated February 2010) that its Application For Certification (AFC) with the California Energy Commission (CEC) and the Application for the Preliminary Determination of Compliance (PDOC) with the Bay Area Air Quality Management District (BAAQMD) for the proposed Contra Costa Project are being amended to reflect 24 hours per day of operation. This will ensure that the requested permits will allow the Contra Costa Project to meet or exceed the operational requirements set forth in the LTRFO Protocol.

As described in the AFC at page 5.1-6, the original applications included a scenario that assumed a curtailment of hours of operation. This was necessary solely as a result of uncertainty, which has since been resolved, concerning the BAAQMD's regulatory status with respect to particulate matter. At the time the applications were filed, the region was designated as "attainment" for particulate matter under the Clean Air Act and the BAAQMD was in the process of applying to the U.S. Environmental Protection Agency (EPA) for re-designation. Since that time, EPA has approved BAAQMD's request for re-designation. Consistent with the new regulatory regime, Contra Costa LLC is amending its AFC and Application for PDOC to eliminate the reduced operating scenario and instead reflect 24 hours per day of operation.

I make this declaration under penalty of perjury, dated March 9th, 2010 at Danville, California.

Greg Lamberg

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT B

DECLARATION OF DENNIS L. SULLIVAN AND CONFIDENTIAL DESIGNATIONS APPEARING IN PG&E'S REPLY TESTIMONY PURSUANT TO D.06-06-066, APPENDIX 1 ("IOU MATRIX")

PACIFIC GAS AND ELECTRIC COMPANY
APPLICATION FOR APPROVAL OF
2008 LONG TERM REQUEST FOR OFFER RESULTS AND
FOR ADOPTION OF COST RECOVERY AND RATEMAKING MECHANISMS
(APPLICATION 09-09-021)

DECLARATION OF Redacted **SUPPORT OF**
CONFIDENTIAL DESIGNATIONS APPEARING IN PG&E'S REPLY TESTIMONY

I, Redacted declare:

1. I am presently employed by Pacific Gas and Electric Company (PG&E). I am the manager of new resource procurement in PG&E's Competitive Solicitations Department. In this position, my responsibilities include project management of PG&E's Long Term Request for Offers (LTRFO). I have been involved in the LTRFO design, issuance, offer evaluation, shortlist selection, negotiations, and the selection of the winning offers in this solicitation.

2. Based on my knowledge and experience, and in accordance with the *Decision Adopting Model Protective Order and Non-Disclosure Agreement, Resolving Petition For Modification and Ratifying Administrative Law Judge Ruling*, D. 08-04-023 (April 18, 2008), p. 22, I make this declaration seeking confidential treatment for certain data and information contained in the reply testimony served but not yet offered into evidence on March 10, 2010 in support of PG&E's "Application for Approval of 2008 Long Term Request for Offer Results and for Adoption of Cost Recovery and Ratemaking Mechanisms".

3. Attached to this declaration is a matrix that identifies the data and information in the reply testimony for which PG&E is seeking confidential treatment. The matrix specifies that the material PG&E is seeking to protect constitutes the particular type of data and information listed in the "IOU Matrix" attached as Appendix 1 of Decision 06-06-066. The matrix also specifies the category or categories in the IOU Matrix to which the data and information corresponds, and why confidential protection is justified. Finally, the matrix specifies that: (1) PG&E is complying with the limitations specified in the IOU Matrix for that type of data or information; (2) the information is not already public; and (3) the data cannot be aggregated,

redacted, summarized or otherwise protected in a way that allows partial disclosure. By this reference I am incorporating into this declaration all of the explanatory text in the attached matrix.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on March 10, 2010, at San Francisco, California.

Dennis L. Sullivan

DENNIS L. SULLIVAN

	PACIFIC GAS AND ELECTRIC COMPANY							
	Application of Pacific Gas and Electric Company (U 39 E) for Approval of 2008 Long-Term Request for Offer Results and for Adoption of Cost Recovery and Ratemaking Mechanisms							
	IDENTIFICATION OF CONFIDENTIAL INFORMATION PER DECISION 06-06-066							
	March 10, 2010							
	Redaction Reference	1) The material submitted constitutes a particular type of data listed in the Matrix, appended as Appendix 1 to D.06-06-066 (Y/N)	2) Which category or categories in the Matrix the data correspond to:	3) That it is complying with the limitations on confidentiality specified in the Matrix for that type of data (Y/N)	4) That the information is not already public (Y/N)	5) The data cannot be aggregated, redacted, summarized, masked or otherwise protected in a way that allows partial disclosure (Y/N)	PG&E's Justification for Confidential Treatment	Length of Time
	Document: Reply Testimony							
1	Page 23, line 18	Y	Page 15, Item VII (Bilateral Contract Terms and Conditions - Electric) B: Contracts and Power Purchase Agreements between utilities and non-affiliated third parties (except RPS)); Confidentiality provision in Section 10.7 of Mirant Marsh Landing PPA; Page 18, Item VIII (Competitive Solicitation (Bidding) Information - Electric) B: Specific quantitative analysis involved in scoring and evaluation of participating bids	Y	Y	Y	This redacted portion of this page shows terms other than contract summary terms, which are terms other than counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date, which are confidential for three years from the date contract states deliveries to begin. PG&E is required by the Mirant Marsh Landing PPA to maintain confidentiality of contract terms. The redacted portion of this page also provides information other than evaluation guidelines, which are confidential for three years after winning bidders are selected.	3 years
2	Page 30, lines 16-26	Y	Page 15, Item VII (Bilateral Contract Terms and Conditions - Electric) B: Contracts and Power Purchase Agreements between utilities and non-affiliated third parties (except RPS)); Confidentiality provision in Section 11.3 of Contra Costa Generating Station PSA.	Y	Y	Y	This redacted portion of this page shows terms other than contract summary terms, which are terms other than counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date, which are confidential for three years from the date contract states deliveries to begin. PG&E is required by the Contra Costa Generating Station PSA to maintain confidentiality of contract terms.	3 years
3	Page 31, lines 4-6	Y	Page 15, Item VII (Bilateral Contract Terms and Conditions - Electric) B: Contracts and Power Purchase Agreements between utilities and non-affiliated third parties (except RPS)); Confidentiality provision in Section 11.3 of Contra Costa Generating Station PSA.	Y	Y	Y	This redacted portion of this page shows terms other than contract summary terms, which are terms other than counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date, which are confidential for three years from the date contract states deliveries to begin. PG&E is required by the Contra Costa Generating Station PSA to maintain confidentiality of contract terms.	3 years
4	Page 32, Table 1 (lines 1-4)	Y	Page 15, Item VII (Bilateral Contract Terms and Conditions - Electric) B: Contracts and Power Purchase Agreements between utilities and non-affiliated third parties (except RPS)); Confidentiality provision in Section 11.3 of Contra Costa Generating Station PSA and in Section 10.7 of Mirant Marsh Landing PPA.	Y	Y	Y	This attachment shows terms other than contract summary terms, which are terms other than counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date, which are confidential for three years from the date contract states deliveries to begin. PG&E is required by the Mirant Marsh Landing PPA to maintain confidentiality of contract terms.	3 years
5	Page 32, lines 14-15	Y	Page 15, Item VII (Bilateral Contract Terms and Conditions - Electric) B: Contracts and Power Purchase Agreements between utilities and non-affiliated third parties (except RPS)); Confidentiality provision in Section 11.3 of Contra Costa Generating Station PSA and in Section 10.7 of Mirant Marsh Landing PPA.	Y	Y	Y	This attachment shows terms other than contract summary terms, which are terms other than counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date, which are confidential for three years from the date contract states deliveries to begin. PG&E is required by the Mirant Marsh Landing PPA to maintain confidentiality of contract terms.	3 years
6	Page 32, line 20	Y	Page 15, Item VII (Bilateral Contract Terms and Conditions - Electric) B: Contracts and Power Purchase Agreements between utilities and non-affiliated third parties (except RPS)); Confidentiality provision in Section 11.3 of Contra Costa Generating Station PSA and in Section 10.7 of Mirant Marsh Landing PPA.	Y	Y	Y	This attachment shows terms other than contract summary terms, which are terms other than counterparty, resource type, location, capacity, expected deliveries, delivery point, length of contract and online date, which are confidential for three years from the date contract states deliveries to begin. PG&E is required by the Mirant Marsh Landing PPA to maintain confidentiality of contract terms.	3 years

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT C

CALIFORNIA ENERGY DEMAND 2010-2020,

ADOPTED FORECAST

CALIFORNIA ENERGY COMMISSION

CALIFORNIA ENERGY DEMAND 2010-2020 ADOPTED FORECAST

COMMISSION REPORT

December 2009

CEC-200-2009-012-CMF

Arnold Schwarzenegger, *Governor*

Loss Factors - Losses are included in the net peak and net energy for load tables		
	Peak	Energy
PG&E	1.097	1.096
SMUD	1.077	1.064
SCE	1.076	1.068
LADWP	1.112	1.135
SDG&E	1.096	1.0709
Burbank, Glendale, Pasadena	1.051	1.064
IID	1.060	1.128
DWR	1.060	1.038

CHAPTER 2: Pacific Gas and Electric Planning Area

The Pacific Gas and Electric (PG&E) planning area includes:

- PG&E bundled retail customers.
- Customers served by energy service providers (ESPs) using the PG&E distribution system to deliver electricity to end users.
- Customers of publicly owned utilities and irrigation districts in PG&E's transmission system, with the exception of the Sacramento Municipal Utility District (SMUD). SMUD is treated as its own planning area and is discussed in a later chapter.

For purposes of this chapter, the PG&E planning area forecast includes the members of the SMUD control area, Roseville, Redding, and the Western Area Power Administration (WAPA). To support electricity and transmission system analysis, staff uses historical consumption and load data to develop individual forecasts for all medium and large utilities in the planning area. Those results are presented in Forms 1.5a through 1.5c following Chapter 1. The results in this chapter are for the entire PG&E transmission planning area.

This chapter is organized as follows. First, forecasted consumption and peak loads for the PG&E planning area are discussed; both total and per capita values are presented. *CED 2009 Draft* values are compared to adopted *CED 2007* values, with differences between the two forecasts explained. The forecasted load factor, jointly determined by the consumption and peak load estimates, is also discussed. Second, the chapter presents sector consumption and peak load forecasts. The residential, commercial, industrial, and "other" sector forecasts are compared to those in *CED 2007*, and differences between the two are discussed. Third, the chapter discusses the forecasts self generation, electric vehicles and effects of conservation and efficiency programs.

For *CED 2009 Draft*, three price scenarios were developed for electricity rates: high rates, low (constant) rates, and a mid-rate scenario in between the two. The high rate case assumed approximately 30 percent higher rates by 2020 relative to 2010, while the mid-rate case assumed 15 percent higher rates over the same period. In the low rate case, rates remained at 2010 levels through 2020 as was done in *CED 2007*. In *CED 2009 Adopted,* the mid rate price forecast is used, and all comparisons to *CED 2009 Draft* are made to the mid rate scenario. Chapter 1 provides more details on price assumptions.

Forecast Results

The following summarizes the results presented in this chapter:

- *CED 2009 Adopted* forecasts of PG&E planning area electricity consumption and peak demand are lower than *CED 2007* levels because of the economic downturn and increased efficiency impacts, but higher than *CED 2009 Draft*.
- Per capita electricity consumption and peak demand are also projected to be lower than *CED 2007* but higher than *CED 2009 Draft*.
- The largest percentage reduction in electricity consumption and peak demand relative to *CED 2007* occurs in the residential sector.
- Alternative economic scenarios increase or decrease electricity consumption and peak demand by around 2.3 percent in 2020.
- Self-generation impacts are projected to be higher than in *CED 2007* because of increased adoption of photovoltaic systems but lower than *CED 2009 Draft* because of a reduced peak factor assumption. .
- Electric vehicles are projected to increase electricity consumption by almost 1,700 GWH in 2020.

Table 10 presents a comparison of the planning area electricity consumption and peak demand forecasts for selected years. *CED 2009 Adopted* compares both *CED 2009 Draft* mid rate and *CED 2007*. The revised electricity consumption forecast is higher than *CED 2009 Draft* by more than 6 percent at the end of the forecast period. This is caused mainly by higher economic forecast values provided in June Moody's Economy.com forecast and inclusion of consumption from electric vehicles included in *CED 2009 Adopted*.

The revised consumption forecast is still about 1.7 percent lower than *CED 2007* at the end of the period. The revised peak forecast is now 3 percent higher than *CED 2009 Draft* by the end of the forecast period. This is still more than 2 percent lower than *CED 2007*. The smaller increase in the revised peak forecast relative to changes in the consumption forecast is caused by increased self-generation assumptions, which reduce net system peak but do not reduce total electricity consumption, and inclusion of consumption from electric vehicles, which are assumed to be primarily charged off peak. Long-term growth rates of both *CED 2009 Adopted* consumption and peak forecasts are similar to the growth rates of *CED 2007*.

Table 10: PG&E Planning Area Forecast Comparison

Consumption (GWH)					
	CED 2007 (Oct. 2007)	*CED 2009 Draft* mid-rate case (June 2009)	*CED 2009 Adopted* (Dec. 2009)	Percent Difference *CED 2009 Adopted* and *CED 2007*	Percent Difference, *CED 2009 Adopted* and *CED 2009 Draft*
1990	86,803	86,803	86,803	0.00%	0.00%
2000	101,331	101,331	101,333	0.00%	0.00%
2008	107,591	106,753	111,128	3.29%	4.10%
2010	110,503	106,240	108,344	-1.95%	1.98%
2015	117,806	110,878	115,828	-1.68%	4.46%
2018	121,873	112,959	119,814	-1.69%	6.07%
Average Annual Growth Rates					
1990-2000	1.56%	1.56%	1.56%		
2000-2008	0.75%	0.65%	1.16%		
2008-2010	1.34%	-0.24%	-1.26%		
2010-2018	1.23%	0.77%	1.27%		
Peak (MW)					
	CED 2007 (Oct. 2007)	*CED 2009 Draft* mid-rate case (June 2009)	*CED 2009 Adopted* (Dec. 2009)	Percent Difference, *CED 2009 Adopted* and *CED 2007*	Percent Difference, *CED 2009 Adopted* and *CED 2009 Draft*
1990	17,055	17,013	17,250	1.14%	1.39%
2000	20,716	20,665	20,628	-0.42%	-0.18%
2008	23,413	23,405	23,805	1.67%	1.71%
2010	24,050	23,240	23,479	-2.37%	1.03%
2015	25,760	24,606	25,163	-2.32%	2.26%
2018	26,754	25,341	26,125	-2.35%	3.09%
Average Annual Growth Rates					
1990-2000	1.96%	1.96%	1.80%		
2000-2008	1.54%	1.57%	1.81%		
2008-2010	1.35%	-0.35%	-0.69%		
2010-2018	1.34%	1.09%	1.34%		

Source: California Energy Commission, 2009

As shown in **Figure 21**, the *CED 2009 Adopted* consumption forecast is about 6 percent higher than *CED 2009 Draft* values by the end of the forecast period but is still below the *CED 2007* projection throughout the forecast period. The dip in the early years of *CED 2009 Adopted* is caused by both the revised economic projections and by elevated assumptions about increased energy efficiency program savings.

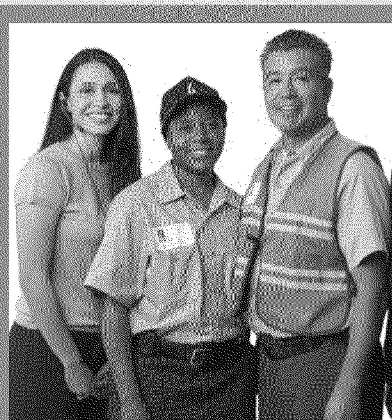
PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT D

2008 CALIFORNIA GAS REPORT, PREPARED BY THE CALIFORNIA GAS AND ELECTRIC UTILITIES

2008 California Gas Report

Prepared by the California Gas and Electric Utilities



FOREWORD

The 2008 California Gas Report presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2030. This report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years, in compliance with California Public Utilities Commission Decision D.95-01-039. The projections in the California Gas Report are for long-term planning and do not necessarily reflect the day-to-day operational plans of the utilities.

The report is organized into three sections: Executive Summary, Northern California, and Southern California. The Executive Summary provides statewide highlights and consolidated tables on supply and demand. The Northern California section provides detail on requirements and supplies of natural gas for Pacific Gas and Electric Company (PG&E), the Sacramento Municipal Utility District (SMUD), Wild Goose Storage, Inc. and Lodi Gas Storage LLC. The Southern California section shows similar detail for Southern California Gas Company (SoCalGas), the City of Long Beach Municipal Oil and Gas Department, and San Diego Gas and Electric Company.

Each participating utility has provided a narrative explaining its assumptions and outlook for natural gas requirements and supplies, including tables showing data on natural gas availability by source, with corresponding tables showing data on natural gas requirements (demand) by customer class. Separate sets of these tables are presented for average and cold year temperature conditions. Any forecast, however, is subject to considerable uncertainty. Changes in the economy, energy and environmental policies, natural resource availability, and the continually evolving restructuring of the gas and electric industries can significantly affect the reliability of these forecasts. This report should not be used by readers as a substitute for a full, detailed analysis of their own specific energy requirements.

A working committee, comprised of the representatives from each utility was responsible for compiling the report. The membership of this Committee is listed in the Respondents section at the end of this report.

Workpapers and next year's report are available upon request from PG&E and SoCalGas/SDG&E. Write, fax or email us at the addresses shown in the Reserve Your Subscription at the end of this report.

STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
Average Temperature and Normal Hydro Year
MMcf/Day

	2008	2010	2015	2020	2025	2030
California's Supply Sources						
Utility						
California Sources	468	468	468	468	468	468
Out-of-State	4,515	4,458	4,378	4,510	4,500	4,534
Utility Total	4,983	4,926	4,846	4,978	4,968	5,002
Non-Utility Served Load (1)	1,471	1,438	1,454	1,479	1,498	1,517
Statewide Supply Sources Total	**6,454**	**6,363**	**6,299**	**6,457**	**6,465**	**6,518**
California's Requirements						
Utility						
Residential	1,213	1,232	1,250	1,255	1,269	1,284
Commercial	504	508	506	493	492	496
Natural Gas Vehicles	30	37	54	75	103	132
Industrial	861	826	800	757	721	689
Electric Generation (2)	1,873	1,826	1,768	1,924	1,929	1,932
Enhanced Oil Recovery Steaming	35	28	28	29	28	28
Wholesale/International+Exchange	227	231	237	243	254	264
Company Use and Unaccounted-for	76	75	78	78	82	87
Utility Total	4,820	4,763	4,721	4,853	4,878	4,912
Non-Utility						
Enhanced Oil Recovery Steaming	781	784	785	787	797	807
EOR Cogeneration/Industrial	164	164	163	166	168	170
Electric Generation	525	490	506	526	533	540
Non-Utility Served Load (1)	1,471	1,438	1,454	1,479	1,498	1,517
Statewide Requirements Total (3)	**6,291**	**6,200**	**6,174**	**6,332**	**6,375**	**6,428**

Notes:

(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants.
Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).

(2) Includes utility generation, wholesale generation, and cogeneration.

(3) The difference between California supply sources and California requirements is PG&E's forecast of off-system deliveries.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT E

INCREMENTAL IMPACTS OF ENERGY POLICY INITIATIVES RELATIVE TO THE *2009 INTEGRATED ENERGY POLICY REPORT* ADOPTED DEMAND FORECAST

CALIFORNIA
ENERGY
COMMISSION

INCREMENTAL IMPACTS OF ENERGY EFFICIENCY POLICY INITIATIVES RELATIVE TO THE *2009 INTEGRATED ENERGY POLICY REPORT* ADOPTED DEMAND FORECAST

DRAFT STAFF REPORT

January 2010
CEC-200-2010-001-D

Arnold Schwarzenegger, *Governor*

On the one hand, the effort to continue increasing efficiency may grow more difficult through time as future initiatives exhaust the "low-hanging fruit." On the other, even though they have not been quantified, there are additional energy efficiency savings that may be accomplished through time across the entire range of delivery mechanisms. For example, the Energy Commission adopted television standards in late 2009, and the savings from such standards are not included within the scope of the state or federal standards evaluated in this project.

The use of scenarios defined through alternative policy initiative assumptions is a key element in incorporating uncertainty about future uncommitted program impacts. This uncertainty reflects in part the question of whether future policy makers will enact the standards and other programs required to achieve ever higher levels of cumulative savings. Commissions and boards typically resist making commitments binding on future commissioners and board members, yet the uncommitted program initiatives that are the basis for the *2008 Goals Study* presume that IOU programs will be continue to be funded at current or higher costs, that the Energy Commission will continually ratchet building standards tighter with each three-year update cycle, and that the Big Bold concepts will actually be enacted on schedule and to an extent comparable to that quantified in the *2008 Goals Study*.

There are other dimensions of uncertainty that have not been fully explored in this analysis. Decision makers should be aware of the following:

- IOU program impacts constitute a large percentage of total future efficiency savings, and they rely upon voluntary decisions by end users to participate. Unprecedented levels of participation are projected, levels which depend on many factors, including the state of the economy.
- The Energy Commission's *2009 IEPR* demand forecast assumes a 15 percent increase in retail prices by 2020, and some impact via price elasticity is included in the base demand forecast. However, it is easily conceivable that retail prices could rise by 30 percent or more in the next 10 years, which would mean more naturally occurring savings and raises the possibility that, given the CPUC's total market gross approach, presumed programmatic activity could be scaled back.

In general, decision makers must consider the implications of efficiency-induced projections of very low or even negative energy and peak demand growth through 2020. While the *Energy Action Plan* loading order emphasizes cost-effective energy efficiency as California's first choice to meet demand growth, relying solely on these resources for long-term resource adequacy is uncharted territory. If decision makers postpone decisions to invest in supply-side resources and energy efficiency fails to deliver as forecasted, then serious reliability (and cost) consequences could result, unless such shortfalls have been anticipated and contingency actions identified.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT F

REVISITING PATH 26 POWER FLOW ASSUMPTIONS

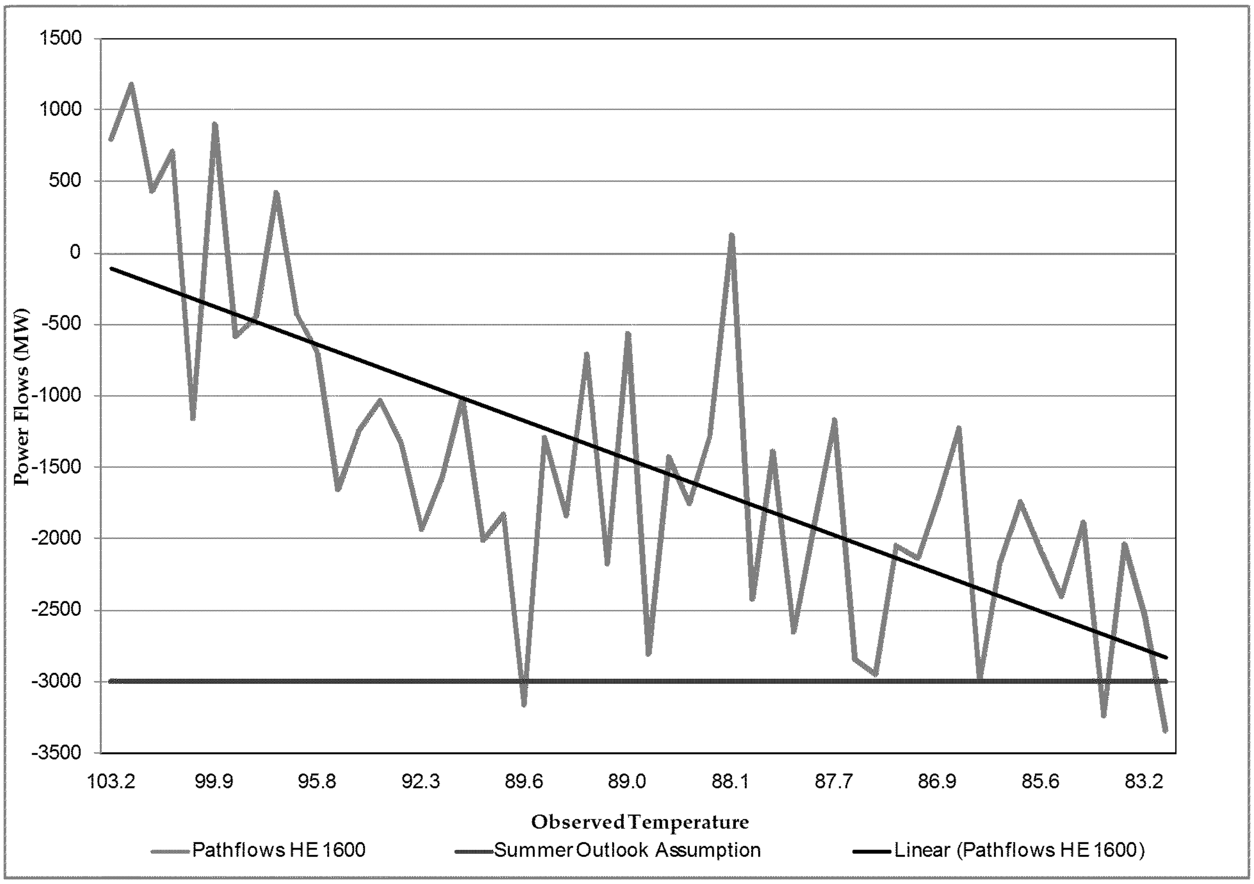
REVISITING PATH 26 POWER FLOW ASSUMPTIONS

Denny Brown
Electricity Analysis Office
Electricity Supply Analysis Division
California Energy Commission

STAFF PAPER

OCTOBER 2008
CEC-200-2008-006

Figure 4: Summer 2008 Path 26 Weekday Flows (MW) Sorted by Temperature (Negative number indicates North to South)



Source: CA ISO Subpoena data and Energy Commission Staff

A study of the 2006 thru 2008 Path 26 power flows presented in **Figure 1** thru **Figure 4** clearly indicates that the 3,000 MW North to South assumption used in Summer Supply and Demand Outlook reports since 2006 and in the CPUC's LTPP decision D.07-12-052 is no longer valid. Energy Commission staff will use an assumption that is significantly lower in future Summer Outlook reports. Determining the correct amount will be difficult, however.

The staff believes that the CPUC Resource Adequacy and Planning Reserve Margin proceedings are likely the best forums to obtain the input of all stakeholders and interested parties in order to determine the best assumption or determine a new methodology. Energy Commission staff encourages additional discussion in these proceedings and establishing a stakeholder working group to further study the issue.

There are a number of factors that impact the amount of capacity flowing in either direction on Path 26. Some of these include temperature and load in each region, major generation outages, imports from other balancing authorities, California ISO operating procedures, must-offer waivers, transmission limitations and economics. This working paper will be updated as staff completes additional analysis for these factors.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT G

DRAFT STATEWIDE WATER QUALITY CONTROL POLICY ON THE USE OF COASTAL AND ESTUARINE WATERS FOR POWER PLANT COOLING

STATEWIDE WATER QUALITY CONTROL POLICY ON THE USE OF COASTAL AND ESTUARINE WATERS FOR POWER PLANT COOLING

DRAFT

1. Introduction

A. Clean Water Act Section 316(b) requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. Section 316(b) is implemented through National Pollutant Discharge Elimination System (NPDES) permits, issued pursuant to Clean Water Act Section 402, which authorize the point source discharge of pollutants to navigable waters.

B. The State Water Resources Control Board (State Water Board) is designated as the state water pollution control agency for all purposes stated in the Clean Water Act.

C. The State Water Board and Regional Water Quality Control Boards (Regional Water Boards) (collectively Water Boards) are authorized to issue NPDES permits to point source dischargers in California.

D. Currently, there are no applicable nationwide standards implementing Section 316(b) for *existing power plants**[1]. Consequently, the Water Boards must implement Section 316(b) on a case-by-case basis, using best professional judgment.

E. The State Water Board is responsible for adopting state policy for water quality control, which may consist of water quality principles, guidelines, and objectives deemed essential for water quality control.

F. This Policy establishes uniform requirements for the implementation of §316(b), using best professional judgment in determining BTA for cooling water intake structures at existing coastal and estuarine power plants that must be implemented in NPDES permits.

G. The intent of this Policy is to ensure that the beneficial uses of the State's coastal and estuarine waters are protected while also ensuring that the electrical power needs essential for the welfare of the citizens of the State are met. The State Water Board recognizes it is necessary to develop replacement infrastructure to maintain electric reliability in order to implement this Policy.

[1] An asterisk indicates that the term is defined in Section 5 of the Policy.

H. During the development of this Policy, State Water Board staff has met regularly with representatives from the California Energy Commission (CEC), California Public Utilities Commission (CPUC), California Coastal Commission (CCC), California State Lands Commission (SLC), California Air Resources Board (ARB), and California Independent System Operator (CAISO) to develop realistic implementation plans and schedules for this Policy that will not cause disruption in the State's electrical power supply. The compliance dates for this Policy were developed considering a report produced by the energy agencies (CEC, CPUC, and CAISO), titled "Implementation of OTC Mitigation Through Energy Infrastructure Planning and Procurement Changes", and the accompanying table, titled "Draft Infrastructure Replacement Milestones and Compliance Dates for Existing Power Plants in California Using Once Through Cooling", included in the Substitute Environmental Document for this Policy. The energy agencies' approach seeks to address the replacement, repowering, or retirement of power plants currently using OTC that (1) maintains reliability of the electric system; (2) meets California's environmental policy goals; and (3) achieves these goals through effective long-term planning for transmission, generation and demand resources. The energy agencies have stated that the dates specified in their report may require periodic updates.

I. To prevent disruption in the State's electrical power supply when the Policy is implemented, the State Water Board will convene a Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS), which will include representatives from the CEC, CPUC, CAISO, CCC, SLC, ARB, and State Water Board. SACCWIS will review implementation plans and schedules submitted by dischargers pursuant to this Policy, and advise the State Water Board on the implementation of this Policy to ensure that the implementation schedule takes into account local area and grid reliability. The State Water Board recognizes the compliance dates in this Policy may require amendment based on, among other factors, the need to maintain reliability of the electric system as determined by the energy agencies included in the SACCWIS, acting according to their individual or shared responsibilities. The State Water Board retains the final authority over changes to the adopted policy.

J. While the CEC, CPUC and CAISO each have various planning or permitting responsibilities important to this effort, the approach relies upon use of competitive procurement and forward contracting mechanisms implemented by the CPUC in order to identify low cost solutions for most OTC power plants. The CPUC has authority to order the investor-owned utilities (IOUs) to procure new or repowered fossil-fueled generation for system and/or local reliability in the Long-Term Procurement Plan (LTPP) proceeding. In response to the Policy, the CPUC anticipates modifying its LTPP proceeding and procurement processes to require the IOUs to assess replacement infrastructure needs and conduct targeted requests for offers (RFOs) to acquire replacement, repowered or otherwise compliant generation capacity. LTPP proceedings are conducted on a biennial cycle and plans are normally approved in odd-numbered years. The next cycle, the 2010 LTPP, is estimated to result in a decision by 2011. The subsequent cycle, the 2012 LTPP, would in turn result in a decision by 2013. Once authorized to procure by a CPUC LTPP decision, the IOUs need approximately 18 months to issue an RFO, sign contracts, and submit applications to the CPUC for approval. Approval by the CPUC takes approximately nine months. If the contract involves a facility already licensed through the CEC generation permitting process, then financing and construction can begin. A typical generation permitting timeline is 12 months, but specific issues such as ability to obtain air permits can delay the process. IOUs often give preference to RFO bids with permits already (or nearly) in place. From contract approval, construction usually takes three years, if generation permits are approved, or approximately five years, if generation permits are pending or other barriers present delays. In total, starting from the initiation of an LTPP proceeding (2010 LTPP or 2012 LTPP), seven years are expected to elapse, before replacement infrastructure is operational. Due to the number of plants affected, efforts to replace or repower OTC power plants would need to be phased.

K. Because the Los Angeles region presents a more complex and challenging set of issues, it is anticipated that more time would be needed to study and implement replacement infrastructure solutions. Therefore, total elapsed time is expected to begin in 2010 and end in 2017 for the Greater Bay Area and San Diego regions, which would be addressed beginning in the 2010 LTPP. For the Los Angeles region, which would be addressed beginning in the 2012 LTPP, total elapsed time is expected to begin in 2012 and end in 2020. A transmission solution is expected to have approximately the same timeframe, but could be delayed by greater potential for significant local opposition. In order to assure that repowering or new power plant development in the Los Angeles basin addresses unique permitting challenges, the SACCWIS will assist the State Water Board in evaluating compliance for power plants not under the jurisdiction of the CPUC or operating within the CAISO Balancing Authority Area.

L. To conserve the State's scarce water resources, the State Water Board encourages the use of recycled water for cooling water in lieu of marine, estuarine or fresh water.

2. Requirements for *Existing Power Plants**

A. Compliance Alternatives

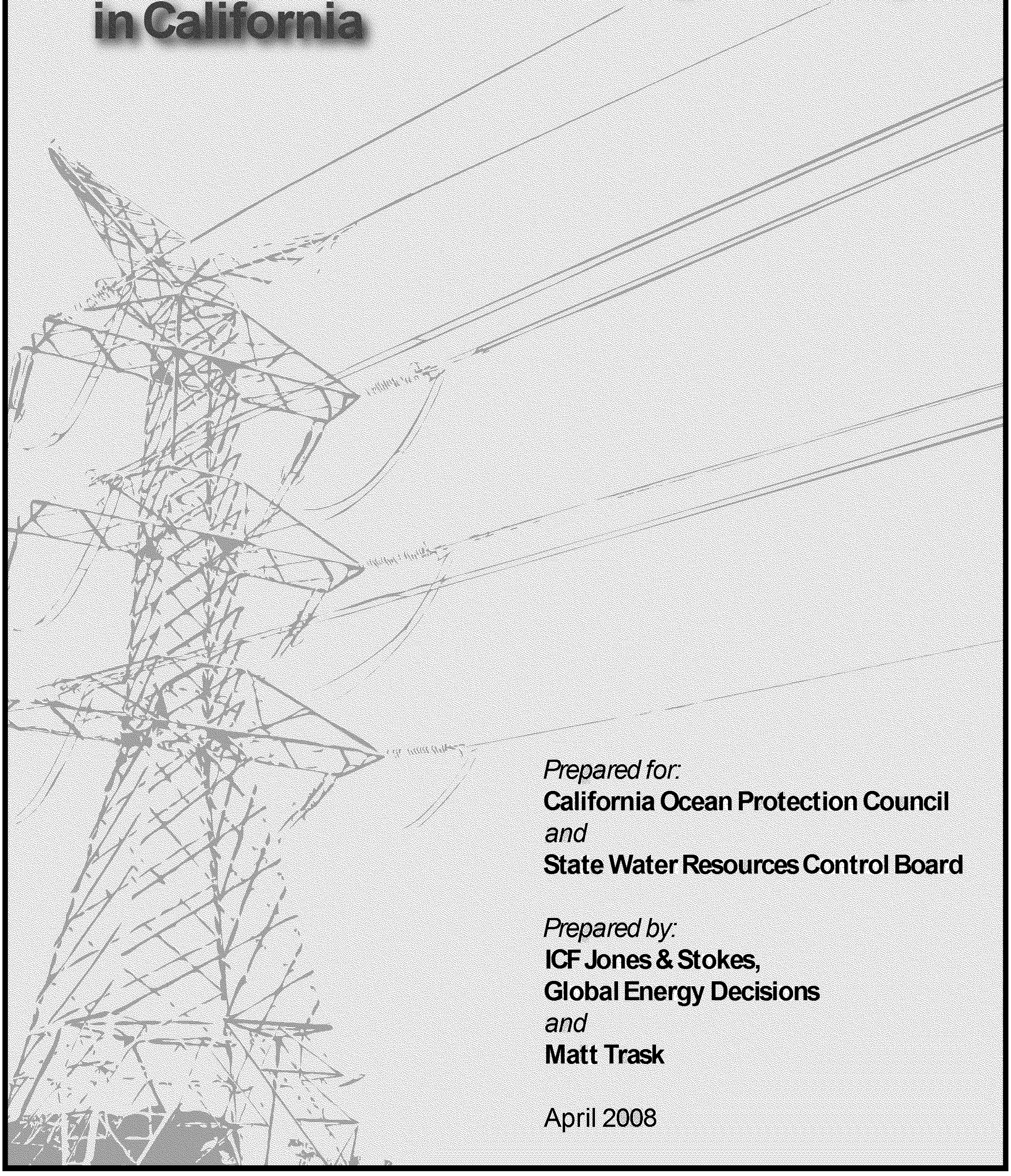
(1) Track 1. An owner or operator of an *existing power plant** must reduce *intake flow rate** at each unit, at a minimum, to a level commensurate with that which can be attained by a *closed-cycle wet cooling system**. A minimum 93 percent reduction in *intake flow rate** for each unit is required for Track 1 compliance, compared to the unit's design *intake flow rate**. The through-screen intake velocity must not exceed 0.5 foot per second.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT H

ELECTRIC GRID RELIABILITY IMPACTS FROM REGULATION OF ONCE-THROUGH COOLING IN CALIFORNIA

Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California



Prepared for:
California Ocean Protection Council
and
State Water Resources Control Board

Prepared by:
ICF Jones & Stokes,
Global Energy Decisions
and
Matt Trask

April 2008

would have no impacts, even during construction. Therefore, with proper planning and oversight, the Board's policy is not likely to result in significant cumulative impacts to public safety and the environment, though one area of concern is cumulative land use impacts because of zoning issues.

The most realistic scenarios examined, in which some OTC plants would be retired while others repower or convert their cooling systems, showed potential for significant benefits to the environment because the overall power sector would be more efficient and produce fewer emissions, and because marine ecosystem impacts caused by use of OTC technology would be greatly reduced.

Recommendations

Though this study makes optimistic conclusions about the industry's ability to compensate for mass OTC plant retirements at relatively modest costs, it is extremely important to understand that the modeling effort conducted for this study was limited in scope, capable of only taking a snapshot of the big picture, due to time constraints. Ideally, the modeling effort would have been expanded to thousands of runs examining each OTC plant in great detail, instead of the limited number of runs that were possible for this study.

Because of this limitation, the key recommendation arising from this study is that the industry must continue comprehensive study of the issue, examining the reliability implications of retirement of each plant individually and in combinations with all other plants, and constantly reassess the reliability implications of the Board's new policy as it is planned and enacted. Fortunately, such a study is now underway at the California Independent System Operator, with full participation by the state's water agencies, the energy industry, non-governmental organizations, and individuals. Cooperation amongst the agencies involved in shaping policy affecting the future reliability of the grid, including the Water Board and the energy agencies, is essential in assuring the Board's policy results in no impact to electric system reliability, nor to the environment.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT I

CAISO PRESENTATION TO THE CALIFORNIA COGENERATION COUNCIL ANNUAL MEETING

California ISO
Your Link to Power

California Cogeneration Council Annual Meeting

Jim Detmers

Vice President Operations

Don Fuller

Director Customer Services & Industry Affairs

October 21, 2009

Topics for Discussion

- Cogen/CHP role in renewables integration
- New market operation and planned additions
- Overcoming renewable resource challenges
- How can Cogen/CHP provide flexibility to assist with integration of environmental initiatives
- Open discussion

California ISO
Your Link to Power

Facilitating environmental initiatives will change how we operate – and Cogen/CHP can help

- CHP can provide efficient energy supply near load centers
- CHP can
  - Contribute to market competitiveness
  - Participate in new market products
  - Provide reliability service to integrate renewables
- If the facilities have…
  - Operational flexibility
  - Contractual flexibility

California ISO
Your Link to Power

New market features

- April 2009
  - Day ahead energy market
  - Pricing transparency through LMP design
  - Improved congestion management
- 2009-2011
  - Payment Acceleration
  - Standard Capacity Product
  - Proxy Demand Response
  - Scarcity Pricing
  - Convergence Bidding
- Under consideration
  - New products to integrate RPS initiatives

California ISO
Your Link to Power

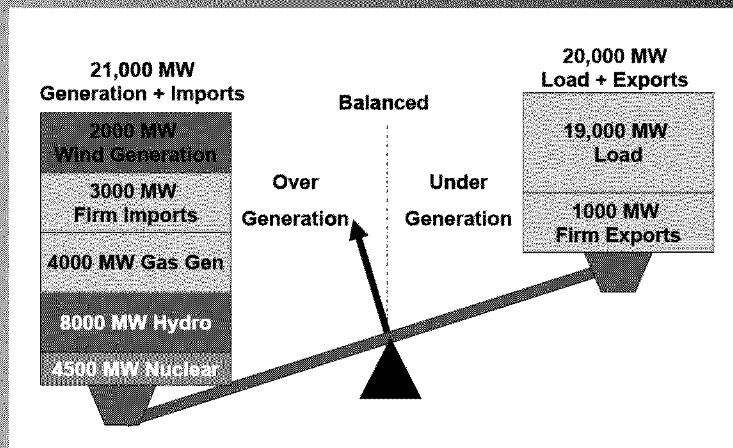
Market Operation since April 2009

- Day Ahead Integrated Forward Market has been stable and competive
- Market activity in the Residual Unit Commitment market has been minimal
- Real Time Market has been very competitive, higher than expected volatility in early months
- Local market power mitigation has been effective.
- Two areas for further improvement
  - Real Time price volatility
  - Use of Exceptional Dispatch

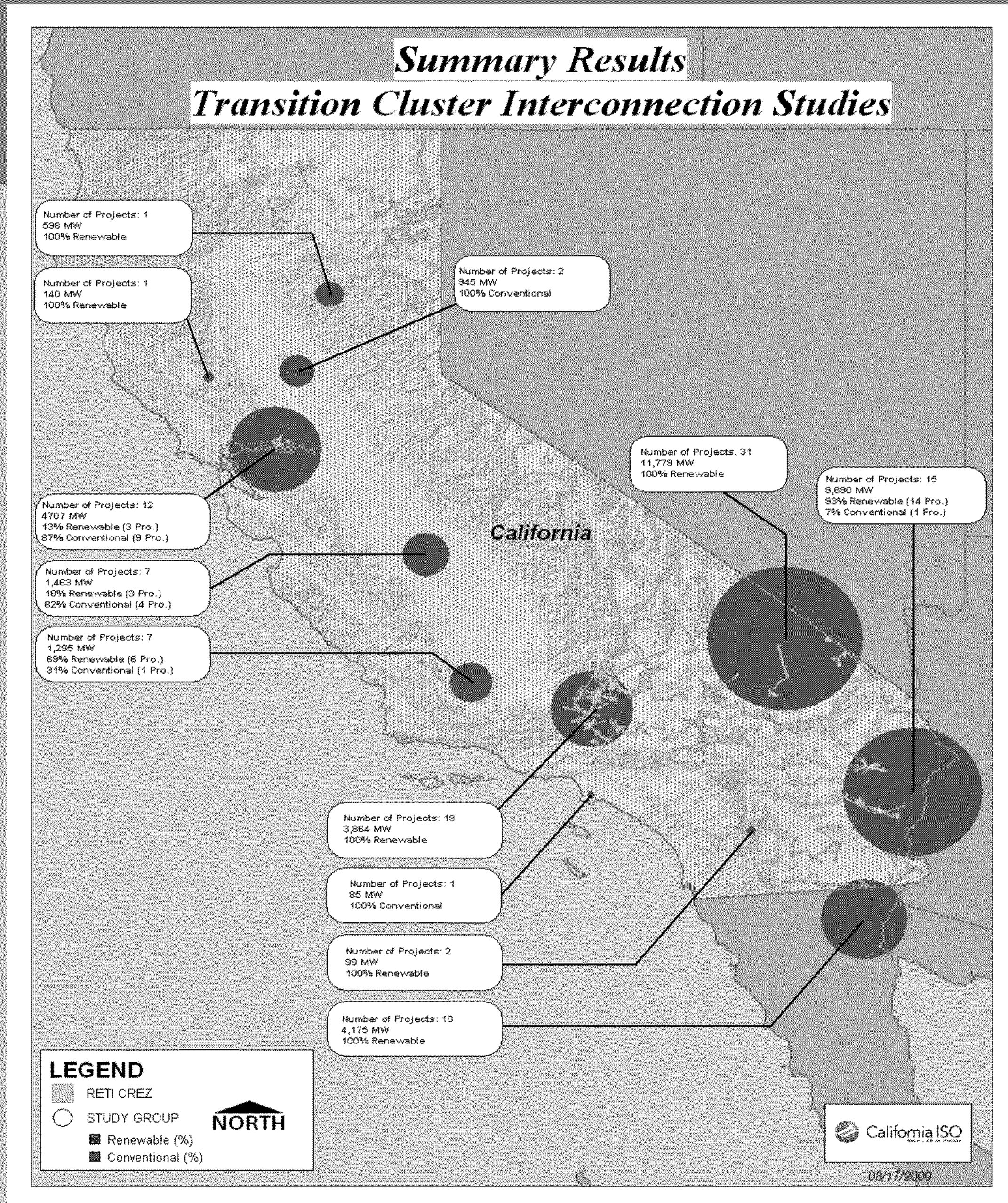
California ISO
Your Link to Power

CHP flexibility can help renewables integration operate

- Historically overgeneration occurs during early morning hours, minimum load, hydro runoff, etc.



- New renewable resources can contribute to overgeneration
- Renewable integration adds variability and uncertainty that we must manage <u>collectively</u>.



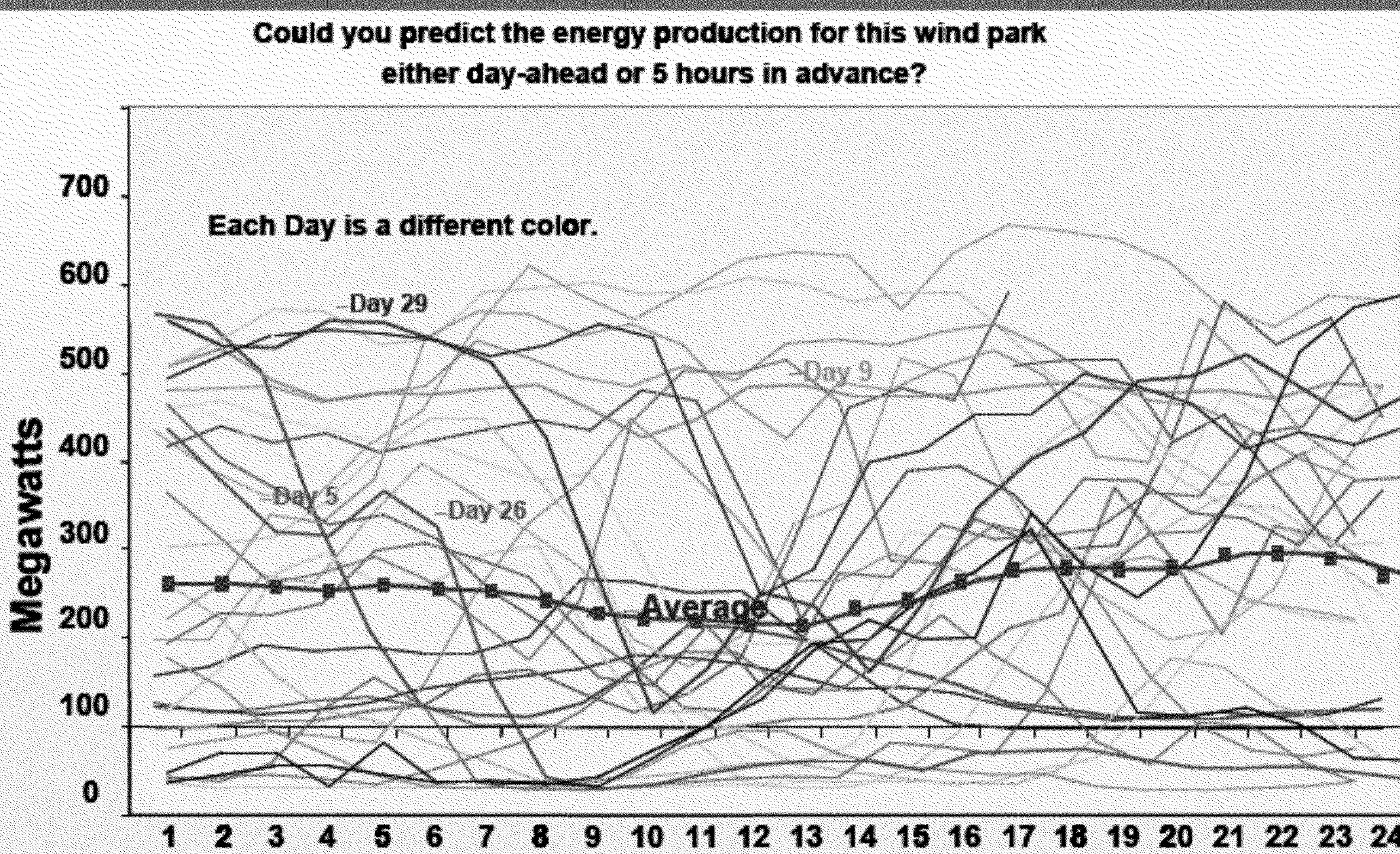
California ISO
Your Link to Power

Overcoming renewable resource challenges

- Variability – Output changes according to availability of primary fuel, resulting in fluctuations in all time scales
- Uncertainty – Magnitude and timing of variable output is less predictable, over supply, under supply
- System Security – ability of the system to withstand disturbances is compromised by lack of inertia of many renewable resource technologies
- Remoteness – located far from load centers, triggering a need for transmission access

Tehachapi Wind generation experienced during April 2005 illustrates variability & predictability

Tehachapi Wind Generation in April – 2005

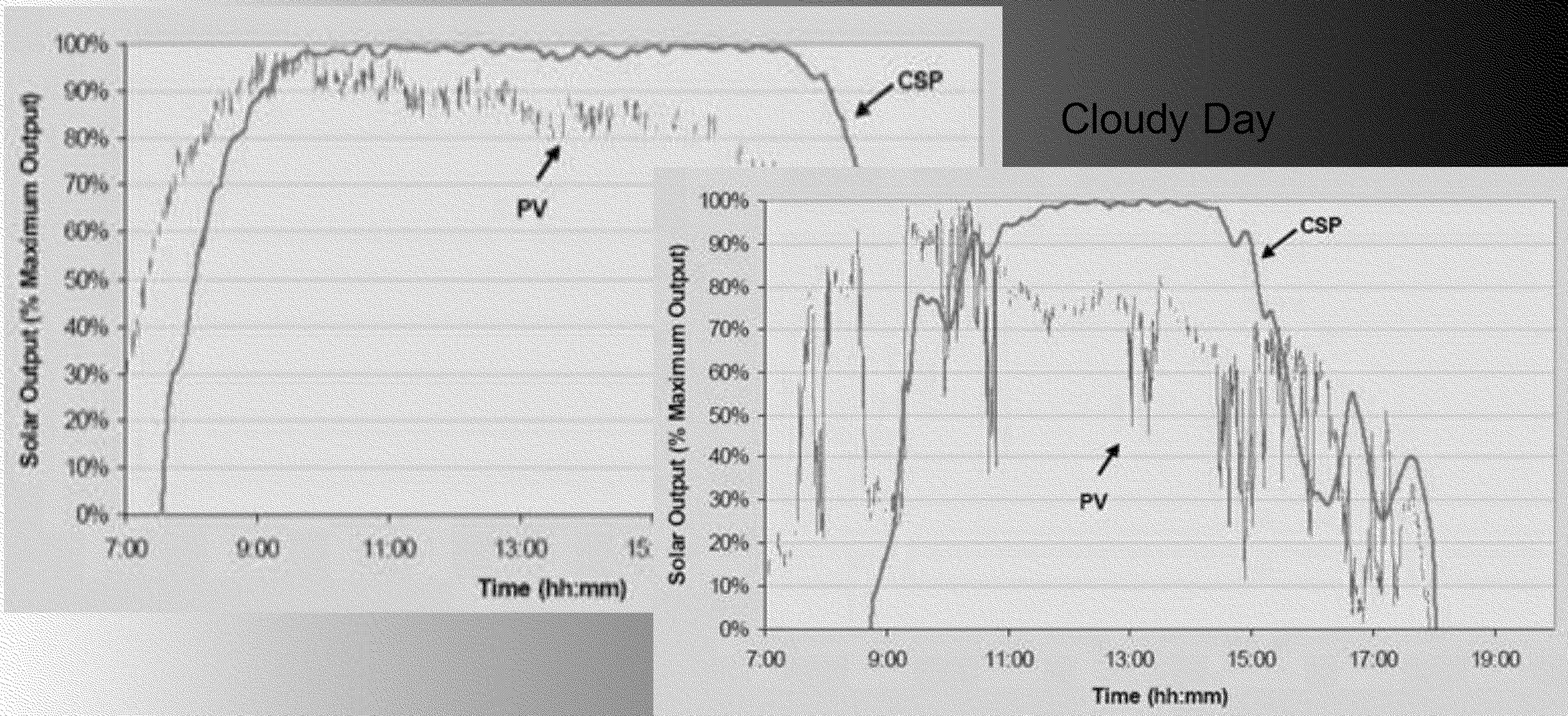


Your Link to Power

Solar Thermal (CSP) vs Photovoltaic (PV) Output

Sunny Day

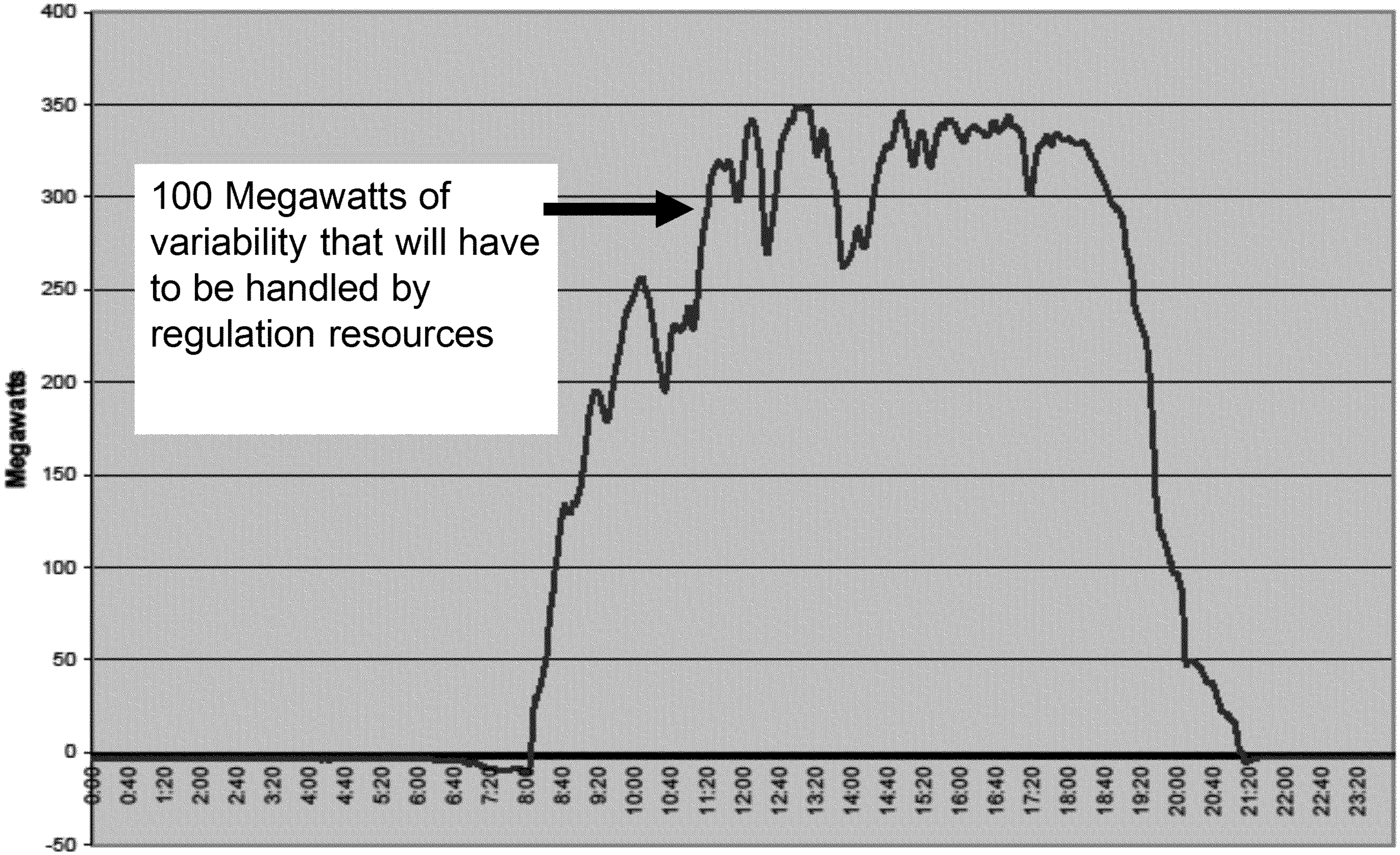
Cloudy Day



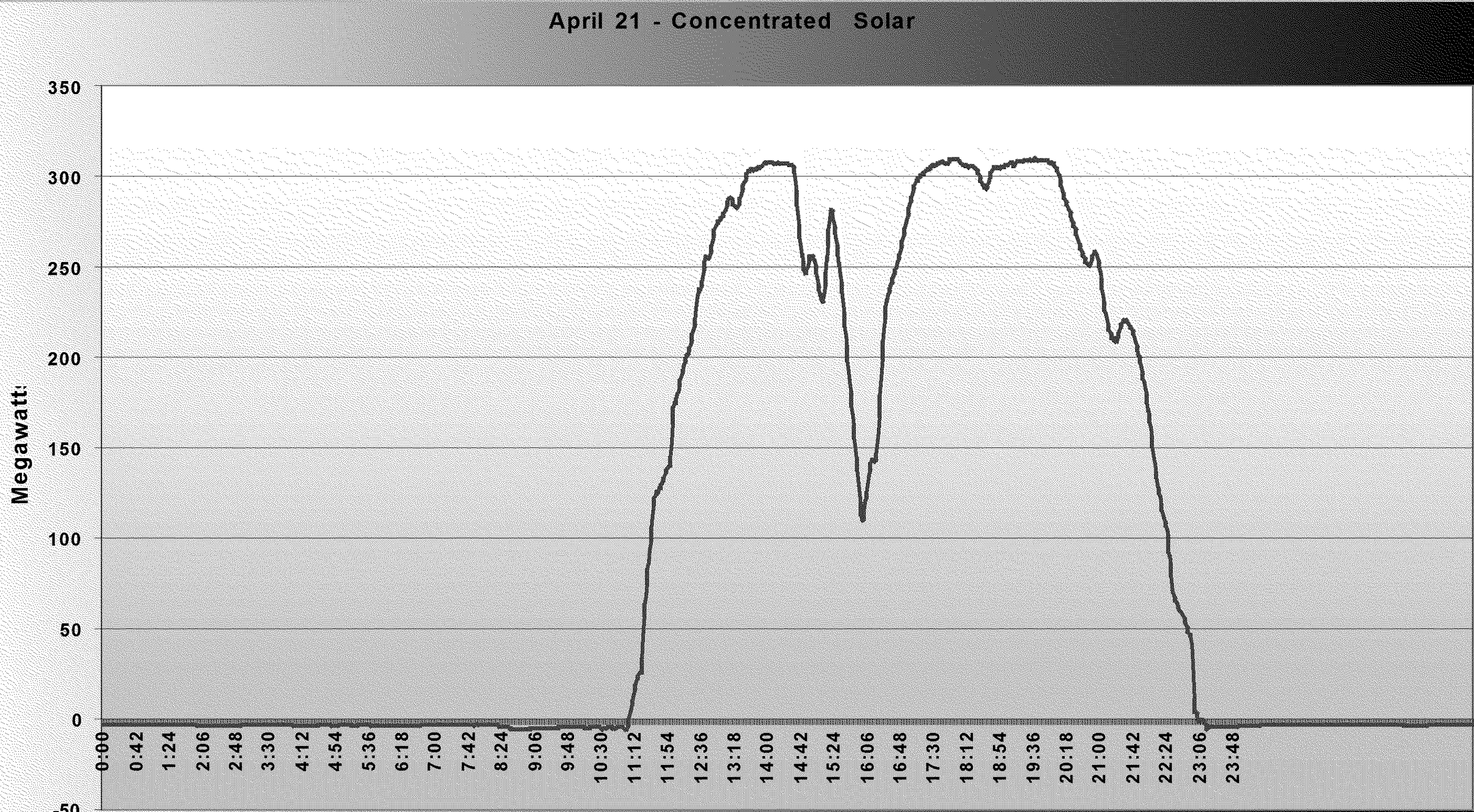
Source: Larry Stoddard, Black & Veatch

California ISO
Your Link to Power

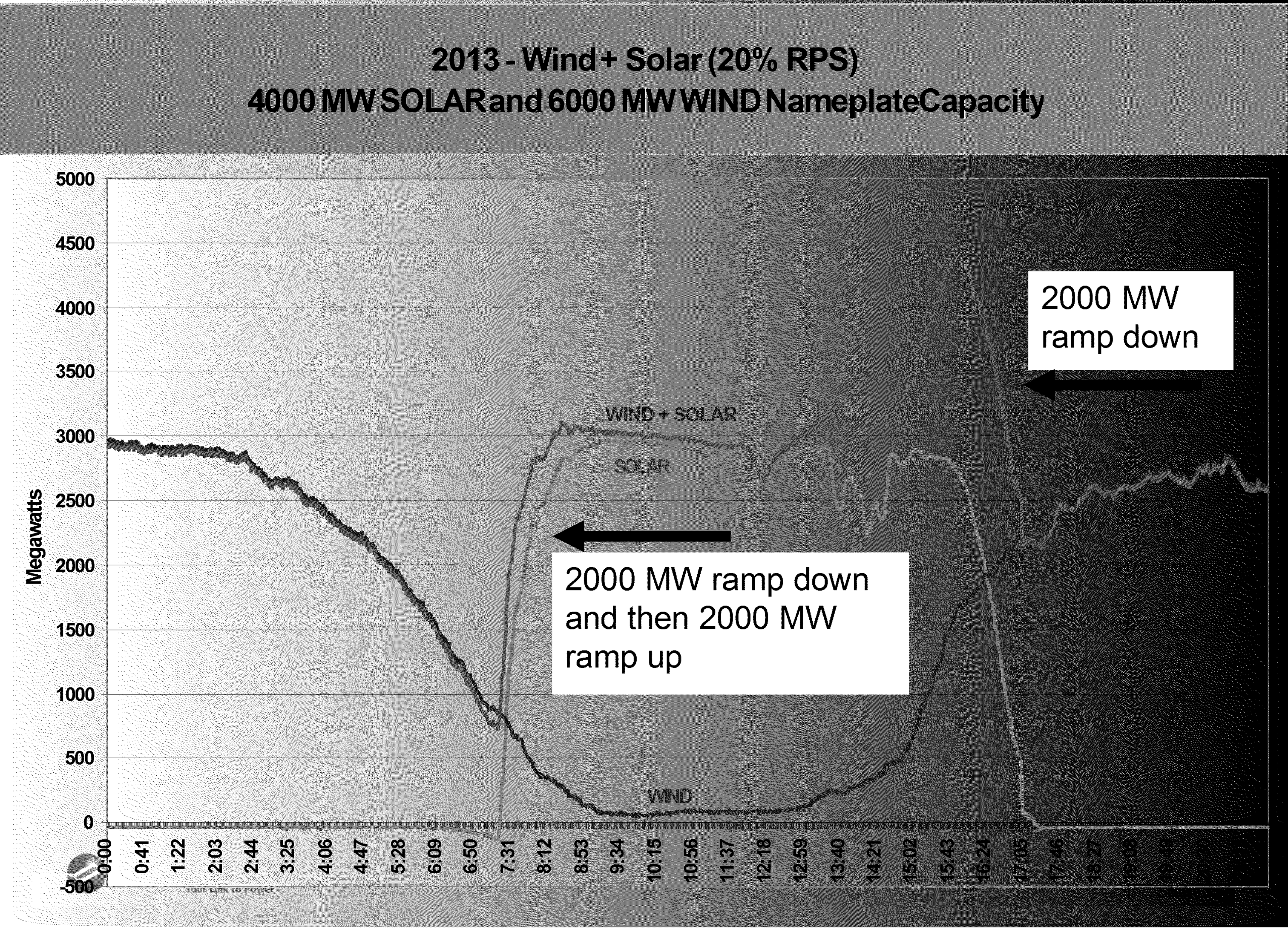
Illustration of the Variable Energy Production from Concentrated Solar



Variability of C. Solar – example 2



California ISO
Your Link to Power


2013 - Wind + Solar (20% RPS)
4000 MW SOLAR and 6000 MW WIND Nameplate Capacity
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
-500
Megawatts
0:00
0:41
1:22
2:03
2:44
3:25
4:06
4:47
5:28
6:09
6:50
7:31
8:12
8:53
9:34
10:15
10:56
11:37
12:18
12:59
13:40
14:21
15:02
15:43
16:24
17:05
17:46
18:27
19:08
19:49
WIND + SOLAR
SOLAR
WIND
2000 MW ramp down
2000 MW ramp down and then 2000 MW ramp up
Your Link to Power

QF PGA Flexibility for Cogen/CHP

- Participating Generator Agreement (PGA) Required for Generating Units 1 MW or Larger
- QF PGA Is Modified Version of PGA to Provide Special Treatment for QFs under CAISO Tariff
  - Net Metering (Aggregate Generation/Self-provided Load)
  - Telemetry Only of Net
  - Operating Limitations Honored
    - Minimum Operating Limit and Other Limitations Specified in QF Operating Instructions
    - CAISO Dispatch Only per Bids or System Emergency
    - No Damage to QF Equipment
    - No Penalty for Operation at Minimum Operating Limit Regardless of CAISO Final Schedule or Operating Order

The ISO must maintain reliability while facilitating environmental initiatives

- Renewable Integration
- Once Through Cooling Initiative
- New Products
  - Under development
- Working with CHP/Cogen
  - Understand operational flexibility and restrictions
  - Find common ground for enhancing participation
  - Maintain contractual flexibility

California ISO
Your Link to Power

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT J

CAISO FEBRUARY 1, 2010 LETTER TO THE CPUC REGARDING PG&E'S APPLICATIONS 09-10-022 AND 09-10-034 SEEKING APPROVAL OF CONTRACTS WITH GWF ENERGY LLC AND CALPINE CORPORATION

California ISO
Your Link to Power

California Independent
System Operator Corporation
Jim McIntosh
Director of Renewable Resource
Integration
(916) 351-2101

February 1, 2010

The Honorable Michael R. Peevey
President
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

The Honorable John A. Bohn
Commissioner
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

The Honorable Timothy Alan Simon
Commissioner
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

The Honorable Dian M. Grueneich
Commissioner
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

The Honorable Nancy E. Ryan
Commissioner
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: Application 09-10-022; Application 09-10-034
Pacific Gas and Electric Company Application for approval of contracts with GWF Energy LLC and Calpine Corporation

Dear President Peevey and Commissioners:

The California Independent System Operator Corporation (ISO) provides the following comments concerning the applications of Pacific Gas and Electric Company (PG&E) to enter into contracts with GWF Energy, LLC and Calpine Corporation. These contracts would support the development of generation resources with operational characteristics that will compliment the ISO's efforts to integrate increased number of renewable resources in the ISO balancing authority area. Apart from identifying the role these resources can play to support the integration of renewable resources, the ISO takes no position regarding the projected ratepayer value of the proposed contracts.

As the California Public Utilities Commission (CPUC) is aware, the ISO will have to manage the integration of many new renewable resources in the coming years as California moves towards the goal of obtaining 33% of its electricity from renewable resources.[1] The vast majority of these resources will be intermittent and require support from gas-fired generation. The ISO will need flexible gas-fired generation resources possessing quick start and significant ramping capability to integrate renewable resources and maintain grid reliability.[2] Consistent with this need, PG&E's proposed contracts with GWF and Calpine support the development of new resources or increased operating capacity from existing resources. By way of example, the Tracy Upgrade Project will result in resources with quick start capability, short minimum run times and the ability to provide ancillary services across a greater operating range than GWF's existing peaker located at Tracy. Once online, the Tracy combined cycle power plant will double its current capacity from 154 MWs to 300 MWs while improving its efficiency by roughly a third. In addition, the facility will provide some 65 MW of duct fired capacity, which increases the operating efficiency of the facility's capacity. The repowered unit will be able to make multiple starts per day and provide valuable ancillary services to the electricity grid. Similarly, the proposed contracts with Calpine will allow for the conversion of Calpine's Los Esteros Critical Energy Facility from combustion turbine units to a combined cycle facility. This repowering will provide the ISO with 106 MWs of additional capacity at Los Esteros. The proposed Calpine contracts also secure greater operating flexibility from existing resources in Calpine's California fleet. This flexibility will permit the ISO to dispatch these units to provide regulation service as well as firm the variable output from renewable resources.

The ISO will shortly be releasing its preliminary Phase I study to determine the amount, type, and location of the required additional generation resources necessary to support the goal of 33% renewable generation. This study examines the integration requirements for four different renewable portfolios and identifies an increased need for regulation and load following resources like the GWF and Calpine Upgrade projects. PG&E's proposed contracts with GWF and Calpine for the output from these projects, if approved by the Commission, would meaningfully contribute to satisfying this growing need. The ISO is willing to provide you and your staff with a briefing of these study results at your convenience.

[1] Executive Order S-21-09 states in part "That the ARB, under its AB 32 authority, shall adopt a regulation consistent with the 33 percent renewable energy target established in Executive Order S-14-08 by July 31, 2010" and "That the ARB shall consult with the [CAISO]... on, among other aspects, impacts on reliability, renewable integration requirements and interactions with wholesale power markets in carrying out the provisions of this Executive Order."

[2] The CAISO forecasts that a 33% renewable generation requirements will result in the addition of 3,200 MW of PV, 7,300 MW of solar thermal, 11,000 MW of wind, 2,400 MW of geothermal, 800 MW of small hydro and 1,000 MW of biogas.

Thank you for consideration of these comments. Please let me know if you have any questions.

Sincerely,

Jim B McIntosh

Jim McIntosh
Director of Renewable Resource Integration

cc: Service List Application 09-10-022 and Application 09-10-034

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT K

CAISO TARIFF ARTICLE 1 – GENERAL PROVISIONS,

SECTION 8 – ANCILLARY SERVICES

8. ANCILLARY SERVICES.

8.1 Scope.

The CAISO shall be responsible for ensuring that there are sufficient Ancillary Services available to maintain the reliability of the CAISO Controlled Grid consistent with NERC and WECC reliability standards, including any requirements of the NRC. The CAISO's Ancillary Services requirements may be self-provided by Scheduling Coordinators as further provided in the Business Practice Manuals. Those Ancillary Services which the CAISO requires to be available but which are not being self-provided will be competitively procured by the CAISO from Scheduling Coordinators in the Day-Ahead Market and the RTM consistent with Section 8.3. The provision of Ancillary Services from the Interties with interconnected Balancing Authority Areas is limited to Ancillary Services bid into the competitive procurement processes in the IFM and RTM. The CAISO will not accept Submissions to Self-Provide Ancillary Services that are imports to the CAISO Balancing Authority Area over the Interties with interconnected Balancing Authority Areas, except from Dynamic System Resources certified to provide Ancillary Services or if provided pursuant to ETCs, TORs or Converted Rights. The CAISO will calculate payments for Ancillary Services supplied by Scheduling Coordinators and charge the cost of Ancillary Services to Scheduling Coordinators based on their Ancillary Service Obligations.

For purposes of this CAISO Tariff, Ancillary Services are: (i) Regulation Up and Regulation Down, (ii) Spinning Reserve, (iii) Non-Spinning Reserve, (iv) Voltage Support, and (v) Black Start capability.

These services will be procured as stated in Section 8.3.5. Bids for Non-Spinning Reserve may be submitted by Scheduling Coordinators for Curtailable Demand as well as for Generation. Bids for Regulation, Spinning Reserve, Non-Spinning Reserve, and Voltage Support may be submitted by a Scheduling Coordinator for other non-generation resources that are capable of providing the specific service and that meet applicable Ancillary Service standards and technical requirements, as set forth in Sections 8.1 through 8.4, and are certified by the CAISO to provide Ancillary Services. The provision of Regulation, Spinning Reserve, Non-Spinning Reserve, and Voltage Support by other non-generation resources is subject to the same requirements applicable to other providers of these Ancillary Services, as set forth in Sections 8.5 through 8.11. Identification of specific services in this CAISO Tariff shall not preclude development of additional interconnected operation services over time. The CAISO and Market Participants will seek to develop additional categories of these unbundled services over time as the operation of the CAISO Controlled Grid matures or as required by regulatory authorities.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT L

IMPACT OF ASSEMBLY BILL 32 SCOPING PLAN ELECTRICITY RESOURCE GOALS ON NEW NATURAL GAS-FIRED GENERATION

CALIFORNIA ENERGY COMMISSION

IMPACT OF ASSEMBLY BILL 32 SCOPING PLAN ELECTRICITY RESOURCE GOALS ON NEW NATURAL GAS-FIRED GENERATION

STAFF REPORT

June 2009
CEC-200-2009-011

Arnold Schwarzenegger, *Governor*

Executive Summary

#$"&!&'( )*!"&!0+/'!.-!+!, (4"K+<%32*P%-./'!'.!-(/'$%/!(3)%/&'+3)!'$%/"3'%</+'".3!.-!</%+'%/!4/D%4&!.-!P/%3%9+:4/&!"3'.!?+4"-./3"+Q&P/4/2'/"2"'*!</")BM!+&&/&&/&!$.9!",04%,%3'+'".3!.-!'$%/%4/2'/"2"'*!P/&.(/2/d0.4"2"%&!2.3'+"3%)!"3!'$%/?+4"-./3"+!O"/!6%&.(/2/&!E.+/)Q&!O&&%, :4*!E"4!cS!eOE!cSf!e_h i%;8!?$+0'%/!^dd8!P'+'('%&!STTYf!B126+'($BC+&)($<3052&)$/1+&!9.(4)!+-%2'!3+'(/+4!<+&!(&/d+3)!<%3%/+'".3!P'+--!)%D%4.0%)!'$P%/d2+&/&5!.3%/d0/.D")%&!+!P%%%32%/d2+&/&!+3)!'$%/d.'$%/!'9.!+P/d\:..P%3)]!P/&'",+'%&B!#$%/d6%%%32%/d2+&/d).%&!3.'!"324()%/d'$%/dP2.0"3<!G4+3!0.4"2"%&!+3)!.34*!+&&(,%&!'$+'!'$%/dST!0%/2%3'!6%3%9+:4/dG./'-.4".!P'+3)+/)!"&!,%'!:*!STVS!&'+'%9")%B!#$%/d'9.!:..P%3)!2+&/&!"324()%/d'$%/dP2.0"3<!G4+3!G.4"2"%&!+&!9%4!+&!,%%'"3<!'$%/dcc!0%/2%3'!6%3%9+:4/&!G./'-.4".!P'+3)+/)!:*!STST!&'+'%9")%B!#$%/&/d'9.!:..P%3)!2+&/&!)"-%%)!"3!'$%/d+,.(3'!.-!9"3)!./!2%3'/+4!&'+'".3!&.4+/!'$+'!9+&!+))%)!'.!,%%'!+!cc!0%/2%3'!6%3%9+:4/&!G./'-.4".!P'+3)+/)!:*!STST!eL"<$!P.4+/!+3)!L"<$!="3)f!B!#$%/d&'()*!",04%,%3'&!+!2.,04"+32%/d0+'$!-./!'$%/dP'+'%/d=+'%/!6%/&.(/2/&!?.3'/.4!E.+/)Q&!0%3)"3<!0.4"2*!'.!P%)(2%/d'$%/d+)D%/&/d",0+2'&!.-!.32%K'$/.(<$!2..4"3<!-/.,!2.+&'+4!<+&K-"P%)!0.9%/!04+3'&B!="'$"3!'$%/&/d2.3&'/+"3'&!'$%/d&'()*!P%VV+,"3%/&!9$%'$%/!'$%/d'*0%/d.-!"3'%/,"''%3'!P%3%9+:4/&!+))%)!$+&!+!&"<3"-"2+3'!",0+2'!.3!'$%/d4.2+'".3!+3)!+,.(3'!.-!"32/%,%3'+4!3+'(/+4!<+&!<%3%/+'".3!3%/&)%)!'.!&/%/D%/d4.2+4!+/%+!+3)!"3%/'"+!/%j("/%,%3'&!.-!'$%/d&*&%,!

?+&%/dV&!'$%/d6%%%32%/d2+&/&!"&!+!&'+/'"3<!0."3'!-./!,%+&(/"3<!'$%/",0+2'&!.-!'$%/d'9.!:..P%3)!2+&/&!?+&/dS!L"<$!P.4+/!+3)!?+&/dc!L"<$!="3)B!?+&/dV!+&&(,%&!3.!+))"'".3+4!P2.0"3<!G4+3!0.4"2"%&!:%*.3)!'$.&/d"324()%)!"3!'$%/d?+4"-./3"+!>3%/<*!?.,,"&&".3Q&!M3'%</+'%)!>3%/<*!G.4"2*!6%0./'!eM>G6f!STTZ!)%,+3)!-./%2+&'B!M3!2.3'/+&'!?+&/dS!L"<$!P.4+/!+3)!?+&/dc!L"<$!="3)!"324()%/d'$%/dP2.0"3<!G4+3!0.4"2"%&!-./%3%/<*P%-"2"%32*!ec^8ZTZ!<"<+9+''!$.(/&!R=$mf8!2.,:"3%)!$%+'!+3)!0.9%/!ecS8cT^!R=$f8!+3)!/..-'.0!0$.'.D.4'+"2!e^8d^X!R=$f!"3!+))"'".3!'.!9$+'!"&!+4/%+)*!"324()%)!"3!'$%/d>3%/<*!?.,,"&&".3Q&!M>G6!STTZ!)%,+3)!-./%2+&'B!?+&/dV!+&&(,%&!+!ST!0%/2%3'!6%3%9+:4/&!G./'-.4".!P'+3)+/)!:*!STVS8!9$"4/d?+&/dS!L"<$!P.4+/!+3)!?+&/dc!L"<$!="3)!:("4)!(0.3!?+&/dV!+3)!+&&(,%/d+!cc!0%/2%3'!6%3%9+:4/&!G./'-.4".!P'+3)+/)!:*!STSTB!?+&/dV!+&&(,%&!+!STST!6%3%9+:4/&!G./'-.4".!P'+3)+/)!+33(+4!0/.2(/%,%3'!'+/<%'!.-!YV8dTT!R=$8!9$"4/d?+&/dS!L"<$!P.4+/!+3)!?+&/dc!L"<$!="3)!+&&(,%/d+3!+33(+4!0/.2(/%,%3'!'+/<%'!.-!Zd8TTT!R=$!:*!STSTB!?+&/dS!L"<$!P.4+/!"324()%&!+!4+/<%/!+,.(3'!.-!&.4+/!9$"4/d?+&/dc!L"<$!="3)!+))&!+!4+/<%/!+,.(3'!.-!9"3)B!#$%/d.32%K'$/.(<$!2..4"3<!2.,04"+32%/d04+3!"&!")%3'"2+4!"3!+44!'$/%/d2+&/&B

E*!+))"3<!&.!,+3*!)%,+3)K/%)(2"3<!0.4"2"%&!+3)!'$%/%:*!/%)(2"3<!'$%/d+,.(3'!.-!"32/%,%3'+4!/%3%9+:4/&!/%j("/%)!'.!/%+2$!cc!0%/2%3'!.-!/%'+"4!&+4/&8!.34*!^X8TTT!R=$!.-!"32/%,%3'+4!/%3%9+:4/&!9%/%/d+))%)!2.,0+/%)!'.!Z^8TTTgZX8TTT!R=$!+))%)!"3!&'()"%&!'$+'!).!3.'!"324()%/d'$%/dP2.0"3<!G4+3!3Q&!,%+&(/%&B!#$%/&/d"32/%,%3'+4!/%3%9+:4/&!+/%/d"3!+))"'".3!'.!'$%/dcc8TTT!R=$!/%3%9+:4/&!+4/%+)*!.3K4"3%/d'.!,%%'!?+4"-./3"+Q&!6%3%9+:4/&!G./'-.4".!P'+3)+/)B

#$%/d&'()*!-.(3)!'$+'!'$/%/&K"-'$&!.-!'$%/P%4/2'/"2"'*!&+D"3<&!",0+2'&!-/.,!+2$"%D"3<!P2.0"3<!G4+3!/%&.(/2%/d<.+4&!2+,%/d-/.,!P%3%/<*P%-"2"%32*8!/..-'.0!0$.'.D.4'+"28!+3)!2.,:"3%)!$%+'!+3)!0.9%/!9$"4/d'9.K"-'$&!.-!'$%/d&+D"3<&!2+,%/d-/.,!/%3%9+:4/&B!#$%/d2.,04%,%3'+/*!

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0/ . </+ , &! : . '$!&+D%) P%3%/<*!+3) !-4+' '%3%) !'$%/d&*&% , !0%+F!4. +)B!P'+'%9 ")%8!'$%/dSTST!0%+F!
)%, +3) !/%) (2'" . 3! . -!'$%8%/dP2. 0"3<!G4+3!< . +4&! 9 +&!VX!0%/2%3'!B

#$%/d&' ( ) *!- . (3) !'$+'!'$%/d0 . '%3'"+4!" , 0+2'&! . -!+))"3<!4+/<%/d+ , . (3'&! . -!"3'%/ , "''%3'!
/%3%9 + :4/&! . 3!3+' (/+4!<+&! (&%/d+3) !'$%/d'*0%/d . -!04+3'&!' . ! :%/d : ("4B!#$%/dP2. 0"3<!
&"<3"-"2+3'!)"/%2'!" , 0+2'&! . 3!3+' (/+4!<+&! (&%/d+3) !'$%/d'*0%/d . -!04+3'&!' . ! :%/d : ("4B!#$%/dP2. 0"3<!
G4+3Q&!/%3%/<*!&+D"3<&!'+/<%'&!'/+3&4+'%) !"3' . !+3!"32/%, %3'+4!^8ZTT! , %<+ 9 +''&!e@ = f! . -!
2. , :"3%) !$%+'!+3) !0 . 9%/BE*!STST8!ST!0%/2%3'! . -!+4!? +4"- . /3"+Q&!3+' (/+4!<+&! (&%) !- . /!0 . 9%/!
<%3%/+'" . 3! 9 +&!2 . 3&(, %) ! : *!2. , :"3%) !$%+'!+3) !0 . 9%/B!#$"&!+ , . (3'! . -!2. , :"3%) !$%+'!+3) !
0 . 9%/!/%) (2%) P/4/2'/"2"'*!&+4/&!' . P/3)K(&%/d2 (&' . , %/&! : ('!)")!3 . '!2/%+'%/d+!0/ . 0 . /'" . 3+4!
/%) (2'" . 3!"3!3+' (/+4!<+&! (&/BM!+4&. !+))%) !+!4+/<%/d+ , . (3'! . -! :+&/4. +) !<%3%/+'" . 3!' . !
P. ('$%/3! ? +4"- . /3"+8!&"32/d'$"&!"&! 9 $%/%/dYT!0%/2%3'! . -!0 . '%3'"+4!$. &'!&"'%&!- . /!4+/<%/d2. , :"3%) !
$%+'!+3) !0 . 9%/!+/%/d4. 2+'%)B!

#$%/d . 32/K'$/ . (<$!2. . 4"3<!0 . 4"2"%&!+4&. !+-%/2%) !'$%/d0 . '%3'"+4!" , 0+2'&! . -!"3'%/ , "''%3'!
/%3%9 + :4/&! :%2+ (&%/d , (2$! . -!'$%/d<%3%/+'" . 3!'$+'!3%/%)&!' . ! :%/d/%'/ . -"''%) ! . /!/%04+2%) !&%/D%&!
4. 2+4!- (32'" . 3&!'$+'!2 . 3'"3 (%/d' . ! :%/d&(0 0 . / '%) ! : *!<%3%/+'" . 3!4. 2+'%) !"3!4. 2+4!/%4"+ :"4"'*!+/%/+&B!
I -!'$%/dVX8TYU!@ = ! . -P/VV&'"3<! . 32/K'$/ . (<$!2. . 4"3<! (3"'&8!UY^!@ = ! 9%/%/d/%'+"3%)8!V8^XT!@ = !
$+D%/d/%2%3'4*! :%/3!/%0 . 9%/%)8!+3) !Z8ZXd!@ = ! 9%/%/d/%04+2%) ! 9"'$!3%98%-"2'%3'! (3"'&BE*!
STST8!)%0%3)"3<! . 3!'$%/d2+&/8! :%' 9%/%3!VV!+3) !Sc!0%/2%3'! . -!3+' (/+4!<+&K-"/%) !<%3%/+'" . 3!"3!
? +4"- . /3"+!"&!-/ . , !0 . 9%/!04+3'&!+&&. 2"+'%) ! 9"'$!'$%/d . 32/K'$/ . (<$!2. . 4"3<!"&&(%B! I 32%/d
2. , :"3%) !$%+'!+3) !0 . 9%/!'+/<%'&!+3) ! . 32/K'$/ . (<$!2. . 4"3<!/%04+2%, %3'&! 9%/%/d , +)%8! . 34*!
+!-%9 !3%9 !3+' (/+4!<+&!04+3'&!$+) !' . ! , %/%'!4. 2+4!2+0+2"'*!+3) P/%3%/<*!3%/%)&B!
#$. &%/d 9%/%/d"3!'$%/dP+2/+ , %3' . !@ (3"2"0+4! ` '"4"'*!H"&'/"2'8!# (/4. 2FM/"<+'" . 3!H"&'/"2'8!+3) !
M, 0%/"+4! J+4/%*!2. 3'/ . 4!+/%+&8! 9 $"2$!$+D%/d3 . ! . 32/K'$/ . (<$!2. . 4"3<! (3"'&!+3) !4" , "'%) !4+/<%/d
$. &'!&!- . /!3%9 !2. , :"3%) !$%+'!+3) !0 . 9%/B!

#$%/d+ , . (3'! . -!3+' (/+4!<+&! (3"'&!+))%) !)")!3 . '!2$+3<%/d :%' 9%/%3!'$%/d :+&%/d2+&%/d+3) !'$%/d' 9 . !cc!
0%/2%3'!2+&%/&B!#$"&!&(<<%/&'&!'$+'!'$%/d2. , :"3%) !$%+'!+3) !0 . 9%/!+))"'" . 3&!+3) !'$. &%/d(&%) !- . /!
. 32/K'$/ . (<$!2. . 4"3<!0 . 4"2"%&!0/ . D"'%) !&(--"2"%3'!<+&!-4/VV' :"4"'*!&. !'$+'! , . /%/d (3"'&! 9%/%/d3 . '!
3%/%)%) P/D%3!"3!'$%/d , . /%/d"3'%/ , "''%3'! 9"3) !2+&%/&BE ('!'$%/d2+0+2"'*!-+2' . /&!- . /!<%3%/+'"2!
+))"'" . 3&!+3) ! . 32/K'$/ . (<$!2. . 4"3<!/%04+2%, %3'!2. , :"3%) !2*24/&8! 9 $"2$!&'+/'! . ('!+'!3 . / , +4!
:+&%/4. +) !4/D%/4&8!) / . 0!' . ! , (2$!4. 9%/!4/D%/4&! : *!STST!- . /!? +&%/dS!+3) !c8! , +F"3<!'$%/d4. 3<K/ (3!
2. &'K%-%2'"D%/3%&&! . -!'$%/&%/d2. , :"3%) !2*24/&! j (%&'" . 3+ :4/B!#$"&!&(<<%/&'&!'$+'!'$%/d&+ , 04%/d
2. , 04"+32%/d0+'$! (&%) !"3!'$"&!' ( ) *! 9 +&!3 . '!0'" , +4!"-!'$%/d4+/<%/d+ , . (3'! . -!2. , :"3%) !$%+'!
+3) !0 . 9%/! : +&%/4. +) !"&!+))%)B!#$ (&8!+!P/%*!-"3) "3<! . -!'$%/&%/d0 . 4"2"%&!
&$. (4) ! :%/d+&&%/&&%) !"3!"&. 4+'" . 3B!#. !'%&'!'$%/&%/d2. 324(&" . 3&8!+))"'" . 3+4! , .)%4"/ (3&!2. (4) ! :%/d
) . 3%/d'$+'!4. 9%/!'$%/d+ , . (3'! . -! , (&'K+P/d2. , :"3%) !$%+'!+3) !0 . 9%/!+3) !&. 9 "'2$!&. , %/d . -!'$%/d
. 32/K'$/ . (<$!2. . 4"3<!2. , :"3%) !2*24/&!' . !2. , : (&'" . 3!' (/ :"3%&B!

N . /!/4/2'/"2"'*!<%3%/+'" . 3&!'$%/d =%/&%/3!>4/2'/"2"'*!? . . /)"3+'"3<!? . (32"4K9 ")%/d+ , . (3'! . -!
3+' (/+4!<+&!)")!) %/2/%+&%/d : *!VX!0%/2%3'!"3! : . '$!- (4!P2. 0"3<!G4+3!2+&%/&!) (%/d' . !'$%/d
2. 3'/" : ('" . 3&! . -/%3%/<*!/%-"2"%32*8!/ . . -' . 0!0$. ' . D . 4'+"2&8!/%3%9 + :4/&!+3) !2. , :"3%) !$%+'!+3) !
0 . 9%/B!

!

6%) (2'" . 3&! 9%/%/d3 . '!) "&'/" : ('%) P/D/%34*k!+'!4/%+&'!ZT!0%/2%3 '! . -!'$%d<+&!/%) (2'" . 3&! . 22 (/ /%) !
. ('K. -K&'+'%BM3K&'+'%d<+&K-"/%) !<%3%/+'" . 3! 9%3'!) . 9 3! . 34*! : *!VT!0%/2%3 '!"3!'$%d L"<$! = "3) !
2+&%d+3) !Vc!0%/2%3 '!"3!'$%d L"<$!P.4+/!2+&%BM3!2. 3'/+&'8! . ('K. -K&'+'%d<+&K-"/%) !<%3%/+'" . 3!
) / . 00%) !SV!+3) !ST!0%/2%3 '8!/%&0%/2'"D/%4*B!#$"&!&(<<%/&'&!'$+'! . ('K. -K&'+'%d3+' (/+4!<+&!"&!'$%d
, +/<"3+4!/%&. (/2%d+3) !'$+'!"3K&'+'%d<+&!"&! (&%) !-. /!4. 2+4!/%4"+ : "4"' *! . /!+32"44+/ * !&%/D"2%&BM3!
'$%dST!0%/2%3 '!2+&%8! , . /%d'$+3!$+4-! . -!+4!3+' (/+4!<+&! (&%d-. /!P/4%2'/"2!<%3%/+'" . 3!"&! . ('K. -K
&'+'%BM3!'$%dP2. 0"3<!G4+3!2+&%&8!<+&! (&%d"&!P/D/%34*!) "D")%) ! :%' 9%%3!"3K&'+'%d+3) ! . ('K. -K&'+'%B

= "'$!'$%/&%d0/%%/ /%) !/%&. (/2%d0 .4"2"%&! : ("4'!"38!'$%d) "--%/%32%/&! :%' 9%%3!'$%d?+&%dc! L"<$!
= "3) !+3) !?+&%dS! L"<$!P.4+/!2+&%&! 9%/%d , . /%d , .)%&'!'$+3!'$%*!9 . (4) !$+D%d :%%3!$+) !4%&&!
+ , : "'". (&!2. , 04%, %3'+/*!0/. </+ , &! :%%3!+&&%/&&%) B!#$%d&' ( ) *!-. (3) !'$+'5!

O!/%&. (/2%d , 'W! 9"'$!+!$"<$!0/. 0. /'" . 3! . -!9"3) !/%j ("/%) ! , . /%d"3K&'+'%d3+' (/+4!<+&!
<%3%/+'" . 3!'$+3!?+&%dS! L"<$!P.4+/!) ")B!#$%d L"<$! = "3) !2+&%d"324( )%) ! , . /%d 9"3) !/%3%/<*!
'$+3!+3!%j ("D+4%3'!+ , . (3'! . -!&.4+/!"3!'$%d L"<$!P.4+/!2+&%B!#$"&!"&!2. 3&"&'%3'!9"'$!'$%d
3%%) !' . ! (&%d<+&K-"/%) ! (3"'&!-. /!4. 2+4!/%4"+ : "4"' *!+3) !'$%/P/V0%/2'+'" . 3!'$+'!9"3) !3%%) &! , . /%d
"3%/ , "''%32*!&(00 . /'!'$+3!) .%&!&.4+/!) (%d' . !"'&!) +"4*!4. +) !0/. -"4%d+3) !</%+'%/!
D+/"+ : "4"' *B!

@. /%d" , 0+2'&! 9%/%d&%%3!"3!P. ('$%/3!?+4"-. /3"+!'$+3!_ . /'$%/3!?+4"-. /3"+B! = $"4%d 9"3) !"&!
) "&'/" : ('%) !+2/ . &&!'$%d&'+'%8!&.4+/!/%&. (/2%&!+/%d+4 , . &'!2. , 04%'%4*!2. 32%3'/+'%) !"3!
P. ('$%/3!?+4"-. /3"+B! I 32%/K'$/. (<$!2. .4"3<! (3"'&!+3) !0. '%3'"+4!2. , : "3%) !$%+'!+3) !
0 . 9%/!&"'%&!+/%d+4&. !2. 32%3'/+'%) !"3!'$%dP. ('$B!#$"&!"3) "2+'%&!'$+'!'$%/%d , +*! :%d , . /%d
&*&'%, !" , 0+2'&!+3) !0. '%3'"+4!&*&'%, !&'/%&&. /&!"3!'$%d&. ('$%/3!'/+3& , "&&". 3!</")B!

!

= $"4%d<+&! (&%) !-. /!&%/D"3<!/%'+"4!4. +) !) / . 00%) 8!' . '+4!<+&! (&%d) ") !"32/%+&%BO&D/01,()&$. 9&!
:%' 9%%3!STVS!+3) !STST8!' . '+4!3+' (/+4!<+&!2. 3&(, 0'". 3!/ . &%d&4"<$'4*!"3!+44!2+&%&B!#$%d
"32/%+&%&!"3!?+&%dS!+3) !?+&%dc! 9%/%d , . /%d , .)%&'! : ('!3 . 3%'$%4%&&!"32/%+&%) !+&!4+/<%d
+ , . (3'&! . -!2. , : "3%) !$%+'!+3) !0 . 9%/8!+4!-(%4%) ! : *!3+' (/+4!<+&8! 9%/%d+))%) !' . !'$%d&*&'%, B!
#$.&%d"32/%+&%&! 9%/%d4%&&!"3!'$%d L"<$!P.4+/!2+&%d'$+3!"3!'$%d L"<$! = "3) !2+&%d 9 $%3!2. , 0+/%) !
' . !'$%d6%/%/%32%d2+&%B!

Table 1: California Natural Gas Use (BCF/day)

!	2012	2016	2020	2020 Change From Case 1
Case 1 Reference Case RPS	2.36	2.57	2.88	
Case 2 High Solar	2.34	2.45	2.52	-12%
Case 3 High Wind	2.34	2.48	2.60	-10%

Source: Energy Commission, Electricity Analysis Office

6%&(4'&!-/. , !'$"&!&' ( ) *!+/%d"3) "2+'"D%d : ('!+/%d4" , "'%) ! : . '$! : *!'$%d+&&(, 0'". 3&! (&%) !+3) !'$%d
-+2'!'$+'!'$%d , .)%4!&'+--! (&%) !) .%&!3 . '!"32. /0. /+'%d"3'%</+'%) !4. 2+4!+/%+!-(32'". 3&!+3) !
/+ , 0"3<!2. 3&'/+"3'&BM&!-"3) "3<&!9 . (4) !3%%) !' . ! :%d'%&'%) !9"'$! , . /%d&%3&"'"D"'%&!+3) !9"'$!
. '$%/! , .)%4&B!

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Table 5: Impact of AB 32 Complementary Policies on Derivation of Incremental Renewables Needed in 2020 (GWh)

		2020 GWh
1	Statewide Net Energy for Load (Used in Production Cost Modeling)	341,755
2	Statewide Losses	21,387
3	LSE Statewide Retail Sales (line 1 – line 2)	320,368
4	Non-RPS Deliveries (CDWR, WAPA and MWD)	12,299
5	Adjusted Retail Sales for RPS Calculation (line 3 – line 4)	308,069
6	AB 32 EE Beyond Amount in Energy Commission Forecast	34,707
7	AB 32 CHP Beyond Amount in Energy Commission Forecast	32,304
8	AB 32 Rooftop PV Beyond Amount in Energy Commission Forecast	4,845
9	Adjusted Retail Sales for 33% AB 32 RPS Calculation (line 5 – 6,7,8)	236,213
10	Renewable Energy Needed for 33% (33% of Line 9)	77,950
11	Existing Renewable Energy as of 12/31/2008	32,469
12	33% Renewable Net Short (Cases 2 and 3 (line 10- Line11))	45,481

Source: Energy Commission staff, compiled from California Energy Demand 2008–2018 Staff Revised Forecast CEC-200-2007-015SF. Forecast extended to 2020 by Energy Commission staff. The actual rooftop PV, EE and CHP impacts in AB 32 Scoping Plan for 2020 are 4,500, 32,000 and 30,000 GWh, respectively. To these estimates the ARB Scoping Plan adds an amount to account for transmission line losses. Existing renewables based on 2008 production cost model simulation results (29,780 GWh) and eligible renewable generation for regions outside California (2,689 GWh).

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Impacts of Incremental Combined Heat and Power

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Table 7: New CHP and California Natural Gas Use in 2020—Case 2 High Solar

Region	Installed New CHP (MW)	New CHP Fuel Use (GBtu)	New CHP Generation (GWh)	All Natural Gas Fuel Use (GBtu)	All Natural Gas Generation (GWh)	Percent of CHP to Total NG Fuel Use	Percent of CHP to Total NG Generation
LADWP	195	7,538	1,313	78,334	10,042	10%	13%
Northern CA	1,750	70,495	11,532	349,923	42,835	20%	27%
San Diego	319	12,191	2,067	78,775	10,830	17%	21%
SMUD	75	3,261	542	70,080	9,818	5%	6%
Southern CA	2,390	95,919	16,041	371,740	48,629	26%	33%
Combined Total	4,730	189,404	31,495	948,852	122,155	20%	26%

Source: Energy Commission, Electricity Analysis Office

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Impact of Modifying Once-Through Cooling Generation

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PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT M

CAISO RENEWABLE RESOURCES AND THE CALIFORNIA ELECTRIC POWER INDUSTRY: SYSTEM OPERATIONS, WHOLESALE MARKETS AND GRID PLANNING

California Independent
System Operator Corporation

California ISO

Renewable Resources and the California Electric Power Industry: System Operations, Wholesale Markets and Grid Planning

July 20, 2009

Prepared by: California ISO

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and deploying these and other new tools and technologies is critical. Similarly, it will require an extraordinary effort to transform the electric transmission system and drive significant changes in how the ISO operates the system in compliance with federal reliability standards. Complicating the integration effort are other important environmental objectives such as limiting the use of once-through cooling (OTC) technology in coastal power plants and reducing air emissions in southern California. This paper discusses the range of technology, market and transmission infrastructure issues so essential to the state's success in this critical effort.

3) Renewables in the California Resource Mix to 2020

For perspective on the magnitude of the investment to achieve current and proposed RPS goals and the potential implications of cap and trade or other carbon pricing mechanisms, once-through-cooling limitations, and other policy choices, it is helpful to understand the current resource mix used to meet California's system needs. The following table, developed by the CEC, summarizes the sources of total system electric energy for the state in 2008.

2008 Total System Electric Energy in Gigawatt Hours					
Fuel Type	**In-State Generation[1]**	**Northwest Imports[2]**	**Southwest Imports[2]**	**Total System Power**	**Percent of Total System Power**
Coal*	3,977	8,581	43,271	55,829	18.2%
Large Hydro	21,040	9,334	3,359	33,733	11.0%
Natural Gas	122,216	2,939	15,060	140,215	45.7%
Nuclear	32,482	747	11,039	44,268	14.5%
Renewables	28,804	2,344	1,384	32,532	10.6%
Biomass	5,720	654	3	6,377	2.1%
Geothermal	12,907	0	755	13,662	4.5%
Small Hydro	3,729	674	13	4,416	1.4%
Solar	724	0	22	746	0.2%
Wind	5,724	1,016	591	7,331	2.4%
Total	**208,519**	**23,945**	**74,113**	**306,577**	**100.0%**

Note: In earlier years, the in-state coal number included coal fired power plants owned by California utilities located out-of-state.

1. In-state generation: Reported generation from units 1 MW and larger.
2. Net electricity imports are based on metered power flows between California and out-of-state balancing authorities.
3. The resource mix is based on utility power source disclosure claims, contract information and calculated estimates on the remaining balance of net imports.

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In 2008, the three large IOUs supplied approximately 13.7 percent of their total sales from eligible renewable resources.[5] Even accounting for the economic downturn, it is clear that California utilities must nearly double the quantity of energy supplied from renewable resources simply to meet the near-term 20 percent RPS target. The CPUC has acknowledged that the gap between the current contribution from renewable resources and the statutory objective is unlikely to close until 2012-2013,[6] assuming that generation under contract actually materializes. .

Total Expected Renewable Deliveries from Contracts Signed Since 2002, by Technology (minimum GWh)

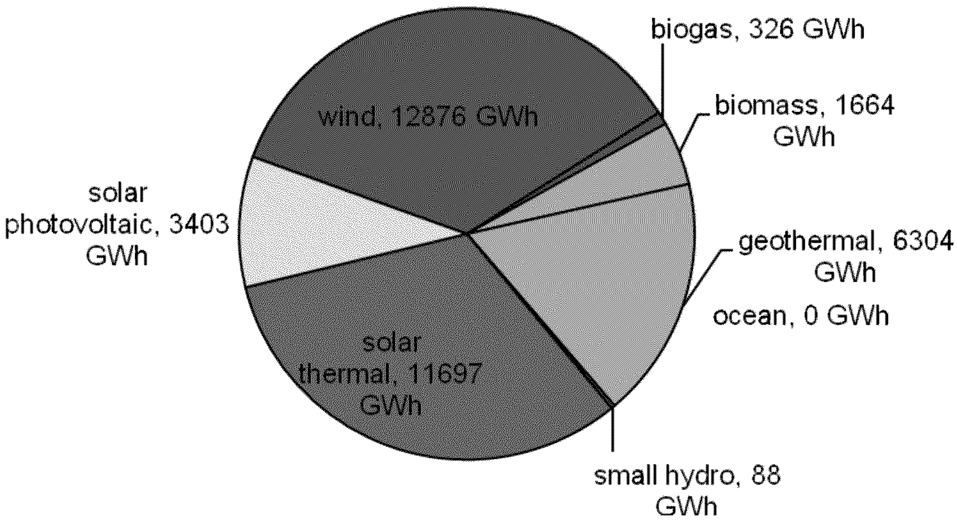

Figure1 [7]

The current IOU renewables contracts include substantial technological and geographic diversity. As shown in Figure 1 above, wind and solar resources represent roughly equal components of the total capacity under contract, with nearly 50 percent of the total wind capacity under contract from out-of-state resources. Only 14 percent of the overall amount under contract is online and incorporated into the energy output calculated in Figure 2.[8]

From a system operations perspective, the geographic and technological diversity of the contracted resources provides benefits by reducing the variability of the renewable

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[5] See http://www.cpuc.ca.gov/NR/rdonlyres/9BFE4B8B-BBD7-405D-A58A-0155083578E7/0/090210CPUCPresentationforSenEUChearingofSB14.pdf

[6] See http://docs.cpuc.ca.gov/word_pdf/REPORT/85936.pdf

[7] The source for Figure 2 is the CEC at http://www.energy.ca.gov/portfolio/contracts_database.html.

[8] See http://www.energy.ca.gov/portfolio/contracts_database.html.

resources. Diversity mitigates variability to some extent because wind and solar radiation patterns vary over large geographic regions and while wind production peaks at night on average, solar resources peak during the day (although not at peak demand hours during some times of year in California). However, as noted by the CPUC, the heavy reliance on largely untested, but transformational, technology, in the portfolios currently under contract such as solar thermal resources, contributes to implementation delays and may not strike the correct balance between in-state job creation and consumer costs.

To establish an analytical framework to evaluate policy considerations and provide an initial quantitative analysis of the costs and risks of alternative means of achieving a 33 percent RPS by 2020, including timing considerations, the CPUC has developed and studied four possible renewable resource portfolios scenarios:[9]

- **33 percent RPS Reference Case** – This represents current renewable procurement practices, which include significant reliance on solar thermal technologies.
- **High Wind Case** – This demonstrates less reliance on in-state solar and more reliance on wind.
- **High Out-Of-State Delivered Case** – This places greater reliance on out-of-state renewable resources and includes the construction of new transmission lines to deliver the energy to California. This scenario does not assume the ability to use tradable RECs to meet RPS obligations.
- **High Distributed Generation Case** – This relies on large penetrations of smaller-scale renewable generation connected at the distribution level.

The underlying resource mix will have a profound impact on achieving California's policy objectives. Each resource strategy performs differently when measured against regulatory or policy criteria, including local air quality, land use impacts, cost minimization and timing of implementation. For example, as evaluated by the CPUC, the high distributed generation case has cost and operational reliability considerations that are not well understood, but it would reduce the need for high-voltage transmission infrastructure and its potential political and environmental risks. In contrast, the high wind case may trigger operational concerns due to substantial over-production in the off-peak hours. Integrating renewables under this scenario would require significant coordination with energy efficiency and storage technologies (see discussion below), to shift energy consumption to periods of high wind production.

The ISO is currently updating existing and developing new statistical and production simulation methodologies to evaluate these portfolios. Some of this analysis will help state agencies clarify their own objectives in the transition from 20 percent to 33 percent RPS. The focus of this analysis is both the operational requirements that the portfolios are likely to entail (see discussion in the next section) as well as determining the portfolio of generation resources and integration technologies that would be most cost-effective. As discussed in the transmission planning section, the ISO is also engaged with renewable transmission planning to achieve the 33 percent RPS.

[9] This report can be found at http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT N

2009 INTEGRATED ENERGY POLICY REPORT,

FINAL COMMISSION REPORT

[redacted]

and 2020, but a net decrease of 11,000 GWhs of in-state gas-fired generation. The different result in the two studies was the result of different modeling assumptions; for example, the Energy Commission study included local reserve and area reliability requirements, including publicly owned utility reserve requirements for new gas-fired capacity needed to modernize the OTC fleet. In addition, the Energy Commission study included 32,000 GWhs of gas-fired CHP, consistent with the target in the ARB's *Climate Change Scoping Plan*, while the ICF study did not add any CHP. Finally, ICF assumed that total natural gas use in the WECC would rise over the forecast period and that California would import more power generated using natural gas, but that the increase in total in-state use would exceed any increase in imports.

The Energy Commission's study results indicate that at least three areas deserve further research because of the affect of study assumptions on the type of proxy generation needed to firm and back up intermittent renewables. First, alternative levels of CHP should be tested, since the addition of baseload power in-state and in Southern California may be difficult to achieve with existing emission credit problems and the lack of a mechanism to make it happen. Second, alternative assumptions about compliance with OTC mitigation requirements should be tested because the interactions of all the *Climate Change Scoping Plan* programs lead to unrealistic capacity factors in the replacement of OTC combined cycles by 2020.

Finally, the possibility of overgeneration, a condition when more generation is provided than there is available load, will require additional analysis. In the June 29, 2009, IEPR Committee workshop on renewable integrating issues, SCE reported that a Nexant study suggests a possible overgeneration problem in April and May as the state moves to 2020 if there is high solar incidence in the desert, high generation of wind, and the need to spill water stored in dams to make room for snow melt. In addition, parties at the July 23, 2009 IEPR workshop on CHP issues noted the risk of overgeneration when large amounts of both renewables and CHP are added to the system mix.

Role of Energy Storage

To the extent that natural gas remains a low-cost fuel, gas-fired generation can help the electricity system absorb the costs of transitioning to higher levels of renewable energy. However, looking forward, some of the firming services provided by gas-fired generation will need to come from existing and emerging energy storage technologies that allow generators and transmission operators to fill the gap between the time of generation (off-peak) and the time of need (on-peak) for intermittent renewable energy. Energy storage systems can respond quickly – in less than a second – to the needs of the electric grid system when compared to conventional gas-fired generation, which takes minutes to tens of minutes, and potentially reduce the overall amount of energy needed to balance the system needs. The fast response of energy storage also suits the variability of renewable energy systems such as wind, and this combination can allow grid operators to use increased levels of renewable energy and still maintain desired levels of reliability and control.

Examples of energy storage technologies commercially available and under development include advanced technology batteries, flywheels, compressed air energy storage, pumped hydroelectric energy storage, capacitors, and others. These technologies can provide value at each level in California's electric grid – generation, transmission and distribution, and end use – with storage technologies varying in type and size depending on the level of service needed. Generation-level energy storage focuses on the ancillary services market[233] and renewable integration, with grid frequency regulation becoming an area of interest of substantial technological advancements over the last few years. Storage at the transmission and distribution level focuses on load shifting, transmission congestion relief, reliability, and capital deferral. For end users, storage at commercial and industrial facilities can provide peak shaving, electricity backup, and increased reliability.

Energy storage continues to be one of the more promising application areas to make renewable generation available when needed. Energy storage technologies will allow better matching of renewable generation with electricity needs as well as address the severe ramping rates observed with wind and PV. The use of energy storage technologies can also reduce the number and amount of natural gas-fired power plants that would otherwise be needed to provide the firming characteristics the system needs to operate reliably. Energy storage systems can respond rapidly to the needs of the electric grid, and Energy Commission research indicates that smaller amounts of energy storage can smoothly and effectively integrate renewable energy when compared to the amount of natural gas-fired power plants required to meet the same response times. California should seize this opportunity and encourage developers to install energy storage to support commercial scale solar and wind farms and reduce the need for new natural gas-fired plants as an energy-firming source.

California can use storage to support renewables in several applications. Storage can provide the ancillary services needed for integrating large amounts of renewables into the system that would otherwise be provided by conventional generating resources. Also, the state can use grid-connected utility-scale energy storage to avoid cutting back on remote wind farm production in response to transmission limits. Another application is to use large-scale energy storage to shift renewable production to times of higher value and demand, which can help address overgeneration by storing excess renewable energy and sending it back to the grid when needed. Finally, fast-response storage can improve electricity system stability and reduce stability and frequency response issues that may occur with high penetrations of renewables.

Research completed by the Energy Commission indicates these utility-scale energy storage systems can provide the grid system a variety of benefits. The energy storage systems can respond rapidly to grid system reliability issues and improve the overall operation of the grid. They can also improve the dispatchability and availability of renewable generation systems by responding to the intermittent nature of wind and solar renewable systems. Additionally,

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[233] Ancillary services support the transmission of electricity from its generation site to the customer. Services could include load regulation, spinning reserve, nonspinning reserve, replacement reserve and voltage support.

energy storage systems can provide the grid operators ancillary services such as frequency response and spinning reserve. Grid operators need a mixture of many types of generation, demand management, and energy storage capabilities to effectively manage the utility grid. When properly integrated, energy storage and automated demand response can offer critical capabilities currently provided by conventional natural gas generation.

Energy storage is typically measured as a combination of time increments and capacity (in kW or MW) and can range from a few minutes up to many hours. Batteries and flywheel systems are examples of short-duration storage that can compensate when passing clouds block the sun and cause generation to drop substantially in less than a minute and jump back to full generation a few minutes later.[234] The Electric Power Research Institute reports that sodium sulfur batteries and lithium ion batteries can provide frequency regulation to mitigate these kinds of fluctuations in PV generation.[235] In addition, the Energy Commission's Public Interest Energy Research (PIER) program has demonstrated that short-term energy storage systems such as flywheel technology can provide this capability.

The U. S. Department of Energy (DOE) recently provided American Recovery and Reinvestment Act (ARRA) loan guarantees to a PIER frequency demonstration project company, permitting it to construct a 20-MW facility. Other energy storage projects have been proposed to DOE that, if awarded ARRA funding, could result in the construction of several major utility-scale energy storage projects in California over the next few years.

For longer duration storage needs, pumped hydropower uses low-cost off-peak energy to pump water from lower to higher elevation reservoirs, and the water is then released during higher-cost peak times to generate electricity. However, most of the existing water infrastructure that could be used for this purpose must compete with irrigation, flood control, in-stream flow requirements, and other demands placed on the state's water systems. Developing dedicated reservoirs for pumped storage is extremely difficult.[236] Also, under current tariff structures for energy services, there is inadequate support for pumped hydropower systems to cover costs, resulting in only a limited number of operational systems in California. In addition, pumped

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[234] Curtright, Aimee E. and Jay Apt, *Progress in Photovoltaics: Research and Applications*, 16: 241-247, "Applications: The Character of Power Output from Utility-Scale Photovoltaic Systems", 2008, available at: [http://www.clubs.psu.edu/up/math/presentations/Curtright-Apt-08.pdf]. See also, presentation by Dan Rastler, EPRI, at the April 2, 2009, IEPR workshop, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-02_workshop/presentations/0_3%20EPRI%20-%20Energy%20Storage%20Overview%20-%20Dan%20Rastler.pdf].

[235] Transcript of the April 2, 2009, IEPR workshop, EPRI presentation, pp. 27-32, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-02_workshop/2009-04-02_TRANSCRIPT.PDF].

[236] Examples of trying to create dedicated pumped-storage reservoirs include Lake Elsinor Pumped Storage and the Eagle Crest facilities, both in Southern California.

hydropower has its own set of environmental challenges, which may limit its use going forward.

In IEPR workshops on energy storage and smart grid, stakeholders indicated that paying for these technologies is a significant barrier to increasing the amount of utility-scale energy storage in California. In many cases, energy storage systems provide utility grid services that cannot be recovered within existing rates and tariffs. Stakeholders recommended that the Energy Commission, California ISO, and the CPUC consider new rates and tariff options to permit adequate reimbursement to the energy storage system for all the services it provides to the grid. System cost-effectiveness models can be developed to more accurately reflect the true value energy storage systems provide to the utility grid for renewable integration, system reliability improvements, and ancillary services markets.

To help in this effort, the PIER program is developing system performance models for several energy storage technologies to help identify more revenue sources for energy storage systems. Because energy storage is not considered generation, transmission, or load, new information is needed to properly integrate these technologies into the utility grid system. Once developed and demonstrated, these system performance models can be used to assist the California ISO in integrating them into the ancillary service and other potential markets operated under the new Market Redesign Technology Upgrade grid management system. In addition, the PIER program is developing similar models for the load reduction capabilities provided by automated demand response systems.

California ISO recognizes the important role of energy storage in integrating renewables into the electricity system, and in September 2009, it released an issue paper about nongenerator resources, including energy storage resources, participating in ancillary services markets.[237] The California ISO is also developing an energy storage pilot program to analyze the performance of storage devices and identify and eliminate barriers to increased deployment.[238] This work should be further expanded in time to encourage installation of storage in the 2015 to 2020 time frame as the state ramps up to the 33 percent level of renewable energy.

Role of Other Renewable Technologies

Baseload renewable technologies such as biomass, biogas, and geothermal also will play an important role in reducing the potential need for gas-fired generation to firm up renewable energy.[239] Geothermal facilities currently provide 42 percent of California's renewable energy and generally operate as baseload; however, in combination with storage, geothermal facilities can offer load following or peaking services as well.

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[237] California Independent System Operator, *Issue Paper for Participation of Non-Generator Resources in California Independent System Operator Ancillary Services Markets*, September 1, 2009, available at: [http://www.caiso.com/241c/241cd4af47ca0.pdf].

[238] California Independent System Operator, see [http://www.caiso.com/2337/2337f16064bc0.pdf].

[239] For example, see comments by ICF, IEPA, and Covanta Energy from the June 29, 2009, IEPR workshop, transcript, pp. 146, 172, and 190.