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California ISO
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California Independent
System Operator Corporation

February 8, 2008

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation,
Docket Nos. ER08-___-000 and ER06-615
Interim Capacity Procurement Mechanism

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Section 35.15 of the regulations of the Federal Energy Regulatory Commission (the "Commission"), 18 C.F.R. § 35.15 and in compliance with Paragraph 380 of the Commission's June 25, 2007 Order concerning the Market Redesign and Technology Upgrade ("MRTU") project,[1] the California Independent System Operator Corporation ("CAISO") hereby submits for filing an original and five copies of proposed amendments to the approved MRTU Tariff to implement an Interim Capacity Procurement Mechanism ("ICPM").

The ICPM is a necessary and appropriate mechanism to complement the MRTU market design. It will enable the CAISO to maintain reliable grid operations in the event Load Serving Entities ("LSEs") do not meet resource adequacy ("RA") requirements established by the California Public Utility Commission ("CPUC") and other Local Regulatory Authorities; procured Resource Adequacy Resources do not meet specific local reliability criteria; or conditions occur during the operating year that create a need for the CAISO to procure additional capacity in order to maintain and sustain reliable operations.[2] As described herein, the ICPM replaces the Reliability Capacity Services

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1 *Cal. Indep. Sys. Operator Corp,* 119 FERC ¶ 61,313 (2007) (June 25 Order).

2 Capitalized terms not otherwise defined herein have the meanings set forth in the Master Definition Supplement, Appendix A to the CAISO Tariff.

Tariff ("RCST") and provides the CAISO with the means to engage in backstop procurement, when necessary, to ensure the reliability of the CAISO Controlled Grid in accordance with Reliability Criteria.

The CAISO proposes an effective date for the ICPM to be coincident with the effective date of MRTU implementation.[3]

I. EXECUTIVE SUMMARY

Over the past nine months, CAISO staff has collaborated with stakeholders to develop an interim, tariff-based, capacity procurement mechanism to be implemented coincident with start-up of MRTU. The purpose of this capacity procurement mechanism is to enable the CAISO to supplement or "backstop" LSE-based RA capacity procurement as needed for reliable grid operations.

As the culmination of a lengthy and rigorous stakeholder process, the ICPM proposal effectively meets the CAISO's objectives for an interim backstop mechanism, is compatible with both the MRTU market design and, in the interim, the State of California's existing RA program, will not interfere with the CPUC's and CAISO's efforts to design a long-term RA framework and a more permanent capacity procurement mechanism, and attempts to strike a reasonable balance between the divergent views of stakeholders. Importantly, the ICPM Proposal supports reliability while not interfering with the efficiency of the markets, both CAISO and bilateral.

Throughout the stakeholder process, parties expressed widely different points of view on many of the elements of an ICPM. In fact, parties were polarized on key issues, especially pricing. This filing reflects numerous modifications to prior CAISO staff proposals in order to address concerns expressed by stakeholders. Even with these changes, the ICPM proposal is not without opposition, and there is not unanimous stakeholder support for each and every element of the proposal. However, CAISO believes that this ICPM proposal constitutes a reasonable, balanced and interim approach that takes into account the widely divergent views expressed by stakeholders and the fact that important long-term RA issues remain unresolved. The CAISO particularly stresses the interim nature of the ICPM. Following the conclusion of the CPUC's long-term RA proceeding, the final recommendation from which is expected in 2008, the CAISO will work with stakeholders to examine capacity pricing issues and attempt to develop a long-term backstop capacity pricing mechanism that can be fully integrated with the long-term RA framework and ensure long-term RA, both system-wide and locationally.

The CAISO also emphasizes the need to view the proposal as a whole. The CAISO has attempted to balance benefits and burdens and to follow cost causation

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[3] The CAISO has recently announced a delay in the startup of MRTU. The CAISO also has commenced a stakeholder process to consider development of an alternative capacity backstop procurement mechanism for the period prior to implementation of MRTU.

principles. Any party can find fault with any single element of the proposal. However, the ICPM does not have to be perfect or even the best backstop mechanism – it must be just and reasonable.[4]

The ICPM will allow the CAISO to backstop or supplement the RA procurement of LSEs if necessary to ensure that there is sufficient generation capacity available to the CAISO operators to maintain reliable grid operations. The key elements of the ICPM are as follows:

- The ICPM tariff provisions automatically sunset on December 31, 2010. As noted above, the CAISO's intent is to revisit and refine the backstop mechanism after further progress is made at the State of California level regarding the design of a long-term RA framework. At that time, the CAISO anticipates developing a more permanent backstop mechanism that will complement the long-term RA design.
- There are two circumstances that would trigger procurement under the ICPM. The first type of procurement would backstop the RA process and occur if an LSE or group of LSEs has not purchased the full amount of their local or system-wide RA requirements by the time of the required RA showing for that year, or, even if they had met the required procurement targets, sufficient capacity was not procured to meet specific CAISO locational needs. This type of backstop procurement would occur in advance of the applicable compliance period. The ICPM provides opportunities for LSEs to "cure" any deficiency before the CAISO procures backstop capacity. The second type of procurement would occur if the CAISO determines that an "ICPM Significant Event" has occurred that creates a need to supplement LSE-procured capacity within the compliance year in order to maintain reliable grid operations.
- ICPM Significant Events are defined as "a substantial event, or a combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the resource adequacy program for purposes of determining the Resource Adequacy Capacity requirements, or produce a material change in system conditions or in CAISO Controlled Grid Operations, that causes, or threatens to cause, a failure to meet Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis". Because it is impossible to foresee all potential events that could occur during the operating year that would jeopardize the CAISO's ability to meet the Reliability Criteria that it must satisfy as a system operator, the definition by necessity affords some discretion to the CAISO. The CAISO's experience with the RCST showed that the RCST Significant Event designation criteria were too prescriptive and unduly limited the CAISO's ability to utilize the RCST to meet

[4] *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984), *cert denied*, 469 U.S. 917 (1984)(utility need establish that its proposed rate design is reasonable, not that it is superior to all alternatives).

reliability needs. The CAISO believes that the revised definition of ICPM Significant Event will enable the CAISO to more effectively and appropriately utilize the backstop mechanism to meet reliability needs, when necessary. To balance this additional discretion and make the designation process more transparent, the CAISO has reduced the initial term of ICPM Significant Event designations to one month -- compared to the three month minimum term under RCST -- with the ability for the CAISO to extend the designation if the ICPM Significant Event is expected to last beyond one month, provided opportunities for LSEs to procure resources or develop alternative solutions to address the ICPM Significant Event, and adopted stringent reporting requirements.

- The term of payments to an ICPM resource varies from one month to up to 12 months depending on the RA requirement deficiency being remedied and the period of the deficiency, whether or not other Scheduling Coordinators have over-procured for the same period, or the length of the ICPM Significant Event.
- The minimum annual price paid to a resource for its ICPM capacity is based on recovery of the going-forward costs of a new small simple-cycle unit (50 MW) built by a merchant generator, as supported by the cost analysis contained in a comprehensive study of the cost of new generation in California conducted by the California Energy Commission ("CEC") in 2007, plus a 10% adder to that number.[5] This unit has the highest going forward costs of six types of simple cycle and combined cycle units studied by the CEC (based on a study of 34 units constructed in California between 2001 and 2006). Going-forward costs are the core fixed costs that a generation unit needs to remain available for operation, but do not include debt service or return on equity. Unlike RCST, the ICPM minimum target annual capacity price of $41/kW-year does not include a deduction for peak Energy revenues (or Ancillary Service revenues). Payment would be subject to an ICPM Availability Factor (so that a unit may receive more or less than the target capacity payment depending on its availability during the designation period) and a level monthly shaping factor. The minimum annual ICPM capacity price is known to be higher than the going-forward costs of many existing units (hence, for those units the payment provides additional revenues) and is in-line with the capacity prices being paid under bilateral contracts to Resource Adequacy Resources in local areas -- indeed it is at the high end of the range -- and is significantly higher than the capacity prices being paid to system RA resources. Nevertheless, to ensure the justness and reasonableness of the ICPM price, a resource owner that believes that its going-forward costs, plus 10%, are greater than $41/kW-year would be able to file at the Commission for a ICPM Capacity price higher than $41/kW-year, but the owner would have to justify that price to be based on the same going forward fixed cost elements cost

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[5] For purposes of the ICPM, going-forward costs are defined as the sum of fixed operation and maintenance costs, ad valorem costs, and administrative and general costs (including insurance), plus a 10% adder. A 10% adder is in-line with adders previously approved by the Commission and, among other things, will further encourage LSEs to not simply rely on the ICPM backstop mechanism to meet their RA requirements.

elements that are considered in setting the $41/kW-year default price. This pricing rule is intended to cover any resource's going forward fixed costs, while allowing the resource to retain all market revenues available to RA units, as a means to cover other costs and provide profits. Thus, it strikes a reasonable balance.

- Participation in the ICPM by a resource is voluntary. A resource owner does not have to accept an ICPM designation when offered by the CAISO. The CAISO considered a mandatory designation scheme, but has determined that there are adequate incentives within the proposal for resources to be willing to accept the designation, including the provision where an owner of a resource can request a payment higher than $41/kW-year if justified to the Commission on a cost-basis. Further, the Commission has ruled that there is no "Must-Offer Obligation" under MRTU.
- Unlike the RCST, the CAISO would have the ability to procure only a portion of a resource rather than its entire capacity. In addition, in the event that multiple resources are eligible to accept the ICPM designation, but not all are needed, the CAISO will select resources based on physical effectiveness in addressing the reliability need, price, and PMin level. Resources accepting the minimum ICPM Capacity price or specifying a higher price prior to the designation process will have a priority in the designation process over resources that have not specified a price and which desire to cost justify an unspecified price. In the unlikely event there is a "tie" among eligible resources, the CAISO would use a random selection mechanism to break the tie.
- Extensive reporting requirements are included to ensure that all ICPM procurement is transparent to the market and to provide an information feedback to the CPUC and other Local Regulatory Authorities so those entities can improve their RA programs over time.
- If an individual Scheduling Coordinator for an LSE is responsible for a shortfall in procurement of Local Capacity Area Resources or Resource Adequacy Resources, and that Scheduling Coordinator fails to cure the deficiency, the costs of the CAISO's ICPM procurement are assigned to the non-complaint Scheduling Coordinator. Costs for designations resulting from collective procurement shortfalls or ICPM Significant Events are allocated proportionately to Scheduling Coordinators for LSEs in the affected areas. LSEs will first be given an opportunity to cure any collective deficiency.
- When the CAISO engages in designations, other than in the case of ICPM Significant Events, it will provide "credit" to the affected Scheduling Coordinators for LSEs for a corresponding quantity of their RA obligations.
- Ultimately, the pricing and procurement rules for a successor to ICPM need to be integrated with the State of California long-term RA program. The question of capacity procurement is a component of the CPUC's long-term RA proceeding, and the CAISO has been an active participant in that proceeding. In particular, the CAISO has provided its preliminary views on the design of centralized

> capacity markets in that proceeding, including the incorporation of backstop procurement. Future designs for capacity procurement mechanisms will be addressed following that proceeding. In particular, the CAISO will be exploring more permanent capacity pricing mechanisms that provide appropriate long-term investment signals and prices that comport with the long-term need for capacity.

II. BACKGROUND

A. MRTU Orders

On February 9, 2006, the CAISO filed its MRTU Tariff with the Commission. As the Commission has recognized, MRTU provides,

> a more effective congestion management system; a day-ahead market for trading and scheduling energy; system improvements to increase operational efficiency and enhance reliability; a more transparent pricing system; improved market power mitigation measures; the opportunity for demand resources to participate in the CAISO markets under comparable requirements as supply; and, lastly, a process that respects the resource adequacy requirements established by the states or Local Regulatory Authorities, with provisions to allow the CAISO to procure additional capacity to meet forecasted needs.[6]

On September 21, 2006, the Commission issued an order conditionally accepting the filing, subject to modifications.[7] On April 20, 2007, the Commission issued an order on rehearing.[8]

On June 25, 2007, the Commission accepted certain compliance filings made by the CAISO, subject to further modifications.[9] The Commission also directed the CAISO to explore with stakeholders opportunities for LSEs to avoid potential CAISO remedial procurement by curing a collective shortfall in Local Capacity Area Resource Requirements.[10] The CAISO was directed to file any necessary MRTU Tariff revisions by August 3, 2007.

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[6] *Cal. Indep. Sys. Operator Corp*., 116 FERC ¶ 61,274 (2006) (September 21 Order) at P 1.

[7] September 21 Order.

[8] *Id.* at P 37-48.

[9] June 25 Order.

[10] *Id.* at P 380.

The CAISO determined that the backstop capacity procurement issues identified in Paragraph 380 of the June 25 Order would best be resolved in the context of its development of the ICPM.[11] The CAISO requested and received an extension of time, until October 31, 2007, to comply with the June 25 Order's requirements concerning backstop procurement of local capacity area resources.[12] On September 19, 2007, the CAISO filed a second request for an extension of time, until January 18, 2008, to make a filing in compliance with the directives of Paragraph 380 of the June 25 Order. The Commission granted this request on September 25, 2007.

On October 12, 2007, the Independent Energy Producers Association ("IEP") filed a Motion for Reconsideration or Clarification in which it asked the Commission to reconsider its September 25, 2007, Notice of Extension of Time. IEP requested that the Commission require the CAISO to file its ICPM to be effective January 1, 2008 (prior to implementation of MRTU). On October 29, 2007, the CAISO filed an Answer to IEP's motion in which it, *inter alia,* objected to IEP's request to require the CAISO to file the ICPM with an effective date of January 1, 2008. In an order issued on December 20, 2007, the Commission denied IEP's Motion for Reconsideration or Clarification, but initiated a Section 206 proceeding in Docket No. EL08-20-000 to investigate the justness and reasonableness of extending the RCST for a short period of time, until the earlier of the implementation of either MRTU or an alternative backstop capacity procurement mechanism.[13]

On January 18, 2008, the CAISO filed a motion requesting an additional extension of time -- until 60 days prior to implementation of MRTU to comply with Paragraph 380 of the June 25 Order. The Commission granted the extension on February 1, 2008. The CAISO had originally intended to present the ICPM proposal to the CAISO Governing Board in December 2007 but "pulled" the matter from that meeting so that it could undertake some additional work with stakeholders and in an attempt to reach some consensus on outstanding issues, in particular the pricing of ICPM service. Accordingly the CAISO needed an extension of time to comply with the June 25 Order because the next CAISO Governing Board meeting was not until January 29, 2008.

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[11] CAISO's Sept. 19, 2007 Motion for Extension of Time, Docket No. ER06-615-003, at 6.

[12] CAISO's Aug. 3, 2007 Motion for Extension of Time, Docket Nos. ER06-615-003, *et al*.; Notice of Extension of Time, Docket Nos. ER06-615-003, *et al*. (Aug. 8, 2007).

[13] *California Indep. Sys. Operator Corp., et. al*., 121 FERC ¶ 61,281 (2007).

B. RCST

As a result of the 2000-2001 California Energy Crisis, the Commission established a prospective mitigation and monitoring plan for the California wholesale electric markets.[14] A fundamental element of the plan was the implementation of the must offer obligation ("MOO"). The CAISO implemented the MOO beginning in July 2001.

In an order issued on July 8, 2004,[15] the Commission advised that if a supplier believed the payments under the MOO to be unjust and unreasonable, they may seek to initiate a Section 206 proceeding to challenge the current method and seek an alternative proposal.[16] On August 26, 2005, IEP filed a complaint in Docket No. EL05-146 to replace the MOO with a tariff-based procurement mechanism entitled the "Reliability Capacity Services Tariff" ("RCST"). Following extensive settlement discussions, on March 31, 2006, certain parties[17] filed an Offer of Settlement of the IEP complaint, which proposed the institution of an RCST. The RCST provided a backstop capacity procurement mechanism to the CAISO that included provisions establishing: (1) must-offer capacity payment rates; (2) RCST rates due to designation resulting from a Significant Event; (3) RCST rates due to designation resulting from deficiency in RA showings; and (4) payments to frequently mitigated units.[18] In addition, the RCST established cost allocation methodologies and governed the rules by which the CAISO can procure RCST capacity.

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[14] *San Diego Gas & Elec. Co.*, 95 FERC ¶ 61,115, at 61,355-57, *order on reh'g*, 95 FERC ¶ 61,418, *order on reh'g*, 97 FERC ¶ 61,275 (2001), *order on reh'g*, 99 FERC ¶ 61,160 (2002), *pet. granted in part and denied in part sub nom. Public Utils. Comm'n of the State of Cal. v. FERC*, 462 F.3d 1027 (9th Cir. 2006).

[15] *Cal. Indep. Sys. Operator Corp.*, 108 FERC ¶ 61,022 (July 2004 Order), *order on reh'g*, 109 FERC ¶ 61,097 (2004).

[16] July 2004 Order, 108 FERC ¶ 61,022 at P 115.

[17] The settling parties were: IEP; the CAISO; the CPUC; Pacific Gas and Electric Company ("PG&E"); San Diego Gas & Electric Company ("SDG&E"); and Southern California Edison Company ("SCE").

[18] *See Indep. Energy Producers Ass'n v. Cal. Indep. Sys. Operator Corp.*, 118 FERC ¶ 61,096 (2007). *See generally Indep. Energy Producers Ass'n v. Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,069 (2006) ("Settlement Order"); *Indep. Energy Producers Ass'n v. Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,297 (2006) ("Clarification Order"); *Indep. Energy Producers Ass'n v. Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,266 (2007) ("First Rehearing Order"), *pet. for review pending sub nom. Cities of Anaheim v. FERC*, Case No. 07-1222, *et al.* (D.C. Cir., filed June 20, 2007); *Cal. Indep. Sys. Operator Corp.*, 118 FERC ¶ 61,097 (2007) (Order on 2007 RCST), *on reh'g, Indep. Energy Producers Ass'n v. Cal. Indep. Sys. Operator Corp.,* 121 FERC ¶ 61,276 (2007), in Docket No. EL05-146-004.

In the RCST Settlement Order, the Commission found that the compensation to generators under the MOO was no longer just and reasonable.[19] Specifically, the Commission found that "under the current market design, the [MOO] does not adequately compensate generators for the reliability services they provide."[20] The Commission further held that it was "unduly discriminatory that units under the [MOO] would be required to operate for reliability purposes in a manner similar to units contracted for capacity under the RA program and not receive similar capacity payment."[21]

The Commission, however, was unable to find, without further factual support, that the rates and cost allocation mechanism under the Offer of Settlement were just and reasonable. The Settlement Order established paper hearing procedures to review evidence on whether the rates and cost allocation under the Offer of Settlement or some other rates and cost allocation would be just and reasonable with respect to the MOO.[22] On February 13, 2007, in the Order on Paper Hearing, the Commission approved, with modifications, the Offer of Settlement as a just and reasonable outcome. The Commission issued its order on rehearing and clarification on December 20, 2007.[23] In its December 20, 2007 rehearing order, the Commission affirmed the findings in its February 13, 2007 Order.

As discussed in the prior section with respect to IEP's request that the Commission require the CAISO to implement the ICPM prior to the start of MRTU, on December 20, 2007, the Commission issued an Order Instituting a Section 206 Investigation and Denying Motion for Reconsideration and Clarification.[24] The Commission has proposed to continue the RCST until either a successor RCST is filed or until the implementation of the ICPM with MRTU.

C. Development of the ICPM – Stakeholder Process

The CAISO held an extensive and robust stakeholder process in connection with the ICPM. As indicated above, the CAISO even extended that process by removing the ICPM from the December CAISO Governing Board agenda so that it could make one last effort to work with stakeholders and attempt to resolve the difficult ICPM pricing issues which had polarized the discussions.

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[19] RCST Settlement Order, 116 FERC ¶ 61,297 at P 38 (2007).

[20] *Id.* at P 35.

[21] *Id.* at P 36.

[22] *Id.* at PP 38-39 and Appendix to Order.

[23] *Independent Energy Producers Ass'n v. Cal. Indep. Sys. Operator Corp.*, 121 FERC ¶ 61,276 (2007) ("RCST Rehearing Order").

[24] *California Indep. Sys. Operator Corp., et. al.*, 121 FERC ¶ 61,281 (2007).

The CAISO initiated the ICPM stakeholder process in April 2007.[25] The CAISO posted an "Issues Paper" on May 9, 2007, and the first stakeholder meeting was held on May 18, 2007. Stakeholders provided formal written comments on May 25, 2007.

The CAISO held a second stakeholder meeting on June 6, 2007 and the CAISO posted its initial ICPM proposal on June 29, 2007. Stakeholders submitted comments on this proposal on August 9, 2007. After evaluating the comments received from stakeholders, the CAISO posted a revised ICPM proposal on October 5, 2007.

The CAISO held a third stakeholder meeting on October 15, 2007 and conducted a conference call with stakeholders on October 18, 2007. Stakeholders submitted additional comments on October 24, 2007. The CAISO posted its third revised ICPM proposal on November 9, 2007. Subsequently, the CAISO held another conference call with stakeholders on November 15, 2007, and there was another round of stakeholder comments which were submitted on November 21, 2007. After "pulling" ICPM from the December 2007 CAISO Governing Board agenda, during the month of December, the CAISO conducted additional outreach to stakeholders to attempt to reach some consensus on the pricing issues.

Based on the stakeholder comments and input from the Market Surveillance Committee ("MSC"), the CAISO prepared a Draft Board Proposal.[26] The Draft Board Proposal was discussed during a stakeholder conference call on December 20, 2007. Written stakeholder comments were received on January 7, 2008. Draft tariff language was posted on January 14, 2008. Stakeholders submitted comments on the draft language on January 22, 2008, and these comments were discussed during a stakeholder conference call on January 24, 2008.

The ICPM proposal was discussed before the CAISO Governing Board on January 29, 2008. The Board voted to authorize this filing.

At the January 29, 2008 Board meeting, a number of stakeholders expressed their general support for the instant ICPM proposal. These stakeholders recognized that the proposal was not perfect and did not give them all they wanted (in fact many identified the specific provisions they would like changes), but they believed that overall

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[25] The complete ICPM stakeholder record can be found at http:// www.caiso.com/1bc5/ 1bc5db284cc80. html. This record includes the CAISO's Issue Paper, initial, as well as revised, CAISO ICPM proposals, all comments submitted by stakeholders during the ICPM stakeholder process, all stakeholder meeting presentations and the draft ICPM tariff language.

[26] A copy of the CAISO's Proposal to Board of Governors for Interim Capacity Procurement Mechanism Tariff Filing is provided as Attachment C. Attachment D contains the CAISO Memorandum to the Board of Governors regarding the *Decision on Interim Capacity Procurement Mechanism Tariff filing* as well as a chronology of the major stakeholder activities and a matrix of stakeholder comments and the CAISO's response thereto.

the ICPM represented a balanced approach that recognized the many conflicting points of view on the issues. The stakeholders expressing this position included the California Large Electricity Consumers Association/California Manufacturers and Technology Association/Energy Users Forum, Southern California Edison Company, Alliance for Retail Energy Markets ("AReM"), the Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside, together the "Six Cities", California Municipal Utilities Association, Pacific Gas & Electric Company, The Utility Reform Network, and the California Public Utilities Commission. Calpine Corporation also presented a new proposal[27] at the Board meeting that accepted several parts of the ICPM proposal, but sought to modify the pricing provisions of the ICPM to: (1) permit units to select the higher of a safe harbor price or a unit-specific, cost of service rate approved by the Commission that would allow a unit to recover all fixed costs (including recovery of and on capital) similar to Schedule F of the RMR Contract, (2) provide for revenue crediting based on the expected revenues of a proxy unit; and (3) require the CAISO to procure backstop capacity for one-year if there is a local RA deficiency.

While the CAISO sought and received extensive participation from stakeholders, the divergent opinions with respect to the rates, terms, and conditions of the ICPM made it impossible to reach a consensus. In particular, stakeholders were deeply polarized over the issue of the appropriate price for ICPM service. The CAISO has made its best efforts to construct a just and reasonable proposal and, in part because of the lack of consensus on the price issue, has made it voluntary on the part of supply resources whether they will accept any ICPM designation offered to them. The CAISO went through numerous iterations in developing an ICPM proposal. Rather than retrace each successive version of the ICPM proposal, the CAISO will discuss, in the following sections, the major elements of the ICPM and the reasons why it chose the various ICPM elements from the alternatives that were considered. However, the CAISO identifies below some of the key revisions that it made to its ICPM proposal in response to stakeholder comments:

- **Duration:** The CAISO initially proposed a sunset date of December 31, 2012; ICPM now sunsets on December 31, 2010.

- **Capacity price:** In its Issue Paper and White Papers, the CAISO explored the following pricing concepts (and considered others presented during the stakeholder process): (1) simple annual escalation of current RCST price with a peak energy rent deduction ("PER"), (2) escalation of current RCST price to a 2008 value and then gradually moving the price toward cost-of-new-entry with a PER, (3) cost-of-new-entry pricing with a PER, coupled with a sloped demand curve that restricted cost of new entry pricing only to areas with a capacity deficiency, and (4) payment of going-forward costs without any market revenues deduction, *i.e.,* no PER. The CAISO ultimately concluded that concept (4) was the most appropriate for the ICPM.

[27] This proposal was not offered during the lengthy ICPM stakeholder process.

- **Opportunity to Cost-Justify a Higher Price:** While the CAISO anticipates that the target annual price of $41/kW-yr will cover the going forward costs of most resources, the CAISO added an opportunity for resources to cost-justify a higher amount.

- **Monthly payment:** The CAISO initially proposed using seasonal shaping factors as were used in the RCST. The ICPM now includes a level monthly shaping factor to better reflects the relatively flat nature of going-forward costs.

- **Designation process:** The CAISO added a 3-step, iterative procurement process, which includes interaction with stakeholders, to address concerns regarding the CAISO's exercise of discretion in connection with ICPM Significant Event procurement.

- **Reporting:** The CAISO expanded the reporting requirements beyond what was provided for in RCST and adopted more robust reporting obligations in response to stakeholder requests.

- **Term of procurement:** The CAISO initially proposed terms for designations of 5 months for annual system deficiencies and 12 months for annual local deficiencies. ICPM now provides for designation terms of 1 month to up to 12 months, based on the period of the actual deficiency.

- **Selection criteria for multiple resources:** Although "ties" are unlikely, the CAISO initially considered adopting a simple auction to break any "ties." There were many objections to this approach, including that it would inappropriately drive down the capacity price ultimately paid to resources. To avoid such price impacts and the unnecessary complexity it would add to the process, the CAISO abandoned the auction concept. ICPM now includes a random selection rule for ties and ensures that no resource can be paid less than the minimum capacity price of $41/kW-year.

- **Reflecting ICPM Procurement in RA showings:** The CAISO initially did not support allowing procurement made to address local "effectiveness" deficiencies to be "credited" toward RA showings. ICPM now permits such procurement to "count" towards system RA requirements.

D. Opinion of the CAISO Market Surveillance Committee

The MSC was actively engaged in the stakeholder process.[28] On November 21, 2007, the MSC issued an *Opinion on "Interim Capacity Payment Mechanism under MRTU"* ("MSC Opinion"). The MSC Opinion recognizes that "[t]he ICPM will allow the ISO to supplement or backstop the resource adequacy (RA) procurement of load-serving entities (LSEs) to ensure there is sufficient generation capacity available to the ISO operators to maintain reliable grid operation in the California ISO control area."[29] The MSC Opinion concludes that the "final ICPM proposal is a compromise solution that does not have any significant defects that are likely to harm system reliability or short-term market efficiency, or interfere with the functioning of the RA procurement process."[30] The MSC Opinion also "emphasize[s] that [ICPM] is an interim mechanism that should be reevaluated or even eliminated once a scarcity pricing mechanism has been implemented and the long-term resource adequacy process at the CPUC has been resolved."[31] As discussed herein, these are reasons why the CAISO is proposing a December 31, 2010 termination date for the ICPM. Following the conclusion of the CPUC's ongoing long-term resource adequacy proceeding, the CAISO intends to evaluate long-term capacity and backstop pricing options and work with stakeholders to develop a long-term capacity backstop mechanism that will fully complement the long-term RA framework.

With respect to the pricing of ICPM Capacity, the MSC stated:

> We also believe that a number of features of the ICPM proposal address potential concerns that we had with previous ICPM proposals. In particular, we were concerned that setting the cost of new entry (CONE) as the cap on the price of capacity for Type 1 procurement was likely to impact the price LSEs had to pay for RA capacity, particularly in areas likely to be subject to the exercise of local market power.[32]

With respect to ICPM Significant Event designations, the MSC "support[ed] giving the ISO Operators considerable discretion to declare a significant event whenever they determine that additional RA capacity is necessary to maintain grid reliability….because the potential reliability consequences of limiting the set of circumstances when the ISO can declare a significant event are simply too great to ignore."[33] The MSC also stated that

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[28] Opinion on "Interim Capacity Payment Mechanism Under MRTU", Market Surveillance Committee of the California ISO dated November 21, 2007 ("MSC Opinion") at 1. A copy of the MSC paper is provided as Attachment E.

[29] MSC Opinion at 1.

[30] *Id.* 1-2.

[31] *Id.* at 2.

[32] *Id.*

[33] *Id.* at 3-4.

"because the units that are at risk to be called upon to provide Type 2 [ICPM Significant Event] ICPM capacity have already made a decision to participate in the ISO's markets without an RA payment, we believe that the payment for Type 2 [ICPM Significant Event] capacity should at most recover the unit's going-forward fixed costs."[34]

Finally, the MSC supported a requirement that unit owners must accept any ICPM designation offer, "particularly for procurements caused by local or regional capacity shortfalls where only one or a small number of generation unit owners can provide the product."[35] For the reasons set forth below, the CAISO has not followed this recommendation.

III. THE ICPM PROPOSAL

A. The Need for the ICPM and Major Changes From Changes from RCST

1. The Need for the ICPM

The ICPM provides an orderly, pre-approved means for the CAISO to procure backstop capacity where and when needed to meet Reliability Criteria or otherwise maintain reliable grid operations. Although RA programs are in place under California law, and RA requirements have been established by Local Regulatory Authorities, there may be instances when Resource Adequacy Resources are not sufficient to meet all of the operational needs of the CAISO and enable it to meet Reliability Criteria. This circumstance could happen as a result of LSEs failing to comply with resource adequacy requirements, unforeseen or changed circumstances affecting system conditions or grid operations, or the ineffectiveness of procured RA resources at meeting the CAISO's specific reliability needs. It is imperative that the CAISO have the appropriate tools at its disposal under such circumstances to maintain reliable operations. In particular, the CAISO needs the ability to procure resources when such instances occur in order to maintain the reliability of the CAISO Balancing Authority Area. The ICPM provides the CAISO with that ability. Further, it is prudent that the ICPM backstop capacity procurement mechanism be in place at the start of MRTU, which represents a fundamental change in the CAISO's market structure. The CAISO also believes that a backstop mechanism should provide a transparent process for the use of any backstop procurement so that the CPUC and other Local Regulatory Authorities can make any necessary modifications to their RA programs. The ICPM proposal provides that transparency via numerous reporting requirements.

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34 *Id.* at 5.

35 *Id.* at 6.

The CAISO notes that the Commission has already recognized that the CAISO needs the authority to engage in backstop procurement to maintain reliable system operations under MRTU. The Commission recently confirmed:

> We find it reasonable to allow the CAISO the flexibility to engage in backstop procurement activities even though LSEs have adequately met their immediate local capacity obligation. We believe this flexibility is appropriate for those unforeseen circumstances where the CAISO must act in response to a system contingency (e.g. transmission outage) that prevents an LSE from meeting its local procurement obligation in its applicable TAC area location. We also emphasize the necessity of this approach because the CAISO is responsible for maintaining the efficiency and reliable operation of the transmission grid consistent with the NERC planning standards. In addition, we note that the CAISO is under an obligation to meet other applicable reliability criteria under its Transmission Control Agreement. While the CAISO has discretion to engage in backstop procurement, we continue to believe there are adequate safeguards to mitigate concerns regarding unnecessary backstop procurement of local capacity area resources…This report should provide transparency to the CAISO's backstop procurement process that is sufficient to ameliorate …concerns.
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> For these reasons, we accept the proposed MRTU tariff language …, allowing the CAISO to engage in backstop procurement activities: (1) when an LSE fails to meet its obligation; and (2) when the applicable reliability criteria cannot be met despite the fact that each LSE has sufficiently procured the minimum amount of local capacity area resources. We also note that our acceptance is without prejudice to the CAISO filing further modifications, if necessary, to coincide with the cost allocation provisions of its backstop procurement program.[36]

The ICPM provides the CAISO with an efficient and effective means to procure backstop capacity to maintain reliable operations. Thus, the CAISO has proposed to add a new Section 43 to the MRTU Tariff, which sets forth the ICPM and replaces Section 40.3.4. In addition to enabling the CAISO to procure backstop capacity to address deficiencies in annual and month-ahead RA requirements, the ICPM, consistent with the RCST, recognizes that backstop procurement may be required to allow the CAISO to respond effectively to ICPM Significant Events. ICPM Significant Events are system conditions, changes in regulatory requirements, or other potential issues that arise after the annual system and locational RA procurement is conducted that may result in conditions that jeopardize the CAISO's ability to meet Reliability Criteria.

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[36] *California Indep. Sys. Operator Corp., et. al*., 122 FERC ¶ 61,017 (2008) at P 63-64.

Thus, the ICPM "fills in the gaps" between a number of existing requirements and programs:

- It is meant as a complement to and not as a substitute for the RA program which is the primary means for ensuring that resources are available when and where needed.

- It is not meant as a substitute for Reliability Must-Run Contracts, which are annual contracts for the purpose of addressing specific long-term local reliability needs not addressed through RA contracts. In other words, the CAISO needs a particular resource, in a particular location on a long-term basis to maintain reliability. As the Commission is aware, the CAISO is attempting to transition from reliance on RMR Contracts and to rely more exclusively on procurement for locational requirements by Scheduling Coordinators for LSEs.

- It also is not a substitute for Exceptional Dispatch which permits the CAISO, *on a given day*, to dispatch units, whether they are RA, non-RA, RMR or ICPM, out-of-merit order or out-of-market in order, *inter alia,* to prevent a situation that threatens System Reliability and which cannot be addressed by the CAISO's Real Time Market optimization and system modeling. In other words, Exceptional Dispatch is a daily product and specified criteria must be met each and every day in order for it to be used; whereas, ICPM involves the forward procurement of capacity that will be needed for the CAISO to maintain reliability for a longer period of time.

- It is not meant as an emergency measure but rather as a means to avoid such situations.

In developing the ICPM proposal, the CAISO sought to achieve a number of objectives. First, the CAISO developed the following criteria for purposes of evaluating backstop procurement options: (1) minimize reliance on backstop procurement where possible by allowing LSEs to procure interim capacity through bilateral transactions; (2) ensure that neither buyers nor sellers have an incentive to defer RA transactions to the ICPM; (3) improve the definition of the interim capacity product; (4) provide for transparent procurement prices; and (5) minimize administrative costs and implementation issues given the interim nature of the product.

Second, the CAISO attempted to develop a backstop resource procurement process that would not interfere with the efforts of LSEs to contract for resources needed to comply with RA requirements established by their respective Local Regulatory Authorities. In other words, the proposal should not set uniform capacity rates (*i.e.,* for all system and local procurement) that are too high (in which case suppliers may demand prices that are higher than they would otherwise be able to command for forward RA contracts) or too low (which could encourage LSEs to fail to procure resources and instead rely on the CAISO's backstop procurement).

Third, after significant discussions with stakeholders, the CAISO recognized that the ICPM should not unnecessarily interfere with the CPUC's ongoing proceeding regarding the appropriate long-term RA program for the utilities within its jurisdiction. In particular, given the CAISO's role in that proceeding to evaluate centralized capacity market alternatives, the CAISO considered but ultimately did not adopt certain ICPM design alternatives (notably a sloped demand curve) because it did not want to prejudge the issue of whether or not to establish a centralized capacity market should be implemented in California (and what the design features of such a market should be).[37] Also, the CAISO did not want to "get ahead" of the future stakeholder process that the CAISO will conduct, likely beginning in mid-to-late 2008, regarding the long-term capacity pricing scheme that should be in-place under a long-term RA framework, which will incorporate backstop procurement functions and pricing. Accordingly, the ICPM has been constructed as an interim proposal.

Fourth, given the interim nature of the program, ICPM is not intended as an incentive for the development of new resources. Likewise, it is not intended to serve as the primary enforcement mechanism to ensure that LSEs comply with RA requirements, which are under the enforcement authority of the CPUC and Local Regulatory Authorities. To the extent that resources are being designated under the ICPM, it should serve as notice to the CPUC and Local Regulatory Authorities to review and evaluate the performance of their RA programs, including any local capacity procurement requirements. To ensure these objectives are met, any ICPM procurement must be transparent to Market Participants and regulators.

In summary, significant time, effort, and resources have been spent on development of a capacity backstop program that the CAISO hopes to use very infrequently. After considering the input of stakeholders and the guidance of the MSC, the CAISO believes that it has developed a just and reasonable interim backstop capacity procurement program that meets these criteria and objectives. This was especially difficult given the lack of consensus - indeed the polarization - among stakeholders on many key issues. However, the CAISO believes that it has developed a balanced proposal. Resources are provided with a capacity payment equal to the higher of $41/kW-year (a price which is at the high end of the capacity prices being paid to Resource Adequacy Resources) or their actual going forward costs, plus 10% (which must be cost-justified in a filing with the Commission). There is no PER deduction from

[37] The CAISO was tasked in the CPUC proceeding to evaluate alternative designs for centralized capacity markets, including backstop procurement. The CAISO's recommendations are reflected in a paper entitled, "Straw Proposal on Alternative Central Capacity Market Designs," Department of Market and Product Development, October 11, 2007, and is available at http://www.caiso.com/1c74/1c74e3765f8a0.pdf. The CAISO will shortly be submitting comments on this issue in the CPUC proceeding in response to the CPUC staff report.

this capacity payment; resources are permitted to keep all of the revenues they earn in the Energy and Ancillary Services markets (in other words, unlike RCST, there is a floor in the payments to be made to generators). Moreover, supply resources are not obligated to accept an ICPM designation; it is voluntary. Scheduling Coordinators for LSEs are provided opportunities to cure shortfalls in order to minimize ICPM cost exposure. Finally, CAISO actions under the ICPM are subject to timely reporting obligations that ensure transparency.

2. Major Changes From the RCST

The ICPM builds on the prior RCST framework. It modifies the RCST to account for the discontinuation of the Commission-imposed MOO, as well as the revised RA program and bidding structure under MRTU. A more complete description of the ICPM is contained in the following sections. Significant changes from the RCST include the following:

- RCST was related to implementation of a Commission-imposed MOO. Accordingly, resources could not refuse to accept designations. In contrast, ICPM designations are voluntary, and the pool of resources that can provided Eligible Capacity has been expanded beyond the generation facilities subject to the MOO.

- The proposed minimum capacity payment under ICPM is lower than the target capacity price under RCST, but, unlike the RCST, the ICPM payments are not subject to a PER reduction. Because there is a floor on the payments to be made to generators, there will not be a circumstance such as occurred under the RCST in July 2006 where high market prices, in conjunction with the PER, resulted in a monthly capacity price of $0. Hence, the ICPM payment will be much less volatile than the RCST payment. In fact, because spot market revenues will be higher in peak months and in locations with tight capacity, the offer caps under MRTU will be increasing, and there will be locational marginal pricing, as well as the introduction of scarcity pricing within one-year of MRTU start-up, the CAISO anticipates that the overall payment to suppliers will be higher in the Summer months and in locations with tight capacity under the ICPM than it was under RCST.

- Because the ICPM Capacity Payment is intended to cover going-forward costs, which are typically spread throughout the year, the CAISO modified the monthly "shaping factor" so that each month an ICPM resource will be paid 1/12 of the target annual capacity price (*i.e*., the shaping factor will be level throughout all months of the year). This will allow for uniform recovery of these costs, while at the same time allowing the supplier to retain all market revenues, thus better reflecting the market value of the resource. There is no evidence that going forward costs are seasonal or higher in any particular month(s).

- The CAISO has provided the opportunity for a cost-justification filing with the Commission if a resource owner believes that its "going forward" costs, plus 10%, are greater than $41/kW-year. The owner would have to justify that price to the Commission based on the same cost elements that are considered in setting the $41/kW-year price.

- Under the ICPM, the CAISO may designate a partial resource; whereas, under RCST, the CAISO only had the ability to designate an entire resource (and then only if the entire Eligible Capacity of the resource was equal to or slightly more than the capacity that was needed). This unduly limited the CAISO's ability to make RCST designations to meet reliability needs. The proposed approach will enhance the CAISO's ability to make designations and will better ensure that the quantity of capacity that is procured is tailored to the amount that is needed.

- An RA credit will be provided for certain ICPM designations other than for ICPM Significant Events.

- The CAISO has modified the definition of "Significant Event", as well as the term of ICPM Significant Event designations and the ICPM Significant Event designation process.

B. Nature of the ICPM Product

The CAISO proposes to procure a "capacity only" product, under a tariff-based schedule for service. Thus, the CAISO would essentially be paying for a call option on the capacity of a resource. This obligation would be comparable to the availability requirements imposed on Resource Adequacy Resources under current Section 40.6. Specifically under Section 43.4, a resource procured under the ICPM would have a daily obligation to submit Economic Bids or Self-Schedules in the Day Ahead Market. The Bid and Self-Scheduling obligation will extend into Real-Time for certain resources, including Short Start Units, Dynamic System Resources, and committed resources with unloaded ICPM Capacity, while Long-Start Units that remain uncommitted after the Day Ahead Market are released from any further Bid obligation. Similar to Resource Adequacy Resources, ICPM resources would be required to submit a $0 availability bid in RUC and not be eligible for Frequently Mitigated Unit Bid Adders, if the CAISO had procured all of the facility's Eligible Capacity. Also, ICPM resources will have an Ancillary-Services offer obligation to the extent they are certified to provide Ancillary Services.

C. Designation of Resources

1. Types of Designations

The ICPM is consistent with RCST in that it provides for the same two primary types of backstop procurement. First, the CAISO would have the ability to procure capacity: (a) in advance of, or during the compliance year if a Scheduling Coordinator for an LSE has not procured the full amount of its Local Capacity Area Resources or resources needed to meet the reserve requirements established by the CPUC or other applicable Local Regulatory Authority or; (b) if the portfolio of resources procured by all Scheduling Coordinators for LSEs in a local area is not sufficient to fully meet the Reliability Criteria for the local area. For purposes of the instant filing letter, the CAISO will call the aforementioned types of ICPM procurement “Type 1 Procurement.”

Second, the CAISO would have the ability to procure additional capacity during the compliance year if an ICPM Significant Event occurs that creates a need to supplement LSE-procured Resource Adequacy Resources to ensure reliable grid operation. For purposes of the instant filing letter, the CAISO will call the aforementioned type of procurement “Type 2 Procurement” or “ICPM Significant Event Procurement.”

While it has been identified in the prior sections, the CAISO believes it important to emphasize that it has tried to structure the ICPM so that Scheduling Coordinators for LSEs can take actions to procure additional resources and minimize their potential exposure to ICPM costs. The specific “cure” opportunities provided by the ICPM are identified below.

a. Type 1 ICPM Procurement

(1) ICPM Procurement if Scheduling Coordinator Fails To Demonstrate Sufficient Local Capacity Area Resources in Either Its Annual or Monthly Resource Adequacy Plan

Under Section 40.3 of the MRTU Tariff, Scheduling Coordinators for LSEs are responsible for procuring Local Capacity Area Resources. If a Scheduling Coordinator fails to engage in the required procurement and, in accordance with existing MRTU Tariff Section 40.7 fails to cure the deficiency once it has been identified by the CAISO, Section 43.1.1 authorizes the CAISO to designate Eligible Capacity as ICPM Capacity under the ICPM. However, the CAISO can make this designation only if, after evaluating all of the Local Capacity Area Resources procured by all other Scheduling Coordinators as well as RMR Contracts, the Local Capacity Area still does not have sufficient Local Capacity Area Resources to permit compliance with the Reliability Criteria applied in the Local Capacity Technical Study. Stated differently, if other Scheduling Coordinators have over-procured, the CAISO will not designate ICPM

Capacity even if a particular Scheduling Coordinator has not met its specific obligation. This protects against unnecessary procurement by the CAISO.

Under Section 43.2.1, designations for failure by a Scheduling Coordinator to demonstrate sufficient Local Capacity Area Resource procurement in its annual plan will have a minimum ICPM designation term of one month and a maximum term of one year. To determine the term of the designation, the CAISO will examine the period of the shortfall based on its evaluation of all of the Resource Adequacy Plans. Thus, if the shortfall (accounting for both under and over procurement) is for only one month of the year, the CAISO would designate only for that month. If the shortfall is for a longer period, the CAISO would designate for a corresponding period of time. If there is a failure to identify sufficient Local Capacity Area Resources in a monthly plan, the ICPM designation term is to be for one month.

(2). ICPM Procurement In Response to Insufficient Collective Local Capacity Area Resources

In the first instance, Scheduling Coordinators for LSEs are given the opportunity to procure the necessary resources to meet their Reserve Margin and Local Capacity Area Resource obligations and reflect those purchases in their annual and monthly Resource Adequacy Plans. However, it is possible that even if all Scheduling Coordinators for LSEs in a particular local area meet their procurement obligation for Local Capacity Area Resources that the collective procurement of all such Scheduling Coordinators will still not permit the CAISO to meet Reliability Criteria. In such a circumstance, the CAISO will *first* give the respective Scheduling Coordinators a chance to purchase additional capacity to resolve the need. In that regard, if there is a collective shortfall for procurement in a Local Capacity Area, Section 43.1.2.1 provides any Scheduling Coordinator for an LSE in the affected Local Capacity Area can procure its proportionate share of the additional resources needed to meet the Reliability Criteria and avoid any further cost allocation under ICPM. Under this provision:

> Where the CAISO determines that a need for ICPM Capacity exists under Section 43.1.2, but prior to any designation of ICPM Capacity, the CAISO shall issue a Market Notice, no later than sixty (60) days before the beginning of the Resource Adequacy Compliance Year, identifying the deficient Local Capacity Area and the quantity of capacity that would permit the deficient Local Capacity Area to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1 and, where only specific resources are effective to resolve the Reliability Criteria deficiency, the CAISO shall provide the identity of such resources. Any Scheduling Coordinator may submit a revised annual Resource Adequacy Plan within thirty (30) days of the beginning of the Resource Adequacy Compliance Year demonstrating procurement of additional Local Capacity Area Resources consistent with the Market Notice issued under this Section. Any Scheduling Coordinator that provides such additional Local Capacity Area Resources consistent with the Market Notice under this

> Section shall have its share of any ICPM procurement costs under Section 43.7.3 reduced on a proportionate basis. If the full quantity of capacity is not reported to the CAISO under revised annual Resource Adequacy Plans in accordance with this Section, the CAISO may designate ICPM Capacity sufficient to alleviate the deficiency.

Thus, if a Scheduling Coordinator for an LSE procures its additional share of this capacity, it will not be assigned ICPM procurement costs if others do not cure the shortfall.

The June 25, 2007 MRTU Order required that the CAISO work with stakeholders "to explore potential opportunities to cure a collective shortfall."[38] The CAISO believes that Section 43.1.2.1 addresses the obligation established in the June 25 Order.

If Scheduling Coordinators do not procure the additional capacity necessary to ensure the Reliability Criteria can be met, Section 43.1.2 authorizes the CAISO to designate additional capacity to address the shortfall. Under Section 43.2.2, the CAISO would designate resources to respond to the collective shortfall situation for a minimum term of one month and a maximum term of one year. Again, the CAISO would base the term of the designation on its evaluation of what the period(s) of the shortfall will be after examining all of the Resource Adequacy Plans for that area.

(3). ICPM Procurement if Scheduling Coordinator Fails To Demonstrate Sufficient Resource Adequacy Resources in Either Its Annual or Monthly Resource Adequacy Plan

In addition to procuring Local Capacity Area Resources, Scheduling Coordinators must submit annual and monthly Resource Adequacy Plans demonstrating that they have procured sufficient Resource Adequacy Resources to meet the Planning Reserve Margin established by their Local Regulatory Authority.[39] For example, LSEs under the CPUC's jurisdiction must procure Resource Adequacy Resources necessary to meet a 115 percent Reserve Margin established by the CPUC.

In accordance with existing MRTU Tariff Section 40.7, the CAISO would analyze the Resource Adequacy Plans submitted by Scheduling Coordinators for LSE(s) to determine if there is a deficiency and, if so, to provide the Scheduling Coordinator the opportunity to cure the shortfall. If the Scheduling Coordinator for the LSE fails to take corrective action, Section 43.1.3 permits the CAISO to designate ICPM Capacity to ensure that additional resources are procured.

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[38] *California Indep. Sys. Operator Corp., et. al.*,119 FERC ¶ 61,313 at P 380.

[39] See Section 40.2.2.4.

Under Section 43.2.4, ICPM Capacity designated under Section 43.1.3 shall have a minimum commitment term or one month and a maximum commitment term commensurate with the maximum duration of the requirements established by the Local Regulatory Authority (currently five months for entities under the CPUC's jurisdiction) if the shortfall is in the annual Resource Adequacy Plan or a term of one month if the deficiency is in the monthly Resource Adequacy Plan. As with the determination of the length of the designation under Section 43.2.1, the CAISO would attempt to limit its procurement to the actual period(s) of the shortfall. Thus, if the Scheduling Coordinator was only short for one month of its annual plan, the CAISO would not engage in a five month procurement.

b. Type 2 Procurement For ICPM Significant Events

The CAISO recognizes that the RA program is the primary means by which resources are to be made available to meet the CAISO Balancing Authority Area operational requirements. The CAISO also understands that the Reserve Margins established by Local Regulatory Authorities should be set at a level that provides sufficient capacity by anticipating that Outages can and will occur.

Nevertheless, the CAISO needs the ability to procure additional capacity under certain circumstances. Specifically, the CAISO must be able to address a single event, or a combination of events, that is determined by the CAISO to either: (i) result in a material difference from what was assumed in the RA program for purposes of determining the RA capacity requirements, or (ii) a material change in system conditions or CAISO-Controlled Grid operations, that causes, or threatens to cause, a failure to meet Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis. Accordingly, the CAISO proposes that it be able to designate ICPM Capacity to respond to an "ICPM Significant Event" which is defined as:

> A substantial event, or a combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the resource adequacy program for purposes of determining the Resource Adequacy Capacity requirements, or produce a material change in system conditions or in CAISO Controlled Grid operations, that causes, or threatens to cause, a failure to meet Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis.
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> Examples of such "ICPM Significant Events" could include the following:
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> 1. Loss of a facility, for any cause, that affects its capability, including but not limited to:
>   a. Loss of a local RA resource after annual LSE RA showing,
>   b. Lack of RA resources causing a shortage of capacity to meet required operating reserves (accumulated total, including ongoing scheduled and forced outages) after monthly LSE RA showing, or

c. Loss of a facility, CAISO Controlled or not, that affects the deliverability of RA, Reliability Must-Run Contract ("RMR") or other resource available to the CAISO, or affects the operation of the grid;

2. Grid study error, forecast changes, incorrect assumptions, bad data, or modeling inaccuracies, including, but not limited to:
   a. An official change in the adopted Load forecast by the CEC after it has been used in RA showings by LSEs,
   b. Error in load distribution factors,
   c. Voltage or reactive resource modeling errors or resource changes,
   d. Errors relative to deliverability of RA resources to load, or
   e. Changes in non-CAISO Controlled Grid affecting previous assumptions;
3. Changes in applicable NERC or WECC reliability criteria or operating policies affecting the CAISO;
4. Insufficiency of RA units in RUC resulting in recurring use of non-RA units;[40]
5. RUC and any subsequent Hour-Ahead Scheduling Procedure ("HASP") or real time run of the Security Constrained Unit Commitment ("SCUC") cannot converge by themselves with only RA units and requires manual addition by the CAISO of non-RA units; or
6. Change in federal or state law or regulation; court action; or imposition of environmental restrictions that affect the operation of resources

Stakeholders had disparate views regarding ICPM Significant Event designations. Some stakeholders wanted to place prescriptive limitations on the CAISO's ability to make resource designations for ICPM Significant Events. Other stakeholders wanted to impose hard triggers for ICPM Significant Event designations, whereby designations would occur automatically if the "trigger" (*e.g..,* if the CAISO was required to call on a non-RA unit one time to meet reliability needs) occurred. Some stakeholders proposed that the CAISO be required to obtain the approval of the CAISO Governing Board before making an ICPM Significant Event designation or extending an ICPM Significant Event designation. Stakeholders also indicated a desire to engage in a dialogue with CAISO management regarding any procurement of ICPM capacity and identify alternative solutions that could be implemented to address the Significant Event (rather than the CAISO having to procure backstop capacity). There also were varied views on the minimum term of ICPM Significant Event designations, with loads generally supporting a shorter minimum term and suppliers supporting longer terms. Over the course of the stakeholder process, the CAISO continued to refine its ICPM

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[40] The use of non-RA units would be an indicator for the CAISO to then assess if an ICPM Significant Event has occurred. Having to use non-RA resources in RUC may mean that there are not enough RA resources and the CAISO has to call on non-RA resources in RUC. Conversely, it is possible that there are sufficient RA resources, but the economic optimization used in RUC selects a non-RA resource.

Significant Event designation proposal, and believes that its current proposal is reasonable and balances the various concerns expressed during the stakeholder process.

Although some stakeholders requested more specificity with regard to ICPM Significant Event designations, the CAISO believes that adequate flexibility is necessary to avoid the unintended consequences of an overly prescriptive approach for ICPM Significant Event designations. A flexible means is needed to address unforeseen or changed circumstances or deficiencies in resource adequacy programs where lack of action by the CAISO to address a known problem could place the CAISO in a position that threatens its ability to meet Reliability Criteria. The CAISO believes that it has proposed a reasonable definition of ICPM Significant Event, which will allow the CAISO to address contingencies and unexpected system conditions and ensure its ability to satisfy reliability requirements. Based on its experience under the RCST, the CAISO found the RCST definition of Significant Event to be overly prescriptive and, as such, it unduly limited the CAISO ability to that tool to address reliability concerns. The proposed definition of ICPM Significant Event provides the CAISO with greater flexibility to use ICPM designations to meet short-term reliability needs. In recognition of this, the CAISO added some steps to the designation process to address LSE concerns and adopted robust reporting requirements which are discussed *infra.*

Similarly, the CAISO does not want to have a prescriptive "hard trigger" for an ICPM Significant Event that does not allow it to exercise prudent judgment based on Good Utility Practice to avoid designations that are not required. Also, hard triggers could require the CAISO to make a prospective designation of capacity even though the event that led to the designation has ended or almost ended. An ICPM Significant Event designation is not a reward for service provided in the past, it is essentially a call-option for the future because the CAISO expects that a unit will be needed on a recurring basis to respond to an ongoing event(s) that creates reliability problems or otherwise threatens the CAISO's ability to meet Reliability Criteria. Stated differently, the purpose of ICPM is to designate units that are needed to meet prospective reliability requirements based on events that have occurred and which will continue in the future. Likewise, the CAISO does not believe that it is appropriate, or necessary, for the CAISO Governing Board to approve ICPM designations or extensions. CAISO management and staff, not the CAISO Governing Board, are responsible for maintaining reliable grid operations on a day-to-day basis. In any event, parties will be informed of the CAISO's staff's activities via the reporting obligations and can bring matters before either the Board or the Commission, if they believe the CAISO is not implementing the tariff properly**.**

The CAISO notes that the MSC also "support[ed] giving the [CA]ISO operators considerable discretion to declare a significant event whenever they determine that additional RA capacity is necessary to maintain grid reliability." The MSC found "the potential reliability consequences of limiting the set of circumstances when the [CA]ISO can declare a significant event are simply too great to ignore."[41]

To address the issues raised by stakeholders, CAISO has crafted a three-step ICPM Significant Event designation process in Section 43.2.5 of the MRTU Tariff that reflects a "compromise" of the various positions raised during the stakeholder process and which provides the CAISO with the designation flexibility it needs, while providing increased transparency as well as certain protections to address concerns about unnecessary procurement. In proceeding to designate ICPM Capacity for ICPM Significant Events, the CAISO proposes to proceed in the following manner:

> **Step 1:**
>
> The CAISO would identify an event or events that may violate an assumption in the resource adequacy program or result in a material change in system conditions or in CAISO-Controlled Grid operations. If the event causes, or threaten to cause, the CAISO to fail to meet Reliability Criteria, the CAISO would determine if the event is of a continuing nature that indicates the need to procure backstop capacity on a forward basis. If the answer to the first step is "yes," the CAISO would procure needed backstop resources on a forward basis for a period of 30 days, and post an explanation of the ICPM Significant Event and inform the market participants of the need to procure the backstop capacity as well as the expected duration of the ICPM Significant Event.
>
> **Step 2:**
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> If the CAISO determines that the ICPM Significant Event has an expected duration greater than 30 days, then the CAISO would extend that designation for another 60 days (for a total of 90 days from beginning of the event). During this extended time, Market Participants would have the opportunity to review the CAISO explanation for the ICPM Significant Event and provide alternative solutions that meet the CAISO's operational needs.[42]
>
> **Step 3:**
>
> Before the end of the 90-day period, the CAISO would conduct an assessment of any proposed solutions to determine whether they totally or partially mitigate the ongoing need for the ICPM Capacity. The CAISO would only extend the designation to the extent the alternatives do not meet the need for capacity.

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[41] MSC Opinion at 3-4.

[42] These would include options such as; procurement of capacity by LSEs, operational fixes by Participating Transmission Owners, or additional Demand Response.

This approach recognizes that, given the nature of ICPM Significant Events, the CAISO is not in a position to delay the designations. If, however, the CAISO must potentially extend the designation beyond the initial 90-day period, the CAISO will offer Scheduling Coordinators for LSEs the possibility of bringing forth alternatives that would alleviate the need for any further ICPM designation.

One change from the RCST, is that the CAISO will be able to make a short-term designation initially. The RCST was problematic, in part, because it required the CAISO to take into account the expected duration of the Significant Event in determining whether or not to make a designation. Thus, the CAISO had to compare the expected duration of the Significant Event with the three-month minimum term for a Significant Event designation. This made it difficult for the CAISO to utilize the RCST for shorter-term events. As proposed, the ICPM provides the CAISO with more flexibility to make designations to meet shorter-term reliability needs without being required to take into consideration the potentially burdensome cost impacts of a minimum three-month designation. However, to the extent the ICPM Significant Event is expected to last more that 30 days, the CAISO will then be able to extend the designation another 60 days. The CAISO's proposal provides for transparency regarding its decisions and an opportunity for stakeholders to be involved in identifying alternatives to an ICPM designation, thereby addressing some of the concerns expressed by LSEs.

2. All Designations are Voluntary

As proposed in Section 43.4.2, a resource owner can decline an ICPM designation when offered by the CAISO. If the designation is accepted however, the resource is responsible for performing for the full period of the designation.

Several stakeholders expressed concerns about the voluntary nature of ICPM designations. The MSC advocated prohibiting facility owners from declining Type 2 designations for ICPM Significant Events arguing that "[o]nly those unit owners able to exercise substantial unilateral market power by not being subject to the [CA]ISO's must-offer requirement will refuse the ICPM designation." [43]

The CAISO notes that the Commission has ruled that the Must Offer Obligation will terminate upon implementation of MRTU. Making participation in the ICPM by a resource mandatory could be comparable to a Must Offer Obligation; so, the CAISO is not proposing it.

Moreover, the CAISO believes that there are adequate incentives for resources to accept a designation. For example, the MSC notes that the proposed capacity price of $41/kW-year" makes it very unlikely that a unit owner will receive revenues that do

[43] MSC Opinion at 6.

not recover its variable operating costs and going-forward fixed costs." [44] Further, the ability of a unit owner to file with the Commission to seek a higher capacity payment (if its going forward costs exceed $41/kW-year, plus 10%), means that unit owners should be declining the designation for only a limited subset of reasons.

In addition, the CAISO believes that making acceptance of ICPM designations voluntary is supported by the fact that there was no consensus among stakeholders regarding the appropriate ICPM Capacity price.

Practically speaking, under the current MRTU Tariff, any market power concerns potentially should only arise in the context of the Residual Unit Commitment ("RUC") process. In this regard, with respect to participation in the CAISO's marketplace, a non-RA unit owner or operator would be confronted with a decision as to choose between accepting a certain ICPM Capacity Payment for a minimum term of one month or participating in the Integrated Forward Market and possibly receiving a high RUC Availability Payment on a daily basis.[45] The Commission has already approved the pricing for RUC capacity in its MRTU orders, and the ICPM is not intended as a mitigation measure. Further, from a reliability perspective, the CAISO will be able to meet its reliability needs whether a unit accepts an ICPM designation or is available on a daily basis through RUC. Under these circumstances, the CAISO does not believe that mandating the acceptance of ICPM designations is necessary at this time.[46]

3. Designation Criteria

The CAISO recognizes that in certain instances two or more resources may be able to resolve the need for additional capacity. Section 43.3 specifies the CAISO's proposed selection criteria to address this situation. It provides that in accordance with Good Utility Practice, the CAISO will make designations of Eligible Capacity under Section 43.1 based on the following criteria:

1) the effectiveness of the Eligible Capacity at meeting the designation criteria set forth in Section 43.1;

2) the capacity costs associated with the Eligible Capacity;

3) the quantity of a resource's available Eligible Capacity, based on a resource's PMin, relative to the remaining amount of capacity needed; and

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[44] MSC Opinion at 6.

[45] The cap on RUC Availability bid offers is $250.

[46] The CAISO's Department of Market Monitoring will , among other things, monitor the markets for signs of physical withholding.

4) for designations under Section 41.1.3, the effectiveness of the Eligible Capacity in meeting local and/or zonal constraints or other CAISO system needs.

The CAISO will allow resources, during an annual process, to specify ahead of time whether they will accept the $41/kW-year price, file with the Commission for a higher price that is specified to the CAISO during the annual notification process, or file with the Commission for a higher price but not specify such price to the CAISO during the annual process. Section 41.1.3 also provides that, in making designation decisions, the CAISO will attempt to designate lower cost resources that have specified a capacity price before designating resources that have not specified a capacity price, taking into account factors (1), (3) and (4) in that section concerning the relative effectiveness of the resource and the resource's minimum load amounts. If after applying these criteria, two or more resources are eligible for designation, the CAISO will utilize a random selection method to determine the designation between those resources.

The first criterion recognizes the obvious – only those resources that can effectively mitigate the specific capacity shortfall or address the particular reliability problems resulting from an ICPM Significant Event should be designated. A deficiency in Local Capacity Area Resources or an ICPM Significant Event that impacts a particular local area may have only a limited pool of potential suppliers to address the problem. On the other hand, for a system-wide shortage, this criterion may not eliminate many resources.

The second criterion that the CAISO will consider is the cost of the Eligible Capacity. For example, if two resources are equally effective in addressing the shortfall, the CAISO would endeavor to designate a unit at the $41/kW–year capacity price before selecting a unit with a specified price above $41/kW-year (which price must still be cost-justified in a filing with the Commission). Under this scenario, the CAISO would also designate a resource that has specified a capacity price before designating a resource that has not specified a capacity price (and which will make a cost justification filing with the Commission).

The third criterion requires that the CAISO attempt to limit its purchases to the amount of capacity needed to resolve the shortfall. Thus, if two facilities are similarly effective and have identical capacity prices, the CAISO will select the facility that has a PMin at or below the capacity that is needed before selecting a resource that has a PMin that would require over-procurement.

The fourth criterion pertains to ICPM procurement to address a deficiency in meeting annual and monthly demand and reserve margin requirements. This criterion recognizes that in selecting between two resources that are equally effective and equally priced, a prudent system operator would designate the resource that provides the most overall benefit to the system, either by resolving other locational or zonal issues or constraints or providing additional system benefits. The CAISO notes that this criterion was included in the RCST.

Finally, in the event that application of the four criteria does not identify a specific resource for designation, the CAISO will utilize a random selection process. A random selection rule is not ideal, but for the reasons discussed herein proved to be the most viable approach.

As stated previously, Section 43.3 incorporates the CAISO's objective to procure the amount of ICPM Capacity needed to meet the Reliability Criteria. Thus, the CAISO is authorized to designate a portion of the Eligible Capacity of a resource if the full output is not needed. The section also recognizes, however, that it may not always be possible to procure the exact amount of the shortfall. In such circumstances, Section 43.3 permits the CAISO to designate under the ICPM an amount of ICPM Capacity that exceeds the amount of capacity identified to ensure compliance with the Reliability Criteria set forth in Section 40.3 due to the minimum operating level or other operational requirements/limits of a resource that has available capacity to provide ICPM service.

During the stakeholder process, the CAISO considered whether to conduct a tie-breaking auction in the event two or more resources were eligible to be designated at the same price. Typically, such a tie would occur if there were multiple resources available for ICPM designation at the $41/kW-year price, but there could also be situations where the CAISO would need to pick between two resources with prices higher than $41/kW-year but would not know the prices at the time it had to make the designation decision. To resolve this situation, resources would have been given a few business days to submit lower cost offers to break the tie. Ultimately, the CAISO agreed with the comments of several Market Participants that an auction would bring additional costs, complications, timing issues, and administrative burdens to the designation process. In addition, because the CAISO would have capped the auction at the $41/kW-year price or the highest cost justified rate, the CAISO agreed with suppliers that such an auction approach would add uncertainty to the price for ICPM Capacity, likely lower the prices ultimately paid for ICPM capacity, and potentially drive down the prices of RA capacity. The CAISO also concluded that an auction would not be the most efficient or timely mechanism for designating capacity in response to ICPM Significant Events, which generally are unforeseen and unexpected and require prompt action. The CAISO believes that in most instances the effectiveness and other criteria described above will serve to narrow the choice of potential resources, thereby reducing the need for use of the random selection rule. Accordingly, the CAISO has not included provisions to implement a tie-breaking auction (or reverse auction) in the filed ICPM proposal.

D. Capacity Payment

1. The Minimum ICPM Capacity Payment

Stakeholders were extremely polarized on the issue of the appropriate pricing for ICPM Capacity. Positions ranged from $22/kW-year or paying actual going forward costs on a unit-by-unit basis, to cost of new entry ("CONE") pricing (with a PER deduction) for all ICPM procurement. In developing the proposed rate for ICPM Capacity, the CAISO considered the broad range of pricing options that covered both market-based and unit-specific cost-based approaches. Some of the specific pricing options that the CAISO considered included:

(1) simply escalating the $73/kW-year RCST target capacity price annually by an inflation factor for each year of the ICPM, and retaining the peak energy rent, *i.e.,* PER, deduction (initially considered by the CAISO);
(2) escalating the $73/kW-year RCST price annually in a stair-step manner toward a CONE price, while retaining a PER deduction (this approach was proposed in the CAISO's first White Paper issued on June 29, 2007 which also proposed a December 31, 2012 sunset date for the ICPM);[47]
(3) applying CONE pricing and a sloped demand curve with a PER deduction (this was proposed in the CAISO's second White Paper issued on October 5, 2007);
(4) pricing options based on fixed cost recovery (the CAISO's Final Proposal); and
(5) options based on auctions or sealed-bid solicitations (proposed in stakeholder comments).

The CAISO was unable to obtain a broad-based consensus on any of these pricing options. The primary criteria that the CAISO identified during the stakeholder process as critical for the pricing of backstop capacity were as follows:

- Provide transparent procurement prices;

- Ensure that pricing rules for interim capacity support efficient forward (bilateral) markets for RA, do not "interfere" with RA contracting, and do not result in undue reliance on backstop procurement;

[47] The CONE price used by the CAISO was based on the cost of new entry studies submitted in the RCST proceeding in Docket No. EL05-146. There was no stakeholder consensus on either proposals (1) or (2); so, the CAISO began exploring other alternatives as the stakeholder process progressed. In response to these options, some stakeholders argued that only a price based on recent CONE estimates should be used, while other stakeholders argued that only a cost-based price should be paid for backstop capacity procured from existing units. Some stakeholders also argued that neither proposals (1) nor (2) above adequately considered the relationship between the pricing for backstop capacity procurement and forward RA procurement. In particular, setting a high fixed price would send the wrong price signal for surplus areas and would only serve to raise prices in areas where new capacity was not needed. On the other hand, suppliers, argued that proposal (2) took to long to implement CONE pricing. The CAISO also concluded that there was no basis for paying a price based on CONE for procurement in response to ICPM Significant Events which are unforeseen, unexpected, and transitory.

- Reflect market and system conditions in the price associated with forward and spot procurement of interim capacity in different locations;

- Mitigate local market power when procuring interim capacity;

- Minimize administrative costs and implementation issues.

None of the options identified above fully addressed or satisfied these criteria. As discussed in greater detail below, the CAISO gave serious consideration to a sloped demand curve approach, which would have allowed locational pricing consistent with market conditions. However, while a few stakeholders were willing to work with a demand curve approach, many loads and suppliers objected to the demand curve approach, albeit for different reasons. Loads objected on the grounds that the demand curve would produce high prices in capacity-constrained local areas which face impediments to entry in the near-term, create market power concerns, and pre-judge capacity pricing and related issues that are being addressed in the CPUC's long-term RA proceeding. Suppliers objected to the sloped demand curve approach because it would have produced potentially very low capacity prices in the areas where there is a capacity surplus, which constitute six of the ten local areas as shown in the table below. Many of these same issues were raised by the CAISO and stakeholders with respect to other market-based approaches such as an auction or sealed-bid solicitation for backstop procurement.

After considering the various pricing options, the CAISO concluded that it was appropriate to adopt the following pricing methodology for ICPM capacity during the interim period pending implementation of a long-term RA framework and a more permanent backstop capacity procurement mechanism: the CAISO will pay ICPM resources a target capacity price equal to the higher of $41/kW-year or a resource's actual going forward costs plus a 10 percent adder (which must be supported in a cost justification filing with the Commission), without any PER deductions, *i.e.,* resources will be able to keep all of the revenues they earn in Energy and Ancillary Service markets. Going forward costs are defined for purposes of this proposal as the sum of fixed operations and maintenance ("O&M"), *ad valorem* costs, and administrative and general ("A&G") costs, which include insurance. Going forward costs are generally understood to be the minimum fixed costs that a resource needs to recover to remain available for operation. The CAISO is proposing a 10% adder that can account for any measurement error in the California Energy Commission ("CEC") study (described below) or hard to quantify costs. In addition, the minimum price of $41/kW-year can provide additional fixed cost recovery to units and will serve as a further incentive for LSEs to meet their RA requirements and not rely on the CAISO backstop.

The minimum price of $41/kW-year is derived from the going forward costs, plus 10 %, of a new 50 MW Simple Cycle CT (constructed by a merchant developer), as calculated in the CEC's 2007 study of cost of new generation in California. The CEC study is the only current comprehensive study of generation costs in California. As indicated below, the CEC studied, *inter alia,* three types of new combined cycle units and three types of new simple cycle units, which are the most common units being built in California. The small simple cycle unit (constructed by a merchant generator) had the highest going forward costs of all these units. For the reasons discussed below, the CAISO based its minimum ICPM capacity price on the going forward costs of the highest cost gas-fired unit.[48]

The results of the CEC's analysis are reflected in a Final Staff Report entitled *Comparative Costs of California Central Station Electricity Generation Technologies* that was issued in December 2007 (hereinafter referred to as the CEC Final Report).[49] Also, at an October 15, 2007 CAISO ICPM stakeholder conference, a CEC representative made a presentation entitled *Comparative Costs Of California Central Station Electricity Generation Technologies (Cost of Generation Model)*, hereinafter referred to as the CEC Presentation. The CEC Presentation discussed (and condensed), *inter alia,* the data and results reflected in the CEC's study. The CEC Final Report and the CEC Presentation are based, *inter alia,* on a survey of new combined-cycle and combustion turbine generation units constructed from 2001-2006.[50] In particular, the CEC surveyed 19 combined-cycle plants and 15 simple cycle plants constructed during that period.[51] Specifically, the CEC studied the following types of new gas units: Conventional Combined Cycle (500 MW); Conventional Combined Cycle—Duct Fired (500 MW); Advanced Combined Cycle (800 MW); Conventional Simple Cycle (100 MW); Small Simple Cycle (50 MW) and Advanced Simple Cycle (200 MW). The CEC report and the CEC Presentation, show the going forward fixed costs (*i.e.,* fixed O&M, insurance and *ad valorem* taxes)[52] of a new 50 MW Simple Cycle CT to be $36.86/kW-year for a

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[48] The CEC Final Report also includes cost estimates for an Integrated Gasification Combined Cycle ("IGCC") unit. An IGCC is a unit that uses synthetic gas produced through a gasification process (*e.g.,* gasification of coal). The CEC's cost estimates for IGCCs are based on studies and reports prepared by third parties and, unlike the cost numbers for the combined cycle and simple cycle units that the CEC studied, do not appear to be based on the costs of actual units constructed in California. CEC Final Report, Appendix B at 88-90. The source data for the CEC's cost estimates for an IGCC plant are identified in Appendix B, pages 88-90 of the CEC Final Report. The CEC Final Report (p.87) also recognizes that the "main inhibiting factor for IGCC is high capital cost, but reliability must also be proven before widespread development can occur." Under these circumstances, it clearly is not appropriate to be using the costs of IGCCs for purposes of developing a price for backstop capacity in California.

[49] The CEC Final Report is provided with this filing as Attachment F and is available on-line at: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD. In June 2007, the CEC issued a Staff Draft Report. The significant changes from the CEC Draft Report to the CEC Final Report are summarized in Appendix D of the CEC Final Report.

[50] *See* CEC Presentation at 39; CEC Final Report at 24. The CEC Presentation is Attachment G to this filing.

[51] *Id.*

[52] The CAISO notes that the CEC Final Report includes costs such as regulatory filings -- which are generally considered to be administrative and general costs -- as fixed O&M costs and treats insurance as a separate category. *See* CEC Final Report at 5.

merchant generator unit, \$32.18/kW-year for an investor owned utility ("IOU") unit , and \$32.75/kW-year for a publicly owned utility ("POU") unit. For a new Conventional Simple Cycle CT unit, the going forward costs are \$28.25/kW-year for a merchant plant, \$23.72/kW-year for an IOU plant, and \$23.93/kW-year for a POU plant. For a new Advanced Simple Cycle Unit, the going forward costs are \$20.99/kW-year for a merchant generator, \$17.23/kW-year for an IOU plant, and \$16.86/kW-year for a POU unit. [53] The going forward costs of the three types of combined cycle units are significantly below \$41/kW-year.[54]

Thus, the CAISO has based the ICPM Capacity price on the gas unit with the highest going forward costs of the six types of new combined cycle and CT units evaluated by the CEC (based on a pool of 34 new units built in California from 2001-2006). To reach a minimum ICPM capacity payment of \$41/kW-year, the CAISO incorporated a 10 percent adder[55] to the going forward costs of the small simple cycle unit, *i.e,* \$36.86/kW-year, and rounded-up. To the extent a resource owner believes that it's going forward costs, plus 10%, exceed \$41/kW-year, it may make a cost justification filing with the Commission to obtain a higher capacity payment.

There are several reasons why the CAISO chose the highest cost gas-fired unit as the basis for the minimum payment. First, this cost level should cover the going forward costs of the vast majority of eligible resources, thereby limiting the number of resource-specific cost justification filings that will have to be made with the Commission. Second, it will also provide most existing resources that have lower going forward costs with some contribution toward recovery of their capital costs and return. Third, using this cost level rather than a lower one will serve as a further incentive for LSEs to enter

[53] *See* CEC Final Report at Appendix E; *see also* CEC Presentation at 19.

[54] The CEC Final Report does not provide the going forward costs of the three types of combined cycle units it studied in terms of a \$kW-year value. *See* CEC Final Report at 10-14 for values in \$/MWh. However, applying the conversion factors provided by the CEC in the CEC Presentation (page 21), the CAISO calculated the going forward costs for such combined cycle units as follows: (1) for a new Conventional Combined Cycle Unit, the going forward costs are \$24.45/kW-year for a merchant unit, \$20.71/kW-year for an IOU unit, and \$22.48/kW-year for a POU unit; (2) for a new Conventional combined Cycle Unit-Duct, the going forward costs are \$24.40/kW-year for a merchant unit, \$20.56/kW-year for an IOU unit, and \$22.20/kW-year for a POU unit; and (3) the going forward costs for a new Advanced Combined Cycle Unit are \$22.57/kW-year for a merchant unit, \$18.88/kW-year for an IOU unit and \$20.37 for a POU unit.

[55] The 10 percent adder is in-line with adders that the Commission has approved in the past. *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange,* 96 FERC ¶61,120 at 61,519 (2001); *Public Service Co. of New Mexico*, 95 FERC ¶ 61,481 at 62,714 (2001); *Niagara Mohawk Power Corporation,* 86 FERC ¶ 61,009 at 61,025 (1999); *Terra Comfort Corporation, et al.* 52 FERC ¶ 61,241 at 61,841 (1990). The 10% adder can account for costs that are difficult to quantify or a margin for error in the CEC's study. The adder can also contribute toward additional fixed cost recovery and serve as a further incentive for LSEs to enter into contracts to meet their RA requirements and not rely on backstop capacity procurement by the CAISO.

into bilateral contracts and not rely on backstop capacity procurement by the CAISO. Finally, the voluntary nature of the ICPM designation will permit a resource to decline designation if it believes that its opportunity costs through other means are greater than the ICPM price along with retention of Energy and Ancillary Service market revenues.

The CAISO believes that its ICPM pricing proposal is a just and reasonable approach at this time, especially considering that ICPM is an interim product that will only be in place for a little more than two years and that the acceptance of designations is voluntary on the part of resource owners. Although the CAISO explored a number of market-based approaches, it decided not to pursue them for a number of reasons. First, there was no stakeholder consensus for a particular market-based approach, as both loads and suppliers objected to various features of the conceptual designs that were presented by the CAISO and other stakeholders. For example, there was significant pushback to the CAISO's sloped demand curve proposal. Second, many of the market-based options that were discussed did not: (1) adequately take into account or distinguish between surplus and scarcity conditions, or (2) effectively mitigate locational market power. Third, market-based approaches such as the demand curve approach initially proposed by the CAISO and use of cost of new entry pricing would unduly "interfere" with the bilateral RA capacity market and RA prices. Fourth, many of the market-based approaches raised complex design and implementation issues. The details of these proposals were not fully fleshed out, or provided, during the stakeholder process. Fifth, given the complexity of the issues, significantly more time and effort would have been required to develop a market-based approach, assuming that stakeholders would have even been able to get behind a specific approach. For these reasons and given the interim nature of the ICPM -- the CAISO eventually turned its attention to developing a more straightforward, cost-based proposal that could be implemented pending implementation of a long-term RA Framework and a more permanent backstop capacity procurement mechanism.

The CAISO's ICPM pricing proposal satisfies most of the criteria that the CAISO established for an interim backstop capacity mechanism. It is transparent, does not raise market power concerns, does not unduly "interfere" with bilateral RA procurement and RA capacity prices, should encourage LSEs and suppliers to negotiate contracts for capacity rather that rely on the backstop, and is simple to implement and administer. The ICPM proposal will ensure that ICPM resources recover their going forward costs, which is the minimum amount necessary to keep a resource available. Further, because of the 10% adder and the fact that the $41/kW-year price is based on the going forward costs of the highest priced gas-fired unit, the ICPM price should also provide most resources with a revenue contribution toward their capital costs and return. The proposed floor of $41/kW-year will also ensure that RA prices are not dampened by ICPM; nor does it set too a high price that would allow suppliers with locational market power to command significantly higher prices (even in local areas where there is surplus capacity but such capacity is held by a small number of suppliers). In particular, as discussed in greater detail below, the ICPM price is high enough to ensure that LSEs will not lean on the backstop and avoid RA procurement.

Also, ICPM is not intended to provide a price signal for investment in new generation capacity. It is an interim product that is intended to procure capacity from existing units on a short-term basis. The units receiving ICPM payments will generally be units that do not have an RA contract, and which will remain available during the year based on the expectation that they will be earning revenues through the markets. Under ICPM, the CAISO is paying, at a minimum, the going forward costs that are necessary for a resource to remain available for the designation period, and the CAISO will also permit the resource to retain its Energy and Ancillary Services revenues. This latter element of ICPM is consistent with the expectation that the resource has in remaining available during the year without an RA contract. Finally, the CAISO is making acceptance of ICPM designations voluntary; so, if a supplier believes that it has a better opportunity to make revenues elsewhere in the marketplace (*e.g.,* by bidding into the IFM and seeking to receive a daily RUC Availability Payment), it is free to do so and can decline the ICPM designation.

The CAISO also believes that the proposed ICPM Capacity pricing scheme will not provide a disincentive for LSEs to enter into bilateral RA contracts and instead rely on CAISO backstop procurement. The CAISO believes that it achieves this goal because the $41/kW-year price is at the upper end of the range of the prices that are being paid for RA capacity. In that regard, the CPUC has indicated that the fixed payments for bilateral RA capacity fall in the range of $15/kW-year to $45/kW-year:

> CPUC staff observations of CPUC jurisdictional LSE capacity procurement indicate that Local RA capacity is generally transacting in a $20 to $45 per kw year price range, depending on the economics of the specific local area; while capacity used to fulfill system-wide RA requirements is generally transacting in the $15 to $25 per kw year price range. It is important to note that this capacity compensation does not include a Peak Energy Rent ("PER") deduction such as that used in some eastern system operators' capacity markets, which would have the effect of reducing the overall capacity payment when energy prices are high.[56]

The proposed ICPM minimum price should be sufficient incentive for LSEs not to be deficient in meeting RA requirements, thereby inducing backstop procurement, because the $41/kW-year price is at the high end of the price range for RA capacity. Moreover, pursuant to proposed Appendix F, Schedule 6, resources that exceed 95% availability during the term of their designation will receive a price higher than $41/kW-year,[57] and resources whose going forward costs (plus 10 percent) are higher than

[56] CPUC memorandum, "CPUC Comments on "Draft Proposal to Board of Governors" posted on December 14, 2007," available at http://www.caiso.com/1f4a/1f4a9d984ad20.pdf.;*see also,* Motion to Intervene and Comments of the California Public Utilities Commission, Docket No. EL08-20, January 9, 2008, attached as Attachment H hereto.

[57] For example, at 100% availability, the Availability Factor is 1.139. For a resource with a target ICPM capacity price of $41/kW-year this results in an annual capacity price of $46.69/kW-year.

$41/kW-year can receive a higher price if they cost justify it in a filing with the Commission. Moreover, if a CPUC jurisdictional LSE is deficient, then it would pay the price for the ICPM Capacity that is procured and a CPUC-imposed penalty for being deficient in meeting its RA requirements.[58]

As discussed in the stakeholder process, pricing mechanisms were considered that would have generated an ICPM price higher than the proposed price in a least certain capacity constrained locations, but probably a lower price in other locations. However, numerous stakeholders, including buyers and sellers, as well as the MSC,[59] indicated that the backstop capacity price has a significant effect on bilateral contracting and prices in the forward RA market because the backstop essentially serves as a known deficiency charge (in addition to any CPUC penalty for deficiency by jurisdictional LSEs). In pricing ICPM Capacity, the CAISO did not want to unduly influence or "interfere" with prices in the RA market one way or the other, particularly without any market power mitigation measures in place. The CAISO believes that the proposed ICPM Capacity price achieves that objective because the minimum price of $41/kW-year is within the range of current RA capacity prices. Moreover, because the ICPM Capacity price is at the high end of the range of RA prices, it will incent LSEs to contract and not "lean" on the CAISO's backstop (especially given that the potential exists for the price to be greater than $41/kW-year). Thus, the CAISO believes that the proposed ICPM price is unlikely to affect RA market incentives by substantially raising or lowering RA prices during the interim period. The MSC agrees and recognizes that the ICPM proposal "is a compromise solution that does not have any significant defects that are likely to harm system reliability, or short-term market efficiency or interfere with the functioning of the RA procurement process.[60]

If the current RA prices of CPUC jurisdictional LSEs are an indicator of the RA prices paid by non-CPUC jurisdictional LSEs, then the ICPM price should have a similar effect on the forward RA prices and market incentives for those LSEs. As indicated above, following the conclusion of the CPUC's long-term RA proceeding, the CAISO will begin evaluating long-term capacity and backstop pricing options and will seek to develop a more permanent pricing scheme that complements RA and ensures that all appropriate incentives are in place for the long-term. The instant ICPM proposal strikes a balance that all parties should be able to live with on an interim basis until a long-term RA framework and capacity pricing mechanism are implemented.

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[58] Currently, the penalty is $40/kW-year for a deficiency in meeting local area RA requirements and $120/kW-year for a deficiency in meeting system RA requirements.

[59] As the MSC recognized, "if the ICPM price is set too high, then retailers may be forced to pay this price for capacity in areas where suppliers have significant local market power, despite the fact that there is adequate generation capacity in the area to meet the ISO's RA needs." MSC Opinion at 4.

[60] MSC Opinion at 1.

The CAISO notes that the MSC supports the ICPM pricing proposed by the CAISO. In that regard, the MSC stated:

> We also believe that a number of features of the ICPM proposal address potential concerns that we had with previous ICPM proposals. In particular, we were concerned that setting the cost of new entry (CONE) as the cap on the price of capacity for Type 1 procurement was likely to impact the price LSEs had to pay for RA capacity, particularly in areas likely to be subject to the exercise of local market power.[61]

The MSC also stated that "because the units that are at risk to be called upon to provide Type 2 [ICPM Significant Event] ICPM capacity have already made a decision to participate in the ISO's markets without an RA payment, we believe that the payment for Type 2 [ICPM Significant Event] capacity should at most recover the unit's going-forward fixed costs."[62] The MSC also added that, the "$41/kW-year ICPM payment for Type 1 and Type 2 procurement makes it very unlikely that a unit owner will receive revenues that do not recover its variable operating costs and gong-forward costs.[63]

Below, the CAISO discusses other ICPM pricing options that were considered and why the CAISO did not adopt them for the interim period.

a. Other Pricing Options Rejected by the CAISO

(1) Cost of New Entry Pricing on a Uniform Basis

In stakeholder discussions, several parties argued for continuation of the RCST pricing method, but contended that the RCST price should be changed to a price equal to recent estimates of the cost of new entry. The CAISO does not concur with the suggestion of some that there should be a uniform ICPM Capacity price based on the cost of new entry. While the CAISO considered a transitional phase-in to CONE when ICPM was being developed as a product that would be in place for five years, the ICPM as currently proposed will sunset on December 31, 2010, and possibly earlier if the CAISO is able to develop a more permanent capacity procurement mechanism prior to then. It will only be in place for a little over two years. Given its short-term existence, it is not the intent of the ICPM to provide an incentive for construction of new generation through the ICPM. The ICPM is solely a means for the CAISO to procure backstop capacity from *existing* resources on a short-term basis to meet short-term reliability needs or backstop RA procurement deficiencies. It is uncertain whether, when and to what extent ICPM Capacity will even need to be procured. The past couple of years

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61 MSC Opinion at 2.

62 *Id.* at 5.

63 *Id.* at 6.

there have not been any deficiencies in RA procurement for which the CAISO has had to backstop, and the CAISO does not expect that there will be any in the future. Further, ICPM Significant Event procurement is for unforeseen, unexpected and transitory events. Given the uncertainty about the location, frequency and duration of ICPM backstop procurement, it is highly unlikely that any resource developer or financer would be "counting on" ICPM designations for purposes of determining whether to build new generation. Thus, pricing as an incentive for new generation is not needed for ICPM. Moreover, the ICPM is not a capacity market. It is simply a tool for the CAISO to be able to procure capacity from existing resources on a timely and efficient basis in order to meet reliability needs.[64]

There are other reasons why uniform CONE pricing is inappropriate for ICPM that became clear during the stakeholder process. Cost of new entry pricing should be considered as a possible backstop price only when there is a capacity deficiency in a local area or system zone and the intent of the mechanism is to incent new generation (which is not the case with ICPM). RA requirements are currently set on both a local area and system basis. Many of the local areas are small relative to total CAISO capacity MW (as shown in the Table below) and have a concentration of ownership. Were the backstop mechanism to be designed to send investment price signals, the cost of new entry should be considered as a possible backstop price only when there is a capacity deficiency in a local area or system zone. The Table below shows the most recent evaluation of the deficiency or surplus in the 10 local capacity areas that the CAISO has defined for the CAISO grid. Only three of these local areas are deficient relative to the RA requirement and one is just above the RA requirement,[65] based on the reliability needs defined in the CAISO's local capacity studies. This assessment suggests that only few locations on the CAISO Controlled Grid would even warrant high backstop prices if a cost of new entry approach were to be applied. However, most of the capacity in those tight areas is either owned by investor owned utilities or is under multi-year RA contract, thereby indicating that even if a cost of new entry approach were to be applied, it would provide no near-term benefits to suppliers. In the remaining load pockets, where there is a surplus of capacity, additional investment does not seem to be needed in the near term; so using cost of new entry pricing to spur additional investment is neither needed nor justifiable for the period under consideration (or any other subsequent development of backstop pricing rules). Using cost of new entry as the backstop price in these circumstances could only serve to increase the forward RA prices in these areas to the extent any generation owners have market power.[66]

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[64] Backstop procurement that includes new investment typically requires a multi-year forward time frame and the identification of specific projects to fulfill an RA need, *e.g.***,** in the four-year RPM process in PJM. That does not exist here. Also, the ICPM is not a capacity market like the RPM or the forward capacity market in New England.

[65] The CAISO also notes that in the San Diego area the new Otay-Mesa plant is expected to come on-line in 2009.

[66] For example, consider a hypothetical scenario in which there is a load pocket with 50% additional capacity (MW) than is needed to fulfill the local RA requirement. There is also substantial

Table -- Comparison of 2008 Locational Capacity Requirement Need and Qualifying Capacity

Local Area Name [1/]	Total '2008 LCR Need based on Category C with Operating Procedure [1/] (MW)	Total Qualifying Capacity [1/] (MW)	Surplus or (Deficit) (MW)	Surplus or (Deficit) (%)
Humbolt	175	180	5	**3%**
North Coast/North Bay	676	883	207	
Sierra	2092	1780	**(312.00)** [2/]	**(15%)** [2/]
Stockton	786	536	**(250.00)** [2/]	**(32%)** [2/]
Greater Bay	4688	6214	1526	33%
Greater Fresno	2382	2991	609	26%
Kern	486	646	160	33%
LA Basin	10130	12093	1963	19%
Big Creek/Ventura	3658	5396	1738	48%
San Diego	3033	2919	**(114.00)** [2/]	**(4%)** [2/]
Total	28106	33638		

[1/] Source: CAISO "2008 Local Capacity Technical Analysis Report and Study Results," Updated April 3, 2007, table on page 4 of 85 pages. Data for San Diego local area is from “Report and Study Results Update for San Diego, Updated June 19, 2007, which was filed with the CPUC.

[2/] Generation deficient Local Capacity Area (or with sub-area that are deficient) – deficiency included in LCR. Generator deficient area implies that in order to comply with the criteria, at summer peak, load must be shed immediately after the first contingency.

Also, the CAISO does not believe that cost of new entry is the appropriate price benchmark for ICPM Significant Event procurement which will result from unexpected, unforeseen and transitory events which create a need for short-term procurement. It is

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concentration of ownership of that capacity because only one or two sellers exist. In that situation, the cost of new entry backstop price would be used not to incent new generation but to provide sellers with a bargaining tool in bilateral RA negotiations with buyers. This occurs because sellers would know that if buyers did not accept the offered forward RA prices, they could rely on the CAISO to procure that capacity through the backstop and at a price at cost of new entry. To mitigate this market power, there would need to be additional rules for backstop capacity pricing, such as an administrative sloped demand curve for capacity that lowers the backstop price in relation to the surplus market supply condition. This would require significantly more work to design these. As the CAISO found in evaluating such options, there would be significantly more effort to design a workable pricing mechanism than would be justified given current market conditions and the interim nature of the ICPM. The CAISO believes that time is better spent designing a long-term RA framework and long-term capacity pricing scheme, not developing demand curves and mitigation for a two-year product.

not appropriate to base payments for such procurement on the cost of new entry because the purpose of this type of procurement is to employ existing resources that are available to address short-term contingencies or reliability needs, not to provide incentives for new generation. Indeed, new generation cannot compete to provide this service. There is no legitimate basis to pay a price based on cost of new entry to existing resources under these types of transitory circumstances. Even ignoring the fact that new entry could not enter the market in the necessary timeframe to provide the service, there is no indication that new resources should even enter the market at that particular location of the ICPM Significant Event in the long-term due to the transient nature of such events.[67] Also, as the MSC has recognized, units providing ICPM Significant Event service, have already made the decision to remain available in the CAISO markets without and RA contract and with only an expectation that they will earn revenues by participating in the markets. The MSC believes that resources providing capacity under these circumstances should not be paid more than their going forward costs. At a minimum, the ICPM proposal will pay those costs, and because the CAISO has based the ICPM price on the going forward costs of the highest cost gas unit, the ICPM price should provide some contribution to the recovery of other fixed costs (*i.e.,* return of and on capital) for many units.

(2) Cost of New Entry Pricing with a Sloped Demand Curve

As mentioned above, during the stakeholder process, the CAISO considered, and even proposed, a market-proxy price derived from a sloped demand curve as a means to introduce cost of new entry pricing, but limited its impact to locations with scarcity of capacity, while also diminishing the impact of market power on the price in areas with surplus capacity. In load pockets with a concentration of ownership, even if there is a surplus of capacity, a resource owner can exert market power; therefore, mitigation measures are needed even in surplus areas to protect against market power. The sloped demand curve was capped at an estimate of the cost of new entry in areas at or below their resource adequacy requirement, and payments would have included an *ex post* PER deduction. It had a price floor for locations with surplus capacity over and above the intercept point (MW) where the demand curve would have indicated a zero price. The demand curve would not have been cleared with voluntary bids, but rather by using the actual MW capacity available in each local area (as determined by the annual LCR study) and at the system level to clear the curve. This approach essentially would have precluded physical or economic withholding and provided an approximation of a competitive price, as set by the demand curve or the price floor. This would thus have been a purely administrative mechanism that was completely transparent, as all Type 1 prices for local areas would have been known ex ante.

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[67] In the event ICPM Significant Events were to take place repeatedly in a particular location, or due to failure of RA resources, then that information will be provided to the CPUC and Local Regulatory Authorities to suggest potential modifications to the RA programs and thereby influencing forward procurement.

Although this proposal did gain support in principle from some stakeholders (although supporters had their own views on how to set the demand curve parameters), others expressed concerns that this type of pricing would (1) "pre-judge" issues being addressed in the ongoing CPUC long-term RA proceeding and the CAISO's consideration of an appropriate centralized capacity market design,(including whether a sloped or vertical demand curve is appropriate) and (2) adversely impact forward resource adequacy prices in the interim. The MSC also opposed the use of CONE.[68] Moreover, among the proposed parties that supported CONE pricing, there was no consensus on what the CONE price should be, and there was a potential range of more than $60/kW-year between high and low estimates. Further, several suppliers also objected to this approach because the sloped demand curve method would produce low prices in the majority of areas on the system where there is a surplus of supply.

The CAISO ultimately agreed that the backstop mechanism needs to be integrated with the RA design, because the backstop mechanism can influence all forward prices and thus procurement and investment decisions. Because the long-term RA design process is ongoing, it would have been an extremely difficult task to develop and implement an appropriate and effective demand curve mechanism for this interim program. Further, as noted above, when the CAISO considered adopting a sloped demand curve that included a fairly generous demand curve slope like that in effect in the New York ISO capacity market, the capacity price in six of the ten local areas with a surplus would have been $0 (absent adoption of some type of price floor). The instant ICPM proposal benefits suppliers by ensuring that the price they are paid for ICPM capacity cannot go below $41/kW-year (unless their availability is less than 95%). For these reasons, the CAISO has not proposed a sloped demand curve based pricing of backstop procurement at this time.

(3) The Proposal Presented by Calpine at the Board of Governors Meeting

At the January 29, 2008 CAISO Governing Board meeting, representatives from Calpine Corporation submitted proposed modifications to the CAISO's proposal to allow a unit either to accept the minimum "safe harbor" price or cost-justify a price at the Commission that would be based on full fixed cost recovery for a resource (including recovery of and a return on capital). The price paid to a unit would *include* a PER deduction based on the revenues that a proxy unit would earn in the market.[69] Calpine

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[68] MSC Opinion at 2 ("In particular, we were concerned that setting the cost of new entry (CONE) as the cap on the price of capacity for Type 1 procurement was likely to impact the price LSEs had to pay for RA capacity, particularly in areas likely to be subject to the exercise of local market power").

[69] The CAISO notes that there was no discussion during the stakeholder process of the appropriate characteristics of the proxy unit or how the PER calculation should be done under an LMP regime. Calpine's proposal to the Board did not flesh out the details of these features. The CAISO also notes that the RMR Condition 1 contract includes an *ex ante* adjustment for expected energy revenues on

would also require the CAISO to procure capacity for one year, even if there is not a deficiency every month of the year, if the CAISO is backstopping a local RA obligation. The CAISO does not support use of this type of pricing. Calpine is essentially proposing a type of RMR pricing for ICPM procurement, but ICPM is not RMR. Further, as the Commission is well aware, the CAISO is seeking to transition away from RMR. In any event, RMR Contracts are annual contracts for the purpose of addressing specific long-term local reliability needs not addressed through RA contracts, and the price receive under the RMR Contract is specific to each unit. In other words, the CAISO needs a particular unit, in a particular location on a long-term basis to maintain grid reliability. To the extent these circumstances exist, the CAISO is not precluded from procuring RMR capacity in the future. However, the CAISO is not using RMR to procure generic capacity that can be provided by a number of units. System wide and in most local areas there is surplus capacity where the units are similarly effective (*see* the table above). The competitive nature of these circumstances should not guarantee the recovery of full fixed costs of a unit, *i.e.,* capital and return. Further, in the areas where there currently is not a surplus, or only a slight surplus, there is either extremely little or no capacity over the RA requirement, indicating that the existing capacity is likely already under an RA contract or an RMR Contract.

Also, units procured under RMR are units that are needed on a long-term basis in that location. On the other hand, ICPM procurement is more short-term or transitory in nature. In particular, ICPM Significant Event procurement will arise following unforeseen or unplanned events. As discussed above, typically these will be events that only require capacity for a short period of time and will not be indicative of a long-term need for capacity in the area of the ICPM Significant Event. RMR-type contracts and pricing is not appropriate under these circumstances.

The CAISO also believes that its proposal is more appropriate under a market-based rate regime. The suppliers that operate in the CAISO's market place have not opted for cost-based rate recovery, they have opted for market-based rates. The CAISO does not believe that it is appropriate to guarantee full cost recovery to units under these circumstances especially where the CAISO has not identified the unit as one that is needed on a long-term basis to meet reliability needs. The Commission too has recognized that it has no obligation in a competitive marketplace to guarantee a unit seeking an RMR Contract its full traditional cost of service.[70] The Commission has also stated that it "finds no basis for a generator operating under market-based rates authority to claim that for it to remain available in a competitive market, it must receive energy revenues equivalent to a full cost of service, including depreciation and a return on and of capital.[71] The CAISO's proposal will, at a minimum, guarantee units recovery

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a per unit basis, not an *ex post* PER deduction as Calpine proposes.

[70] *Bridgeport Energy LLC,* 113 FERC ¶ 61,311 at 62,263 (2005).

[71] *Id.*

of their going forward costs (the costs necessary to keep a unit operating) for the period of their designation and will permit resources to retain all revenues they earn in the Energy and Ancillary Services markets. As indicated above, in many instances the minimum ICPM Capacity payment will likely provide an additional contribution toward a resource's full cost of service (including capital and return). As noted above, the MSC Opinion also discusses why recovery of going forward costs is the appropriate pricing mechanism for ICPM, particularly given that the payments are being made to existing units who do not have RA contracts, and as such, are remaining available during the year based on the expectation of making money in the market. The ICPM proposal is consistent with that expectation because it permits those units to retain all market revenues, plus it provides them, at a minimum, with going forward cost recovery which are the costs necessary to keep their resource available.

The CAISO also submits that Calpine's proposal is flawed because it would require the CAISO to procure a unit for one-year to backstop a local RA deficiency, even if the deficiency does not exist for the entire year. This would result in unnecessary over-procurement. In summary, Calpine is essentially seeking RMR type treatment for ICPM designations. There is no basis for that.

(4) Other Pricing Options

In the stakeholder process, CAISO also reviewed other cost-based and market-based proposals for setting the target capacity price. Certain buyers proposed paying going forward costs on a unit-by- unit basis. This would result in many ICPM payments being below RA market prices and potentially would dampen prices in the bilateral RA market. Further, such an approach would not be efficient from an administrative perspective because it would require every unit designated under the ICPM to cost justify its price. This increased price uncertainty would, in turn, impact the designation process which considers price as one of the designation criteria. For these reasons and the reasons discussed above, the CAISO determined that the minimum ICPM payment should be based on a unit with high going forward costs.

Proposed market approach considered by the CAISO included (1) conducting an auction for backstop capacity or (2) allowing resources to specify a price in a sealed bid that would be opened by the CAISO as needed for ICPM designation. The CAISO is not, in principle, opposed to such market-based approaches, but for the reasons discussed above, including the need to consider the competitive conditions in the 10 local areas with RA requirements, developing appropriate and effective market power mitigation measures would be extremely difficult and time consuming. Given the complexity of such issues, the CAISO believes that they are best addressed when the CAISO develops a more permanent backstop procurement mechanism in connection with the new long-term RA framework, and not in an interim proposal.

There were several key considerations that the CAISO used to evaluate these market-based mechanisms. First, the forward RA market is not transparent for Type 1 procurement, so the CAISO would have no prior market information to judge whether a particular ICPM offer in a location was reflective of market prices or not. Second, in many local areas, the ICPM market would be very thin and the ownership of ICPM resources concentrated. While the RA market may be reasonably competitive in the forward time frame, any unit not obtaining an RA contract would likely simply offer its capacity at the maximum price available through an ICPM auction or in a sealed bid, especially since new entrants cannot compete given the time horizon for delivery of the service. Similarly, during Significant Events, units could be designated by the CAISO for particular, transitory locational purposes, and thus might have "temporary" market power under the circumstances. Thus, in both types of procurement, the CAISO would face concerns over market power, and potentially have to define offer caps or other market power mitigation measures. In the Type 1 situation, because these rules would be transparent, might influence the forward RA market. Moreover, while these market-based mechanisms were discussed, no effective mitigation measures were defined during the stakeholder process. The sloped demand curve concept that the CAISO considered constituted an attempt to address these locational market power concerns and avoid the difficulties raised by an open auction or sealed bids by using an administrative mechanism to derive a reasonable competitive price. But, as indicated above, the demand curve itself did not gain sufficient stakeholder support and proved to be unworkable as an interim mechanism. Finally, an auction was deemed unworkable for the ICPM Significant Event procurement, given that ICPM Significant Events generally will require a prompt response by the CAISO. Thus, from an implementation perspective, use of an auction would create an additional administrative burden because it would require the CAISO to develop and administer separate pricing mechanisms for Type 1 and Type 2 procurement. This is particularly inappropriate for an interim mechanism. Primarily for these reasons, the CAISO determined not to propose either of these market-based approaches for backstop procurement. However, the CAISO will re-evaluate the use of market-based capacity procurement mechanisms it in the context of a long-term RA market design and a more permanent capacity backstop mechanism. That will allow such procurement to occur, to the extent possible in the context of a transparent market with appropriate market power mitigation rules.

b. Summary

In summary, to the parties who argue that $41/kW-year is too low of a minimum ICPM price, the CAISO would note:

- As discussed in the next section, the CAISO has provided a means by which a resource owner can accept a designation, but file with the Commission if it can support going forward costs above $41/kW-year;

- There are no good policy reasons for using the cost of new entry at this time. No other reliability generation in the CAISO service model is paid the cost of new entry. While the CAISO agrees that it *may* be appropriate to adjust capacity payments in the future in conjunction with implementation of a long-term resource adequacy framework or a centralized capacity market that is designed to elicit investment in generation, the ICPM proposal is an interim measure; long-term RA is an issue that is currently being addressed in a proceeding at the California Public Utilities Commission.

- The $41/kW-year figure is based on the going forward costs of the highest cost gas unit, of the units typically being built in California, as reflected in the CEC Final Report; and

- Acceptance of any designation is voluntary.

To the parties who would argue that the $41/kW-year price is too high, the CAISO would respond:

- The figure is consistent capacity prices in the RA markets (albeit on the higher end of the range); and

- The figure is high enough so that LSEs will be encouraged to engage in forward contracts and not inappropriately lean on the ICPM as a means of meeting their resource adequacy obligations.

2. Units May Cost-Justify Higher Capacity Payments

In their comments on the CAISO's ICPM proposals, certain stakeholders recommended that the CAISO consider situations where a resource may have "going forward" costs that are greater than the $41/kW-year annual capacity price and develop a mechanism that would accommodate these resources. To address this potential situation, the CAISO developed Section 43.6.2, which outlines a process by which a resource can qualify for a unit-specific ICPM payment above $41/kW-year. Instead of being paid the $41/kW-year, the unit is electing to be paid pursuant to a rate formula specified in the tariff.[72] That rate formula allows a unit to be paid based on the following

[72] A formula rate specifies the cost components that form the basis of the rates a utility charges its customers. *Hampshire Gas Co.*, 6 F.E.R.C. p 61,249, at 61,607 (1979). The Commission's acceptance of formula rates is premised on the rate design's "fixed, predictable nature," *Ocean State Power II*, 69 F.E.R.C. p 61,146, at 61,552 (1994), which both allows a utility to recover costs that may fluctuate over time and prevents a utility from utilizing excessive discretion in determining the ultimate amounts charged to customers. See id. Thus, " '[w]hen the Commission accepts a formula rate as a filed rate, it grants waiver of the filing and notice requirements of [s 205] [, and] [t]he utility's rates, then, can change repeatedly, without notice to the Commission, provided those changes are consistent with the formula.' " *Ala. Power Co. v. FERC*, 993 F.2d 1557, 1567-68 (D.C. Cir. 1993) (quoting *San Diego Gas & Elec. Co*., 46 F.E.R.C. p 61,363, at 62,129-30 (1989)). As further explained, because "the formula itself is the rate, not the particular components of the formula, ... periodic adjustments made in accordance with the Commission-approved formula do not constitute changes in the rate itself and accordingly do not require [s] 205 filings." *Ocean State Power II*, 69 F.E.R.C. at 61,544-45 (footnote omitted).

The CAISO notes that the Commission has previously-considered the CAISO's pass though of RMR contract costs as a formula rate, *Pub. Utils. Comm'n of Cal. V. FERC*, 254 F. 3d 250, 254 (D.C. Cir 2001).

formula: the sum of the resource's fixed O&M costs, A&G costs (including insurance), and *ad valorem* taxes, plus 10% of that amount, converted to a $/kW-year amount. On a monthly basis, a unit will receive 1/12 of the $/kW-year amount for each month it receives an ICPM designation, subject to adjustment (upward or downward) depending on the unit's availability.

If the CAISO designates a resource that has proposed a capacity price above $41/kW-year, and the sales from the resource are under the jurisdiction of the Commission, the Scheduling Coordinator for the resource shall make a cost justification filing with the Commission to determine the just and reasonable capacity payment for the going- forward costs for the resource to be used in determining the monthly ICPM Capacity Payment. If the sales from the resource are not under the jurisdiction of the Commission, the Scheduling Coordinator for the resource can make a non-jurisdictional filing with the Commission to determine the just and reasonable capacity payment for the going-forward costs for the resource to be used in determining the CAISO's monthly ICPM Capacity Payment. Essentially, the CAISO is adopting a cost justification process like that currently in place when a supplier submits a bid in the Energy market above the $400 soft cap. The supplier must subsequently make a cost justification filing at the Commission to justify the higher price.

Under Section 43.6.2, ICPM Capacity will be paid a capacity price of the higher of $41/kW-year or its actual going forward costs as determined by the Commission. In making this filing with the Commission, the Scheduling Coordinator for the resource cannot propose an amount higher than any going forward cost offer price that it had previously proposed to the CAISO as its going-forward cost offer price under Section 43.6.2.[73] In that regard, in the designation process, the CAISO will first consider resources at the $41/kW-year price and other resources that have proposed specific going forward cost offer price, before it will consider units that have not specified a price and will accept whatever going forward cost price the Commission determines is appropriate for them under the specified rate formula. This limitation is designed to prevent gaming in that it prevents units from specifying a low price just so they can get the designation and then going to the Commission and seeking a higher price.

The CAISO proposes that this cost justification filing be *limited* to a demonstration of the resource's going forward costs. The resource should be required to demonstrate its rate based on the same cost-of-service considerations used to develop the $41/kW-rate. Thus, going forward costs are to be calculated based on the following formula: fixed O&M costs, plus *ad valorem* taxes, plus administrative & general costs, plus ten percent (10%) of the foregoing amounts provided such costs

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[73] In other words if the Scheduling Coordinator for the resource had voluntarily given the CAISO a resource-specific price that the CAISO had then used in apply its selection criteria for purposes of designation, the Scheduling Coordinator can not subsequently file for a higher price with the Commission.

shall be converted to a fixed kW/year amount. Fixed O&M is composed of staffing costs and non-staffing costs for equipment, and other direct costs.

For the period between the CAISO's designation and the outcome of the Commission proceeding, the CAISO proposes to utilize the $41/kW-year rate for purposes of financial Settlement, subject to surcharge based on the Commission's determination in order to make the supplier whole as to the approved rate. The CAISO has adopted the surcharge approach rather than an alternative method based on utilization of the resources proposed resource-specific price subject to refund, because of potential concerns associated with obtaining refunds, especially as related to parties not under the Commission's jurisdiction. The use of the $41/kW-year price eliminates the potential problem of refunds as this is the lowest price a resource could be paid. Any resource-specific cost-justified price would be higher.

As with the $41/kW-year rate, the resource-specific rate would be subject to adjustment based on the ICPM Availability Factor (but not for any PER deduction). The uniform monthly shaping factor of 1/12 would also apply.

3. Shaping and Availability

The CAISO also proposes changing the "shaping factor" that was developed in the RCST so that each month a resource would be paid 1/12 of the annual capacity price.[74] The CAISO believes that this is an appropriate modification based on two factors. First, resources will have incentives that are already aligned in the summer months because the ICPM has no PER deduction for peak energy rents and there are typically higher energy rents during the summer months. Secondly, the CAISO agrees with comments from certain Market Participants that a level shaping factor better aligns with a going forward fixed-cost based rate for the capacity payment that does not vary during the year. The CAISO has no evidence that gong-forward costs vary materially depending on the month of the year.

The CAISO does not propose to modify the availability factor that was applied under the RCST that would adjust the target ICPM Capacity Payment based on the resource's actual ability to supply capacity in a month. As reflected in Appendix F, Schedule 6 of the MRTU Tariff, the ICPM Availability Factor is set at 95%. To the extent a resource is "available" more than 95% of the time during the period of its designation, it will earn a capacity payment greater than $41/kW-year. To the extent a resource is "available" less than 95% of the time during the designation period, it will earn a capacity payment less than $41/kW-year. If a resource's availability during the designation period is 40% or less, it will not earn any availability payment. The CAISO has proposed clarifying the application of the ICPM Availability Factor to ICPM Significant Event Designations in recognition of the fact that such designations can

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[74] *See* Appendix F, Schedule 6 of the MRTU Tariff.

occur and end at anytime during the month. Accordingly, the ICPM Availability Factor is determined over the month(s) or partial month(s) of the designation.

In its Order approving the RCST Settlement, the Commission approved the RCST target availability payment finding that (1) it "reflects the fact that RCST is designed to enhance reliability, and availability is a key component," and (2) the 95 percent target is a reasonable component of the RCST payment calculation."[75] The Commission also found that the "availability provisions provide economic incentives for generators to be available" and that "[h]igher availability can provide enhanced reliability -- assuming units are properly maintained -- and thus provide additional benefits merit compensation."[76] For similar reasons, the Commission should retain the same target availability level and incentive scheme for ICPM.

E. ICPM Cost Allocation

In developing the cost allocation proposal for the ICPM, the CAISO has sought to match payment responsibility to those entities that are either responsible for the shortfall or will benefit the most by the CAISO's backstop procurement. The proposal is generally consistent with the approach utilized under the RCST and previously approved by the Commission.

Pursuant to Section 43.7.1, if the CAISO makes ICPM designations under Section 43.1.1.1 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area Resources to meet its applicable Local Capacity Area capacity requirements in its annual Resource Adequacy Plan, then the CAISO proposes to allocate the total costs of the ICPM Capacity Payments *pro rata* to each Scheduling Coordinator for every deficient LSE based on the ratio of the LSE's Local Capacity Area Resource Deficiency to the sum of shortfall in Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area. This approach is consistent with basic cost causation principles because it ensures that only deficient LSEs pay for the costs of ICPM procurement resulting from such deficiencies.

Similarly, pursuant to Section 43.7.2, if the CAISO makes ICPM designations under Section 43.1.1.2 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area Resources in its monthly Resource Adequacy Plan, then the CAISO proposes to allocate the total costs of the ICPM Capacity Payments for such ICPM designations in the same manner as for in the same manner as described for an deficiency in an annual Resource Adequacy Plan. This approach ensures that deficient LSEs bear the costs of ICPM procurement

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[75] RCST Settlement Order at P 97; RCST Rehearing Order at PP 34-35.

[76] *Id.* at P 98.

that results from such deficiencies and is consistent with the cost allocation principles adopted under the RCST.

Under Section 43.7.3, if the CAISO makes designations under Section 43.1.2 for a collective shortfall, the CAISO proposes to allocate the costs of such designations to all Scheduling Coordinators for LSEs that serve Load in the deficient TAC Area(s) based on the Scheduling Coordinators' proportionate share of load in such TAC Area(s) as calculated pursuant to Section 40.3.2**.** This is the same basis upon which the original Local Capacity Area Resource requirements were developed as approved by the Commission under Section 40 of the MRTU Tariff. This allocation methodology recognizes that, for "effectiveness" procurement, no LSE was deficient in meeting its RA obligations, only that the resources procured were insufficient to meet the CAISO's defined reliability needs. The CAISO would exclude Scheduling Coordinators for LSEs that procured additional capacity in accordance with Section 43.1.2.1 on a proportionate basis, to the extent of their additional procurement. This approach recognizes that LSEs who cure their allocable portion of a collective deficiency should not be charged for the additional ICPM procurement associated with any remaining deficiency.

Pursuant to Section 43.7.4, if the CAISO makes ICPM designations under Section 43.1.3 for the failure of a Scheduling Coordinator or group of Scheduling Coordinators to procure sufficient Resource Adequacy Resources to meet applicable Demand and Reserve Margin requirements, then the CAISO proposes to allocate the total costs *pro rata* to each Scheduling Coordinator for an LSE based on the proportion of its deficiency to the aggregate deficiency. This approach is consistent with the RCST cost allocation provisions for LSEs that are deficient in meeting their RA requirements.

Under Section 43.7.5, if the CAISO makes any ICPM Significant Event designations under Section 43.1.4, the CAISO will allocate the costs of such designations to all Scheduling Coordinators for LSEs in the TAC Area(s) in which the ICPM Significant Event caused or threatened to cause a failure to meet Reliability Criteria based on the LSE's percentage of actual load in the TAC Area(s) to total load in the TAC Area(s) as recorded in the CAISO Settlements system for the actual days during any Settlement month over which the designation occurred. This allocation methodology recognizes that the load that is using the grid during an ICPM Significant Event is the load that benefits from the capacity that is procured to address the ICPM Significant Event. In other words, the ICPM Capacity has a 24 hour a day availability obligation and helps to support reliability throughout the period of the ICPM Significant Event.

The CAISO believes that the proposed cost allocation methodologies are consistent with cost causation principles.[77] Section 43.7 properly aligns the payment

[77] The Commission has stated its goal is to "allocate to each class of [customer] and to each time period and each company its fair share of costs." *Pennsylvania Power and Light Co.*, Opinion No. 176, 23 FERC ¶ 61,395 at 61,850 (1983).

obligations with the entities that are either responsible for, or benefit the most from, the ICPM procurement. The allocation should also provide the correct incentive for Scheduling Coordinators to meet their resource adequacy obligations and not lean on the procurement of others.

F. Other Elements of the ICPM

1. Sunset Date

The CAISO has always envisioned ICPM as an *interim* mechanism. The CAISO initially proposed a five-year term for the ICPM, but stakeholders generally considered that to be too long for an interim program. Accordingly, the CAISO revised its proposal. As proposed, the ICPM tariff provisions would automatically sunset on December 31, 2010. While the CAISO understands that parties need certainty with respect to their supply arrangements, the CAISO's goal ultimately is to design a long-term backstop mechanism under MRTU that works effectively under, and is aligned with, the long-term RA design that is currently under discussion in the CPUC's ongoing proceeding regarding the long-term resource adequacy framework (which includes an examination of centralized capacity market issues).

Given that (i) the CPUC's long-term resource proceeding has not been completed, (ii) experience under the new RA paradigm is limited, (iii) the CAISO will be operating without benefit of the Commission-imposed MOO for the first time since 2001, and (iv) that the new MRTU market design will be in place for the first time, the CAISO believes that it is neither feasible nor advisable to propose a *permanent* backstop procurement program at this time. The CAISO recognizes it may be appropriate to revisit the ICPM sooner than the year 2010, depending on the timing of implementation of the long-term resource adequacy program. Nothing herein prevents the CAISO and interested stakeholders from revisiting ICPM sooner than 2010.

2. Reporting

The CAISO recognizes the need for transparency in any backstop procurement, and stakeholders demanded such transparency. In particular, stakeholders requested that robust reporting obligations be implemented to ensure that all ICPM procurement is transparent to the market and that a "feedback loop" is established to provide information to stakeholders and regulators on how well RA resources, by themselves, are meeting the various operational needs of the CAISO. It is expected that such "feedback loop" would, over time, lead to improvements in the RA programs and result in less reliance on ICPM procurement.

The CAISO believes that Market Participants and regulators must have confidence that the CAISO is not over or under procuring or designating resources in a discriminatory manner. Moreover, the ICPM is designed to be utilized infrequently. If the volume of designations is higher than anticipated, the reporting obligations should trigger the need for corrective action such as modifications to the resource adequacy programs established by Local Regulatory Authorities or changes to the parameters of the CAISO's annual Local Capacity Technical Study.

The ICPM proposal includes several different types of reports to promote transparency and support the objectives identified above. The reporting requirements under ICPM are set forth in Section 43.5 *et seq.* The CAISO's ICPM reports would appropriately maintain the confidentiality of market sensitive information, while providing enough data so that the CAISO, stakeholders, the CPUC and LRAs can be informed of ICPM and other non resource adequacy procurement by the CAISO. The CAISO proposes to publish the following information:

- **Report 1: Market Notice within Two Business Days of Each Designation (Section 43.5.1).** The CAISO would issue a Market Notice within two Business Days of procuring a resource to address an ICPM Significant Event. The Market Notice would contain a preliminary description of what caused the ICPM Significant Event, the name of the resource procured, the preliminary expected duration of the ICPM Significant Event, and the initial designation period.

- **Report 2: Designation of a Resource under the ICPM Tariff (Section 43.5.2).** A "designation report" would be posted to the CAISO Web site within 30 days of when the CAISO has procured a resource through the ICPM tariff authority. It would include: (1) a description of the reason for the designation; (2) basic information such as the resource name, the amount of capacity procured, the date capacity was procured, the duration of the designation, and the price; and (3) if the reason for the designation is for an ICPM Significant Event, a discussion of the event or events that have occurred and an initial assessment of the expected duration of the ICPM Significant Event, the duration of the initial designation, and whether the initial designation has been extended (such that the backstop procurement is now for more than 30 days), and, if it has been extended, the length of the extension (days).

- **Report 3: Non-Market Commitments and Repeated Market Commitments of Non-RA Capacity and Why it was Committed (Section 43.5.3).** This report would be posted to the CAISO Web-site within 10 calendar days after the end of each month, examining the previous month. It would identify: (1) any non-market commitments of non-Resource Adequacy Resources, and (2) all market commitments of non-resource adequacy capacity (*i.e.*, capacity procured by RUC). The report would include information such as the resource name, the IOU service area and local area, the maximum capacity committed over the event, how capacity was procured (RUC, Exceptional Dispatch), the reason capacity was committed, and whether all Resource Adequacy Resources were used first and if not, why not.

- The CAISO also would include in the Operations report that currently is provided to the CAISO Governing Board at each Board meeting a summary of all ICPM costs (Section 45.3.4).

The CAISO believes that these reports will allow Market Participants and regulators to effectively monitor the ICPM. The reports will provide timely information to market participants and regulators to enable any necessary adjustments to be made to the resource adequacy program to reduce the need for potential ICPM designations in the future.

3. Counting ICPM Capacity for Resource Adequacy Purposes

During the stakeholder process, a number of commentors raised the issue of whether Scheduling Coordinators for LSEs would be given “credit” for resource adequacy purposes for capacity designated by the CAISO under the ICPM whose costs are assigned to them. The CAISO agrees that to prevent potential over-procurement, Scheduling Coordinators for LSEs should be given credit toward certain of their RA obligations as a result of certain ICPM procurement. The proposed Section 43.8 provides as follows:

- To the extent the cost of CAISO designation under Section 43.1.1.1 (designations as a result of a Scheduling Coordinator’s failure to demonstrate sufficient Local Capacity Area Resources) is allocated to a Scheduling Coordinator on behalf of an LSE under Section 43.7.1, the CAISO proposes to provide the Scheduling Coordinator on behalf of the LSE, credit towards: (1) the LSE’s Local Capacity Area Resource obligation under Section 40.3.2 and (2) the LSE’s Demand and Reserve Margin requirements determined under Section 40.

- To the extent the cost of CAISO designation under Section 43.1.2 (designations as a result of a collective deficiency in local capacity area resources) is allocated to a Scheduling Coordinator on behalf of an LSE under Section 43.7.3, the CAISO will provide the Scheduling Coordinator on behalf of the LSE credit towards the Load Serving Entity’s Demand and Reserve Margin requirements determined under Section 40.

- To the extent the cost of CAISO designation under Section 43.1.3 (designations as a result of a Scheduling Coordinator’s failure to demonstrate sufficient RA resources to meet annual and monthly Demand and Reserve Margin requirements) is allocated to a Scheduling Coordinator on behalf of an LSE under Section 43.7.4, and the designation is for greater than one month under Section 43.2.4, the CAISO will provide the Scheduling Coordinator on behalf of the LSE credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40.

These mechanisms will allow Scheduling Coordinators for LSEs to receive credit for ICPM Capacity for which they have paid. A few stakeholders also argued that backstop procurement for ICPM Significant Events should be credited toward RA showings. The CAISO does not support allowing ICPM Significant Event designations to count toward RA showings. In that regard, the reason for ICPM Significant Event procurement is that the CAISO would have determined that the RA resources already procured by LSEs were insufficient to meet Reliability Criteria. Thus, allowing LSEs to include ICPM Significant Event procurement in subsequent RA showings would result in a decrease of the available RA capacity, which was already insufficient, and this would only exacerbate the conditions that led to the ICPM Significant Event, and potentially cause additional ICPM procurement.

The credit provided under Section 43.8 is to be used solely for determining the need for the additional designation of ICPM Capacity under Section 43.1 and for allocation of ICPM costs under Section 43.7.

For each Scheduling Coordinator that is provided credit under Section 43.8, the CAISO will provide information, including the quantity of capacity procured (stated in MW), necessary to allow the CPUC, Local Regulatory Authority, or federal agency with jurisdiction over the Load Serving Entity on whose behalf the credit was provided, to determine whether the LSE should receive credit toward its resource adequacy requirements adopted by the CPUC, Local Regulatory Authority, or federal agency.

4. Definitions

The CAISO has proposed modifications to the Master Definition Supplement, Appendix A of the tariff to facilitate the ICPM program. These changes include:

- ICPM Availability Factor. A factor as set forth in Appendix F, Schedule 6 that is used in calculating a resource's monthly ICPM Capacity Payment.

- Eligible Capacity. Capacity of Generating Units, System Units, System Resources, or Participating Load that is not already under a contract to be a Resource Adequacy Resource, is not under an RMR Contract or is not currently designated as ICPM Capacity that will effectively resolve a procurement shortfall or reliability concern and thus is eligible to be designated under the ICPM in accordance with Section 43.1.

- ICPM. Interim Capacity Procurement Mechanism.

- ICPM Capacity. Capacity of Generating Units, System Units, System Resources, or Participating Load that is designated under the ICPM in accordance with Section 43 during the term of the designation.

- ICPM Capacity Payment. The payment provided pursuant to Section 43.6.

- ICPM Significant Event. A substantial event, or a combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the resource adequacy program for purposes of determining the Resource Adequacy Capacity requirements, or produce a material change in system conditions or in CAISO Controlled Grid operations, that causes, or threatens to cause, a failure to meet Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis.

- Interim Capacity Procurement Mechanism (ICPM). The Interim Capacity Procurement Mechanism, as set forth in Section 43.

- Local Capacity Area Resource Deficiency. The difference in MW between any applicable Local Capacity Area Resource requirements for an LSE as established pursuant to Section 40.3.2 and the quantity of MW shown in the LSE's Resource Adequacy Plan.

The definition most discussed during the stakeholder process was that for "ICPM Significant Event." As stated above, the CAISO recognizes that certain parties would prefer a more prescriptive definition. As discussed in greater detail *supra,* the CAISO disagrees. Given that MRTU is a new program, that CAISO Controlled Grid operations have been supported by the Commission must-offer requirement for a number of years and that this feature of the marketplace is being eliminated with the implementation of MRTU, the inability of the CAISO to perfectly predict all of the contingencies that may take place during a given year, and the CAISO's experience with the overly prescriptive definition of "Significant Event" under the RCST, the CAISO believes that the revised definition strikes a reasonable balance and provides the CAISO with the flexibility it needs to use the ICPM effectively to meet short-term reliability needs. Together with the CAISO's reporting obligations, stakeholders should have confidence that the CAISO will neither engage in excessive ICPM procurement nor will fail to make necessary designations for ICPM Significant Events where appropriate.

5. Summary of Changes

Table 1 provides a summary of the tariff changes reflected in this filing.

Table 1

Section	Reason for Change
11.20	Cost allocation is specified in Section 43.7
30.5.2.7	Correct typo and specify that ICPM Capacity is not eligible for RUC Availability Bid
39.8.1	ICPM Capacity is not eligible for Bid Adder
40.3.4	Deleted – replaced by the ICPM program in Section 43
43.	Overview of ICPM and specify sunset date
43.1	Provide basis for ICPM designation
43.2	Specifies term of ICPM designation
43.3	Specifies criteria for selection of Eligible Capacity
43.4	Specifies obligation of ICPM resources to make capacity available to the CAISO
43.5	Describes reports that the CAISO is to produce
43.6	Identifies payments for provision of ICPM Capacity
43.7	Specifies cost allocations
43.8	Identifies how ICPM designations will be credited to Scheduling Coordinators for resource adequacy purposes
Appendix A	Adds new defined terms to facilitate understanding of ICPM provisions
Appendix F, Schedule 6	Identifies the price of ICPM capacity, the monthly shaping factor, and the ICPM Availability Factor

IV. EFFECTIVE DATE AND REQUEST FOR WAIVER

The CAISO proposes to implement the ICPM on the effective date of MRTU implementation. As the Commission is aware, the CAISO will not be implementing MRTU on March 31, 2008, the proposed effective date included in the CAISO's Fourth Replacement Electric Tariff filed on December 21, 2007 in Docket No. ER08-367. As discussed in the monthly MRTU status reports filed in ER06-615, the CAISO will not be able to announce a new proposed effective date until the CAISO resumes its market simulation activities and is confident that the MRTU software is operating successfully. Accordingly, the CAISO is filing clean tariff sheets without indicating a proposed effective date and, therefore, requests waiver of Order No. 614[78] and applicable provision of Section 35.9 of the Commission's regulations. [79]

The CAISO understands that in the absence of a proposed effective date the Commission is not compelled to take any action within the 60-day time frame prescribed by the Federal Power Act. Although the Commission is not compelled to take action within any prescribed timeframe, the CAISO requests the Commission issue an order in this docket within 60-days or as soon thereafter as possible. A timely order will allow for a more orderly transition to MRTU for the CAISO and its Market Participants.

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[78] *Designation of Electric Rate Schedule Sheets*, FERC Stats. & Reg., ¶ 31,096 [Preambles 1996-2000] (2000).

[79] 18.C.F.R. § 35.9 (2007).

Because the exact date of MRTU implementation is unknown at this time, the CAISO also requests waiver, if necessary, of Section 35.3 of the Commission's regulations to permit and effective date of more than 120 days after this filing. Making the filing at this time hopefully will permit the CAISO, Market Participants, state authorities and the Commission to resolve the issues prior to the implementation of MRTU and provide greater certainty to the CAISO Markets. Granting a waiver in this instance would be consistent with the similar waivers of Section 35.3 that the Commission has granted for the other MRTU tariff filings.

V. EXPENSES

No expense or cost associated with this filing has been alleged or judged in any judicial proceeding to be illegal, duplicative, unnecessary, or demonstratively the product of discriminatory employment practices.

VI. COMMUNICATIONS

Correspondence and other communications regarding this filing should be directed to:

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VII. SERVICE

The CAISO has served copies of this filing on the Public Utilities Commission of the State of California, the California Energy Commission, the California Electricity Oversight Board, and all parties with Scheduling Coordinator Agreements under the CAISO Tariff. In addition, the CAISO has posted a copy of the filing on the CAISO Website and will provide courtesy copies of this filing to all parties in the MRTU proceeding, FERC Docket Nos. ER06-615-000 and the RCST proceeding, FERC Docket No. EL05-146.

VIII. CONTENTS OF THIS FILING

This filing comprises:

This Transmittal Letter

Attachment A:	Clean Tariff Sheets from the MRTU Tariff
Attachment B:	Blacklined Tariff Sheets showing changes from the MRTU Tariff
Attachment C:	CAISO's Proposal to Board of Governors for Interim Capacity Procurement Mechanism Tariff Filing
Attachment D:	Memorandum to the Board of Governors re *Decision on Interim Capacity Procurement Mechanism Tariff Filing,* chronology of the major stakeholder activities, and matrix of stakeholder comments and the CAISO's response
Attachment E:	MSC Opinion on ICPM Proposal
Attachment F:	December 2007 California Energy Commission, Final Staff Report, Comparative Costs of California Central Station Electricity Generation Technologies ("CEC Final Report")
Attachment G:	Presentation of Joel Klein at October 15, 2007 ICPM Stakeholder Meeting entitled *Comparative Costs of California Central Station Electricity Generation Technologies* ("CEC Presentation").
Attachment H:	Motion to Intervene and Comments of the California Public Utilities Commission, Docket No. EL08-20, January 9, 2008.

IX. CONCLUSION

The CAISO respectfully requests that the proposed ICPM as reflected in the tariff sheets attached to this filing be approved, without modification, suspension, or hearing to go into effect upon the commencement of MRTU.

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February 8, 2008

Attachment A – Clean Sheets

Interim Capacity Procurement Mechanism Amendment Filing

4th Replacement CAISO Tariff (MRTU)

February 8, 2008

Services in the following order from higher to lower capacity: (a) Regulation Up; (b) Spinning Reserve; and (c) Non-Spinning Reserve. For resources providing Regulation Up, the upper regulating limit shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid (i.e. that portion not associated with capacity committed to provide Ancillary Services) shall constitute a Bid to provide Energy.

30.5.2.7 RUC Availability Bids.

Scheduling Coordinators may submit RUC Availability Bids for specific Generating Units in the DAM; however, Scheduling Coordinators for Resource Adequacy Capacity or ICPM Capacity must submit RUC Availability Bids for that capacity to the extent that the capacity has not been submitted in a Self-Schedule or already been committed to provide Energy or capacity in the IFM. Capacity that does not have Bids for Supply of Energy in the IFM will not be eligible to participate in the RUC process. The RUC Availability Bid component is MW-quantity of non-Resource Adequacy Capacity in $/MW per hour, and $0/MW for Resource Adequacy Capacity or ICPM Capacity.

30.5.3 Demand Bids.

Each Scheduling Coordinator representing Demand, including Non-Participating Load and Aggregated Participating Load, shall submit Bids indicating the hourly quantity of Energy in MWh that it intends to purchase in the IFM for each Trading Hour of the Trading Day. Scheduling Coordinators must submit Demand Bids, including Self Schedules, for CAISO Demand at Load Aggregation Points except as provided in Section 30.5.3.2. Scheduling Coordinators must submit a zero RUC Availability Bid for the portion of their qualified Resource Adequacy Capacity. If submitting Self-Schedules at Scheduling Points for export in the IFM, the Scheduling Coordinator shall indicate whether or not the export is served from Generation from Resource Adequacy Capacity, and if submitting Self-Schedules at Scheduling Points for export in HASP the Scheduling Coordinator shall indicate whether or not the export is served from Generation from Resource Adequacy Capacity or RUC Capacity. The procedure for identifying the non-Resource Adequacy Capacity or non-RUC Capacity is specified in the Business Practice Manuals.

simulations. The FI requires solving the network model having removed all internal resources of a supplier and modifying the candidate constraints of the network model such that the flow limits of the set of candidate constraints can be exceeded with a penalty imposed for excess flow. The resulting solution to the network model produces constraint flows that can be used to calculate the FI. The FI is calculated for each constraint as the proportion of the constraint limit that is exceeded to solve the FNM without the specified supplier's supply. FI values less than zero indicate the supplier is pivotal in relieving Congestion on the specified constraint. The process is repeated by removing the supply portfolio of two and three suppliers for paths with non-negative FI. If any three suppliers are jointly pivotal in relieving congestion on a candidate path, as indicated by an FI value less than zero, the candidate path will be deemed uncompetitive. Otherwise, the candidate path will be deemed competitive. The portfolio of each supplier will be based on ownership information available to the CAISO, taking into account any material transfer of sufficient length that the transfer of control could have persistent impact on the relative shares of supply within the CAISO Balancing Authority Area. These transfers of control will be utilized in the assessment as provided to the CAISO by the supplier reflecting its triennial filing with FERC for market-based rate authority.

39.8 Eligibility for Bid Adder.

A Scheduling Coordinator submitting Bids for Generating Units is eligible to have a Bid Adder applied to a Generating Unit for the next operating month if the criteria in Section 39.8.1 are met as determined on a monthly basis in the preceding month.

39.8.1 Bid Adder Eligibility Criteria.

To receive a Bid Adder, a Generating Unit must: (i) have a Mitigation Frequency that is greater than eighty percent (80%) in the previous twelve (12) months; and (ii) must not have a contract to be a Resource Adequacy Resource for its entire Net Qualifying Capacity, or be designated under the ICPM for its entire Eligible Capacity, or be subject to an obligation to make capacity available under this CAISO Tariff. If a

Generating Unit is designated under the ICPM for a portion of its Eligible Capacity, the provisions of this section apply only to the portion of the capacity not designated. Scheduling Coordinators for Generating Units seeking to receive Bid Adders must further agree to be subject to the Frequently Mitigated Unit option for a Default Energy Bid. Run hours are those hours during which a Generating Unit has positive metered output. During the first twelve (12) months after the effective date of this Section, the Mitigation Frequency will be based on a rolling twelve (12)-month combination of RMR Dispatches and incremental Bids dispatched out of economic merit order to manage local Congestion from the period prior to the effective date of this Section, which will serve as a proxy for being subject to Local Market Power Mitigation, and a Generating Unit's Local Market Power Mitigation frequency after the effective date of this Section. Generating Units that received RMR Dispatches and/or incremental Bids dispatched out of economic merit order to manage local Congestion in an hour prior to the effective date of this Section will have that hour counted as a mitigated hour in their Mitigation Frequency. After the first twelve (12) months from the effective date of this Section, the Mitigation Frequency will be based entirely on a Generating Unit being mitigated under the MPM-RRD procedures in Sections 31 and 33.

39.8.2 New Generating Units.

For new Generating Units, with less than twelve (12)-months of operation, determination of eligibility for the Bid Adder will be based on data beginning with the first date the Generating Unit participated in the CAISO Markets through the end date of the period for which the Mitigation Frequency is being calculated. The 200 run hour criteria will be pro-rated for the proportion of a twelve (12)-month period that the new Generating Unit submitted effective Bids in the CAISO markets.

39.8.3 Bid Adder Values.

The value of the Bid Adder will be either: (i) a unit-specific value determined in consultation with the CAISO or an independent entity selected by the CAISO, or (ii) a default Bid Adder of $24/MWh. For Generating Units with a portion of their capacity identified as meeting an LSE's Resource Adequacy Requirements, that Generating Unit's Bid Adder value will be reduced by the percent of the Generating Unit's capacity that is identified as meeting an LSE's Resource Adequacy Requirements. The reduced Bid Adder will be applied to that Generating Unit's entire Default Energy Bid Curve.

40.3.4 [NOT USED]

[NOT USED]

40.3.4.1 [NOT USED]

40.3.4.2 [NOT USED]

40.4 General Requirements on Resource Adequacy Resources.

deficiencies, at least ten (10) days prior the effective month of the relevant Resource Adequacy Plan, the Scheduling Coordinator for the Load Serving Entity shall (i) demonstrate that the identified deficiency is cured by submitting a revised Resource Adequacy Plan or (ii) advise the CAISO that the CPUC, Local Regulatory Authority, or federal agency, as appropriate, has determined that no deficiency exists. In the case of a mismatch between Resource Adequacy Plan(s) and Supply Plan(s), if resolved, the relevant Scheduling Coordinator(s) must provide the CAISO with revised Resource Adequacy Plan(s) or Supply Plans, as applicable, at least ten (10) days prior to the effective month. If the CAISO is not advised that the deficiency or mismatch is resolved at least ten (10) days prior to the effective month, the CAISO will use the information contained in the Supply Plan to set the obligations of Resource Adequacy Resources under this Section 40 and/or to assign any costs incurred under this Section 40 and Section 43.

40.7.1 Other Compliance Issues.

Scheduling Coordinators representing Generating Units, System Units or System Resources supplying Resource Adequacy Capacity that fail to provide the CAISO with an annual or monthly Supply Plan, as applicable, as set forth in Section 40.7, shall be subject to Section 37.6.1. Further, Scheduling Coordinators representing Generating Units, System Units or System Resources supplying Resource Adequacy Capacity that fail to provide the CAISO with information required for the CAISO to determine Net Qualifying Capacity shall not be eligible for inclusion in the Net Qualifying Capacity annual report under Section 40.4.2 for the next Resource Adequacy Compliance Year and may be subject to Sanctions under Section 37.6.1.

40.7.2 Penalties for Non-Compliance.

The failure of a Resource Adequacy Resource or Resource Adequacy Capacity to be available to the CAISO in accordance with the requirements of this Section 40 and the failure to operate a Resource Adequacy Resource by placing it online or in a manner consistent with a submitted Bid or Default Energy Bid shall be subject to the Sanctions set forth in Section 37.2. However, any failure of the Resource Adequacy Resource to satisfy any obligations prescribed under this Section 40 during a Resource

43 Interim Capacity Procurement Mechanism.

This Section 43 shall be referred to as the Interim Capacity Procurement Mechanism (ICPM). The ICPM as well as changes made to other Sections to implement the ICPM shall expire at midnight on December 31, 2010, except that the provisions concerning compensation, cost allocation and Settlement shall remain in effect until such time as ICPM resources have been finally compensated for their services rendered under the ICPM prior to the termination of the ICPM, and the CAISO has finally allocated and recovered the costs associated with such ICPM compensation.

43.1 Designation.

The CAISO shall have the authority to designate Eligible Capacity to provide ICPM Capacity services under the ICPM as follows:

43.1.1 Scheduling Coordinator Failure to Demonstrate Sufficient Local Capacity Area Resources.

43.1.1.1 Annual Resource Adequacy Plan.

Where a Scheduling Coordinator fails to demonstrate in an annual Resource Adequacy Plan, submitted separately for each represented LSE, procurement of each LSE's share of Local Capacity Area Resources, as determined in Section 40.3.2 for each month of the following Resource Adequacy Compliance Year, the CAISO shall have the authority to designate ICPM Capacity; provided, however, that the CAISO shall not designate ICPM Capacity under this Section 43.1.1.1 until after the Scheduling Coordinator has had the opportunity to cure the deficiency set forth in Section 40.7. The CAISO's authority to designate ICPM Capacity under this Section 43.1.1.1 is to ensure that each Local Capacity Area in a TAC Area in which the LSE serves Load has Local Capacity Area Resources in the amounts and locations necessary to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1, after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all

Resource Adequacy Resources reflected in all submitted annual Resource Adequacy Plans and any supplements thereto, as may be permitted by the CPUC, Local Regulatory Authority, or federal agency and provided to the CAISO in accordance with Section 40.7, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area.

43.1.1.2 Monthly Resource Adequacy Plan.

Where a Scheduling Coordinator fails to demonstrate in a monthly Resource Adequacy Plan, submitted separately for each represented LSE, procurement of each LSE's share of Local Capacity Area Resources, as determined in Section 40.3.2 for the reported month, the CAISO shall have the authority to designate ICPM Capacity; provided, however, that the CAISO shall not designate ICPM Capacity under this Section 43.1.1.2 until after the Scheduling Coordinator has had the opportunity to cure the deficiency as set forth in Section 40.7. The CAISO's authority to designate ICPM Capacity under this Section 43.1.1.1 is to ensure that each Local Capacity Area in a TAC Area in which the LSE serves Load has Local Capacity Area Resources in the amounts and locations necessary to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1, after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual and monthly Resource Adequacy Plans and any supplements thereto, as may be permitted by the CPUC, Local Regulatory Authority, or federal agency and provided to the CAISO in accordance with Section 40.7, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area.

43.1.2 Collective Deficiency in Local Capacity Area Resources.

The CAISO shall have the authority to designate ICPM Capacity where the Local Capacity Area Resources specified in the annual Resource Adequacy Plans of all applicable Scheduling Coordinators, after the opportunity to cure under Section 43.1.2.1 has been exhausted, fail to ensure compliance in one or more Local Capacity Areas with the Local Capacity Technical Study criteria provided in Section 40.3.1.1, regardless of whether such resources satisfy, for the deficient Local Capacity Area, the minimum amount of Local Capacity Area Resources identified in the Local Capacity Technical Study, and after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual Resource Adequacy Plans, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area. The CAISO may, pursuant to this Section 43.1.2, designate ICPM Capacity in an amount and location sufficient to ensure compliance with the Reliability Criteria applied in the Local Capacity Technical Study.

43.1.2.1 LSE Opportunity to Resolve Collective Deficiency in Local Capacity Area Resources.

Where the CAISO determines that a need for ICPM Capacity exists under Section 43.1.2, but prior to any designation of ICPM Capacity, the CAISO shall issue a Market Notice, no later than sixty (60) days before the beginning of the Resource Adequacy Compliance Year, identifying the deficient Local Capacity Area and the quantity of capacity that would permit the deficient Local Capacity Area to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1 and, where only specific resources are effective to resolve the Reliability Criteria deficiency, the CAISO shall provide the identity of such resources. Any Scheduling Coordinator may submit a revised annual Resource Adequacy Plan within thirty (30) days of the beginning of the Resource Adequacy Compliance Year demonstrating procurement of additional Local Capacity Area Resources consistent with the Market Notice issued under this Section.

Any Scheduling Coordinator that provides such additional Local Capacity Area Resources consistent with the Market Notice under this Section shall have its share of any ICPM procurement costs under Section 43.7.3 reduced on a proportionate basis. If the full quantity of capacity is not reported to the CAISO under revised annual Resource Adequacy Plans in accordance with this Section, the CAISO may designate ICPM Capacity sufficient to alleviate the deficiency.

43.1.3 Scheduling Coordinator Failure to Demonstrate Sufficient Resource Adequacy Resources to Meet Annual and Monthly Demand and Reserve Margin Requirements.

The CAISO shall have the authority to designate ICPM Capacity where a Scheduling Coordinator fails to demonstrate in an annual or monthly Resource Adequacy Plan, submitted separately for each represented LSE, procurement of sufficient Resource Adequacy Resources to comply with each LSE's annual and monthly Demand and Reserve Margin requirements under Section 40; provided that the CAISO shall not designate ICPM Capacity under this Section 43.1.3 until after the Scheduling Coordinator has had the opportunity to cure the deficiency as set forth in Section 40.7.

43.1.4 ICPM Significant Events.

The CAISO may designate ICPM Capacity to provide service on a prospective basis following an ICPM Significant Event, to the extent necessary to maintain compliance with Reliability Criteria and taking into account the expected duration of the ICPM Significant Event.

43.2 Terms of ICPM Designation.

43.2.1 Term – Scheduling Coordinator Failure to Demonstrate Local Capacity Area Resources in Annual Resource Adequacy Plan.

ICPM Capacity designated under Section 43.1.1.1 shall have a minimum commitment term of one (1) month and a maximum commitment term of one (1) year, based on the period(s) of overall shortage as reflected in the annual Resource Adequacy Plans that have been submitted. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.2.2 Term – Scheduling Coordinator Failure to Demonstrate Local Capacity Area Resources in Monthly Resource Adequacy Plan.

ICPM Capacity designated under Section 43.1.1.2 shall have a minimum commitment term of one (1) month. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.2.3 Term – Insufficient Collective Local Capacity Area Resources in Annual Resource Adequacy Plans.

ICPM Capacity designated under Section 43.1.2 shall have a minimum commitment term of one (1) month and a maximum commitment term of one year, based on the period(s) of overall shortage as reflected in the annual Resource Adequacy Plans that have been submitted. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.2.4 Term – Scheduling Coordinator Failure to Demonstrate Sufficient Resource Adequacy Resources.

ICPM Capacity designated under Section 43.1.3 shall: (a) have a minimum commitment term of one (1) month and a maximum commitment term equal to the maximum annual procurement period established by the Local Reliability Authority based on the period of the deficiency reflected in the annual Resource Adequacy Plan or (b) have a commitment term of one (1) month if the deficiency is in the monthly Resource Adequacy Plan. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.2.5 Term – ICPM Significant Event.

ICPM Capacity designated under Section 43.1.4 shall have an initial term of thirty (30) days. If the CAISO determines that the ICPM Significant Event is likely to extend beyond the thirty (30) day period, the CAISO shall extend the designation for another sixty (60) days. During this additional sixty (60) day period, the CAISO will provide Market Participants with an opportunity to provide alternative solutions to meet the CAISO's operational and reliability needs in response to the ICPM Significant Event, rather than rely on the CAISO's designation of capacity under the ICPM. The CAISO shall consider and implement, if acceptable to the CAISO in accordance with Good Utility Practice, such alternative solutions provided by Market Participants in a timely manner. If Market Participants do not submit any alternatives to the designation of ICPM capacity that are fully effective in addressing the deficiencies in Reliability Criteria resulting from ICPM Significant Event, the CAISO shall extend the term of the designation under Section 43.1.4 for the expected duration of the ICPM Significant Event.

If the solutions offered by Market Participants are only partially effective in addressing the CAISO's operational and reliability needs resulting from the ICPM Significant Event, the CAISO shall extend the designation under Section 43.1.4 for the expected duration of the ICPM Significant Event, but only as to the amount of ICPM Capacity necessary to satisfy the CAISO's operational and reliability needs after taking into account the effective capacity provided by the alternative solution. If there is a reasonable alternative solution that fully resolves the CAISO's operational and reliability needs, the CAISO will not extend the designation under Section 43.1.4. In no event shall the term of the designation under Section 43.1.4 extend beyond midnight on December 31, 2010.

43.3 Selection of Eligible Capacity under the ICPM.

In accordance with Good Utility Practice, the CAISO shall make designations of Eligible Capacity as ICPM Capacity under Section 43.1 based on the following criteria:

(1) the effectiveness of the Eligible Capacity at meeting the designation criteria specified in Section 43.1;

(2) the capacity costs associated with the Eligible Capacity;

(3) the quantity of a resource's available Eligible Capacity, based on a resource's PMin, relative to the remaining amount of capacity needed; and

(4) for designations under Section 41.1.3, the effectiveness of the Eligible Capacity in meeting local and/or zonal constraints or other CAISO system needs.

In making this determination, the CAISO will attempt to designate lower cost resources that have specified a capacity price before designating resources that have not specified a capacity price, taking into account factors (1), (3) and (4) of this Section concerning the relative effectiveness of the resource and the resource's PMin. If after applying these criteria, two or more resources that are eligible for designation equally satisfy these criteria, the CAISO shall utilize a random selection method to determine the designation between those resources.

While the CAISO does not have to designate the full capability of a resource, the CAISO may designate under the ICPM an amount of ICPM Capacity from a resource that exceeds the amount of capacity identified to ensure compliance with the Reliability Criteria set forth in Section 40.3 due to the PMin or other operational requirements/limits of a resource that has available capacity to provide ICPM service. The CAISO shall not designate the capacity of a resource for an amount of capacity that is less than the resource's PMin.

43.4 Obligations of a Resource Designated under the ICPM.

43.4.1 Availability Obligations.

Capacity from resources designated under the ICPM shall be subject to all of the availability, dispatch, testing, reporting, verification and any other applicable requirements imposed under Section 40.6 on Resource Adequacy Resources identified in Resource Adequacy Plans. In accordance with those requirements, ICPM Capacity designated under the ICPM shall meet the Day-Ahead availability requirements specified in Section 40.6.1 and the Real-Time availability requirements of Section 40.6.2. Also in accordance with those requirements, Generating Units designated under the ICPM that meet the definition of Short Start Units shall have the obligation to meet the additional availability requirements of Section 40.6.3, and Generating Units designated under the ICPM that meet the definition of Long Start Units will have the rights and obligations specified in Section 40.6.7.1.

If the CAISO has not received an Economic Bid or a Self-Schedule for ICPM Capacity, the CAISO shall utilize a Default Energy Bid in accordance with the procedures specified in Section 40.6.8.

In addition to Energy Bids, resources designated under the ICPM shall submit Ancillary Service Bids for their ICPM Capacity to the extent that the resource is certified to provide the Ancillary Service.

43.4.2 Obligation To Provide Capacity and Termination.

The decision to accept an ICPM designation shall be voluntary for the Scheduling Coordinator for any resource. If the Scheduling Coordinator for a resource accepts an ICPM designation, it shall be obligated to perform for the full quantity and full period of the designation with respect to the amount of ICPM Capacity for which it has accepted an ICPM designation. If a Participating Generator's or Participating Load's Eligible Capacity is designated under the ICPM after the Participating Generator or Participating Load has filed notice to terminate its Participating Generator Agreement or Participating Load Agreement or withdraw the Eligible Capacity from its Participating Generator Agreement or Participating Load Agreement, and the Scheduling Coordinator for the resource agrees to provide service under the ICPM, then the Scheduling Coordinator shall enter into a new Participating Generator Agreement or Participating Load Agreement, as applicable, with the CAISO.

43.5 Reports.

The CAISO shall publish the following reports and notices.

43.5.1 ICPM Significant Event Market Notice.

The CAISO shall issue a Market Notice within two (2) Business Days of an ICPM designation to address each ICPM Significant Event. The Market Notice shall include a preliminary description of what caused the ICPM Significant Event, the name of the resource(s) procured, the preliminary expected duration of the ICPM Significant Event, the initial designation period, and an indication that a designation report is being prepared in accordance with Section 43.5.2.

43.5.2 Designation of a Resource under the ICPM.

Within thirty (30) days of procuring a resource under the ICPM, the CAISO shall post a designation report to the CAISO Website and provide a Market Notice of the availability of the report. The designation report shall include the following information:

(1) A description of the reason for the designation (LSE procurement shortfall, Local Capacity Area Resource effectiveness deficiency, or ICPM Significant Event), and an explanation of why it was necessary for the CAISO to utilize the ICPM authority);

(2) The following information would be reported for all backstop designations:

(a) the resource name;

(b) the amount of ICPM Capacity designated (MW);

(c) an explanation of why that amount of ICPM Capacity was designated;

(d) the date ICPM Capacity was designated;

(e) the duration of the designation; and

(f) the price for the ICPM procurement; and

(3) If the reason for the designation is an ICPM Significant Event, the CAISO will also include:

(a) a discussion of the event or events that have occurred, why the CAISO has procured ICPM Capacity, and how much has been procured;

(b) an assessment of the expected duration of the ICPM Significant Event;

(c) the duration of the initial designation (thirty (30) days); and

(d) a statement as to whether the initial designation has been extended (such that the backstop procurement is now for more than thirty (30) days), and, if it has been extended, the length of the extension.

43.5.3 Non-Market Commitments and Repeated Market Commitments of Non-Resource Adequacy Capacity.

Within ten (10) calendar days after the end of each month, the CAISO shall post a report to the CAISO Website that identifies for the prior month:

(1) Any non-market commitments of non-Resource Adequacy Capacity; and

(2) All market commitments of non-Resource Adequacy Capacity.

The CAISO will provide a Market Notice of the availability of this report. The report will not include commitments of RMR Generation capacity, Resource Adequacy Capacity or designated ICPM Capacity. The report shall include the following information:

(a) the name of the resource;

(b) the IOU Service Area and Local Capacity Area (if applicable);

(c) the maximum capacity committed in response to the event (MW);

(d) how capacity was procured (for example, by RUC or Exceptional Dispatch);

(e) the reason capacity was committed; and

(f) information as to whether or not all Resource Adequacy Resources and previously-designated ICPM Capacity were used first and, if not, why they were not.

43.5.4 Board of Governors Report.

The CAISO will include in the operations report provided to the CAISO Governing Board at each board meeting a summary of ICPM costs.

43.6 Payments to Resources Designated Under the ICPM.

Within thirty (30) days of the effective date of this Section 43, Scheduling Coordinators for Eligible Capacity may submit to the CAISO an intention to be paid a monthly ICPM Capacity Payment under Section 43.6.1 or Section 43.6.2. Scheduling Coordinators for Eligible Capacity will be able to change their selections annually within thirty (30) days of a CAISO Market Notice seeking such payment preferences. To the extent a Scheduling Coordinator for Eligible Capacity does not submit a selection to be compensated in accordance with Section 43.6.1, the Scheduling Coordinator shall be deemed to have selected to be paid on a resource-specific basis pursuant to Section 43.6.2, for purposes of the CAISO's ICPM designation determinations.

43.6.1 Monthly ICPM Capacity Payment.

Scheduling Coordinators representing resources receiving payment under this Section 43.6.1 shall receive a monthly ICPM Capacity Payment for each month of ICPM designation equal to the product of the amount of their ICPM Capacity, the relevant ICPM Availability Factor, as determined in accordance with Appendix F, Schedule 6, a monthly shaping factor as set forth in Appendix F, Schedule 6, and a fixed ICPM Capacity price of $41/kW-year, so that the formula for determining the monthly ICPM Capacity Payment would be as follows:

(ICPM Capacity MW) x (ICPM Availability Factor) x (1/12 monthly shaping factor) x ($41/kW-year).

The foregoing formula shall apply to all ICPM Capacity receiving monthly ICPM Capacity Payments under this Section 43.6.1 except for ICPM Capacity designated to respond to an ICPM Significant Event, in which case the monthly ICPM Capacity Payment shall be based proportionately on the actual number of days the resource was designated as ICPM Capacity during the month to the total number of days in the month.

For purposes of ICPM designations, except for designations for ICPM Significant Events, the ICPM Availability Factor shall be calculated as the ratio of: (1) the sum of the ICPM Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the CAISO, if less than the ICPM Capacity MW, shall be substituted for ICPM Capacity MW for each hour the resource is not available and is not on an authorized Outage, to (2) the product of ICPM Capacity MW and the total hours in the month.

For purposes of ICPM designations for ICPM Significant Events, the ICPM Availability Factor shall be calculated as the ratio of: (1) the sum of the ICPM Capacity MW for each hour across all hours of the month or part of the month for which a unit is designated, whichever is applicable, where the actual capacity MW available to the CAISO, if less than the ICPM Capacity MW, shall be substituted for ICPM Capacity MW for each hour the resource is not available and is not on an authorized Outage, to (2) the product of ICPM Capacity MW and the total hours in the month or part of the month for which a unit is designated, whichever is applicable.

For purposes of this Section 43.6.1, an authorized Outage shall be limited to a CAISO Approved Maintenance Outage.

43.6.2 Resource-Specific ICPM Capacity Payment.

If a Scheduling Coordinator for Eligible Capacity believes that the $41/kW-year ICPM Capacity price under Section 43.6.1 will not compensate a resource for its going forward costs, as calculated in accordance with the formula provided in Section 43.6.2.1, the Scheduling Coordinator may, within thirty (30) days of the effective date of this Section 43 and annually thereafter in accordance with Section 43.6, inform the CAISO of what proposed higher ICPM Capacity price would compensate the resource for its going forward costs and which the Scheduling Coordinator is willing to have the CAISO use for purposes of the ICPM designation process ("going forward cost offer price"). A Scheduling Coordinator for a resource is not required to submit a specific going forward cost offer price for such resource within thirty (30) days after the effective date of Section 43 or under the process provided for in Section 43.6; however, a Scheduling Coordinator that has not previously identified the going forward cost offer price for a resource must notify the CAISO of what that price is before any CAISO designation of that resource's capacity as ICPM Capacity can become effective.

If the CAISO designates a resource that has proposed an ICPM Capacity price above $41/kW-year, and the sales from the resource are under the jurisdiction of the FERC, the Scheduling Coordinator for the resource shall make a limited resource-specific filing before the FERC to determine the just and reasonable capacity price for the going forward costs for the resource to be used in applying the CAISO's FERC jurisdictional monthly ICPM Capacity Payment formula. If the sales from the resource are not under the jurisdiction of the FERC, the Scheduling Coordinator for the resource shall make a non-jurisdictional filing with the FERC to determine the just and reasonable capacity price for the going forward costs for the resource to be used in applying the CAISO's FERC-jurisdictional monthly ICPM Capacity Payment formula.

43.6.2.1 Going Forward Cost.

In making the cost justification filing with FERC for an ICPM Capacity price above $41/kW-year, the Scheduling Coordinator for the resource may not propose -- and shall not get paid --an amount higher than the going forward cost offer price that it had previously proposed to the CAISO as its going forward cost offer price under Section 43.6 or this Section 43.6.2, either prior to or at the time of ICPM designation.

Going forward costs for any resource-specific filing under this Section shall be calculated based on the following formula:

> (fixed operation & maintenance costs, plus ad valorem taxes, plus administrative & general costs, plus ten percent (10%) of the foregoing amounts),

provided such costs shall be converted to a fixed $/kW-year amount.

43.6.2.2 Resource-Specific Monthly ICPM Capacity Payment.

Scheduling Coordinators representing resources receiving payment under this Section 43.6.2 shall receive a monthly ICPM Capacity Payment for each month of ICPM designation equal to the product of the amount of their ICPM Capacity, the relevant ICPM Availability Factor as determined in accordance with Appendix F, Schedule 6, a monthly shaping factor as set forth in Appendix F, Schedule 6, and the resource-specific ICPM Capacity price, as determined by FERC in accordance with the following formula:

> (ICPM Capacity MW) x (ICPM Availability Factor) x (1/12 monthly shaping factor) x (the resource-specific ICPM Capacity price as determined by FERC).

The foregoing formula shall apply to all ICPM Capacity receiving monthly ICPM Capacity Payments under this Section 43.6.2 except for ICPM Capacity designated to respond to an ICPM Significant Event, in which case the monthly ICPM Capacity Payment shall be based proportionately on the actual number of days the resource was designated as ICPM Capacity during the month to the total number of days in the month.

Prior to the determination by FERC of the resource-specific going forward costs for ICPM Capacity designated and paid pursuant to this Section 43.6.2, the CAISO shall proceed as follows. For the period between the CAISO's designation and the FERC's determination, the CAISO shall utilize the $41/kW-year rate for purposes of the resource-specific monthly ICPM Capacity Payment for financial Settlement. This amount shall be subject to surcharge based on the outcome of the FERC proceeding so that the resource will receive any higher actual resource-specific payment as determined by FERC for the full period of the ICPM designation. Once approved by FERC, the CAISO shall apply the higher of $41/kW-year or the resource-specific ICPM Capacity price as determined by the FERC.

For purposes of ICPM designations, except for designations for ICPM Significant Events, the ICPM Availability Factor shall be calculated as the ratio of: (1) the sum of the ICPM Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the CAISO, if less than the ICPM Capacity MW, shall be substituted for ICPM Capacity MW for each hour the resource is not available and is not on an authorized Outage, to (2) the product of ICPM Capacity MW and the total hours in the month.

For purposes of ICPM designations for ICPM Significant Events, the ICPM Availability Factor shall be calculated as the ratio of: (1) the sum of the ICPM Capacity MW for each hour across all hours of the month or part of the month for which a unit is designated, whichever is applicable, where the actual capacity MW available to the CAISO, if less than the ICPM Capacity MW, shall be substituted for ICPM Capacity MW for each hour the resource is not available and is not on an authorized Outage, to (2) the product of ICPM Capacity MW and the total hours in the month or part of the month for which a unit is designated, whichever is applicable.

For purposes of this Section 43.6.2, an authorized Outage shall be limited to a CAISO Approved Maintenance Outage.

43.6.3 Market Payments.

In addition to the ICPM Capacity Payment identified in Section 43.6, ICPM resources shall be entitled to retain any revenues received as a result of their selection in the CAISO Markets, provided, however, that ICPM resources are required to participate in the RUC process through submission of a zero ($0) dollar RUC Availability Bid and are not eligible to receive compensation through the RUC process.

43.7 Allocation of ICPM Capacity Payment Costs.

For each month, the CAISO shall allocate the costs of ICPM Capacity Payments made pursuant to Section 43.6 as follows:

43.7.1 LSE Shortage of Local Capacity Area Resources in Annual Resource Adequacy Plan.

If the CAISO makes ICPM designations under Section 43.1.1.1 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area Resources to meet its applicable Local Capacity Area capacity requirements in its annual Resource Adequacy Plan, then the CAISO shall allocate the total costs of the ICPM Capacity Payments for such ICPM designations (for the full term of those ICPM designations) pro rata to each Scheduling Coordinator for an LSE based on the ratio of its Local Capacity Area Resource Deficiency to the sum of the deficiency of Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area. The Local Capacity Resource Deficiency under this Section shall be computed on a monthly basis and the ICPM Capacity Payments allocated based on deficiencies during the month(s) covered by the ICPM designation(s).

43.7.2 LSE Shortage of Local Capacity Area Resources in Monthly Resource Adequacy Plan.

If the CAISO makes ICPM designations under Section 43.1.1.2 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area Resources to meet its applicable Local Capacity Area capacity requirements in its monthly Resource Adequacy Plan, then the CAISO shall allocate the total costs of the ICPM Capacity Payments for such ICPM designations (for the full term of those ICPM designations) pro rata to each Scheduling Coordinator for an LSE based on the ratio of its Local Capacity Area Resource Deficiency to the sum of the deficiency of Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area.

43.7.3 Collective Deficiency in Local Capacity Area Resources.

If the CAISO makes designations under Section 43.1.2 the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs serving Load in the TAC Area(s) in which the deficient Local Capacity Area was located. The allocation will be based on the Scheduling Coordinators' proportionate share of Load in such TAC Area(s) as determined in accordance with Section 40.3.2, excluding Scheduling Coordinators for LSEs that procured additional capacity in accordance with Section 43.1.2.1 on a proportionate basis, to the extent of their additional procurement.

43.7.4 LSE Shortage of Demand or Reserve Margin Requirements in Annual or Monthly Resource Adequacy Plan.

If the CAISO makes ICPM designations under Section 43.1.3, then the CAISO will allocate the total costs of the ICPM Capacity Payments for such ICPM designations (for the full term of those ICPM designations) pro rata to each LSE based on the proportion of its deficiency to the aggregate deficiency.

43.7.5 Allocation of ICPM Significant Event Costs.

If the CAISO makes any ICPM Significant Event designations under Section 43.1.4, the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs that serve Load in the TAC Area(s) in which the ICPM Significant Event caused or threatened to cause a failure to meet Reliability Criteria based on the percentage of actual Load of each LSE represented by the Scheduling Coordinator in the TAC Area(s) to total Load in the TAC Area(s) as recorded in the CAISO Settlement system for the actual days during any Settlement month period over which the designation has occurred.

43.8 Crediting of ICPM Capacity.

The CAISO shall credit ICPM designations to the resource adequacy obligations of Scheduling Coordinators for Load Serving Entities as follows:

(a) To the extent the cost of ICPM designation under Section 43.1.1.1 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.7.1, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards (1) the LSE's Local Capacity Area Resource obligation under Section 40.3.2 in an amount equal to the LSE's pro rata share of the ICPM Capacity designated under Section 43.1.1.1 and (2) the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the ICPM Capacity designated under Section 43.1.1.1.

(b) To the extent the cost of CAISO designation under Section 43.1.2 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.7.3, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the ICPM Capacity designated under Section 43.1.2.

(c) To the extent the cost of ICPM designation under Section 43.1.3 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.7.4, and the designation is for greater than one month under Section 43.2.4, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the ICPM Capacity designated under Section 43.1.3.

(d) The credit provided in this Section shall be used for determining the need for the additional designation of ICPM Capacity under Section 43.1 and for allocation of ICPM costs under Section 43.7.

(e) For each Scheduling Coordinator that is provided credit pursuant to this Section, the CAISO shall provide information, including the quantity of capacity procured in MW, necessary to allow the CPUC, other Local Regulatory Authority, or federal agency with jurisdiction over the LSE on whose behalf the credit was provided to determine whether the LSE should receive credit toward its resource adequacy requirements adopted by such agencies or authorities.

Electric Facility	An electric resource, including a Generating Unit, System Unit, or a Participating Load.
Eligible Capacity	Capacity of Generating Units, System Units, System Resources, or Participating Load that is not already under a contract to be a Resource Adequacy Resource, is not under an RMR Contract or is not currently designated as ICPM Capacity that effectively resolves a procurement shortfall or reliability concern and thus is eligible to be designated under the ICPM in accordance with Section 43.1.
Eligible Customer	(i) any utility (including Participating TOs, Market Participants and any power marketer), Federal power marketing agency, or any person generating Energy for sale or resale; Energy sold or produced by such entity may be Energy produced in the United States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled transmission service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Participating TO.
Eligible Intermittent Resource	A Generating Unit that is powered solely by 1) wind, 2) solar energy, or 3) hydroelectric potential derived from small conduit water distribution facilities that do not have storage capability.
ELS Resource	Extremely Long-Start Resource
Embedded Control Area (ECA)	A Control Area that has direct interconnections exclusively with the CAISO Control Area, and no other Control Area.
Emissions Cost Demand	The level of Demand specified in Section 11.18.3.
Emissions Cost Invoice	The invoice submitted to the CAISO in accordance with Section 11.18.6.
Emissions Costs	The mitigation fees, excluding capital costs, assessed against a Generating Unit by a state or federal agency, including air quality districts, for exceeding applicable NOx emission limitations.
Emissions Eligible Generator	A Generator with a Generating Unit that is a BCR Eligible Resource.
EMS	Energy Management System

Hour-Ahead Scheduling Process (HASP)	The process conducted by the CAISO beginning at seventy-five minutes prior to the Trading Hour through which the CAISO conducts the following activities: 1) accepts Bids for Supply of Energy, including imports, exports and Ancillary Services imports to be supplied during the next Trading Hour that apply to the MPM-RRD, RTUC, STUC, and RTD; 2) conducts the MPM-RRD on the Bids that apply to the RTUC, STUC, and RTD; and 3) conducts the RTUC for the hourly pre-dispatch of Energy and Ancillary Services.
Hourly Demand	The average of the instantaneous Demand integrated over a single clock hour, in MWh.
Hourly Real-Time LAP Price	The load deviation weighted average of the hourly average of the Dispatch Interval LMPs for the LAP in the relevant Trading Hour used for the settlement of UIE.
HVAC	High Voltage Access Charge
HVTRR	High Voltage Transmission Revenue Requirement
Hydro Spill Generation	Hydro-electric Generation in existence prior to the CAISO Operations Date that: i) has no storage capacity and that, if backed down, would spill; ii) has exceeded its storage capacity and is spilling even though the generators are at full output; iii) has inadequate storage capacity to prevent loss of hydro-electric Energy either immediately or during the forecast period, if hydro-electric Generation is reduced; or iv) has increased regulated water output to avoid an impending spill.
IBAAOA	Interconnected Balancing Authority Area Operating Agreement
ICAOA	Interconnected Control Area Operating Agreement
ICPM	Interim Capacity Procurement Mechanism
ICPM Availability Factor	A factor as set forth in Appendix F, Schedule 6 that is used in calculating a resource's monthly ICPM Capacity Payment.

ICPM Capacity	Capacity of Generating Units, System Units, System Resources, or Participating Load that is designated under the ICPM in accordance with Section 43 during the term of the designation.
ICPM Capacity Payment	The payment provided pursuant to Section 43.6.
ICPM Significant Event	A substantial event, or a combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the resource adequacy program for purposes of determining the Resource Adequacy Capacity requirements, or produce a material change in system conditions or in CAISO Controlled Grid operations, that causes, or threatens to cause, a failure to meet Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis.
Identification Code	An identification number assigned to each Scheduling Coordinator by the CAISO.

Interconnection System Impact Study	An engineering study conducted by the Participating TO(s), CAISO, or a third party consultant for the Interconnection Customer that evaluates the impact of the proposed interconnection on the safety and reliability of the CAISO Controlled Grid and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.
Interconnection System Impact Study Agreement	The form of agreement accepted by FERC and posted on the CAISO Website for conducting the Interconnection System Impact Study.
Interest	Interest shall be calculated in accordance with the methodology specified for interest on refunds in the regulations of FERC at 18 C.F.R. §35.19(a)(2)(iii) (1996). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment, except as provided in Section 11.29.13.1. When payments are made by mail, bills shall be considered as having been paid on the date of receipt.
Interim Black Start Agreement	An agreement entered into between the CAISO and a Participating Generator (other than a Reliability Must-Run Agreement) for the provision by the Participating Generator of Black Start capability and Black Start Energy on an interim basis until the introduction by the CAISO of its Black Start auction (or until terminated earlier by either party in accordance with its terms).
Interim Capacity Procurement Mechanism (ICPM)	The Interim Capacity Procurement Mechanism, as set forth in Section 43.
Intermediary Balancing Authority	The Balancing Authority that operates an Intermediary Balancing Authority Area.

Local Capacity Area Resource Deficiency	The monthly difference in MW between any applicable Local Capacity Area Resource requirements for an LSE as established pursuant to Section 40.3.2 and the quantity of monthly MW shown in the LSE's Resource Adequacy Plan.
Local Capacity Area Resources	Resource Adequacy Capacity from a Generating Unit listed in the technical study or Participating Load that is located within a Local Capacity Area capable of contributing toward the amount of capacity required in a particular Local Capacity Area.
Local Capacity Technical Study	The study performed by the CAISO pursuant to Section 40.3.
Local Furnishing Bond	Tax-exempt bonds utilized to finance facilities for the local furnishing of electric energy, as described in section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).
Local Furnishing Participating TO	Any Tax-Exempt Participating TO that owns facilities financed by Local Furnishing Bonds.
Local Market Power Mitigation (LMPM)	The mitigation of market power that could be exercised by an entity when it is needed for local reliability services due to its location on the grid and a lack of competitive supply at that location pursuant to Section 39.7.
Local Publicly Owned Electric Utility	A municipality or municipal corporation operating as a public utility furnishing electric services, a municipal utility district furnishing electric services, a public utility district furnishing electric services, an irrigation district furnishing electric services, a state agency or subdivision furnishing electric services, a rural cooperative furnishing electric services, or a Joint Powers Authority that includes one or more of these agencies and that owns Generation or transmission facilities, or furnishes electric services over its own or its members' electric Distribution System.
Local Regulatory Authority (LRA)	The state or local governmental authority, or the board of directors of an electric cooperative, responsible for the regulation or oversight of a utility.

CAISO TARIFF APPENDIX F

SCHEDULE 6

ICPM SCHEDULES

Monthly ICPM Capacity Payment

The monthly ICPM Capacity Payment shall be calculated by multiplying the monthly shaping factor of 1/12 by the annual ICPM Capacity price of $41/kW-year in accordance with Section 43.6.1, unless the Scheduling Coordinator for the ICPM Capacity resource has agreed to another price that has been determined in accordance with Section 43.6.2.

Availability

The target availability for a resource designated under ICPM is 95%. Incentives and penalties for availability above and below the target are as set forth in the table below, entitled “Availability Factor Table.” The CAISO shall calculate availability on a monthly basis using actual availability data. The ICPM Availability Factor for each month shall be calculated using the following curve:

AVAILABILITY FACTOR TABLE

Availability (excluding only Scheduled Maintenance)	**Capacity Payment Factor**	**ICPM Availability Factor**
100%	3.3%	1.139
99%	3.3%	1.106
98%	3.3%	1.073
97%	2.5%	1.040
96%	1.5%	1.015
95%	-	1.000
94%	-1.5%	.985
93%	-1.5%	.970
92%	-1.5%	.955
91%	-1.5%	.940
90%	-1.5%	.925
89-80%	-1.7%*	.908-.755
79-41%	-1.9%*	.736-.014
-40%	-	0.0

*The “Capacity Payment Factor” decreases by 1.7% and 1.9% respectively for every 1% decrease in availability.

The ICPM Capacity Payment shall be adjusted upward from the 95% availability starting point by the positive percentages listed as the "Capacity Payment Factor" above, by multiplication by the amounts listed for each ICPM Availability Factor above 95%, so that, for example, if a 97% availability is achieved for the month, then the ICPM Capacity Payment for that month would be the monthly value for 95% plus an additional 4% (1.5% for the first percent availability above 95%, and 2.5% for the second percent availability above 95%), i.e., multiplication of the otherwise applicable ICPM Capacity Payment by the ICPM Availability Factor of 1.040. Reductions in the ICPM Capacity Payment shall be made correspondingly according to the "Capacity Payment Factor" above for monthly availability levels falling short of the 95% availability starting point, by multiplication by the amounts listed for each ICPM Availability Factor below 95%.

Attachment B – Blacklines

Interim Capacity Procurement Mechanism Amendment Filing

4th Replacement CAISO Tariff (MRTU)

February 8, 2008

* * *

30.5.2.7 RUC Availability Bids.

Scheduling Coordinators may submit RUC Availability Bids for specific Generating Units in the DAM; however, Scheduling Coordinators for Resource Adequacy~~.~~ Capacity or ICPM Capacity must submit RUC Availability Bids for that capacity to the extent that the capacity has not been submitted in a Self-Schedule or already been committed to provide Energy or capacity in the IFM. Capacity that does not have Bids for Supply of Energy in the IFM will not be eligible to participate in the RUC process. The RUC Availability Bid component is MW-quantity of non-Resource Adequacy Capacity in $/MW per hour, and $0/MW for Resource Adequacy Capacity or ICPM Capacity.

* * *

39.8.1 Bid Adder Eligibility Criteria.

To receive a Bid Adder, a Generating Unit must: (i) have a Mitigation Frequency that is greater than eighty percent (80%) ~~percent~~ in the previous twelve (12) months; and (ii) must not have a~~n~~ contract to be a Resource Adequacy Resource for its entire Net Qualifying~~net dependable c~~Capacity, or be designated under the ICPM for its entire Eligible Capacity, or be subject to an obligation to make capacity available under this CAISO Tariff. If a~~Additionally, the Scheduling Coordinator for the~~ Generating Unit is designated under the ICPM for a portion of its Eligible Capacity, the provisions of this section apply only to the portion of the capacity not designated. Scheduling Coordinators for Generating Units seeking to receive Bid Adders must further agree to be subject to the Frequently Mitigated Unit ~~O~~option for a Default Energy Bid. Run hours are those hours during which a Generating Unit has positive metered output. During the first twelve (12) months after the effective date of this Section, the Mitigation Frequency will be based on a rolling twelve (12)-month combination of RMR ~~d~~Dispatches and incremental ~~b~~Bids dispatched out of economic merit order to manage local ~~c~~Congestion from the period prior to the effective date of this Section, which will serve as a proxy for being subject to Local Market Power Mitigation, and a Generating Unit's Local Market Power Mitigation frequency after the effective date of this Section. Generating Units that received RMR ~~d~~Dispatches and/or incremental ~~b~~Bids dispatched out of economic merit order to manage local Congestion in an hour prior to the effective date of this Section will have that hour counted as a mitigated hour in their Mitigation Frequency. After the first twelve (12) months from the effective date of this Section, the Mitigation Frequency will be based entirely on a Generating Unit being mitigated under the MPM-RRD procedures in Sections 31 and 33.

* * *

40.3.4 [NOT USED]~~Procurement of Local Capacity Area Resources by the CAISO.~~

~~The CAISO may procure Local Capacity Area Resources, pursuant to applicable provisions of the CAISO Tariff, including any mechanism incorporated into the CAISO Tariff specifically to permit procurement of Local Capacity Area Resources by the CAISO, to the extent:~~

~~(a) a Scheduling Coordinator representing a Load Serving Entity serving Load in the TAC Area in which the Local Capacity Area is located fails to demonstrate in an annual Resource Adequacy Plan procurement of the Load Serving Entity's share of Local Capacity Area Resources, as determined in Section 40.3.2, in which case the CAISO may procure Local Capacity Area Resources to remedy the deficiency; provided that the CAISO shall not procure Local Capacity Area Resources to remedy the deficiency of the Load Serving Entity unless in the aggregate a deficiency in the Local Capacity Area exists that results in the failure to comply with the Reliability Criteria applied in the Local Capacity Technical Study, after assessing the effectiveness of Generating Units under Reliability Must-Run Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual Resource Adequacy Plans and any supplements thereto, as may be permitted by the CPUC, Local Regulatory Authority, or federal agency and provided to the CAISO in accordance with Section 40.7, whether or not such Resource Adequacy Resources are located in the applicable Local Capacity Area; or~~

~~(b) the Local Capacity Area Resources specified in the annual Resource Adequacy Plans of all Scheduling Coordinators fail to permit or ensure compliance in one or more Local Capacity Areas with the Reliability Criteria applied in the Local Capacity Technical Study, regardless of whether such resources satisfy, for the deficient Local Capacity Area, the minimum amount of Local Capacity Area~~

~~Resources identified in the Local Capacity Technical Study and after assessing the effectiveness of Generating Units under Reliability Must-Run Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual Resource Adequacy Plans, whether or not such Resource Adequacy Resources are located in the applicable Local Capacity Area, in which case the CAISO will procure Local Capacity Area Resources in the Local Capacity Area in an amount and location sufficient to permit or ensure compliance with the Reliability Criteria applied in the Local Capacity Technical Study.~~

~~The cost of CAISO procurement under this Section shall be allocated in accordance with Section 11. To the extent the cost of CAISO procurement under this Section is allocated to a Scheduling Coordinator on behalf of a Load Serving Entity, that Scheduling Coordinator will receive credit toward its Local Capacity Area Resource obligation for the Load Serving Entity's pro rata share of the procured Local Capacity Area Resources. Whether or not the share of the Local Capacity Area Resources procured by the CAISO under this Section may count towards satisfaction of a Load Serving Entity's Reserve Margin shall be determined by the CPUC, Local Regulatory Authority, or federal agency with jurisdiction over the Load Serving Entity, unless the CPUC, Local Regulatory Authority, or federal agency has failed to establish a Reserve Margin, in which case the CAISO will assign the Load Serving Entity's share of the Local Capacity Area Resources towards satisfaction of its Reserve Margin pursuant to Sections 40.2.1.1(b), 40.2.2.1(b), and 40.2.3.1(b). For each Scheduling Coordinator that is allocated the cost of CAISO procurement under this Section on behalf of an LSE, the CAISO will provide information, including the quantity of capacity procured in MW, necessary to allow the CPUC, Local Regulatory Authority, or federal agency with jurisdiction over the LSE on whose behalf costs were allocated to determine whether the LSE should receive credit toward its Reserve Margin for the CAISO's procurement under this Section.~~

40.3.4.1 [NOT USED]~~Factors for Procuring Local Capacity Area Resources.~~

~~The CAISO shall procure Local Capacity Area Resources under Section 40.3.4 considering the effectiveness of the capacity at meeting the Reliability Criteria, set forth in 40.3.1, in the Local Capacity Area and the costs associated with the capacity. The CAISO is permitted to procure a Generating Unit or~~

~~Participating Load resource even where only a portion of capacity of the Generating Unit or Participating Load resource is needed to meet the Reliability Criteria applied in the Local Capacity Technical Study for the Local Capacity Area.~~

40.3.4.2 [NOT USED]~~Local Capacity Area Procurement Report.~~

~~Within ninety (90) days of any initial procurement of Local Capacity Area Resources by the CAISO for any Resource Adequacy Compliance Year, the CAISO shall publish a report on the CAISO Website showing the Local Capacity Area Resources procured under Section 40.3.4, the megawatts of capacity procured, the duration of the procurement, the reason(s) for the procurement, and all payments in dollars, itemized for each Local Capacity Area. The CAISO will provide a Market Notice regarding the availability of this report, and shall update the report within ninety (90) days of any Local Capacity Area Resource that is procured after the posting of the report.~~

* * *

40.7 Compliance.

The CAISO will evaluate whether each annual and monthly Resource Adequacy Plan submitted by a Scheduling Coordinator on behalf of a Load Serving Entity demonstrates Resource Adequacy Capacity sufficient to satisfy the Load Serving Entity's (i) allocated responsibility for Local Capacity Area Resources under Section 40.3.2 and (ii) applicable Demand and Reserve Margin requirements. If the CAISO determines that a Resource Adequacy Plan does not demonstrate Local Capacity Area Resources sufficient to meet its allocated responsibility under Section 40.3.2, compliance with applicable Demand and Reserve Margin requirements, or compliance with any other resource adequacy requirement in this Section 40 or adopted by the CPUC, Local Regulatory Authority, or federal agency, as applicable, the CAISO will notify the relevant Scheduling Coordinator, CPUC, Local Regulatory Authority, or federal agency with jurisdiction over the relevant Load Serving Entity, or in the case of a mismatch between Resource Adequacy Plan(s) and Supply Plan(s), the relevant Scheduling Coordinators, in an attempt to resolve any deficiency in accordance with the procedures set forth in the Business Practice Manual. The notification will include the reasons the CAISO believes a deficiency exists. If the deficiency relates to the demonstration of Local Capacity Area Resources in a Load Serving Entity's annual Resource Adequacy Plan, and the CAISO does not provide a written notice of resolution of the deficiency as set forth in the

Business Practice Manual, the Scheduling Coordinator for the Load Serving Entity may demonstrate that the identified deficiency is cured by submitting a revised annual Resource Adequacy Plan within thirty (30) days of the beginning of the Resource Adequacy Compliance Year. For all other identified deficiencies, at least ten (10) days prior the effective month of the relevant Resource Adequacy Plan, the Scheduling Coordinator for the Load Serving Entity shall (i) demonstrate that the identified deficiency is cured by submitting a revised Resource Adequacy Plan or (ii) advise the CAISO that the CPUC, Local Regulatory Authority, or federal agency, as appropriate, has determined that no deficiency exists. In the case of a mismatch between Resource Adequacy Plan(s) and Supply Plan(s), if resolved, the relevant Scheduling Coordinator(s) must provide the CAISO with revised Resource Adequacy Plan(s) or Supply Plans, as applicable, at least ten (10) days prior to the effective month. If the CAISO is not advised that the deficiency or mismatch is resolved at least ten (10) days prior to the effective month, the CAISO will use the information contained in the Supply Plan to set the obligations of Resource Adequacy Resources under this Section 40 and/or to assign any costs incurred under this Section 40 and Section 43.

* * *

43 Interim Capacity Procurement Mechanism.~~[NOT USED]~~

This Section 43 shall be referred to as the Interim Capacity Procurement Mechanism (ICPM). The ICPM as well as changes made to other Sections to implement the ICPM shall expire at midnight on December 31, 2010, except that the provisions concerning compensation, cost allocation and Settlement shall remain in effect until such time as ICPM resources have been finally compensated for their services rendered under the ICPM prior to the termination of the ICPM, and the CAISO has finally allocated and recovered the costs associated with such ICPM compensation.

43.1 Designation.

The CAISO shall have the authority to designate Eligible Capacity to provide ICPM Capacity services under the ICPM as follows:

43.1.1 Scheduling Coordinator Failure to Demonstrate Sufficient Local Capacity Area Resources.

43.1.1.1 Annual Resource Adequacy Plan.

Where a Scheduling Coordinator fails to demonstrate in an annual Resource Adequacy Plan, submitted separately for each represented LSE, procurement of each LSE's share of Local Capacity Area Resources, as determined in Section 40.3.2 for each month of the following Resource Adequacy Compliance Year, the CAISO shall have the authority to designate ICPM Capacity; provided, however, that the CAISO shall not designate ICPM Capacity under this Section 43.1.1.1 until after the Scheduling Coordinator has had the opportunity to cure the deficiency set forth in Section 40.7. The CAISO's authority to designate ICPM Capacity under this Section 43.1.1.1 is to ensure that each Local Capacity Area in a TAC Area in which the LSE serves Load has Local Capacity Area Resources in the amounts and locations necessary to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1, after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual Resource Adequacy Plans and any supplements thereto, as may be permitted by the CPUC, Local Regulatory Authority, or federal agency and provided to the CAISO in accordance with Section 40.7, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area.

43.1.1.2 Monthly Resource Adequacy Plan.

Where a Scheduling Coordinator fails to demonstrate in a monthly Resource Adequacy Plan, submitted separately for each represented LSE, procurement of each LSE's share of Local Capacity Area Resources, as determined in Section 40.3.2 for the reported month, the CAISO shall have the authority to designate ICPM Capacity; provided, however, that the CAISO shall not designate ICPM Capacity under this Section 43.1.1.2 until after the Scheduling Coordinator has had the opportunity to cure the deficiency as set forth in Section 40.7. The CAISO's authority to designate ICPM Capacity under this Section 43.1.1.1 is to ensure that each Local Capacity Area in a TAC Area in which the LSE serves Load has Local Capacity Area Resources in the amounts and locations necessary to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1, after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual and monthly Resource Adequacy Plans and any supplements thereto, as may be permitted by the CPUC, Local Regulatory Authority, or federal agency and provided to the CAISO in accordance with Section 40.7, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area.

43.1.2 Collective Deficiency in Local Capacity Area Resources.

The CAISO shall have the authority to designate ICPM Capacity where the Local Capacity Area Resources specified in the annual Resource Adequacy Plans of all applicable Scheduling Coordinators, after the opportunity to cure under Section 43.1.2.1 has been exhausted, fail to ensure compliance in one or more Local Capacity Areas with the Local Capacity Technical Study criteria provided in Section 40.3.1.1, regardless of whether such resources satisfy, for the deficient Local Capacity Area, the minimum amount of Local Capacity Area Resources identified in the Local Capacity Technical Study, and after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual Resource Adequacy Plans, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area. The CAISO may, pursuant to this Section 43.1.2, designate ICPM Capacity in an amount and location sufficient to ensure compliance with the Reliability Criteria applied in the Local Capacity Technical Study.

43.1.2.1 LSE Opportunity to Resolve Collective Deficiency in Local Capacity Area Resources.

Where the CAISO determines that a need for ICPM Capacity exists under Section 43.1.2, but prior to any designation of ICPM Capacity, the CAISO shall issue a Market Notice, no later than sixty (60) days before the beginning of the Resource Adequacy Compliance Year, identifying the deficient Local Capacity Area and the quantity of capacity that would permit the deficient Local Capacity Area to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1 and, where only specific resources are effective to resolve the Reliability Criteria deficiency, the CAISO shall provide the identity of such resources. Any Scheduling Coordinator may submit a revised annual Resource Adequacy Plan within thirty (30) days of the beginning of the Resource Adequacy Compliance Year demonstrating procurement of additional Local Capacity Area Resources consistent with the Market Notice issued under this Section. Any Scheduling Coordinator that provides such additional Local Capacity Area Resources consistent with the Market Notice under this Section shall have its share of any ICPM procurement costs under Section

43.7.3 reduced on a proportionate basis. If the full quantity of capacity is not reported to the CAISO under revised annual Resource Adequacy Plans in accordance with this Section, the CAISO may designate ICPM Capacity sufficient to alleviate the deficiency.

43.1.3 Scheduling Coordinator Failure to Demonstrate Sufficient Resource Adequacy Resources to Meet Annual and Monthly Demand and Reserve Margin Requirements.

The CAISO shall have the authority to designate ICPM Capacity where a Scheduling Coordinator fails to demonstrate in an annual or monthly Resource Adequacy Plan, submitted separately for each represented LSE, procurement of sufficient Resource Adequacy Resources to comply with each LSE's annual and monthly Demand and Reserve Margin requirements under Section 40; provided that the CAISO shall not designate ICPM Capacity under this Section 43.1.3 until after the Scheduling Coordinator has had the opportunity to cure the deficiency as set forth in Section 40.7.

43.1.4 ICPM Significant Events.

The CAISO may designate ICPM Capacity to provide service on a prospective basis following an ICPM Significant Event, to the extent necessary to maintain compliance with Reliability Criteria and taking into account the expected duration of the ICPM Significant Event.

43.2 Terms of ICPM Designation.

43.2.1 Term – Scheduling Coordinator Failure to Demonstrate Local Capacity Area Resources in Annual Resource Adequacy Plan.

ICPM Capacity designated under Section 43.1.1.1 shall have a minimum commitment term of one (1) month and a maximum commitment term of one (1) year, based on the period(s) of overall shortage as reflected in the annual Resource Adequacy Plans that have been submitted. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.2.2 Term – Scheduling Coordinator Failure to Demonstrate Local Capacity Area Resources in Monthly Resource Adequacy Plan.

ICPM Capacity designated under Section 43.1.1.2 shall have a minimum commitment term of one (1) month. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.2.3 Term – Insufficient Collective Local Capacity Area Resources in Annual Resource Adequacy Plans.

ICPM Capacity designated under Section 43.1.2 shall have a minimum commitment term of one (1) month and a maximum commitment term of one year, based on the period(s) of overall shortage as reflected in the annual Resource Adequacy Plans that have been submitted. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.2.4 Term – Scheduling Coordinator Failure to Demonstrate Sufficient Resource Adequacy Resources.

ICPM Capacity designated under Section 43.1.3 shall: (a) have a minimum commitment term of one (1) month and a maximum commitment term equal to the maximum annual procurement period established by the Local Reliability Authority based on the period of the deficiency reflected in the annual Resource Adequacy Plan or (b) have a commitment term of one (1) month if the deficiency is in the monthly Resource Adequacy Plan. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year.

43.2.5 Term – ICPM Significant Event.

ICPM Capacity designated under Section 43.1.4 shall have an initial term of thirty (30) days. If the CAISO determines that the ICPM Significant Event is likely to extend beyond the thirty (30) day period, the CAISO shall extend the designation for another sixty (60) days. During this additional sixty (60) day period, the CAISO will provide Market Participants with an opportunity to provide alternative solutions to meet the CAISO's operational and reliability needs in response to the ICPM Significant Event, rather than rely on the CAISO's designation of capacity under the ICPM. The CAISO shall consider and implement, if acceptable to the CAISO in accordance with Good Utility Practice, such alternative solutions provided by Market Participants in a timely manner. If Market Participants do not submit any alternatives to the designation of ICPM capacity that are fully effective in addressing the deficiencies in Reliability Criteria resulting from ICPM Significant Event, the CAISO shall extend the term of the designation under Section 43.1.4 for the expected duration of the ICPM Significant Event.

If the solutions offered by Market Participants are only partially effective in addressing the CAISO's operational and reliability needs resulting from the ICPM Significant Event, the CAISO shall extend the designation under Section 43.1.4 for the expected duration of the ICPM Significant Event, but only as to the amount of ICPM Capacity necessary to satisfy the CAISO's operational and reliability needs after taking into account the effective capacity provided by the alternative solution. If there is a reasonable alternative solution that fully resolves the CAISO's operational and reliability needs, the CAISO will not extend the designation under Section 43.1.4. In no event shall the term of the designation under Section 43.1.4 extend beyond midnight on December 31, 2010.

43.3 Selection of Eligible Capacity under the ICPM.

In accordance with Good Utility Practice, the CAISO shall make designations of Eligible Capacity as ICPM Capacity under Section 43.1 based on the following criteria:

(1) the effectiveness of the Eligible Capacity at meeting the designation criteria specified in Section 43.1;

(2) the capacity costs associated with the Eligible Capacity;

(3) the quantity of a resource's available Eligible Capacity, based on a resource's PMin, relative to the remaining amount of capacity needed; and

(4) for designations under Section 41.1.3, the effectiveness of the Eligible Capacity in meeting local and/or zonal constraints or other CAISO system needs.

In making this determination, the CAISO will attempt to designate lower cost resources that have specified a capacity price before designating resources that have not specified a capacity price, taking into account factors (1), (3) and (4) of this Section concerning the relative effectiveness of the resource and the resource's PMin. If after applying these criteria, two or more resources that are eligible for designation equally satisfy these criteria, the CAISO shall utilize a random selection method to determine the designation between those resources.

While the CAISO does not have to designate the full capability of a resource, the CAISO may designate under the ICPM an amount of ICPM Capacity from a resource that exceeds the amount of capacity identified to ensure compliance with the Reliability Criteria set forth in Section 40.3 due to the PMin or other operational requirements/limits of a resource that has available capacity to provide ICPM service. The CAISO shall not designate the capacity of a resource for an amount of capacity that is less than the resource's PMin.

43.4 Obligations of a Resource Designated under the ICPM.

43.4.1 Availability Obligations.

Capacity from resources designated under the ICPM shall be subject to all of the availability, dispatch, testing, reporting, verification and any other applicable requirements imposed under Section 40.6 on Resource Adequacy Resources identified in Resource Adequacy Plans. In accordance with those requirements, ICPM Capacity designated under the ICPM shall meet the Day-Ahead availability requirements specified in Section 40.6.1 and the Real-Time availability requirements of Section 40.6.2. Also in accordance with those requirements, Generating Units designated under the ICPM that meet the definition of Short Start Units shall have the obligation to meet the additional availability requirements of Section 40.6.3, and Generating Units designated under the ICPM that meet the definition of Long Start Units will have the rights and obligations specified in Section 40.6.7.1.

If the CAISO has not received an Economic Bid or a Self-Schedule for ICPM Capacity, the CAISO shall utilize a Default Energy Bid in accordance with the procedures specified in Section 40.6.8.

In addition to Energy Bids, resources designated under the ICPM shall submit Ancillary Service Bids for their ICPM Capacity to the extent that the resource is certified to provide the Ancillary Service.

43.4.2 Obligation To Provide Capacity and Termination.

The decision to accept an ICPM designation shall be voluntary for the Scheduling Coordinator for any resource. If the Scheduling Coordinator for a resource accepts an ICPM designation, it shall be obligated to perform for the full quantity and full period of the designation with respect to the amount of ICPM Capacity for which it has accepted an ICPM designation. If a Participating Generator's or Participating Load's Eligible Capacity is designated under the ICPM after the Participating Generator or Participating Load has filed notice to terminate its Participating Generator Agreement or Participating Load Agreement or withdraw the Eligible Capacity from its Participating Generator Agreement or Participating Load Agreement, and the Scheduling Coordinator for the resource agrees to provide service under the ICPM, then the Scheduling Coordinator shall enter into a new Participating Generator Agreement or Participating Load Agreement, as applicable, with the CAISO.

43.5 Reports.

The CAISO shall publish the following reports and notices.

43.5.1 ICPM Significant Event Market Notice.

The CAISO shall issue a Market Notice within two (2) Business Days of an ICPM designation to address each ICPM Significant Event. The Market Notice shall include a preliminary description of what caused the ICPM Significant Event, the name of the resource(s) procured, the preliminary expected duration of the ICPM Significant Event, the initial designation period, and an indication that a designation report is being prepared in accordance with Section 43.5.2.

43.5.2 Designation of a Resource under the ICPM.

Within thirty (30) days of procuring a resource under the ICPM, the CAISO shall post a designation report to the CAISO Website and provide a Market Notice of the availability of the report. The designation report shall include the following information:

(1) A description of the reason for the designation (LSE procurement shortfall, Local Capacity Area Resource effectiveness deficiency, or ICPM Significant Event), and an explanation of why it was necessary for the CAISO to utilize the ICPM authority);

(2) The following information would be reported for all backstop designations:

(a) the resource name;

(b) the amount of ICPM Capacity designated (MW);

(c) an explanation of why that amount of ICPM Capacity was designated;

(d) the date ICPM Capacity was designated;

(e) the duration of the designation; and

(f) the price for the ICPM procurement; and

(3) If the reason for the designation is an ICPM Significant Event, the CAISO will also include:

(a) a discussion of the event or events that have occurred, why the CAISO has procured ICPM Capacity, and how much has been procured;

(b) an assessment of the expected duration of the ICPM Significant Event;

(c) the duration of the initial designation (thirty (30) days); and

(d) a statement as to whether the initial designation has been extended (such that the backstop procurement is now for more than thirty (30) days), and, if it has been extended, the length of the extension.

43.5.3 Non-Market Commitments and Repeated Market Commitments of Non-Resource Adequacy Capacity.

Within ten (10) calendar days after the end of each month, the CAISO shall post a report to the CAISO Website that identifies for the prior month:

(1) Any non-market commitments of non-Resource Adequacy Capacity; and

(2) All market commitments of non-Resource Adequacy Capacity.

The CAISO will provide a Market Notice of the availability of this report. The report will not include commitments of RMR Generation capacity, Resource Adequacy Capacity or designated ICPM Capacity. The report shall include the following information:

(a) the name of the resource;

(b) the IOU Service Area and Local Capacity Area (if applicable);

(c) the maximum capacity committed in response to the event (MW);

(d) how capacity was procured (for example, by RUC or Exceptional Dispatch);

(e) the reason capacity was committed; and

(f) information as to whether or not all Resource Adequacy Resources and previously-designated ICPM Capacity were used first and, if not, why they were not.

43.5.4 Board of Governors Report.

The CAISO will include in the operations report provided to the CAISO Governing Board at each board meeting a summary of ICPM costs.

43.6 Payments to Resources Designated Under the ICPM.

Within thirty (30) days of the effective date of this Section 43, Scheduling Coordinators for Eligible Capacity may submit to the CAISO an intention to be paid a monthly ICPM Capacity Payment under

Section 43.6.1 or Section 43.6.2. Scheduling Coordinators for Eligible Capacity will be able to change their selections annually within thirty (30) days of a CAISO Market Notice seeking such payment preferences. To the extent a Scheduling Coordinator for Eligible Capacity does not submit a selection to be compensated in accordance with Section 43.6.1, the Scheduling Coordinator shall be deemed to have selected to be paid on a resource-specific basis pursuant to Section 43.6.2, for purposes of the CAISO's ICPM designation determinations.

43.6.1 Monthly ICPM Capacity Payment.

Scheduling Coordinators representing resources receiving payment under this Section 43.6.1 shall receive a monthly ICPM Capacity Payment for each month of ICPM designation equal to the product of the amount of their ICPM Capacity, the relevant ICPM Availability Factor, as determined in accordance with Appendix F, Schedule 6, a monthly shaping factor as set forth in Appendix F, Schedule 6, and a fixed ICPM Capacity price of $41/kW-year, so that the formula for determining the monthly ICPM Capacity Payment would be as follows:

(ICPM Capacity MW) x (ICPM Availability Factor) x (1/12 monthly shaping factor) x ($41/kW-year).

The foregoing formula shall apply to all ICPM Capacity receiving monthly ICPM Capacity Payments under this Section 43.6.1 except for ICPM Capacity designated to respond to an ICPM Significant Event, in which case the monthly ICPM Capacity Payment shall be based proportionately on the actual number of days the resource was designated as ICPM Capacity during the month to the total number of days in the month.

For purposes of ICPM designations, except for designations for ICPM Significant Events, the ICPM Availability Factor shall be calculated as the ratio of: (1) the sum of the ICPM Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the CAISO, if less than the ICPM Capacity MW, shall be substituted for ICPM Capacity MW for each hour the resource is not available and is not on an authorized Outage, to (2) the product of ICPM Capacity MW and the total hours in the month.

For purposes of ICPM designations for ICPM Significant Events, the ICPM Availability Factor shall be calculated as the ratio of: (1) the sum of the ICPM Capacity MW for each hour across all hours of the month or part of the month for which a unit is designated, whichever is applicable, where the actual capacity MW available to the CAISO, if less than the ICPM Capacity MW, shall be substituted for ICPM Capacity MW for each hour the resource is not available and is not on an authorized Outage, to (2) the product of ICPM Capacity MW and the total hours in the month or part of the month for which a unit is designated, whichever is applicable.

For purposes of this Section 43.6.1, an authorized Outage shall be limited to a CAISO Approved Maintenance Outage.

43.6.2 Resource-Specific ICPM Capacity Payment.

If a Scheduling Coordinator for Eligible Capacity believes that the $41/kW-year ICPM Capacity price under Section 43.6.1 will not compensate a resource for its going forward costs, as calculated in accordance with the formula provided in Section 43.6.2.1, the Scheduling Coordinator may, within thirty (30) days of the effective date of this Section 43 and annually thereafter in accordance with Section 43.6, inform the CAISO of what proposed higher ICPM Capacity price would compensate the resource for its going forward costs and which the Scheduling Coordinator is willing to have the CAISO use for purposes of the ICPM designation process ("going forward cost offer price"). A Scheduling Coordinator for a resource is not required to submit a specific going forward cost offer price for such resource within thirty (30) days after the effective date of Section 43 or under the process provided for in Section 43.6; however, a Scheduling Coordinator that has not previously identified the going forward cost offer price for a resource must notify the CAISO of what that price is before any CAISO designation of that resource's capacity as ICPM Capacity can become effective.

If the CAISO designates a resource that has proposed an ICPM Capacity price above $41/kW-year, and the sales from the resource are under the jurisdiction of the FERC, the Scheduling Coordinator for the resource shall make a limited resource-specific filing before the FERC to determine the just and reasonable capacity price for the going forward costs for the resource to be used in applying the CAISO's FERC jurisdictional monthly ICPM Capacity Payment formula. If the sales from the resource are not under the jurisdiction of the FERC, the Scheduling Coordinator for the resource shall make a non-jurisdictional filing with the FERC to determine the just and reasonable capacity price for the going forward costs for the resource to be used in applying the CAISO's FERC-jurisdictional monthly ICPM Capacity Payment formula.

43.6.2.1 Going Forward Cost.

In making the cost justification filing with FERC for an ICPM Capacity price above $41/kW-year, the Scheduling Coordinator for the resource may not propose -- and shall not get paid -- an amount higher than the going forward cost offer price that it had previously proposed to the CAISO as its going forward cost offer price under Section 43.6 or this Section 43.6.2, either prior to or at the time of ICPM designation.

Going forward costs for any resource-specific filing under this Section shall be calculated based on the following formula:

> (fixed operation & maintenance costs, plus ad valorem taxes, plus administrative & general costs, plus ten percent (10%) of the foregoing amounts),

provided such costs shall be converted to a fixed $/kW-year amount.

43.6.2.2 Resource-Specific Monthly ICPM Capacity Payment.

Scheduling Coordinators representing resources receiving payment under this Section 43.6.2 shall receive a monthly ICPM Capacity Payment for each month of ICPM designation equal to the product of the amount of their ICPM Capacity, the relevant ICPM Availability Factor as determined in accordance with Appendix F, Schedule 6, a monthly shaping factor as set forth in Appendix F, Schedule 6, and the resource-specific ICPM Capacity price, as determined by FERC in accordance with the following formula:

> (ICPM Capacity MW) x (ICPM Availability Factor) x (1/12 monthly shaping factor) x (the resource-specific ICPM Capacity price as determined by FERC).

The foregoing formula shall apply to all ICPM Capacity receiving monthly ICPM Capacity Payments under this Section 43.6.2 except for ICPM Capacity designated to respond to an ICPM Significant Event, in which case the monthly ICPM Capacity Payment shall be based proportionately on the actual number of days the resource was designated as ICPM Capacity during the month to the total number of days in the month.

Prior to the determination by FERC of the resource-specific going forward costs for ICPM Capacity designated and paid pursuant to this Section 43.6.2, the CAISO shall proceed as follows. For the period between the CAISO's designation and the FERC's determination, the CAISO shall utilize the $41/kW-year rate for purposes of the resource-specific monthly ICPM Capacity Payment for financial Settlement. This amount shall be subject to surcharge based on the outcome of the FERC proceeding so that the resource will receive any higher actual resource-specific payment as determined by FERC for the full period of the ICPM designation. Once approved by FERC, the CAISO shall apply the higher of $41/kW-year or the resource-specific ICPM Capacity price as determined by the FERC.

For purposes of ICPM designations, except for designations for ICPM Significant Events, the ICPM Availability Factor shall be calculated as the ratio of: (1) the sum of the ICPM Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the CAISO, if less than the ICPM Capacity MW, shall be substituted for ICPM Capacity MW for each hour the resource is not available and is not on an authorized Outage, to (2) the product of ICPM Capacity MW and the total hours in the month.

For purposes of ICPM designations for ICPM Significant Events, the ICPM Availability Factor shall be calculated as the ratio of: (1) the sum of the ICPM Capacity MW for each hour across all hours of the month or part of the month for which a unit is designated, whichever is applicable, where the actual capacity MW available to the CAISO, if less than the ICPM Capacity MW, shall be substituted for ICPM Capacity MW for each hour the resource is not available and is not on an authorized Outage, to (2) the product of ICPM Capacity MW and the total hours in the month or part of the month for which a unit is designated, whichever is applicable.

For purposes of this Section 43.6.2, an authorized Outage shall be limited to a CAISO Approved Maintenance Outage.

43.6.3 Market Payments.

In addition to the ICPM Capacity Payment identified in Section 43.6, ICPM resources shall be entitled to retain any revenues received as a result of their selection in the CAISO Markets, provided, however, that ICPM resources are required to participate in the RUC process through submission of a zero ($0) dollar RUC Availability Bid and are not eligible to receive compensation through the RUC process.

43.7 Allocation of ICPM Capacity Payment Costs.

For each month, the CAISO shall allocate the costs of ICPM Capacity Payments made pursuant to Section 43.6 as follows:

43.7.1 LSE Shortage of Local Capacity Area Resources in Annual Resource Adequacy Plan.

If the CAISO makes ICPM designations under Section 43.1.1.1 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area Resources to meet its applicable Local Capacity Area capacity requirements in its annual Resource Adequacy Plan, then the CAISO shall allocate the total costs of the ICPM Capacity Payments for such ICPM designations (for the full term of those ICPM designations) pro rata to each Scheduling Coordinator for an LSE based on the ratio of its Local Capacity Area Resource Deficiency to the sum of the deficiency of Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area. The Local Capacity Resource Deficiency under this Section shall be computed on a monthly basis and the ICPM Capacity Payments allocated based on deficiencies during the month(s) covered by the ICPM designation(s).

43.7.2 LSE Shortage of Local Capacity Area Resources in Monthly Resource Adequacy Plan.

If the CAISO makes ICPM designations under Section 43.1.1.2 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area Resources to meet its applicable Local Capacity Area capacity requirements in its monthly Resource Adequacy Plan, then the CAISO shall allocate the total costs of the ICPM Capacity Payments for such ICPM designations (for the full term of those ICPM designations) pro rata to each Scheduling Coordinator for an LSE based on the ratio of its Local Capacity Area Resource Deficiency to the sum of the deficiency of Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area.

43.7.3 Collective Deficiency in Local Capacity Area Resources.

If the CAISO makes designations under Section 43.1.2 the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs serving Load in the TAC Area(s) in which the deficient Local Capacity Area was located. The allocation will be based on the Scheduling Coordinators' proportionate share of Load in such TAC Area(s) as determined in accordance with Section 40.3.2, excluding Scheduling Coordinators for LSEs that procured additional capacity in accordance with Section 43.1.2.1 on a proportionate basis, to the extent of their additional procurement.

43.7.4 LSE Shortage of Demand or Reserve Margin Requirements in Annual or Monthly Resource Adequacy Plan.

If the CAISO makes ICPM designations under Section 43.1.3, then the CAISO will allocate the total costs of the ICPM Capacity Payments for such ICPM designations (for the full term of those ICPM designations) pro rata to each LSE based on the proportion of its deficiency to the aggregate deficiency.

43.7.5 Allocation of ICPM Significant Event Costs.

If the CAISO makes any ICPM Significant Event designations under Section 43.1.4, the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs that serve Load in the TAC Area(s) in which the ICPM Significant Event caused or threatened to cause a failure to meet Reliability Criteria based on the percentage of actual Load of each LSE represented by the Scheduling Coordinator in the TAC Area(s) to total Load in the TAC Area(s) as recorded in the CAISO Settlement system for the actual days during any Settlement month period over which the designation has occurred.

43.8 Crediting of ICPM Capacity.

The CAISO shall credit ICPM designations to the resource adequacy obligations of Scheduling Coordinators for Load Serving Entities as follows:

(a) To the extent the cost of ICPM designation under Section 43.1.1.1 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.7.1, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards (1) the LSE's Local Capacity Area Resource obligation under Section 40.3.2 in an amount equal to the LSE's pro rata share of the ICPM Capacity designated under Section 43.1.1.1 and (2) the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the ICPM Capacity designated under Section 43.1.1.1.

(b) To the extent the cost of CAISO designation under Section 43.1.2 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.7.3, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the ICPM Capacity designated under Section 43.1.2.

(c) To the extent the cost of ICPM designation under Section 43.1.3 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.7.4, and the designation is for greater than one month under Section 43.2.4, the CAISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the ICPM Capacity designated under Section 43.1.3.

(d) The credit provided in this Section shall be used for determining the need for the additional designation of ICPM Capacity under Section 43.1 and for allocation of ICPM costs under Section 43.7.

(e) For each Scheduling Coordinator that is provided credit pursuant to this Section, the CAISO shall provide information, including the quantity of capacity procured in MW, necessary to allow the CPUC, other Local Regulatory Authority, or federal agency with jurisdiction over the LSE on whose behalf the credit was provided to determine whether the LSE should receive credit toward its resource adequacy requirements adopted by such agencies or authorities.

* * *

Appendix A
Master Definition Supplement

* * *

Eligible Capacity Capacity of Generating Units, System Units, System Resources, or Participating Load that is not already under a contract to be a Resource Adequacy Resource, is not under an RMR Contract or is not currently designated as ICPM Capacity that effectively resolves a procurement shortfall or reliability concern and thus is eligible to be designated under the ICPM in accordance with Section 43.1.

* * *

ICPM	Interim Capacity Procurement Mechanism

* * *

ICPM Availability Factor	A factor as set forth in Appendix F, Schedule 6 that is used in calculating a resource's monthly ICPM Capacity Payment.

* * *

ICPM Capacity	Capacity of Generating Units, System Units, System Resources, or Participating Load that is designated under the ICPM in accordance with Section 43 during the term of the designation.

* * *

ICPM Capacity Payment	The payment provided pursuant to Section 43.6.

* * *

ICPM Significant Event	A substantial event, or a combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the resource adequacy program for purposes of determining the Resource Adequacy Capacity requirements, or produce a material change in system conditions or in CAISO Controlled Grid operations, that causes, or threatens to cause, a failure to meet Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis.

* * *

Interim Capacity Procurement Mechanism (ICPM)	The Interim Capacity Procurement Mechanism, as set forth in Section 43.

* * *

Local Capacity Area Resource Deficiency	The monthly difference in MW between any applicable Local Capacity Area Resource requirements for an LSE as established pursuant to Section 40.3.2 and the quantity of monthly MW shown in the LSE's Resource Adequacy Plan.

* * *

CAISO TARIFF APPENDIX F

SCHEDULE 6

ICPM SCHEDULES

Monthly ICPM Capacity Payment

The monthly ICPM Capacity Payment shall be calculated by multiplying the monthly shaping factor of 1/12 by the annual ICPM Capacity price of $41/kW-year in accordance with Section 43.6.1, unless the Scheduling Coordinator for the ICPM Capacity resource has agreed to another price that has been determined in accordance with Section 43.6.2.

Availability

The target availability for a resource designated under ICPM is 95%. Incentives and penalties for availability above and below the target are as set forth in the table below, entitled "Availability Factor Table." The CAISO shall calculate availability on a monthly basis using actual availability data. The ICPM Availability Factor for each month shall be calculated using the following curve:

AVAILABILITY FACTOR TABLE

Availability (excluding only Scheduled Maintenance)	**Capacity Payment Factor**	**ICPM Availability Factor**
100%	3.3%	1.139
99%	3.3%	1.106
98%	3.3%	1.073
97%	2.5%	1.040
96%	1.5%	1.015
95%	-	1.000
94%	-1.5%	.985
93%	-1.5%	.970
92%	-1.5%	.955
91%	-1.5%	.940
90%	-1.5%	.925
89-80%	-1.7%*	.908-.755
79-41%	-1.9%*	.736-.014
-40%	-	0.0

*The "Capacity Payment Factor" decreases by 1.7% and 1.9% respectively for every 1% decrease in availability.

The ICPM Capacity Payment shall be adjusted upward from the 95% availability starting point by the positive percentages listed as the "Capacity Payment Factor" above, by multiplication by the amounts listed for each ICPM Availability Factor above 95%, so that, for example, if a 97% availability is achieved for the month, then the ICPM Capacity Payment for that month would be the monthly value for 95% plus an additional 4% (1.5% for the first percent availability above 95%, and 2.5% for the second percent availability above 95%), i.e., multiplication of the otherwise applicable ICPM Capacity Payment by the ICPM Availability Factor of 1.040. Reductions in the ICPM Capacity Payment shall be made correspondingly according to the "Capacity Payment Factor" above for monthly availability levels falling short of the 95% availability starting point, by multiplication by the amounts listed for each ICPM Availability Factor below 95%.

* * *

Attachment C

California ISO
Your Link to Power

Proposal to Board of Governors for Interim Capacity Procurement Mechanism Tariff Filing

California Independent System Operator
Market & Product Development Group
January 18, 2008

Table of Contents

Proposal to Board of Governors for Interim Capacity Procurement Mechanism Tariff Filing

Section 1
Executive Summary

The purpose of this initiative is to develop and obtain Board of Governors and Federal Energy Regulatory Commission ("FERC") approval for an interim tariff-based capacity procurement mechanism to be implemented at Market Redesign and Technology Update ("MRTU") start-up that will enable the California Independent System Operator ("CAISO") to supplement or "backstop" Load Serving Entity ("LSE")-based Resource Adequacy ("RA") capacity procurement as needed for reliable grid operation. The CAISO's goal is to file this new Interim Capacity Procurement Mechanism ("ICPM")[1] with FERC on January 30, 2008 and to propose an effective date coincident with the start of the MRTU markets. As the culmination of a lengthy and rigorous stakeholder process, the proposal described in this paper effectively and efficiently meets the objectives of the backstop mechanism, is compatible with both the MRTU market design and the state of California's RA framework, and attempts to strike a reasonable balance between the divergent views of the CAISO stakeholders.

The CAISO started working with stakeholders on a successor to the Reliability Capacity Services Tariff ("RCST") in April 2007, and, as a result of these discussions, an "Issues Paper" was posted on May 9, 2007. At stakeholder meetings on May 18 and June 6, 2007, the CAISO discussed issues associated with development of a successor to the RCST." An initial CAISO proposal for the ICPM (hereinafter referred to as "Proposal #1") was posted in a white paper on June 29, 2007. Proposal #1 was discussed at a stakeholder meeting on July 25, 2007, and stakeholders provided written comments on August 9, 2007. A second CAISO proposal (hereinafter referred to as "Proposal #2") was posted in a white paper on October 5, 2007. Proposal #2 was discussed at a stakeholder meeting on October 15, 2007, and on a conference call on October 18, 2007. Stakeholders provided written comments on Proposal #2 on October 24, 2007. A third CAISO proposal (hereinafter referred to as the "Final Proposal") was posted on November 9, 2007. The Final Proposal was discussed at a stakeholder conference call on November 15, 2007. Stakeholders provided written comments on the Final Proposal on November 21, 2007. A fourth CAISO proposal (hereinafter referred to as the "Draft Board Proposal") was posted on December 14, 2007. The Draft Board Proposal was discussed at a stakeholder conference call on December 20, 2007. Stakeholders provided written comments on the Draft Board Proposal on January 7, 2008. The present paper presents a revised proposal (hereinafter referred to as the "Board Proposal") that will be presented to the Board of Governors' on January 28-29, 2008 for their consideration.

This Board Proposal makes several modifications in the following key areas where the CAISO previous proposals were viewed by stakeholders as being either unsatisfactory, controversial, or both: obligations of an ICPM resource, accountability in the procurement process, scope of reporting obligations, clarity regarding the applicable

[1] This mechanism is called "interim" because it will include a sunset date at the end of 2010. Prior to that date the CAISO will reopen the matter of backstop procurement to explore possible changes or enhancements to ICPM to reflect changed market conditions.

terms of designations, methodology for determining the Target Annual Capacity Price, formulas for calculating monthly compensation, cost allocation, process to be used to differentiate among multiple resources eligible to be designated, and circumstances where the CAISO supports an LSE including ICPM capacity in its RA showing.

During the stakeholder process stakeholders expressed divergent points of view on many of the elements in the ICPM proposals. It is not likely that this Board Proposal has eliminated all controversy, nor is it likely that there will be unanimous stakeholder support for each and every element of the Board Proposal. However, the CAISO has made significant changes to many of the key elements of the previous proposals and believes that the Board Proposal does a better job of finding the right balance on the controversial items than its predecessor did. It is a reasonable, balanced approach in response to the divergent views expressed by stakeholders.

Overview of the Board Proposal:

The CAISO proposes to follow a RCST-type structure with modifications to be compatible with the MRTU market design and facilitate the CAISO's ability to meet Applicable Reliability Criteria ("ARC"),[2] as well as certain other enhancements. The CAISO believes that it makes sense to utilize some of the RCST design elements and make modifications to others in order to adapt it to function effectively under MRTU because stakeholders have invested substantial resources in developing RCST, FERC has found it to be just and reasonable, and many stakeholders have stated a desire to use it as a general framework for developing an interim MRTU backstop capacity procurement mechanism.

The Board Proposal is consistent with RCST in that it provides for the same two primary types of backstop procurement. Under "Type 1" procurement, the CAISO would procure capacity (a) in advance of the compliance year if an LSE has not procured the full amount of its Resource Adequacy Requirement ("RAR") by the time of the required RA showing, or if the portfolio of resources procured by all LSEs in a local area is not sufficient to fully meet the operating needs of the local area, or (b) during the compliance year if an LSE has not procured the full amount of its RAR in the month-ahead time frame. Under "Type 2" procurement, the CAISO would procure additional capacity during the compliance year if a "Significant Event" occurs that creates a need to supplement LSE-procured RA capacity to ensure reliable grid operation. For example, a Significant Event could be a sustained outage of a generation or transmission facility.

The Board Proposal modifies the RCST design to obtain certain improvements and address stakeholder concerns. Key modifications to the RCST are listed below.

Sunset Date – The ICPM tariff provisions would automatically sunset on December 31, 2010. The ultimate goal is to design a long-term backstop mechanism under MRTU that works effectively under, and is aligned with, the long-term RA design. The long-term RA design is currently under discussion at the California Public Utilities Commission ("CPUC"). It may be appropriate to revisit the ICPM sooner than the year 2010,

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[2] As part of ARC, the CAISO must comply with applicable North American Electric Reliability Council/Western Electricity Coordinating Council ("NERC/WECC") requirements, including Minimum Operating Reliability Criteria ("MORC").

depending on the timing of implementation of the long-term RA mechanism and the types of mechanisms being implemented as part of that design.

Voluntary Designation – A resource owner can decline an ICPM designation when offered by the CAISO (i.e., an ICPM designation is voluntary). The CAISO notes that there is no Must Offer Obligation under MRTU.

Pricing – This Board Proposal utilizes a target capacity price for ICPM procurement that has both similarities and differences with the RCST methodology. Prior to this Board Proposal, CAISO had sought various market-based options for ICPM procurement. Proposal #2 significantly changed the RCST pricing approach in favor of a market-proxy price derived from a demand curve and price floor for Type 1 procurement and a uniform price based on going forward costs for Type 2 procurement. The Type 1 demand curve was capped at an estimate of the cost of new entry ("CONE") in areas at or below their RA requirement ("RAR"). Although that proposal did gain support from some stakeholders, others were not supportive based on concerns that the proposed Type 1 pricing would interfere with issues being addressed in the ongoing California Public Utilities Commission ("CPUC") RA Phase 2 Track 2 proceeding (henceforth CPUC Proceeding) and would adversely impact forward RA prices in the interim. The CAISO agrees that the ICPM needs to be integrated with the RA design, because the backstop mechanism will influence forward prices and thus procurement and investment decisions. Given, *inter alia,* that the long-term RA design process is ongoing and the difficult task of implementing an appropriate and effective demand curve mechanism, this Board Proposal will not seek market-proxy based pricing of backstop procurement. Rather, it sets forth a pricing method intended to meet the following criteria: (1) falls within the range of just and reasonable prices established by FERC in the RCST settlement; (2) guarantees that any designated resource will cover its "going forward" [3] costs (and potentially more) for the term of designation, and (3) does not create incentives for buyers or sellers to shift procurement to the ICPM.

The proposed pricing model is as follows. Based on the current RA market design and the CPUC penalty structure, as well as estimates of the range of going forward costs, the Type 1 and Type 2 target capacity price offer will be the higher of $41/kW-year or actual going forward costs plus retention of all eligible market revenues, i.e. not subject to peak energy rent ("PER") deductions. A resource owner that believes that its going forward costs are greater than $41/kW-year would be able to file at FERC for a price higher than $41/kW-year, but the owner would have to justify that price to FERC based on the same cost elements that are considered in setting the $41/kW-year default price. While the CAISO believes that the $41/kW-yr price is sufficient to cover the costs for the majority of resources located in the CAISO control area, this change in the ICPM should ensure that the going forward costs of all resources are appropriately paid under an ICPM designation. Also, based on PER calculations under RCST, the CAISO estimates that this new pricing method will potentially increase revenues to units designated relative to the RCST price in the summer peak months. Finally, the CAISO now proposes changing the "shaping factor" so that each month a resource would be paid 1/12 of the target annual capacity price (i.e., the shaping factor would be level throughout all months of the year). The CAISO believes that this is an appropriate modification based on two factors. First, resources will have incentives that are already

[3] Going forward costs are defined here as the sum of fixed operations and maintenance ("O&M"), ad valorem costs, and insurance costs plus a 10% adder to account for other costs.

aligned in the summer months as the ICPM has no PER deduction for peak energy rents and there are typically higher energy rents during the summer months. Secondly, resource owners have voiced their desire and the CAISO agrees that a level shaping factor better aligns with a fixed-cost based rate for the capacity payment because these costs do not typically vary during the year.

This interim pricing proposal aims to strike a balance between competing stakeholder positions and recognize that long-term RA design issues are still being discussed, which makes it difficult to design a more permanent market-based backstop mechanism at this time. The CAISO will initiate stakeholder discussion over a permanent market-based pricing mechanism for backstop procurement in connection with implementation of a long-term RA design and will seek to ensure that both structures are complementary. The CAISO discusses alternatives that were considered in Section 3 of this document.

<u>Reporting</u> - A detailed report would be posted within 30 days after the CAISO has procured a resource through the ICPM that describes the reason for and duration of the procurement to ensure that all ICPM procurement is fully transparent to the market. The CAISO also would issue a market notice within two business days of any ICPM procurement so that stakeholders would be aware of all ICPM designations. In addition to the posting of ICPM procurement reports, the CAISO also would post a monthly report within 10 calendar days after the end of each month of the non-market commitments of non-RA capacity (i.e., capacity procured manually by the CAISO operators) and repeated market commitments of non-RA capacity (i.e., capacity procured by the Residual Unit Commitment ("RUC") feature of MRTU) and why such resources were committed. These monthly reports would provide timely feedback to stakeholders and regulators on how well RA resources, by themselves, are meeting the various operational needs of the CAISO. It is expected that this feedback loop would, over time, lead to improvements in the RA programs by their sponsors and less reliance on ICPM procurement. The CAISO also would include in the Operations report that currently is provided to the CAISO Board of Governors at each Board meeting a summary of all ICPM costs and procurement activities.

<u>Summary Tables</u> - The table below provides a summary of the key elements of the ICPM, and illustrates the differences between the two major types of products: Type 1 ICPM Procurement where the CAISO procures forward to backstop the RA process, and Type 2 ICPM Procurement where the CAISO procures during the compliance year to address a Significant Event.

Key Elements of Interim Capacity Procurement Mechanism

Type 1 ICPM Procurement
CAISO procures Forward to backstop Resource Adequacy Process

Trigger	Term of Designation	Cost Allocation	Target Annual Capacity Price ($/kW-year)	Compensation Formula
Deficiency in Year-Ahead System showing	**1 month up to 5-months** (May – Sept)	Costs would be allocated only to the deficient load serving entity	$41.00, not subject to deductions for peak energy rents	Compensation = Price times Quantity, where: P = Level Monthly Shaping Factor times Target Annual Capacity Price Q = Designated Capacity times Availability Factor
Deficiency in Month-Ahead System showing	**1 month**			
Deficiency in Year-Ahead Local showing	**1 month up to 12-months** (compliance year is currently Jan – Dec)			
Deficiency in Year-Ahead Local capacity procured due to "Effectiveness Factors"	**12-months** (compliance year is currently Jan – Dec)	Costs would be allocated to all load serving entities in Transmission Access Charge area based on Load share		

Type 2 ICPM Procurement
CAISO procures during Compliance Year to backstop for a Significant Event

Trigger	Term of Designation	Cost Allocation	Target Annual Capacity Price ($/kW-year)	Compensation Formula
Significant Event has been determined by CAISO to have occurred	**1-month or greater** (maximum is up to time CAISO determines Significant Event will remain in effect	Costs would be allocated to all load serving entities in Transmission Access Charge area (or areas, depending on event) based on Load share	$41.00, not subject to deductions for peak energy rents	Compensation = Price times Quantity, where: P = Level Monthly Shaping Factor times Target Annual Capacity Price Q = Designated Capacity times Availability Factor

Section 2
Proposal to Board of Governors

The Board Proposal

The CAISO believes that a backstop mechanism is an appropriate and necessary feature to complement the MRTU market design and has worked with stakeholders to implement a backstop mechanism that would become effective coincident with the start of MRTU. The CAISO proposes to retain the basic RCST framework, and make modifications to improve upon the RCST and adapt it to be consistent with the MRTU market design. Stakeholders have expressed divergent views on many of the elements of the RCST and previous ICPM proposals. The CAISO believes that this Board Proposal represents a balanced approach that would allow the CAISO to engage in efficient backstop procurement of resources, if necessary, to support reliable grid operations.

Changes made to Draft Board Proposal to create Board Proposal

The CAISO considered stakeholder comments on the December 14, 2007 Draft Board Proposal in developing this Board Proposal. The key changes made to the major elements of the Draft Board Proposal to create the Board Proposal include the following:

- Updated the section that describes the stakeholder process so that it includes the most recent activities and dates (see Stakeholder process section).
- Clarified the formula that would be used for the ICPM Capacity Payment to be clear that, since the CAISO can procure a "partial unit" under ICPM, the amount of capacity that is designated under ICPM would be used to calculate the compensation to be paid rather than the entire rated capacity of the resource, i.e., the total Net Qualifying Capacity of the resource would not be used in the formula (see Formula for Capacity Payment section).
- Clarified the method to be used to break ties when there are multiple resources that are eligible to be designated. The CAISO now proposes to use a random selection rule to determine designation when there are ties (see Selection among Multiple Resources section).

Changes made to Final Proposal to create Draft Board Proposal

The CAISO considered stakeholder comments on the November 9, 2007 Final Proposal in developing the Draft Board Proposal. The key changes made to the major elements of the Final Proposal to create the Draft Board Proposal include the following:

- Updated the section that describes the stakeholder process so that includes the most recent activities and dates (see Stakeholder process section and Attachment 2 Key Milestones section).
- Clarified the obligations of an ICPM resource by adding back into the Draft Board Proposal the words "and Ancillary Services" that were inadvertently not included in the Final Proposal but were included in Proposal #2 (see Backstop Product section).
- Changed the pricing so that a resource owner that believes that its "going forward" costs[4] are greater than $41/kW-year would be able to file at FERC for a price higher than $41/kW-year, but the owner would have to justify that price to FERC based on

[4] Going forward costs are defined here as the sum of fixed operations and maintenance costs ("O&M"), ad valorem costs, and insurance costs plus a 10% adder to account for any other going forward costs.

the same cost elements that are considered in setting the $41/kW-year default price (see Target Annual Capacity Price section).

- Clarified the formula that would be used for the ICPM Capacity Payment and changes from the formula that is currently in the RCST, and inserted the specific Availability Factors from the RCST that are proposed to be used for the ICPM (see Formula for Capacity Payment section).
- Changed the "shaping factor" so that each month an ICPM resource would be paid 1/12 of the target annual capacity price, i.e., the shaping factor would be level throughout all months of the year (see Formula for Monthly Capacity Charge section).
- Clarified the method to be used in the situation where there are multiple resources that are eligible to be designated and cannot be differentiated using physical criteria such as effectiveness. The CAISO would apply a tie-breaking method using a simple sealed-bid auction and pay each accepted offer the price of the highest accepted offer, i.e., a uniform clearing price (see Selection among Multiple Resources section).
- Clarified the circumstances in which the CAISO supports an LSE including ICPM capacity in a RA showing, including a change where the CAISO now supports allowing an LSE to include Type 1 ICPM procurement that was made to address "effectiveness factors" in its RA System showing (see Allowing ICPM Capacity to be included in RA Showings section).

Changes made to Proposal #2 to create Final Proposal

The CAISO considered stakeholder comments to the October 5, 2007 Proposal #2 in developing the November 9, 2007 Final Proposal. The key changes made to the major elements of Proposal #2 to create the Final Proposal include the following:

- Clarified the obligations of a resource that is designated as an ICPM resource (see Backstop Product section).
- Changed the procurement process to include a report on ICPM designations that would be sent to the Board of Governors for each Board meeting (see Process and Trigger for Backstop section).
- Added text to clarify the definition of a Significant Event and the examples of events that the CAISO might evaluate to determine whether a Significant Event has occurred (see Definition of Significant Event section).
- Added a new requirement that the CAISO would issue a market notice within two business days of procurement, revised the reporting such that all market commitments of non-Ra capacity would be reported, and added Exceptional Dispatch to the type of procurement information that would be reported (see Reporting section).
- Revised the text to clarify that the term of a designation for a deficiency in a year-ahead system showing is from one month to up to five months, and the term for a deficiency in a year-ahead local showing it is from one month to up to 12 months. Also clarified that a procurement to address an "effectiveness" issue is for a 12 month term (see Committed Term of Payments section).
- Changed the pricing such that there would be one uniform flat price for both Type 1 and Type 2 procurement, set at $41/lkW-year, with no deductions for peak energy rents. For Type 1 procurement there would be a simple auction to break ties if needed at the $41/kW-year price offer (see Target Annual Capacity Price section).
- Clarified that If an LSE causes the need to procure under the ICPM due to a deficiency in its RA showing, whether for system (year-ahead or month-ahead) or local, that LSE is charged with all of the cost of ICPM procurement, including any

"lumpiness" of procurement, i.e., none of the cost is spread to other LSEs (see Allocation of Costs section).

- Removed the provision for a Significant Event where the CAISO would seek to first charge an LSE that was deficient in a previous RA showing but for which ICPM procurement was not made initially because there was sufficient RA capacity in aggregate (see Allocation of Costs section).
- Clarified the circumstances in which the CAISO supports an LSE including ICPM capacity in a RA showing (see Allowing ICPM Capacity to be included in RA Showings section).

Stakeholder Process

A stakeholder outreach effort was initiated in April 2007. Stakeholder meetings were held on May 18, June 6, July 25 and October 15, 2007, and conference calls were held on October 18, November 15 and December 20, 2007, to formally gather input.

An "Issues Paper" was posted on May 9. Proposal #1, Proposal #2, the Final Proposal and the Draft Board Proposal were posted on June 29, October 5, November 9 and December 14, 2007, respectively.

Stakeholders provided formal written comments on May 25, August 9, October 24 and November 21, 2007 and January 7, 2008. These comments were considered in preparing this Board Proposal. All stakeholder comments can be found at http://www.caiso.com/1bc5/1bc5db284cc80.html. The most recent stakeholder written comments were received on January 7, 2008 from AReM, CLECA, CMUA, Constellation, CPUC, Dynegy, IEP, Reliant, PG&E, SCE, TURN and the Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside, California.

All of the documents described in this section, as well as the materials that were posted for the seven stakeholder meetings and conference calls, can be found at http://www.caiso.com/1bc5/1bc5db284cc80.html.

Attachment 1 provides a list of acronyms used in this paper. Key milestones for the ICPM tariff filing are provided in Attachment 2.

Evaluation Criteria

To evaluate options and provide a foundation for a proposal, the CAISO used the following criteria:

- Improve the definition of the interim capacity product;
- Provide transparent procurement prices;
- Minimize reliance on backstop procurement where possible by allowing LSEs to procure interim capacity through bilateral transactions;
- Ensure that neither buyers nor sellers have an incentive to defer RA transactions to the ICPM; and
- Minimize administrative costs and implementation issues.

Need for Backstop Mechanism

The backstop described in this proposal is an appropriate mechanism to complement the MRTU market design. It is necessary as a last resort to enable the CAISO to maintain reliable grid operations: (1) in the event LSEs do not meet RARs; (2) RA resources do not meet specific local reliability needs; or (3) conditions change or events occur during the operating year and create a need for the CAISO to procure capacity in order to maintain reliable operations.

Although RA programs are in place, there may be instances during the year where RA resources are not sufficient to meet all of the operational needs of the CAISO and allow it to meet ARC. Without a flexible means to procure capacity to address unforeseen or changed circumstances or any inefficiencies or deficiencies in RA programs or showings, the CAISO could be placed in the position in the day-ahead time frame of planning for the interruption of firm load or needing to obtain access to non-RA Participating Generator Agreement ("PGA") resources. The CAISO believes that (1) it is necessary to allow the CAISO the ability to procure resources when such instances occur in order to maintain reliable operations, (2) it is prudent to have the ICPM in place at the start of MRTU implementation, and (3) the CAISO should provide feedback on such use of any backstop procurement to the CPUC and Local Regulatory Authorities ("LRAs") so that they can take such information into account in designing or modifying RA programs in the future.

Proposed Filing Date

On January 28-29, 2008, the CAISO intends to seek approval from the CAISO Board of Governors regarding the policy elements of an ICPM and to make a tariff filing reflecting those elements of policy. If such approval is granted, the CAISO would develop the appropriate tariff provisions and make a tariff filing on January 30, 2008. The CAISO is proposing to implement the ICPM on the effective date of MRTU implementation.

Effective Date

In the ICPM tariff filing the CAISO proposes to implement the ICPM on the effective date of MRTU implementation. [5]

Backstop Product

The CAISO proposes to procure a "capacity only" product, under a tariff-based schedule for service. The CAISO would be paying for a call option on the capacity of a resource. This obligation would be comparable to the RA-based offer obligation. Specifically, a resource procured under the ICPM would have a daily obligation to submit Economic Bids or Self-Schedules in the Day Ahead Market[6]. The Bid and Self-Scheduling obligation will extend into Real-Time for certain units, including Short Start Units, Dynamic System Resources, and committed resources with unloaded ICPM capacity, while Long-Start Units that remain uncommitted after the Day Ahead Market will be released from any further Bid obligation. Similar to RA Resources, ICPM resources would be required to submit a $0 availability bid in RUC and not be eligible for Frequently Mitigated Unit ("FMU") Bid Adders.

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[5] MRTU is scheduled for a "go live" date of March 31, 2007 for an initial trade date of April 1, 2008.
[6] The ICPM resource is expected to offer bids or self-schedule the full quantity of ICPM capacity for both Energy and the Ancillary Services that it is qualified to provide.

Sunset Date

The ICPM would automatically sunset on midnight on December 31, 2010. The CAISO would retain all Section 205 rights with respect to the ICPM.

This mechanism is intended to be an interim mechanism. The ultimate goal is to design a backstop that works under the long-term RA market structure. This topic is currently under discussion at the CPUC and the CPUC is expected to issue its initial direction in an Order scheduled for early 2008. It may be appropriate to revisit the ICPM sooner than the year 2010, depending on the timing of implementation of the long-term RA mechanism and the types of mechanisms being implemented as part of that design.

Use of Backstop Authority

The CAISO would use the new backstop authority to procure capacity in the circumstances described below.

Type 1 Backstop to the RA Process where the CAISO procures forward capacity to cure: (1) a RA deficiency that results if an LSE fails to meet all of its respective applicable local and system RA capacity requirements, or (2) a RA deficiency that results if the collective RA procurements by LSEs fail to meet the CAISO ARC, even if the LSEs have collectively met their RA requirements. For example, the CAISO would make sure that LSEs under the CPUC's jurisdiction procure RA resources necessary to meet the 115 percent Reserve Margin established by the CPUC. The CAISO also would make sure that the capacity of the procured RA resources meets the capacity requirement established by the applicable LRA for each LSE that is under that LRA's jurisdiction. Action by the CAISO would include:

- An LSE has not procured sufficient RA capacity on its own to meet its full RAR and is "short" in its RA showing, or otherwise violates a "counting rule" or "counting constraint" like the Path 26 counting constraint (i.e., the LSE fails to make up an identified deficiency in an RA showing, whether annual local, annual system, or monthly system, after it has been given an opportunity to cure the deficiency).
- The aggregate amount of resources that are contracted for in a local area by the applicable LSEs and included in their RA showings is in compliance with the aggregate MW amount of the RA capacity requirement, but the CAISO still needs additional capacity to comply with ARC due to the "effectiveness" of the individual units that have been procured by LSEs and now form the aggregate portfolio that the CAISO has available for its use.[7]

Type 2 Backstop for Significant Event, where the CAISO procures capacity to address a single event, or a combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the RA program for purposes of determining the RA capacity requirements, or a material change in system conditions or CAISO-Controlled Grid Operations, that causes, or threatens to cause, a failure to meet ARC absent the recurring use of a non-RA resource(s) on a prospective basis.

[7] The CAISO also may need to procure backstop capacity in the circumstance where LSEs may be compliant with RA requirements, but insufficient capacity was procured in a specific load pocket. This issue can arise because an LRA may allow the aggregation of load pockets in a particular Transmission Access Charge ("TAC") area for procurement compliance purposes. For example, the CPUC allows for the aggregation of load pockets in the Pacific Gas and Electric Company TAC area.

Process and Trigger for Backstop

It is important that the process used to procure backstop capacity be transparent. The CAISO may need to procure capacity to address three broad needs. As a result, the mechanism and criteria leading to a procurement decision should appropriately be based on triggers that align with the underlying need. The variety of types of events that might initiate the proposed process is summarized in the table below.

Event Type	Backstop Purpose	Trigger
Type 1 Backstop to RA Process: (a) LSE Procurement Shortfall (b) Local Effectiveness Deficiency	(a) Ensure that RAR is met (b) Ensure that RAR is met	(a) Known deficiency in LSE RA showing that it is not cured by the LSE (b) Engineering analysis identifies a deficiency in meeting the local capacity needs
Type 2 Backstop for Significant Event	Ensure that CAISO can meet ARC	A single event, or a combination of events (see definition of Significant Event in subsequent section)

The CAISO proposes to follow the process described below for each situation.

Type 1 Backstop to RA Process
(a) LSE Procurement Shortfall
The need for this capacity arises because one or more LSEs have not reflected sufficient RA resources in their RA showings to meet their obligations as established by their respective LRA. Therefore, the CAISO needs to procure capacity on behalf of the LSE(s).

a) The CAISO would analyze the showings submitted by LSE(s) to determine if there is a deficiency. The CAISO will make its assessment based on the total system RA needs, i.e. other LSEs may have cured the deficiency through over-procurement.
b) If there is no deficiency, the CAISO would take no action(s).
c) If there is an aggregate deficiency, the CAISO would: (1) notify the Scheduling Coordinator ("SC") for the LSE(s) and the LRA(s) of the deficiency and provide an opportunity for the LSE(s) to cure the deficiency, (2) if the LSE(s) does not cure the deficiency, the CAISO would proceed to procure resources to meet the deficiency.
d) The CAISO would procure the minimum capacity necessary to meet RA requirements, subject to limitations on partial unit purchases,
e) Costs would be charged to the LSE(s) that contributed to the deficiency (cost allocation is described later in this paper).

(b) Local Effectiveness Deficiency
The CAISO expects that LSEs will acquire sufficient capacity at levels that meet the established locational needs. However, it is possible that the combination of resources acquired will not be fully effective in addressing all contingencies that underlie the local capacity requirements. Therefore, the need for backstop capacity arises because the local RA resources procured by LSEs are found to be ineffective in meeting all contingencies.

a) The CAISO would analyze the showings submitted by LSE(s) to determine whether additional local capacity is needed beyond the aggregate amount procured by the LSEs that have complied with the applicable RA requirements.
    I. The CAISO will load the resources procured by LSEs and included in their annual local showings into its grid model and analyze the portfolio of resources against the same study assumptions used to establish the local capacity requirement to see if sufficient capacity has been procured in the local area to meet the local capacity requirement.
b) If there is no deficiency, the CAISO would take no action.
c) If there is a deficiency, the CAISO would procure the minimum sufficient capacity to alleviate the deficiency.
d) All costs would be charged to the LSEs based on their proportionate contribution to Transmission Access Charge ("TAC") Area peak Demand.

<u>Type 2 Backstop for Significant Event</u>
The need for this capacity arises because the CAISO has experienced a set of operating conditions that cannot be met within its obligations to meet ARC. Therefore, the CAISO proposes to perform an assessment of whether an event or events have occurred that would constitute a Significant Event (see definition in subsequent section). Stakeholder comments have indicated their desire to engage in a dialog with CAISO management regarding any procurement of ICPM capacity under a Significant Event, and to have a report on ICPM designations sent to the CAISO Board of Governors. To address these points, the CAISO proposes to utilize a three-step designation process to initiate backstop procurement under a Significant Event and provide ICPM summary reports at each CAISO Board of Governors meeting.

Step One:

I. CAISO would identify an event or events that may violate an assumption in the RA program or result in a material change in system conditions or in CAISO-Controlled Grid Operations.
II. CAISO would evaluate if that event or events cause, or threatens to cause, a failure to meet ARC.
III. Based on i and ii, the CAISO would determine if the event constitutes a Significant Event (see the definition below of Significant Event for more details).
IV. If the answer is "no," the CAISO would take no further action.
V. If the answer is "yes," the CAISO would determine if the Significant Event is of an enduring nature that indicates the need for procuring backstop capacity on a forward basis.
VI. If the answer is "no" the CAISO would take no further action.
VII. If the answer is "yes" the CAISO would (1) procure needed backstop resources on a forward basis for a period of 30 days, and (2) post an explanation of the Significant Event and inform the market participants of the need to procure the backstop capacity as well as the expected duration of the Significant Event.

Step Two:

- If the CAISO determined in completing its explanation of the Significant Event that the event has an expected duration greater than 30 days, then it would extend that designation for another 60 days (for a total of 90 days from beginning of Significant Event).

- During this extended time, market participants would have the opportunity to review the CAISO explanation for the Significant Event and engage in a dialog with the CAISO to understand the basis for that designation.
- Market participants would be encouraged to provide solutions that meet the CAISO operational needs. These would include options such as; procurement of capacity by LSEs, operational fixes by Participating Transmission Owners ("PTOs"), additional Demand Response ("DR"), etc.

Step Three:

I. Before the end of the 90-day period, the CAISO would conduct an assessment of proposed solutions to determine whether they sufficiently mitigate the ongoing need for the designated capacity.

II. If the answer is "yes", and a specific solution is undertaken, the CAISO would not extend the designation of capacity procured for the Significant Event.

III. If the answer is "no" in total or partially, the CAISO would extend the necessary capacity for the remaining expected duration of the Significant Event.

The CAISO Board of Governors will be provided with a high-level summary report on ICPM costs in the existing Operations informational report that is provided to the Board for each Board meeting.

Note: The CAISO proposes to report instances where it has procured capacity under the new backstop mechanism. The Reporting section below provides the details regarding the report content. In addition, the CAISO does not expect that it will need to designate a resource for more than one instance during the calendar year. If this were to be necessary, the CAISO proposes to fully describe why the additional designation is required in the proposed report required in step one of this process.

Definition of Significant Event

While some stakeholders may feel it is preferable for the successor mechanism to be more prescriptive and/or have more specificity than the RCST, particularly with regard to Significant Event designations, the CAISO believes that adequate flexibility is necessary to avoid the unintended consequences of an overly prescriptive approach for Significant Event designations. A flexible means is needed to address unforeseen or changed circumstances or inherent inefficiencies or deficiencies in RA programs where lack of action by the CAISO to address a known problem could place the CAISO in the position, in the Day-Ahead timeframe, of planning for the interruption of firm load or failing to meet ARC. The CAISO proposes that a sufficiently flexible definition of Significant Event be used, which would allow the CAISO to address contingencies and unexpected system conditions and ensure its ability to satisfy reliability requirements.

Similarly, the CAISO does not want to have a prescriptive "hard trigger" for a Significant Event that does not allow prudent judgment in avoiding designations that are not required. Accordingly, a hard trigger must be avoided in favor of using "indicators" serving as warnings that a designation *may* be required. Also, a hard trigger could result in ICPM designations based on past events that are not continuing in the designation period. The purpose of ICPM is to designate units that are needed to meet prospective reliability requirements based on Significant Events that have occurred and which will continue in the future. Stakeholders have indicated interest in knowing what the CAISO would use for thresholds for making decisions on designations. Unfortunately, electric system operation does not always present itself with a consistent set of completely black and white conditions that would make hard triggers always possible. It is appropriate to enable decisions to be made using latest available information without restricting operations (based on triggers) to prescriptive decisions that would ultimately not be prudent. For example, suppose that there was a hard trigger and the threshold was that the operating condition had to be experienced four times before a Significant Event could be designated. If a section of the Third AC Transmission Line was taken out of service by a plane crash (which obviously would take a long time to repair), after analysis the CAISIO may determine that it is appropriate to declare that a Significant Event has occurred, even though the event happened just one time and the operating condition was experienced just one time. A hard trigger of four times would not allow designation. On the other hand, if there were a hard trigger of "one time," there may be events that occur where it would not make sense to designate because the operating condition is not expected to be recurring.

The concept of Significant Event is an element that was discussed at length at the May 18, June 6, July 25, and October 15 2007 stakeholder meetings. The CAISO acknowledges that this reason for backstop procurement by the CAISO should be appropriately defined. However, establishing a clear definition is challenging due to the very nature of unforeseen events that are nevertheless high impact events that cause the CAISO to be unable to meet requirements for reliable system operations. Most parties have reflected in their written comments that it is important that this concept be well defined, and a detailed listing be provided, if possible, of examples of items that could trigger procurement for a Significant Event. The CAISO has provided such a listing and attempted to refine that listing to reinforce its intention that ICPM procurement will be based on a determination of need for additional capacity and not specifically triggered by the events provided as examples. These examples, therefore, represent a compendium of indicators that warrant further investigation and possible real-time action. That action may include further, closer monitoring, or it may be apparent that some designation of resources is prudent. If procurement designations are made as a result, such designations must be reported in a manner that promotes appropriate visibility and opportunities to make long-term adjustments to the RA Program.

On the contrary, making these indicators the precursors of definite (and in some cases unwarranted) procurement designations is imprudent. The CAISO cannot support absolute prescriptive triggers unless they provide maximum assurance that the CAISO can meet ARC. The CAISO, therefore, strongly advocates a definition of Significant Event that incorporates expert judgment and informed decision making.

The CAISO proposes that the ICPM tariff language would include the following definition of Significant Event:

> *Significant Event is a substantial event, or a combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the RA program for purposes of determining the RA capacity requirements, or produce a material change in system conditions or in CAISO-Controlled Grid Operations, that causes, or threatens to cause, a failure to meet ARC absent the recurring use of a non-RA resource(s) on a prospective basis.*

Provided below, is information on the events or similar types of events that the CAISO might evaluate to determine whether a Significant Event has occurred. This language below would not be included in the ICPM tariff.

1. Loss of a facility, for any cause, that affects its capability, including but not limited to:
    a. Loss of a local RA resource after annual LSE RA showing
    b. Lack of RA resources causing a shortage of capacity to meet required operating reserves (accumulated total, including ongoing scheduled and forced outages) after monthly LSE RA showing
    c. Loss of a facility, CAISO Controlled or not, that affects the deliverability of RA, Reliability Must-Run Agreement ("RMR") or other resource available to the CAISO, or affects the operation of the grid
2. Grid study error, forecast changes, incorrect assumptions, bad data, or modeling inaccuracies, including, but not limited to:
    a. An official change in the adopted Load forecast by the California Energy Commission ("CEC") after it has been used in RA showings by LSEs
    b. Error in load distribution factors
    c. Voltage or reactive resource modeling errors or resource changes
    d. Errors relative to deliverability of RA resources to load
    e. Changes in non-CAISO Controlled Grid affecting previous assumptions
3. Changes in applicable NERC or WECC reliability criteria or operating policies affecting the CAISO
4. Insufficiency of RA units in RUC resulting in recurring use of non-RA units (Note: The use of non-RA units as described above would be an indicator for the CAISO to then assess if a Significant Event has occurred. Having to use non-RA resources in RUC may mean that there are not enough RA resources and the CAISO has to call on non-RA resources in RUC or that there are sufficient RA resources but the economic optimization used in RUC selects a non-RA resource.)
5. RUC and any subsequent Hour-Ahead Scheduling Procedure ("HASP") or real time run of the Security Constrained Unit Commitment ("SCUC") cannot converge by themselves with only RA units and requires manual addition by the CAISO of non-RA units. (Note: Same clarifying comment applies as at the end of #5 above.)
6. Change in federal or state law or regulation; court action; or imposition of environmental restrictions that affect the operation of resources

For item 2 above, errors occur, and they occur in many forms and for many reasons. While the CAISO uses its best efforts to avoid errors, the reality is the CAISO and others can perform studies and/or make use of other efforts to anticipate capacity needs, which are subsequently found to be incorrect. However, once identified, the CAISO has an obligation to take corrective actions to protect system reliability. Who or why the error occurred is largely irrelevant. As noted, what is relevant is that the consequences of the error are mitigated as appropriate and until the RA program can be adjusted as needed.

Regarding items 3 and 6 above, the CAISO notes that potential changes in such things as criteria, laws or regulation do not arise in a vacuum or short period of time. However, the actual <u>imposition</u> of a change can occur in a relatively short time. Even so, taking action to change a program so involved and complex as the RA program must reasonably occur only *after* the decision is officially communicated. It is reasonable to presume that implementing decision could take some extended process in order to work out details into existing programs, and subsequent to that, some time to incorporate changes into software of advanced applications (*i.e.,* at the CAISO, as well as with Market Participants and other interested parties). Even if this were not the case and criteria or regulatory changes could be easily and quickly translated into the RA program, a "decision" could occur shortly after a RA program has been set in place for the upcoming compliance year. LSEs will have already procured to meet the RAR for that compliance year. If a "decision" happens after the wheels have been set in motion for the next compliance year, entities that have RA programs would then need to take action to revise their program for the subsequent compliance year. This alone can take many months. As a result, there may not be sufficient time to incorporate such a change in the compliance year. That raises the issue of how the CAISO would operate the system and meet ARC if this happens? Stakeholders suggest that the CAISO should be able to monitor such items and that there is time for the "CAISO to change the RA program." It is not the CAISO that has a RA program. The CAISO cannot just simply change an RA program. The RA programs are under the jurisdiction of the CPUC and LRAs, and they have their own processes in place for establishing and changing RA requirements. Those entities would need to change their programs, and that takes time.

For items 4 and 5 above, stakeholders have expressed concern that it is unclear how the CAISO intends for these events to be considered, or are inappropriate to include because they either are defects in the MRTU hardware/software that should be fixed, or transitory daily operational issues for which it is not appropriate to backstop with a month or longer of backstop capacity. These items are examples of indicators potential Significant Events, not hard triggers in and of themselves. They are indicators of something that may warrant closer scrutiny and *possibly* some action, but not necessarily an ICPM designation. They may be indicators of issues that are rooted in forecast or modeling errors, or greater than expected outages, or some other unforeseen conditions. Granted, while these other conditions may be indicators of a Significant Event, it is never a bad thing to have corroboration or alerts to warrant further investigation. For example, the knowledge of a facility outage may not immediately include the encroachment on flow limits being managed by SCUC, or may not initially recognize the A/S impact that would otherwise be expected to be covered by RUC. The CAISO would be remiss not to utilize to these advanced applications to their full potential. That utilization includes evaluation of causes for non-convergence when convergence is expected. It is important to remember that the CAISO's assessment of non-convergence does not necessarily equate to the designation of units under the ICPM.

To say that such non-convergence is an indication of MRTU defects and therefore should not be addressed is short-sighted. It is essentially the same as saying that if there are defects found in the RA program that they should not be addressed. It is appropriate that the CAISO be enabled to deal with those issues appropriately if and when they occur until such time as the problems can be fixed. Some problems take more time to fix than others. Again, any subsequent procurement designations resulting from the CAISO's need to address a RUC, HASP, or other convergence issue would be reported in a manner that promotes visibility and provides opportunities to make long-term adjustments in whatever programs or applications that may be deficient. In summary, the key points are: (1) these items are not hard triggers, but rather indicators; (2) such indicators would be analyzed by the CAISO; and (3) all commitments of non-RA capacity will be reported in the monthly use of non-RA capacity report (as described elsewhere in the Draft Board Proposal), which provides a feedback loop to the CPUC, LRAs and stakeholders.

While the CAISO understands the desire of certain stakeholders for specificity in the types of Significant Events that may occur, the CAISO notes that parties must consider that the ICPM is first and foremost a backstop procurement mechanism. Consistent with its overall requirement to conduct its affairs in accordance with Good Utility Practice and in a way that meets ARC, the CAISO must be able to respond to any circumstances that threaten our ability to maintain reliable operations. As proposed, the Significant Event procurement process is of limited scope and limited duration. Accordingly, it provides the appropriate balance – enabling the CAISO, as appropriate, to obtain necessary resources in a timely and efficient manner, while respecting the boundaries of the RA programs established by the CPUC and LRAs.

Reporting

The CAISO proposes to use the reporting framework that is in the RCST for the ICPM, and to augment that reporting by posting additional information so that effective feedback can be provided to the CPUC and LRAs. ICPM reports would appropriately maintain the confidentiality of market sensitive information, while providing enough data so that the CAISO, stakeholders, the CPUC and LRAs can consider the effectiveness of RA programs and make improvements to those programs in the future.

Report 1: Market Notice within Two Business Days of Each Designation
The CAISO would issue a market notice within two business days of procuring a resource(s) to address a Significant Event. The market notice would include a preliminary description of what caused the Significant Event, the name of the resource(s) procured, the preliminary expected duration of the Significant Event, the initial designation period, and that a "designation report" (Report 1 above) is being prepared.

Report 2: Designation of a Resource under the ICPM Tariff
The "designation report" would be posted to the CAISO web site within 30 days of when the CAISO has procured a resource through the ICPM tariff authority. The CAIS0 would provide a market notice of the availability of this report. The report[8] would include the items listed below.

1. Description of the reason for the designation (the categories are: LSE Procurement Shortfall, Local Effectiveness Deficiency, or Significant Event, and the report would discuss why it was necessary to procure under the ICPM authority)
2. If the reason for the designation is for a Significant Event, the description will include a discussion of the:
    a. Event or events that have occurred (what happened, what is going on, what criteria was violated, why the CAISO has procured backstop capacity, and how much has been procured)
    b. Initial assessment of the expected duration of the Significant Event
    c. Duration of the initial designation (30 days)
    d. Whether the initial designation has been extended (such that the backstop procurement is now for more than 30 days), and, if it has been extended, the length of the extension (days)
3. The following information would be reported for all backstop designations:
    a. Resource name
    b. Amount of capacity procured (MW)
    c. Date capacity was procured (month/day/year)
    d. Duration of the designation (days)

[8] The CAISO does not expect that it will need to designate a resource for more than one instance during the calendar year. If this were to be necessary, the CAISO proposes to fully describe why the additional designation is required.

e. Price

Report 3: Non-Market Commitments and Repeated Market Commitments of Non-RA Capacity and Why it was Committed

This report would be posted to the CAISO web site within 10 calendar days after the end of each month, looking back at previous month. It would report on the following:

1. Any non-market commitments of non-RA capacity (i.e., capacity procured manually by the CAISO operators).
2. All market commitments of non-RA capacity (i.e. capacity procured by RUC).

This report would not include commitments of RA capacity, RMR capacity, or capacity that has been designated as ICPM. The CAISO would provide a market notice of the availability of this report. The Non-Market Commitments and Repeated Market Commitments of Non-RA Capacity during the previous month report would include the types of information listed below.

- Resource Name
- IOU service area and local area (if applicable)
- Maximum capacity committed over the event (MW)
- How capacity was procured (RUC, Exceptional Dispatch)
- Reason capacity was committed
- Were all RA resources used first? If not, why not?

Some stakeholders have asked if the CAISO, CPUC and CEC can provide additional, historic actual data to assist stakeholders in assessing how well RA programs are performing and to help improve future RA programs (see the list below). The data may be provided to as fine a level of granularity as daily (if it changes daily), with the information posted to a public web site. The CAISO notes that some of this data is already posted to the CAISO web site, and, where applicable, the hyperlink to access the information on a CAISO web site is provided below. Some of this data may also be available on the web sites of the CPUC and CEC. The CAISO is willing to work with the CPUC and CEC to explore the extent to which such information is available, and whether it can be posted to a public web site. For the CAISO, the extent to which this information already exists in CAISO systems, is readily available, and has no legal restrictions to posting it, will be a determining factor on whether this information is posted by the CAISO. The types of data that have been requested be posted are:

Historic Actual Data

- Net imports
- Demand response/interruptible load – The CPUC has this information, which is provided to the CPUC by the investor-owned utilities. The CPUC periodically issues reports on this information. The CPUC would need to post this data.
- Actual load, by zone or location
- Aggregate wind contribution on peak
- Transmission outages http://www.caiso.com/docs/2005/09/27/2005092712073824778.html (click on "Transmission Outage Reports")
- Generation outages http://www.caiso.com/unitstatus/index.html

Allocation Data

- Import allocations http://www.caiso.com/1c44/1c44b2dd750.html

- Aggregate Path 26 allocations – The CPUC has this information as it was developed to implement a CPUC Order to establish a counting convention that is applicable to the LSEs that are under CPUC jurisdiction. The CPUC would need to post this data.

Committed Term of Payments

The term of payments to an ICPM resource varies from one month to up to 12 months depending on the term of the Significant Event designation or the type of RA requirement deficiency being remedied. For example, where no LSE is individually deficient in its year-ahead showings, but the aggregate portfolio due to relative effectiveness factors nevertheless fails to permit compliance with Reliability Criteria applied in the Local Capacity Technical Study, the CAISO will procure the necessary Local Area Capacity for the entire calendar year. However, where an LSE's year-ahead local showing demonstrates a failure to procure up to its allocated Local Area Capacity requirement throughout the year, and that deficiency precludes compliance with the Reliability Criteria, the CAISO would procure capacity for a year term to resolve the deficiency. Where, in contrast, the LSE's year-ahead local showing demonstrates a failure to procure its allocated Local Capacity requirement only for selected months, and those deficiencies preclude compliance with Reliability Criteria, the CAISO would procure the needed capacity only for the months in which the showing is deficient. The objective is to ensure that LSE and CAISO procurement, in combination, satisfies on an annual basis the quantity of Local Area Capacity identified in the CAISO's Local Capacity Technical Study.

The table below describes terms applicable for specific applications of the backstop mechanism.

Situation:	Committed Term:
Deficiency in: a) Year-Ahead System showing (including violation of Path 26 counting constraint) b) Year-Ahead Local showing 1) "short" in showing deficiency 2) effectiveness factor deficiency c) Month-Ahead System showing (including violation of Path 26 counting constraint)	a) 1 month up to 5 months (May-Sept) consistent with the duration of the deficiency b) 1) 1 month up to 1 year 2) 1 year c) 1 month
A Significant Event" has occurred	Minimum of 1 month, and maximum of up to time event will remain in effect

An ICPM designation made in a given compliance year to backstop the RA process would not extend into the subsequent compliance year. Such procurement would not be extended beyond the end of the year because the CAISO would only backstop for RA for the immediate compliance year. In the event of a deficiency in a month-ahead RA showing for the month of December, the CAISO would only procure for that one month (i.e., the procurement would not extend into January of the next year). However, the term for procurement under a Significant Event would extend for the term of the event, and that procurement could extend into the subsequent compliance year.

Target Annual Capacity Price

In Proposal #2, the CAISO proposed a backstop price that had the following features:

- Two types of pricing, corresponding to "Type 1" procurement for forward RA backstop and "Type 2" procurement during Significant Events.
- Type 1 procurement was based on a sloped demand curve with a price floor. The demand curve was to be capped at CONE, with the entrant unit represented by a 50 MW simple cycle CT; the price floor was based on the fixed O&M costs of the same unit. The sloped region of the demand curve was the straight line between the point determined by CONE and the RA requirement and a zero price intercept. The price was set by clearing the actual capacity (whether RA or non-RA) in each local and system area against the demand curve/price floor. This price setting method ensured that high backstop prices were correlated with scarcity of capacity and low backstop prices with surplus of capacity.
- Type 2 pricing was based in all cases on the fixed O&M costs of the 50 MW simple-cycle CT.

These pricing proposals attracted substantial stakeholder comment. With respect to Type 1 pricing, stakeholders generally divided into two groups: those that accepted the sloped demand curve methodology, but had comments on elements of the demand curve; and those that opposed the demand curve methodology and proposed an alternative pricing basis. Within both groups there were several major substantive concerns: the interaction of the ICPM proposal with the ongoing CPUC RA Phase 2 Track 2 proceeding; the specifications of the demand curve, in particular the identification and cost analysis of the new entrant unit; and the impact of the demand curve price on forward RA prices. There were fewer comments on Type 2 pricing. Stakeholder comments are summarized and discussed in Section 3.

In principle, the CAISO believes that a sloped demand curve approach for valuation of capacity and the proposed price clearing method is potentially a reasonable market-proxy pricing methodology for backstop procurement in the context of the annual bilateral RA market (and possibly with other long-term RA market designs). There is no other administratively simple method for deriving stable backstop prices on the basis of market supply conditions without potentially complicated additional rules (e.g., a last-minute backstop auction would need potentially complicated ex ante or ex post market power mitigation rules, as discussed in Section 3).

However, as a practical matter, several stakeholder concerns about the sloped demand curve and the pricing methodology are difficult to resolve at this time. First, there is the issue of the ongoing CPUC proceeding, in which the CPUC is addressing long-term RA design, including issues regarding a centralized capacity market. The issues being addressed there include many of the same issues of capacity pricing being raised here. Although several stakeholders have shown great latitude in their comments to accommodate the proposed Type 1 mechanism as an interim measure, others, including the CPUC, have expressed discomfort with introducing a type of market-based capacity pricing that could be interpreted as suggesting a preferred capacity market design while the CPUC proceeding is ongoing. That was, as emphasized in the prior White Paper, not the objective of the ICPM Type 1 pricing proposal, which was developed based on the CAISO's evaluation of the various alternatives and determination that a market-proxy based pricing approach would generate prices that reflected capacity supply conditions, thereby balancing the opposing positions of stakeholders. However, CAISO certainly agrees that after the CPUC decision on long-term RA market design is known, there should be a clearer opportunity to design a long-term market-based backstop mechanism that is closely aligned with the incentives created by the forward RA market design and which can be implemented in coordination with implementation of that long-term RA design.

The second issue is the relationship of the proposed Type 1 pricing and the prices in the forward RA markets as they currently operate. Although both RCST and ICPM are intended as backstop procurement, there is no way to establish a transparent backstop price that does not have some impact on forward prices.[9] Several stakeholders commented on the impact of the RCST price on forward prices and hence the CAISO, although lacking price data on the forward RA markets, presumes that the proposed ICPM prices would have some similar effect as well. In fact, as noted in Proposal #2, the impact of a well designed backstop pricing mechanism would be to support efficient forward RA procurement, meaning that the effect of market power (if any) in the forward RA market would be reduced and that market supply conditions (i.e., scarcity/surplus) and forward prices would be positively correlated. Moreover, there are modifications to the demand curve that could help mitigate some parties' concerns about the impact on forward prices. For example, the CONE-based cap could be phased in over 2-3 years, beginning (and perhaps ending) at some fraction of CONE, thus allowing buyers and sellers time to adjust.[10] We explore these considerations in Section 3. However, the question remains as to whether the RA market is ready for a potential price shift at this time while the CPUC proceeding is underway.

Finally, the CAISO is concerned that any subsequent steps to refine the proposed Type 1 sloped demand curve methodology will take significantly more time and resources than is likely to be worthwhile for an interim product. In particular, it could require the CAISO to justify all aspects of the demand curve with empirical or analytical evidence which in turn would require stakeholders to provide extensive input and justification regarding their desired elements. The CAISO notes that in other ISO/RTO markets, the determination of capacity demand curve parameters took months or years to finalize, and hence the prior White Paper noted that the timely implementation of an interim demand curve would have required that stakeholders accept it as an interim pricing tool without an extensive technical debate (albeit with certain reasonable modifications as discussed in Section 3). In part, that suggestion relied on the acceptance of the 2007 CEC study, when final, as the best available analysis of CONE to be used on an interim basis. Given stakeholder comments, this does not appear to be the case: there is substantial interest in disputing the CEC study, in providing alternative unit types and cost estimates for consideration, and in examining all other aspects of the demand curve. These issues are also discussed in Section 3.

Given these three major issues – the ongoing CPUC proceeding, the concern about the immediate impact of ICPM Type 1 prices on forward RA prices, and the need for a comprehensive, time-consuming examination of the demand curve technical parameters – the CAISO will not seek at this time to establish a market-proxy based price for Type 1 procurement through a demand curve. We believe that it is appropriate to revisit to this issue

[9] Although the concept of an auction was suggested as a means to keep the Type 1 backstop price from being known unless there was an LSE deficiency, the auction proposal also had a market power mitigation measure based on Reliability Must-Run ("RMR") costs, which upon investigation was found to require potentially a new type of cost-based contract. We discuss the feasibility and incentive implications of an auction in Section 3.

[10] E.g., NYISO phased in capacity demand curves.

after the CPUC acts in the long-term RA proceeding and in connection with the implementation of a long-term RA design. Thus, the CAISO has revised the Type 1 proposal again in favor of a simpler uniform pricing method similar to the RCST method.

Type 1 Target Annual Capacity Price

In this proposal, the CAISO proposes a Target Annual Capacity Price for Type 1 procurement that meets the following criteria:

1. falls within the range of just and reasonable prices established by FERC in the RCST settlement,
2. guarantees that any designated resource will cover its "going forward" costs for the term of designation, and
3. does not create incentives for buyers or sellers to shift procurement to the ICPM..

The first criterion concerns what the appropriate range for a just and reasonable target annual capacity price should be. In the RCST proceeding, FERC noted that "the paper hearing in the instant proceeding has established two reference levels in determining the price of procuring backstop capacity. At the lower end, the price should at least cover the fixed costs of existing generation that is needed for reliability. At the higher end, the price should not exceed the cost of new entry that would allow investment in new generation capacity."[11] As noted, the CAISO will not seek to base the ICPM price on CONE, even in tight capacity locations, until more definition is given to the long-term RA design. Instead, the target capacity price proposed here is based on two primary criteria: coverage of going forward costs and RA market incentives.

With regard to the first criteria, the CAISO has been examining cost data on going forward costs that would provide a basis for a target payment. The CAISO defines "going forward" costs here as the sum of fixed O&M, administrative and general (including insurance) and ad valorem taxes. The CAISO will also provide for an adder that can, *inter alia,* account for measurement error and any other minor costs that might appropriately be considered going forward costs.

The 2007 CEC study provides data on going forward costs of various generation types. In that study, the highest going forward cost of any gas-fired unit (either simple cycle or combined cycle) is the going forward cost of a 50 MW simple cycle combustion turbine ("CT") built by a merchant. The going forward cost of that unit is $37.25/kW-year. The CAISO proposes the going forward cost of this highest cost gas unit as the baseline for establishing the price of ICPM backstop capacity. In addition, the CAISO proposes to include a 10 % adder to this amount for the reasons stated above. This results in a price of $41/kW-year.

The CAISO proposes to offer suppliers an interim Type 1 target capacity price of the higher of $41/kW-year or a resource's actual going forward costs that will not be subject to PER deduction. These and other cost data reviewed provide justification for assuming that this target capacity price along with retention of PER will be sufficient for almost all units to accept designation as Type 1 backstop resources.

The prior proposal did not have the "higher of" rule proposed here, but rather offered only the base price of $41/kw-year. In their comments on the Final Proposal, some stakeholders recommended that the CAISO consider situations where a resource may have going forward

[11] Independent Energy Producers Association, 118 FERC 61,096, at P 70.

costs that are greater than the $41/kW-year target annual capacity price and develop a mechanism that would accommodate these resources. After consideration, the CAISO now proposes that a resource owner that believes that its going forward costs[12] are greater than $41/kW-year would be able to file at FERC for a price higher than $41/kW-year, but the owner would have to justify that price to FERC based on the same cost elements that are considered in setting the $41/kW-year default price. While the CAISO believes that the $41/kW-year price is sufficient to cover the costs for the majority of resources located in the CAISO control area, this change in the ICPM should ensure that the going forward costs of all resources are appropriately covered under an ICPM designation.

One response of commenters to this proposed price will be to question why units are not paid on a per-unit basis for going forward costs, because some units have lower going forward costs than $41/kW-year. The CAISO believes that promulgating a per-unit backstop pricing method on this basis could severely undermine the incentives in the RA market, causing buyers potentially to enter the backstop procurement despite the potential for CPUC penalties. This is because there are units with low capacity costs but with a high RA value (e.g., in load pockets) that could be reflected in RA contracts. With regard to market incentives, FERC has noted that "the price for backstop capacity should be high enough that LSEs do not simply rely on the backstop mechanism to meet their resource adequacy requirements."[13] In this regard, the CAISO has been informed that the CPUC penalty for LSE RA deficiency will be applied independently of whether the CAISO procures backstop capacity to cover that deficiency. So an LSE will prefer the backstop price if

$$\text{CAISO backstop price} + \text{CPUC penalty} \leq \text{Generator offer for RA}$$

The CPUC penalty for deficiency in System RAR is 3 times the cost of new capacity, but is only 1 times the cost of new capacity for deficiency in Local RAR. However, this calculation is also affected by whether the CPUC grants a Local RA waiver, which can be requested at a trigger price of $40/kW-year. The CAISO understands that waivers have been requested, but not yet been granted, so for purposes of this discussion will assume that an LSE cannot ex ante determine the price at which a waiver will be granted. This creates some uncertainty about LSE incentives. Hence, in the current regulatory environment, there is no exact method to assess what Type 1 price would be sufficient to prevent LSEs to prefer the backstop price. We assume here, based on experience with RA showings while the RCST price was available, that a $41/kW-year Type 1 price combined with uncertainty about the CPUC waiver and penalty price is sufficient to not induce LSEs to resort to the ICPM (since $40/kW-year is roughly the expected average net RCST price).

One of the concerns raised in prior discussions by suppliers is that the existing RCST price does not capture the scarcity value of capacity. The CAISO sought to capture scarcity pricing based on CONE in locations with RA deficiency in its prior sloped demand curve proposal. However, for this interim product, given the pendency of long-term RA pricing issues and the interrelationship between a backstop capacity product and long-term RA market design, we no longer propose a scarcity capacity value for the ICPM, but will instead not deduct PER. Given the uniform price of $41/kW-year, then, the new price formula has potential to provide higher payments than the RCST price during some hours (when the PER

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[12] Going forward costs are defined here as the sum of fixed operations and maintenance (O&M), ad valorem costs, and insurance costs plus a 10% adder to account for other costs.
[13] Independent Energy Producers Association, 118 FERC 61,096, at P 71.

is currently greater than the RCST payment).[14] In general, the CAISO estimates that the proposed price will potentially increase revenues to units designated relative to the RCST price in the summer peak months and decrease them in the shoulder and off-peak months. Higher payments that would have been deducted under a PER adjustment will also come through other changes in the pricing of energy and ancillary services under MRTU. As noted in some comments, the introduction under MRTU of locational marginal pricing (LMP) with higher energy bid caps, as well as scarcity pricing during regulation and operating reserve shortages (to be implemented in a subsequent MRTU stage) should improve the energy and ancillary service market scarcity rents.

The final per unit price that results from these pricing procedures will be the Type 1 Target Capacity Price, and will be subject to adjustments for availability and the level monthly shaping factor, as discussed below.

Type 2 Target Annual Capacity Price

The proposed Type 2 pricing attracted less attention from stakeholders. However, some parties argued that the pricing based on fixed O&M was too low to cover going forward costs and others argued that Type 1 and Type 2 pricing should be on the same basis.

In this proposal, the CAISO raises the Type 2 price to the same level as the proposed Type 1 price, such that both will have a target price of the higher of $41/kW-year or a resource's actual going forward costs not subject to PER deduction.

As discussed above under the Type 1 target annual capacity price subsection, the CAISO now proposes that a resource owner that believes that its going forward costs are greater than $41/kW-year would be able to file at FERC for a price higher than $41/kW-year, but the owner would have to justify that price to FERC based on the same cost elements that are considered in setting the $41/kW-year default price. While the CAISO believes that the $41/kW-year price is sufficient to cover the costs for the majority of resources located in the CAISO control area, this change in the ICPM should ensure that the going forward costs of all resources are appropriately paid under an ICPM designation.

The final price that results from these pricing procedures will be the Type 2 Target Capacity Price, and will be subject to adjustments for availability and the level monthly shaping factor, as discussed below.

Escalating Target Annual Capacity Price

The CAISO proposes that for the period of the ICPM, an escalation factor not be included. This is due primarily to the short duration of this proposal, i.e. the sunset provision for December 31, 2010.

Formula for Capacity Payment

In their comments on the Final Proposal, stakeholders requested that the CAISO clarify the formula for the Capacity Payment, and any changes that are being proposed from the

[14] PER values exceeded monthly maximum RCST payments for the months of June and July 2006 in the PG&E service territory. See the report on CAISO website at http://www.caiso.com/18a0/18a088e322a40.pdf.

formula that is in the RCST. In their subsequent comments on the Draft Board Proposal, stakeholders requested that the CAISO clarify that it is the amount of capacity that would be designated under an ICPM designation that would appear in the formula for the capacity payment and not the total capacity value of the resource, i.e., the term "Net Qualifying Capacity" should not be used in the formula (as was the case in the RCST). This concept is particularly important given that under the ICPM the CAISO can designate a "partial unit." This change has been made in the formula below (the term "Designated Capacity" is used rather than "Net Qualifying Capacity"). The CAISO has revised this section for the Board Proposal to make the section more clear.

As discussed above in the Target Annual Capacity Price section, the CAISO proposes to modify the general approach reflected in the RCST Settlement and in the prior proposals for the proposed Type 1 and Type 2 capacity payments (i.e., the Target Annual Capacity Price).

The CAISO proposes the following formula for the Capacity Payment:

(Designated Capacity) x (Availability Factor) x (Monthly ICPM Charge)

As a point of reference, the formula in the RCST is:

(Net Qualifying Capacity) x (Availability Factor) x (difference between Monthly RCST Charge and 95% of PER)

For the ICPM, the CAISO proposes to use the same Availability Factor in the formula as is currently in the RCST. As noted above in the Target Annual Capacity Price section, the Target Annual Capacity Price would be calculated differently than under RCST; hence, the "Monthly ICPM Charge" element shown also would be calculated differently to reflect a monthly a value as was done in the RCST (it was called a "Monthly RCST Charge" in the RCST, and it is proposed to now be called a "Monthly ICPM Charge" under ICPM). The Capacity Payment formula under ICPM also is different than under RCST in that the ICPM pricing does not deduct PER, so this element is now not part of the Capacity Payment formula (under the RCST, the Capacity Payment formula had an element that was "difference between Monthly RCST Charge and 95% of PER").

As requested by stakeholders, the CAISO has inserted below the specific language from the current RCST regarding Availability Factor.

Excerpts from IS0 TARIFF APPENDIX F
Schedule 6
RCST SCHEDULES

Availability

The target Availability for a resource designated under RCST is 95%. Incentives and penalties for availability above and below the target are as set forth in the table below, entitled "Availability Factor Table." The IS0 will calculate availability on a monthly basis using actual availability data. The "Availability Factor" for each month shall be calculated using the following curve:

AVAILABILITY FACTOR TABLE

Availability (excluding only Scheduled Maintenance)	Capacity Payment Factor	Availability Factor
100%	3.3	1.139
99%	3.3	1.106
98%	3.3	1.073
97%	2.5	1.040
96%	1.5	1.015
95%	-	1.000
94%	-1.5%	.985
93%	-1.5%	.970
92%	-1.5%	.955
91%	-1.5%	.940
90%	-1.5%	.925
89-80%	-1.7%*	.908-.755
79-41 %	-1.9%*	.736-.014
-40%	-	0.0

*The "Capacity Payment Factor" decreases by 1.7% and 1.9% respectively for every 1 % decrease in availability.

The capacity payment will be adjusted upward from the 95% Availability starting point by the positive percentages listed as the Capacity Payment Factor above, by the amounts listed for each availability factor above 95%, so that, for example, if a 97% Availability is achieved for the month (as described below), then the capacity payment for that month would be the monthly value for 95% plus an additional 4% (1.5% for the first percent Availability above 95%, and 2.5% for the second percent Availability above 95%). Reductions in capacity payment will be made correspondingly according to the Capacity Payment Factor above for monthly availability levels falling short of the 95% availability starting point.

Formula for Monthly Capacity Charge

As discussed above in the Target Annual Capacity Price section, the CAISO proposes to modify the general approach reflected in the RCST Settlement and in the prior proposals for the proposed Type 1 and Type 2 capacity payments (i.e., the Target Annual Capacity Price).

The CAISO proposes the following formula for the Monthly Capacity Charge:
(Monthly shaping factor) x (Target Capacity Price)

As requested by stakeholders, the CAISO has considered changing the shaping factor such that resources can better recover their costs at any time during the year if designated under the ICPM. Some stakeholders have expressed concern that using shaping factors such as those in the current RCST and included in previous ICPM proposals could provide a resource with only a small portion of the target annual capacity price if that resource was designated in non-summer months compared to summer months (the RCST shaping factors allocate larger percentages of the capacity payment to the summer months than the non-summer months, ranging from a high value of 17.0% in a summer month to as low as 4.6% in a non-summer month). The CAISO now proposes changing the "shaping factor" so that each month a resource would be paid 1/12 of the target annual capacity price (i.e., the shaping factor would be level throughout all months of the year). The CAISO believes that this is an appropriate modification based on two factors. First, resources will have incentives that are already aligned in the summer months as the ICPM has no PER deduction for peak energy rents and there are typically higher energy rents during the summer months. Secondly, resource owners have voiced their desire and the CAISO agrees that a level shaping factor better aligns with a fixed-cost based rate for the capacity payment because these costs do not typically vary during the year.

Allocation of Costs

The RCST provides for an allocation of costs for system, local and Significant Event procurements; therefore, since the ICPM proposal has similar procurement categories, the CAISO proposes to continue the general approach reflected in the RCST language in Section 43.8 of the current CAISO Tariff, with some additional changes as described below. The proposed methodology to allocate the total costs of ICPM capacity payments is summarized below for each of the ICPM procurement situations. Numeric examples also are provided.

Backstop to RA Process

The types of procurement where the CAISO procures to backstop the RA process (Type 1 procurement) are discussed below.

Annual System ICPM Designations (i.e., deficiency in year-ahead System showing) – Allocated pro rata to each SC-RA Entity based on its portion of the aggregate Year-Ahead System Deficiency.[15]
Example 1: If an LSE was determined to have not procured sufficient capacity to meets its Year-Ahead System showing based on targets established by the CPUC or LRA (e.g., LSE fails to procure 10 MW of its five summer month requirement even after being provided an

[15] The Year-Ahead System Deficiency is defined as the monthly deficiency in meeting Year-Ahead System RA Requirements as determined by the CPUC and applicable LRAs.

opportunity to cure the deficiency), then the CAISO would procure 10 MW for each the five summer months under the ICPM and charge that LSE the cost of that procurement. Or, as another example, if the LSE was only short 10 MW in just two of the five summer months, the CAISO would procure 10 MW for only the two summer months under the ICPM and charge that LSE the cost of that procurement. This assumes the CAISO can purchase exactly 10 MW from a resource. Generally, under ICPM there should not be a "lumpiness" issue because the CAISO will not be limited to buying whole units. Nevertheless, lumpiness could arise if the minimum operating level of the only available resource is greater than the deficiency. In that circumstance, the deficient LSE is still the only LSE charged for the ICPM procurement. For system deficiencies, this lumpiness scenario should happen, if at all, very infrequently because the CAISO is not constrained by the location of resources from which to procure. Nevertheless, in the unusual circumstance where the CAISO is limited to a unit with a minimum operating level greater than the deficiency, all of the costs of the ICPM procurement would be assigned to the deficient LSE (i.e., the deficient LSE caused the need for the ICPM procurement and it would be charged the full cost of that procurement – in following with cost causation principles it would not be appropriate to spread any of this procurement cost to other LSEs that were otherwise sufficiently procured).

Local ICPM Designations (i.e., deficiency in year-ahead Local showing) – Either allocated to the LSE(s) that caused the deficiency, or allocated pro rata to each SC-RA Entity based on the ratio of its Local RA Requirement Deficiency to the aggregate Local RA Requirement Deficiency in each TAC Area (see examples below).
Example 1: If the LSEs are short and the CAISO can resolve the situation by making ICPM purchases equal to the total LSE Local RA Requirement Deficiency, then the CAISO will split the cost to the deficient LSEs based on the ratio of their Local RA Requirement Deficiency to the aggregate Local RA Requirement Deficiency in Local Reliability Area. For example, if LSE 1 is deficient by 50 MW, LSE 2 is deficient by 100 MW, and the CAISO can solve all the deficiency by securing a 150 MW unit, the costs would be split 33.33% to LSE 1 and 66.67% to LSE 2.
Example 2: If an LSE is short in its local capacity showing and the CAISO can only resolve the situation by making an ICPM purchase of capacity that is greater than the MW deficiency (due to lumpiness of procurement), then the CAISO will charge the deficient LSE for the total capacity procured. For example, if an LSE is deficient by 100 MW and the minimum amount of capacity that can be acquired by the CAISO is 120 MW (the smallest available increment of additional capacity is a resource with a "PMIN" of 120 MW), then the full cost of the 120 MW of procurement would be assigned to the deficient LSE (i.e., this one LSE caused the need for the ICPM procurement and it would be charged the full cost of that procurement - – in following with cost causation principles it would not be appropriate to spread any of this procurement cost to other LSEs that were otherwise sufficiently procured).
Example 3: If all LSEs are in compliance with their respective RA local capacity requirements and there still is a deficiency (there is an "effectiveness" issue where the LSE portfolios fail to resolve all criteria violations), then the costs of the ICPM procurement will be allocated to all LSEs in the TAC area based on the ratio of each LSE's contribution to peak Demand in the TAC Area as determined by CEC Demand Forecasts.

Monthly System ICPM Designations (i.e., deficiency in month-ahead system showing) – Allocated pro rata to each SC-RA Entity based on its portion of the aggregate Month-Ahead System Deficiency.[16]

Example 1: If an LSE was determined to have not procured sufficient capacity to meets its month-ahead system target, as determined by the CPUC or LRA (for example it was required to procure 20 MW more than it did for the upcoming compliance month, and it did not do so after a cure opportunity), then the CAISO would procure 20 MW for that one month under the ICPM and charge that the deficient LSE for the cost of that procurement(assuming that the CAISO could purchase exactly 20 MW from a resource). However, if there was a need to cure a 20 MW deficiency, and there was lumpiness of procurement (such as the minimum operating level of the only available resource is 25 MW, not 20 MW), then the CAISO would purchase the 25 MW and that LSE, and only that LSE, would be charged for the one-month ICPM procurement of 25 MW (i.e., the deficient LSE caused the need for the ICPM procurement and it would be charged the full cost of that procurement - – in following with cost causation principles it would not be appropriate to spread any of this procurement cost to other LSEs that were otherwise sufficiently procured).

Backstop for Significant Event

When the CAISO engages in ICPM due to the occurrence of a Significant Event (Type 2 procurement), the CAISO would use the actual load for each month as recorded in the CAISO settlement system for cost allocation purposes.

Significant Event Designations – Allocated to all SC-RA Entities in the TAC Area(s) in which the Significant Event caused or threatened to cause a failure to meet ARC based on SCs' RA Entity Load Share Percentage(s) in such TAC Area(s).[17] Costs for Significant Event procurement are spread because no one could have known or predicted that a Significant Event would occur.

Note: The CAISO could procure capacity to address operating situations that may be of a system or local nature, or for the geographic area north of Path 26 or south of Path 26. The cost allocation discussed above would allocate costs to entities in one TAC area if only one TAC Area was affected, or to entities in more than one TAC area if more than one TAC Area was affected.

Selection among Multiple Resources

As in the prior proposals, the CAISO proposes to continue the general approach to selection among multiple resources reflected in the RCST Settlement. The criteria for selection of backstop resources is currently provided in the RCST language in Section 43.2.2, Selection of Eligible Capacity Designated for Local Reliability, and Section 43.3.3, Selection of Eligible Capacity Designated for System Reliability.

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16 The Month-Ahead System Deficiency is defined as the monthly deficiency in meeting the Month-Ahead System RAR as determined by the CPUC and applicable LRAs for each RA Entity subject to their jurisdiction.

17 The RA Entity Load Share Percentage shall be calculated for each RA Entity by dividing the RA Entity's actual coincident peak Load in each TAC Area by the total coincident peak Load of all RA Entities in the TAC Area.

As before, the CAISO also proposes a change to the existing RCST program to allow the CAISO to designate a partial unit to provide service under the capacity backstop mechanism.

The CAISO remains confident that the physical characteristics of the specific resources (e.g., effectiveness on local contingencies) and partial unit procurement will allow for differentiation between resources that are eligible for designation such that ties will rarely take place. In the prior proposals, the CAISO asked for comments about tie-breaking in the event that following the application of the physical criteria for selection there are still multiple units eligible to be designated as Type 1 resources. The primary option that was considered was a simple auction capped at the $41/kw-year price. However, with the subsequent modification to allow submission of going forward costs higher than that price (which would have to be filed and approved by FERC), and in the face of stakeholder concern about the implementation of such an auction, the CAISO has decided not to adopt an auction. Rather, in the event of ties, CAISO will first choose units that accept at the $41/kw-year level, and only subsequently choose offers which are indicated at a higher price. If the tie is not resolved, CAISO will use a random selection rule to determine designation. All resources will be paid either $41/kw-year or the higher price approved by FERC. The resulting price per resource will not be subject to PER deduction but will be subject to the other adjustments listed above (availability factor and monthly shaping factor). The same rule will now apply to Type 2 procurement.

ICPM Designation is Voluntary

A resource owner can decline an ICPM designation when offered by the CAISO (i.e., an ICPM designation is voluntary). The CAISO's objective is to keep the MRTU markets voluntary and motivated by market incentives as much as possible.

However, many stakeholders and the MSC believe that an ICPM designation should be mandatory. They believe that the CAISO has developed this mechanism to ensure that the CAISO can procure capacity when needed, and that the CAISO should be able to compel resources to accept the offer so that the CAISO's needs can be assured to be met and with minimal "shopping." Many stakeholders also are concerned that if the ICPM is voluntary some resources may decline the offer of ICPM designation, and hence the requirement to offer into the Integrated Forward Market ("IFM"), which could make it difficult to procure the necessary capacity and adversely affect reliability. Another concern is that resources reject an ICPM designation for purposes of market power.

The CAISO continues to believe that it is appropriate to make the ICPM designation voluntary. First, FERC has ruled there is no type of Must-Offer Obligation that non-RA/RMR resources would be subject to under MRTU, and a mandatory ICPM designation requirement would be like re-imposing a Must-Offer Obligation.

Second, CAISO believes that the ICPM pricing provides sufficient incentives for resources to accept a designation – it at least covers their going-forward costs (if not more) and also allows resources to retain all revenues from the MRTU markets.

Third, the CAISO has not seen any compelling evidence to suggest that suppliers would have a clear reason not to accept ICPM designation due to expectations of greater compensation in the MRTU markets as non-ICPM resources. Moreover, even if that was the case, resources that had opted not to become ICPM resources would not be withholding their capacity from the MRTU markets, but rather continuing to offer it. Hence, the CAISO would have the resources available that it needs and reliability would not be affected.

Fourth, the CAISO Department of Market Monitoring will be monitoring whether resources have both rejected ICPM designations and are not participating in the market, to see if there is any physical withholding. If there is a finding of potential withholding, there may be a need to establish a mandatory designation.

Finally, the CAISO has additional tools under the MRTU tariff to operate the system reliably if resources, for whatever reason, decline an ICPM designation (i.e., Exceptional Dispatch[18] and emergency declarations).

Allowing ICPM Capacity to be included in RA Showings

The CAISO proposes to provide information to the CPUC and local regulatory authorities on all ICPM procurement so that capacity procured under the ICPM can be considered by the CPUC and local regulatory authorities and potentially allowed to count towards satisfying an LSE's RA requirement.[19] Stakeholders have requested, and the CAISO supports, allowing all Type 1 ICPM capacity procurement (procurement to backstop the RA process) to be included in RA showings so that LSEs receive credit for ICPM capacity for which they have paid. However, some stakeholders have requested that all ICPM procurement be allowed to be included in RA showings. The CAISO does not support allowing Type 2 procurement (procurement to backstop for a Significant Event) to be included in RA showings and will reflect this position to the CPUC and local regulatory authorities. The CAISO is differentiating between Type 1 and Type 2 procurement on this issue because the reason for Type 2 ICPM procurement is that the RA resources already procured by LSEs are determined by the CAISO to be insufficient to meet Applicable Reliability Criteria. Thus, allowing LSEs to include Type 2 capacity in subsequent RA showings would result in a decrease of the available RA capacity, which would only exacerbate the conditions that lead to the Significant Event and potentially cause additional ICPM procurement.

The CAISO makes the following addition points on this subject. First, in their comments on the Final Proposal, stakeholders have requested that the CAISO support allowing ICPM capacity that is procured to address local "effectiveness factors" being counted in a LSE's system RA showing. After consideration, the CAISO now supports allowing LSEs to include Type 1 procurement that was made to address a local "effectiveness factors" deficiency in RA system showings (i.e., such procurement cannot be used to offset the amount of local capacity that would otherwise be required to fulfill a local RAR in a subsequent RA month).

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[18] Under MRTU, Exceptional Dispatches are similar to the current out-of-sequence and out-of-market actions that may be taken by CAISO operators to address a system or local reliability issue that cannot be resolved through the CAISO market software or dispatches to Reliability Must Run resources. There are two major potential reasons why Exceptional Dispatches may be needed for local reliability issues: forced transmission or generation outages, and local reliability constraints not modeled in market software. In such cases, the CAISO has authority to manually dispatch specific generation units to address reliability issues. Units receiving Exceptional Dispatches for energy will be paid the higher of their bid price or the Locational Marginal Price. The CAISO expects that the frequency and duration of Exceptional Dispatches will be limited.

[19] The CPUC and LRAs determine the rules under which capacity is allowed to "count" towards an entity's RA requirement. Capacity that is determined to count towards a RA requirement is then included in a RA showing by the LSE. The CAISO does not determine the counting/crediting rules for capacity used by LSEs to fulfill a RA requirement.

Secondly, the CAISO does not dictate whether specific resources are eligible to count for meeting CPUC or LRA imposed procurement obligations. Accordingly, only those regulatory entities can determine whether LSEs under their jurisdiction will be entitled to receive credit toward meeting RAR for CAISO procured resources. In this regard, FERC has directed the CAISO to ensure that it provides the CPUC and other LRAs with sufficient information to allow those entities to calculate the appropriate credit for their jurisdictional LSEs should they chose to do so. The CAISO will provide information on all ICPM procurement, both Type 1 and type 2 procurement.

Third, the timing of RA showings erects a limitation on the viability of extending this credit under certain circumstances. For example, where CAISO procurement is triggered by a deficiency first revealed in a month-ahead showing, the CAISO will procure only for the affected month. Under this circumstance, the term of the CAISO's procurement will expire prior to the period for which the next LSE showing must be made. There is simply no opportunity for the credit to be captured by the LSE. Thus, as a practical matter, it will only be possible for an LSE, if allowed by the CPUC or its LRA, to reflect ICPM procurement in a showing where the ICPM procurement term is greater than one month.

Section 3
Changes to Proposal #2 regarding Pricing

This section examines some of the issues raised in comments on Proposal #2. CAISO appreciates the great effort that many parties undertook to address the new concepts introduced in the prior proposals in a short time-frame. CAISO anticipates that many of these issues may arise in the future evolution of backstop procurement in the context of long-term RA market design and hence discussion here will help set the stage for future consideration.

Would an auction or standing sealed-bid offer diminish the price impact of the backstop mechanism on the forward RA market?

In both prior rounds of comments on ICPM, proposals were made for an auction or standing sealed-bid offer process to procure interim capacity. An attractive property of both of these proposals, in the view of some commenters, was that in the event that no backstop procurement was needed, the CAISO would not promulgate a transparent price that would then affect bilateral contract negotiations (whether raising them or lowering them). We believe that auctions can potentially play a role in backstop procurement as a component of a long-term RA market design. For example, PJM conducts an auction for backstop procurement in year 3 of its 4-year Reliability Pricing Model market design, but with detailed rules that place any purchases in this backstop auction in the context of the long-term RA market.

The primary difficulty with proposals for full auctions (as opposed to the tie-breaking auction discussed above) for Type 1 procurement in the current context is that the bilateral RA market does not readily support a capacity auction operating just before the delivery year (i.e., month ahead or even weeks ahead). At the very least, additional rules would be needed to verify that if the auction took place, or if the sealed bids were opened, the prices would be reflective of competitive market conditions. As a first step in this direction, the CAISO would have to declare a uniform offer cap ahead of time, such as an estimate of CONE, for these auctions or solicitations. If it did, then this cap would already affect forward market contracting, since suppliers would have some sense of the maximum backstop price in locations where capacity is scarce (relative to the RA requirement). If the CAISO did not, then it would face the prospect that prices would be in excess of reasonable competitive benchmarks and that ex post market power mitigation would be needed.

Although some commenters had market power mitigation rules to suggest, the CAISO faced the prospect of an involved process to work internally and with stakeholders to appropriately define such rules in a voluntary market setting. There are a variety of possible ex ante rules to consider, including structural screens (such as identification of pivotal suppliers), offer caps, and the determination of the appropriate mitigated price, if needed. One suggestion about a mitigated price was to resort to RMR contracts either to benchmark individual unit offers or as a substitute for offers considered uncompetitive. The CAISO reviewed the terms and conditions of RMR contracts and has found that there is no simple mapping of these terms and conditions into the ICPM framework. While an RMR contract may fit some circumstances, in at least some cases, a new type of contract would need to be developed – a prospect which appeared unlikely in the time-frame of this procedure. An alternative way to resolve these market power issues is via the method that the CAISO proposed in its prior Type 1 proposal: by "clearing" a pre-defined capacity demand curve using actual capacity rather than clearing it with voluntary bids. This was a method originally proposed to mitigate market power in annual locational capacity auctions. This approach appeared consistent with the time frame of the ICPM implementation. It is discussed further below.

The CAISO has proposed a simple auction to break ties over Type 1 procurement in the current proposal. While it is not clear whether such an auction will ever take place, it will create the potential for a lower backstop price in some locations based on competition.

Finally, the CAISO could not hold an auction for Type 2 procurement due to the urgent nature of Significant Events, therefore two different pricing methods would still be required. We feel that the Type 2 circumstance is even less amenable to ex post market power mitigation, given the time frames. For these reasons, in both the prior proposal and this one, we have opted not to implement a full auction at the present time, but will reconsider this approach in developing backstop procurement in the context of a long-term RA market design.

<u>Did the proposed Type 1 demand curve and pricing methodology exacerbate or diminish market power in the forward RA market?</u>

Some commenters argued that the proposed demand curve and pricing methodology would exacerbate market power by introducing a CONE-based price in local areas with tight capacity. Other commenters suggested that the proposed demand curve and price floor would lower prevailing RA prices by mitigating market power in the local areas with surplus capacity. In principle, the mechanism proposed in the prior White Paper was intended to diminish market power but also reflect market scarcity. Within the proposed procurement mechanism, there was no voluntary auction, so no opportunity to withhold either physically or economically (through raising bid prices). However, the scarcity value is determined administratively, through the selection of the parameters in the demand curve. We believe that it was this transparent scarcity value and the lack of time to adjust to it in the forward RA market and not market power that caused concern among stakeholders. We agree with commenters that with this transparent backstop price available, forward RA prices in areas with scarce capacity (relative to the RA requirement) could increase to reflect the scarcity value, while prices in surplus areas could diminish to the reflect the market power mitigation effect of the backstop procurement methodology. Some possible remedies to such price shifts are suggested next.

<u>Could the proposed Type 1 demand curve have been modified to mitigate the price impact?</u>

Had the determination been made to proceed with the sloped demand curve approach, the CAISO was prepared to address the local area price impact issues. There were three parameters in the proposed demand curve that could have been modified to mitigate the possible price impacts:

1. the estimate of CONE,
2. the slope of the demand curve/zero price intercept, and
3. the price floor.

With respect to the estimate of CONE, several commenters argued for selection of a different peaking technology to use as the new entrant or to consider other cost analysis in addition to the CEC study.[20] CAISO agrees that the selection of the technology could have been discussed further and should be if CONE is a parameter in capacity pricing on a more permanent basis. Certainly other ISOs have undertaken more extensive analysis of unit type, including consideration of locational constraints that affect the size and type of unit. However, in this instance, the CAISO was constrained by the element of time and in our review of data that was available, particularly the CEC study but also other data, we felt that the unit chosen and the price as proposed was not outside the range of reasonable CONE estimates. Had we continued on this course for ICPM, the preferred route would have been to work further with the CEC and stakeholders to determine a CONE estimate, if different from our starting point, but remaining within the CEC analysis.

A further modification to the demand curve could have been to phase in the curve over several years. For example, in year 1, the cap could be set at 60% of CONE and in year 2 at 80% of CONE. This would have established the principle that the backstop procurement is based on capacity pricing principles, but given parties time to adapt to the pricing regime. This approach was followed by NYISO when it introduced capacity demand curves.

Finally, several parties noted that the price floor was too low. This is the only feature of the prior pricing proposal that is essentially addressed in this proposal, by raising the price to reflect a more robust estimate of going forward costs.

Should there be a different price for Type 1 and Type 2 procurement?

The CAISO's prior pricing proposal distinguished Type 1 and Type 2 procurement on the basis that procurement during Significant Events was not intended to fulfill annual RA requirements but was rather for the purpose of supporting short-term operational needs. A further economic justification was that the forward RA market had cleared and any generation that was operable in the time-frame of a Significant Event was not operable due its RA contract but rather due to its expectation of energy and ancillary service revenues. As such, a capacity payment based on capacity pricing principles, including scarcity value and PER, such as was proposed for Type 1 procurement using a demand curve, was not justified. Instead, a payment based on going forward costs but with no deduction for PER was seen as sufficient to elicit designation for the period.

The CAISO has changed its pricing basis in this final proposal for both types of procurement, but again we do not offer exactly the same pricing method for Type 1 and Type 2 procurement. However, we have aligned the Type 2 and Type 1 base price at $41/kW-year (in some circumstances, the Type 1 price could be lower than this price if there are multiple resources available).

We note that some commenters made the exact opposite argument to the one above: they prefer that Type 1 procurement does not reflect scarcity value of capacity but that Type 2 procurement could include some kind of scarcity premium to reflect the emergency nature of Significant Events. The scarcity premium could be limited to the first month of the Significant Event. A scarcity premium for Significant Events is a possible market pricing rule, but would be an arbitrary number and the question is then raised as to whether there would also be an ex post PER deduction. Our preference, as stated in this paper, is that any scarcity premium

[20] Given the time constraints, we will reserve our reply here to the selection of peaking technology and not address other comments on CONE calculation at this time.

during Significant Events come through the energy and ancillary services markets rather than ICPM payments.

Attachment 1

List of Acronyms

ARC	Applicable Reliability Criteria
AReM	Alliance for Retail Energy Markets
CAISO	California Independent System Operator
CEC	California Energy Commission
CLECA	California Large Energy Consumers Association
CMTA	California Manufacturers & Technology Association
Constellation	Constellation Energy Commodities Group, Constellation NewEnergy, Inc, and Constellation Generation Group, LLC
CPUC	California Public Utilities Commission
DR	Demand Response
Dynegy	Dynegy Power Marketing, Inc.
FERC	Federal Energy Regulatory Commission
FMU	Frequently Mitigated Unit
ICPM	Interim Capacity Procurement Mechanism
IEP	Independent Energy Producers Association
ISO	Independent System Operator
LCR	Locational Capacity Requirement
LRA	Local Regulatory Authority
LSE	Load Serving Entity
MORC	Minimum Operating Reliability Criteria
MRTU	Market Redesign and Technology Upgrade
MSC	Market Surveillance Committee
MW	Megawatt
NERC	North American Electric Reliability Council
NQC	Net Qualifying Capacity
NRG	NRG Energy
O&M	Operation and maintenance
PER	Peak Energy Rent
PGA	Participating Generator Agreement
PG&E	Pacific Gas and Electric Company
PTO	Participating Transmission Owner
RA	Resource Adequacy
RCST	Reliability Capacity Services Tariff
Reliant	Reliant Energy, Inc.
RMR	Reliability Must-Run Agreement
RUC	Residual Unit Commitment
SCE	Southern California Edison Company
SCUC	Security Constrained Unit Commitment
TAC	Transmission Access Charge
WECC	Western Electricity Coordinating Council

Attachment 2

Key Milestones of Stakeholder Process

Development of Issues Paper

Apr 23, 2007	CAISO issues market notice announcing initiative and date of first meeting
Apr-May	Informal discussion with stakeholders
May 9	CAISO posts Issues Paper

Development of Proposal #1

May 18	CAISO holds stakeholder meeting on Issues Paper (10:00 a.m. - 3:00 p.m.)
May 25	Stakeholders submit their written comments on Issues Paper
May 29	CAISO posts the written comments submitted on Issues Paper
Jun 6	Joint MSC/Stakeholder meeting (9:00 a.m. – 5:00 p.m.)
Jun 29	CAISO posts White Paper (Proposal #1)

Development of Proposal #2

Jul 25	CAISO holds stakeholder meeting on Proposal #1 (10:00 a.m. – 4:00 p.m.)
Aug 9	Stakeholders submit their written comments on Proposal #1
Aug 10	CAISO posts the written comments submitted on Proposal #1
Oct 5	CAISO posts White Paper #2 (Proposal #2)

Development of Final Proposal

Oct 15	CAISO holds stakeholder meeting on Proposal #2 (10:00 a.m. – 4:00 p.m.)
Oct 18	CAISO holds stakeholder conf. call on Proposal #2 (9:00 a.m. – 12:00 p.m.)
Oct 24	Stakeholders submit their written comments on Proposal #2
Oct 25	CAISO posts the written comments submitted on Proposal #2
Nov 9	CAISO posts the Final Proposal

Development of MSC Opinion

Nov 19	MSC posts the draft MSC Opinion
Nov 21	MSC holds a conference call to adopt the MSC Opinion
Nov 27	MSC submits to CAISO the adopted MSC Opinion

Development of Draft Board Proposal

Nov 15	CAISO holds stakeholder conf. call on Final Proposal (10:00 a.m. – 2:00 p.m.)
Nov 21	Stakeholders submit their written comments on Final Proposal
Nov 27	CAISO posts the written comments submitted on Final Proposal
Dec 14	CAISO posts Draft Board Proposal

Development of Proposal to Board

Dec 20	CAISO holds conf. call on Draft Board Proposal (8:30 a.m. – 12:00 p.m.)
Jan 7, 2008	Stakeholders submit their written comments on Draft Board Proposal
Jan 8	CAISO posts the written comments submitted on Draft Board Proposal
Jan 17	CAISO completes Board Proposal, and attaches MSC Opinion
Jan 28-29	CAISO requests approval from Board to make tariff filing

Attachment D

California ISO
Your Link to Power

California Independent
System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Charles A. King, P.E., Vice President, Market Development & Program Management
Phil Pettingill, Manager, Infrastructure Policy & Contracts

Date: January 18, 2008

Re: ***Decision on Interim Capacity Procurement Mechanism Tariff Filing***

This memorandum requires Board action.

EXECUTIVE SUMMARY

Over the past nine months, California ISO staff has collaborated with stakeholders to develop an interim, tariff-based, capacity procurement mechanism to be implemented coincident with start-up of the Market Redesign and Technology Update ("MRTU"). The purpose of this capacity procurement mechanism is to enable the CAISO to supplement or "backstop" Load Serving Entity ("LSE")-based Resource Adequacy ("RA") capacity procurement as needed for reliable grid operations. For example, if a LSE did not procure sufficient capacity to meet its full RA requirement, and it did not cure the deficiency when given an opportunity to do so, then the CAISO would procure the needed capacity to fulfill the RA requirement.

The goal is to file this new Interim Capacity Procurement Mechanism ("ICPM")[1] with the Federal Energy Regulatory Commission ("FERC") on January 30, 2008 and propose an effective date coincident with the start of the MRTU markets. As the culmination of a lengthy and rigorous stakeholder process, the ICPM proposal effectively meets the CAISO's objectives for an interim backstop mechanism, is compatible with both the MRTU market design and, in the interim, the State of California's existing RA program as well as efforts to design a long-term RA framework, and attempts to strike a reasonable balance between the divergent views of stakeholders.

Throughout the stakeholder process, parties expressed widely different points of view on many of the elements of an ICPM. This proposal reflects numerous modifications to prior staff proposals in order to address concerns expressed by stakeholders. Even with these changes, this proposal is not without controversy, and there is not unanimous stakeholder support for each and every element of the proposal. However, Management believes that this ICPM proposal constitutes a reasonable,

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[1] This mechanism is an "interim" mechanism because it will include a sunset date at the end of 2010. Prior to that date, the CAISO will explore with stakeholders the development of a backstop procurement mechanism that will effectively complement the long-term RA framework that is currently being developed in an ongoing proceeding before the California Public Utilities Commission ("CPUC").

balanced and interim approach that takes into account the widely divergent views expressed by stakeholders and the fact that important long-term RA issues remain unresolved.

The ICPM will allow the CAISO to backstop or supplement the RA procurement of LSEs to ensure that there is sufficient generation capacity available to the CAISO operators to maintain reliable grid operations. The CPUC and local regulatory authorities establish the RA requirements, and RA generation is then made available to the CAISO through required offers into the MRTU daily markets for energy and ancillary services.

The key elements of the ICPM are as follows:

- The tariff provisions automatically sunset on December 31, 2010. The intent is to revisit and refine the backstop mechanism after further progress is made at the State of California level regarding the design of a long-term RA framework. The CAISO's intent is to develop a more permanent backstop mechanism in the future that will complement the long-term RA design.
- There are two circumstances that would trigger procurement under the ICPM. The first type of procurement would backstop the RA process and occur if an LSE or group of LSEs has not purchased the full amount of their local or system-wide RA requirements by the time of the required RA showing for that year,, or, even if they had met the required procurement targets, sufficient capacity was not procured to meet specific CAISO locational needs. This type of backstop procurement would occur in advance of the applicable compliance period. The second type of procurement would occur if the CAISO determines that a "Significant Event" has occurred that creates a need to supplement LSE-procured capacity within the compliance year in order to maintain reliable grid operations.
- Significant Events are defined as "a substantial event, or a combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the resource adequacy program for purposes of determining the Resource Adequacy Capacity requirements, or produce a material change in system conditions or in CAISO-Controlled Grid Operations, that causes, or threatens to cause, a failure to meet Applicable Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis". As it is impossible to foresee all potential events that could occur during the operating year that would jeopardize the CAISO's ability to meet the reliability criteria that it must satisfy as a system operator, the definition by necessity accords some discretion to the CAISO. Thus, the need for the reporting requirements described below.
- The term of payments to an ICPM resource varies from one month to up to 12 months depending on the RA requirement deficiency being remedied or the length of the Significant Event.
- The price paid to a resource for its capacity is based on the going-forward costs of a new conventional simple-cycle unit, as reflected in a draft June 2007 California Energy Commission ("CEC") report,[2] plus a 10% adder from that number.[3] Going-forward costs

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[2] June 2007 California Energy Commission Draft Staff Report, Comparative Costs of California Central Station Electricity Generation Technologies

[3] Going-forward costs are defined here as the sum of fixed operations and maintenance costs, ad valorem costs, and administrative and general costs. A 10% adder is in-line with previously approved adders and, among other things, will encourage LSEs to not simply rely on the ICPM backstop mechanism to meet their RA requirements.

are the core fixed costs that a generation unit needs to make itself available for operation for the term of designation, but do not include such elements as return on investment.[4] The ICPM offers a Target Annual Capacity Price of $41/kW-year, but with no deductions for peak energy revenues (or ancillary service revenues). Payment would be subject to an availability factor and a level monthly shaping factor. The target price is known to be higher than the going-forward costs of many existing units (hence, for those units the payment provides additional revenues). A resource owner that believes that its going-forward costs are greater than $41/kW-year would be able to file at FERC for a price higher than $41/kW-year, but the owner would have to justify that price to FERC based on the same cost elements that are considered in setting the $41/kW-year default price. This pricing rule is intended to cover certain costs while allowing the resource to retain energy and ancillary service revenues as a means to cover other costs and provide profits; however, it is not intended to be a cost recovery guarantee mechanism such as a Reliability Must Run Agreement.

- Participation in the ICPM by a resource is voluntary. A resource owner does not have to accept an ICPM designation when offered by the CAISO. The CAISO considered a mandatory designation scheme, but has determined that there are adequate incentives within the proposal for resources to be willing to accept the designation, including the provision where an owner of a resource can request a payment higher than $41/kW-year if justified to FERC on a cost-basis. Further, FERC has ruled that there is no "Must-Offer Obligation" under MRTU. The CAISO also believes that a voluntary approach is appropriate given that there is no consensus among stakeholders – indeed the parties are extremely polarized on the issue of the appropriate price to be paid to resources designated under the ICPM.
- The CAISO would have the ability to procure a portion of a resource rather than its entire capacity. Criteria are provided for determining which resource would be selected for an offer of an ICPM designation when there are multiple resources that could fulfill the need for the capacity. The CAISO has the expectation that such criteria will always lead to a set of specific resources that are uniquely qualified. However, in the event there is a "tie" among resources, the CAISO would use a random selection mechanism.
- Extensive reporting requirements are included to ensure that all ICPM procurement is transparent to the market and an information feedback loop is provided to the CPUC and local regulatory authorities so that those entities can improve their RA programs over time.
- Ultimately, the pricing and procurement rules for a successor to ICPM need to be integrated with the State of California RA program. The question of backstop capacity procurement is a component of the CPUC long-term RA proceeding and CAISO has provided its preliminary views on backstop procurement in that proceeding.[5] Alternative future designs for such procurement may emerge from that proceeding.

The full proposal is provided in Attachment A.

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[4] This is a different pricing basis than the prior Reliability Capacity Services Tariff price formula, which offered a higher Target Annual Capacity Price, based on a settlement price, but then deducted peak energy revenues.

[5] California ISO, Assessment of Centralized Capacity Market Proposals, September 14, 2007.

The Market Surveillance Committee ("MSC") has issued an Opinion on the ICPM, which is provided in Attachment B.

MOTION

Moved, that the ISO Board of Governors approve the Interim Capacity Procurement Mechanism as outlined in the memorandum dated January 18, 2008, and related attachments; and

That the ISO Board of Governors authorizes Management to make all the necessary and appropriate filings with the Federal Energy Regulatory Commission to implement this proposal.

BACKGROUND

The CAISO's Reliability Capacity Services Tariff ("RCST"), which came about as a result of an Offer of Settlement filed at FERC on March 31, 2006 and approved by FERC on February 13, 2007 allows the CAISO to procure capacity in advance of the compliance year to backstop RA procurement and during the compliance year to backstop for a Significant Event. The RCST was initially intended to provide a daily capacity payment for units subject to a must-offer waiver denial, which meant that they were required to offer into the CAISO market. The State of California established its annual RA requirements roughly contemporaneously with the RCST implementation, but local RA requirements were never factored into RCST pricing. Subsequently, the ICPM discussions became a forum for airing RA issues and for exploring RA-type pricing options for backstop procurement on both the local and system levels. However, as discussed below, given the difficulties in resolving those issues at this time, CAISO has decided to continue with an interim pricing approach similar to RCST.

Under the ICPM, the CAISO proposes to follow a RCST-type framework with certain modifications to make it compatible with the MRTU market design and facilitate the CAISO's ability to meet Applicable Reliability Criteria,[6] as well as other enhancements. In general terms, an "RCST-type framework" means that the CAISO is able to procure capacity to backstop either RA requirements or address a Significant Event, and pay resources a tariff-based price for the service provided for a term of varying length depending on the need..

The CAISO believes that it makes sense to retain some of the RCST design elements and make modifications to others in order to adapt it to function effectively under MRTU. This is because stakeholders invested substantial resources in developing the RCST, FERC has found it to be just and reasonable, and many stakeholders have stated a desire to use it as a general framework for developing an interim MRTU backstop mechanism.

This proposal is consistent with RCST in that it provides for the same two primary types of backstop procurement. Under "Type 1" procurement, the CAISO would procure capacity (a) in advance of the compliance year if an LSE has not procured the full amount of its RA requirement by the time of the required RA showing, or if the portfolio of resources procured by all LSEs in a local area is not

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6 As part of Applicable Reliability Criteria, the CAISO must comply with applicable North American Electric Reliability Council/Western Electricity Coordinating Council requirements, including Minimum Operating Reliability Criteria.

sufficient to fully meet the operating needs of the local area, or (b) during the compliance year if an LSE has not procured the full amount of its RA requirement in the month-ahead time frame. Under "Type 2" procurement, the CAISO would procure additional capacity during the compliance year if a "Significant Event" occurs that creates a need to supplement LSE-procured RA capacity to ensure reliable grid operations. For example, a Significant Event could be a sustained outage of a generation or transmission facility.

POSITIONS OF THE PARTIES

A matrix summarizing stakeholder views on the key elements of this proposal is included in Attachment C. General comments related to the design of the ICPM are discussed below.

Effective Date – The CAISO proposes to implement the ICPM on the effective date of MRTU implementation. Some stakeholders have argued that ICPM should be implemented prior to MRTU, upon the expiration of the RCST. On December 20, 2007, in response to a motion filed by the Independent Energy Producers Association ("IEP") requesting that FERC require the CAISO to file the ICPM proposal to be effective January 1, 2008, FERC ordered that the ICPM need not be filed and made effective on January 1, 2008, and instead preliminarily concluded that the RCST should be extended until the start of MRTU or an alternative backstop mechanism is filed. FERC has initiated a Section 206 proceeding to address the limited issue of whether the RCST should be extended until the earlier of MRTU implementation or implementation of an alternate backstop capacity mechanism. Comments regarding the justness and reasonableness of extending the RCST were filed on January 9, 2008, and reply comments are due on January 24, 2007. FERC has indicated that should be able to render a decision on this issue by March 30, 2008.

Need for ICPM –The CAISO believes that a backstop mechanism is an appropriate and necessary feature to complement the MRTU market design, and many stakeholders generally support the concept of the CAISO having a backstop capacity procurement mechanism. However, in many cases, that support is conditioned on certain features that the party would like to see (or not see) included in the ICPM. There are stakeholders that do not support Type 1 procurement, some that do not support Type 2 procurement, and some that do not support either type of procurement. The CAISO has worked with stakeholders over the last nine months to attempt to resolve these issues, and in response to their concerns has added many features to the ICPM to provide for increased transparency and appropriate checks and balances to protect against unnecessary over-procurement. Management feels strongly that both Type 1 and Type 2 procurement are necessary mechanisms to include in the MRTU market design in order to enable the CAISO to maintain reliable grid operations.

Duration of Tariff Provisions – The CPUC has an ongoing proceeding to develop a long-term design for RA. This design may include a capacity market - and a backstop mechanism may be part of that structure. Numerous stakeholders have requested that the design of ICPM not get out ahead of efforts to develop the long-term RA framework. In response to this request, the CAISO has proposed that the ICPM tariff provisions will automatically sunset on December 31, 2010. The ultimate goal is to design a long-term backstop mechanism under MRTU that works effectively under, and is aligned with and complementary to, the long-term RA design. It may be appropriate to revisit the ICPM sooner than the year 2010, depending on the timing of implementation of the long-term RA mechanism and types of mechanisms being implemented as part of that design. CAISO staff expects to return to the Board at some point in the future with a proposal for a more permanent backstop mechanism than ICPM.

Compensation Paid to Resources for Capacity – Pricing has been one of the more complicated and controversial issues with backstop procurement. The current RCST Target Annual Capacity Price is $73/kW-year, subject to *ex-post* deductions for peak energy rent revenues and other adjustments. While this was a negotiated value for both Type 1 and Type 2 procurement that was included in an Offer of Settlement, FERC has approved it as a just and reasonable rate as part of the current Must-Offer Obligation.

In initial discussions with stakeholders for a successor to the RCST, stakeholders were split, with one group favoring extending the RCST with most of its provisions intact, updating as needed to function under MRTU, and another group, that included most merchant generators, that desired a very different successor, with a much higher Target Annual Capacity Price and more liberal criteria for designating units (for example, calling on a resource one time during the year would automatically result in a designation for many months – perhaps as long as 12 months – at a price as high as about $160/kW-year).

The initial pricing proposal presented to stakeholders by the CAISO used the RCST $73/kW-year price, updated it to a 2008 value of $74.83/kW-year, and then stair-stepped it up to a price of $95.09/kW-year for the year 2012 (all of these prices would have been subject to the peak energy rent revenue deductions). This pricing structure was a compromise approach for a transitional phase-in toward the cost of new entry. There was some support for this proposal, but many stakeholders did not support it, for varying reasons. Some stakeholders said that it was not appropriate to pay the cost of new entry or even close to that value for this product (arguing that the existing RCST price was already too high), and recommended prices based on the actual cost of the existing fleet of resources (which would have been considerably less than $73/kW-year). Conversely, merchant suppliers said that the pricing structure was too low and the price should be at the cost of new entry, which would be in the range of $150-$200/kW-year. Given this wide disparity in positions, the CAISO determined that it needed to try to develop a pricing structure that could bridge these points of view.

During the ensuing weeks after the initial proposal was presented, the CAISO explored pricing options suggested by stakeholders. Many stakeholders thought that the prices included in previous ICPM proposals were either too high or too low. Merchant suppliers generally supported higher prices (many supported a price based on the cost of new entry – and some supported that price for all backstop procurement), whereas LSEs, the CPUC and the California Electricity Oversight Board generally supported lower prices (many supporting either cost-based prices similar to the structure of Reliability Must Run Agreements, or a going-forward fixed cost methodology on a per unit basis). None of these options distinguished Type 1 and Type 2 procurement. However, the CAISO identified deficiencies with each of these options that made them unworkable without modification. Essentially, the CAISO basically agreed with merchant suppliers that locations where capacity was tight potentially justified a Type 1 backstop price based on cost of new entry, which is intended to signal a need for investment. However, locations where capacity was in substantial surplus did not seem to justify a Type 1 price that high. Rather, the pricing needed to reflect the surplus by providing for locational prices that were proportionately less than the cost of new entry. The CAISO also agreed in principle that Type 2 pricing did not need to reflect RA market fundamentals. In that instance, the CAISO was procuring a temporary product for operational purposes and a cost-based price to cover "going forward" costs seemed sufficient.

Hence, the CAISO attempted to find a middle ground based on RA market design principles by using a market-proxy price derived from an administrative capacity demand curve and price floor for Type 1 procurement and a uniform price based on "going forward" costs for Type 2 procurement. The Type 1 demand curve was capped at an estimate of the cost of new entry in areas at or slightly below their RA requirements. Under this approach, the cost of new entry price signal only applied initially to four local areas (out of 10 local areas). Although that proposal had support from some stakeholders, other stakeholders opposed the concept based, *inter alia,* on concerns that the implementation of such Type 1 pricing would interfere with market design issues being addressed in the ongoing CPUC long-term RA proceeding (which is considering, among other things, similar pricing mechanisms) and would adversely impact forward RA prices in the interim.

Having reviewed with stakeholders this large number of pricing alternatives, the CAISO believes that the current ICPM pricing proposal is preferable in the interim to the other options that were considered. Given the concerns raised during the stakeholder process, in particular the concern that the CAISO not get ahead of development of the long-term RA design with this interim mechanism, Management proposes that a uniform target annual capacity price of $41/kW-year be paid for all capacity procured under the ICPM regardless of the type of procurement. Further, suppliers will be permitted to retain all market revenues. This price is based on four criteria: (1) it is based on the results of a June 2007 CEC study that identifies the going-forward costs of new generation in California; (2) it is consistent with FERC's rationale in the order approving the RCST Settlement in that it does not create incentives for buyers or sellers to shift procurement to the ICPM; (3) it provides a uniform price sufficiently high to cover the "going-forward" costs of most generators that might be designated under ICPM (thereby reducing the need for individual generator cost justification filings); and (4) it will not change the incentives of CPUC-jurisdictional LSEs to procure RA prior to ICPM given the existing CPUC penalties and the $40/kw-year trigger used by the CPUC to consider LSE requests for waivers from procuring capacity to meet RA requirements.

To meet these considerations, the $41/kW-year price is based on recent cost estimates of the going-forward costs of gas-fired single and combined-cycle generating units. As noted, unlike the RCST pricing approach, there would be no deductions for peak energy rents. Payment would be adjusted by an availability factor that is currently in the RCST and a level (1/12) monthly shaping factor (i.e., the Target Annual Capacity Price of $41/kW-year would be divided by 12 to determine the target monthly capacity price). Based on peak energy rent calculations under RCST, the CAISO estimates that this proposed pricing method will potentially increase revenues to units designated relative to the RCST price in the summer peak months. In addition, a resource owner that believes that its "going forward" costs are greater than $41/kW-year would be able to file at FERC for a price higher than $41, but the owner would have to justify that price to FERC based on the same types of costs that produced the $41/kW-year default price.

The pricing reflected in this interim proposal recognizes that long-term RA design issues are still being discussed, which makes it difficult to design a more permanent market-based pricing rule at this time. The CAISO will initiate discussions with stakeholders regarding a permanent market-based pricing mechanism for backstop procurement in connection with implementation of a long-term RA design and seek to ensure that both structures are complementary.

Designation Process – The CAISO has developed a detailed process that sets forth the determination of the need for ICPM procurement, triggering events and interaction with stakeholders. The designation process for backstop procurement to remedy deficiencies in RA procurement is fairly straightforward (either the RA requirement has been met or it has not). Many stakeholders support this Type 1 procurement, although some stakeholders question the need for this type of procurement given the compliance measures in place at the CPUC such as a penalty for non-compliance. The CAISO believes that it is prudent to provide Type 1 procurement authority to the CAISO as "a last resort" in the event that the RA requirement is not met. The imposition of a penalty on an LSE does not guarantee that capacity will be there if the CAISO needs it.

Stakeholders generally expressed greater concern with Type 2 procurement for a Significant Event than with Type 1 RA backstop procurement. Some stakeholders support the Type 2 procurement. However, other stakeholders question the need for Type 2 procurement given the level of the RA requirements established by the CPUC and local regulatory authorities (they think the RA requirements level should be sufficient for the CAISO to reliably operate the grid). Virtually all stakeholders have requested that the CAISO clearly specify the circumstances that would give rise to a Significant Event and justify the CAISO's procurement of capacity. Many stakeholders feel that the mechanism for Significant Events should to be more prescriptive and/or specific than what is already included in the RCST.

Management believes that adequate flexibility is necessary to avoid the unintended consequences of an overly prescriptive approach. In that regard, Management believes that the Significant Event provisions of the RCST are overly prescriptive, and more flexibility is needed. In particular, sufficient flexibility is needed so that the CAISO can address unforeseen or changed circumstances or inherent inefficiencies or deficiencies in RA programs where lack of action by the CAISO to address a known problem could place the CAISO in the position, in the Day-Ahead timeframe, of facing the possible interruption of firm load or failure to meet Applicable Reliability Criteria. A reasonably flexible definition of a Significant Event is necessary to allow the CAISO to address contingencies and unexpected system conditions, and ensure its ability to satisfy reliability requirements. The CAISO does not support a prescriptive "hard trigger" for a Significant Event because it would not allow the CAISO to exercise prudent judgment and not make designations when they are not required. Adoption of a "hard trigger" could require the CAISO to make designations on a prospective basis even though the event that led to use of the unit has ended.

Designation is Voluntary – The proposal provides that a resource does not have to accept an offer of an ICPM designation from the CAISO. The intent is to keep the MRTU markets voluntary and motivated by market incentives as much as possible. However, many stakeholders and the MSC believe that a resource should be required to accept an ICPM offer from the CAISO. They believe that the CAISO has developed this mechanism to ensure that the CAISO can procure capacity when needed, and that the CAISO should be able to compel resources to accept the offer so that the CAISO's needs can be assured to be met and with minimal "shopping." It makes sense to them to make it mandatory. Many stakeholders also are concerned that if the ICPM is voluntary some resources may decline the offer of ICPM designation, and hence the requirement to offer into the Integrated Forward Market ("IFM"), which could make it difficult to procure the necessary capacity and adversely affect reliability.

The CAISO believes that it is appropriate to make the ICPM designation voluntary because FERC has ruled there is no type of Must-Offer Obligation that non-RA/Reliability Must Run resources would be subject to under MRTU, and a mandatory designation requirement would be like a Must-Offer Obligation that FERC has ruled will go away at the implementation of MRTU. The CAISO believes that a voluntary approach is appropriate given that there is no consensus among stakeholders – indeed the parties are extremely polarized on the issue of the appropriate price to be paid to resources designated under the ICPM. In addition, the ICPM pricing provides sufficient incentives for resources to accept a designation – it at least covers their going-forward costs and also allows resources to retain all revenues from the MRTU markets. The CAISO has not seen any compelling evidence to suggest that suppliers would have a clear reason not to accept ICPM designation due to expectations of greater compensation in the MRTU markets as non-ICPM resources. Moreover, even if that were the case, resources that had opted not to become ICPM resources would not be withholding their capacity from the MRTU markets, but rather continuing to offer it. Hence, the CAISO would have the resources available that it needs and reliability would not be affected.

As an additional safeguard, the CAISO Department of Market Monitoring will be monitoring whether resources have rejected designations and not participating in the market, to see if there is any physical withholding. Finally, the CAISO has additional tools under the MRTU tariff to operate the system reliably if resources, for whatever reason, decline an ICPM designation (i.e. Exceptional Dispatch[7] and emergency declarations).

Interrelationship with Exceptional Dispatch – As noted above, the CAISO intends to keep the MRTU markets voluntary and motivated by market incentives as much as possible. Therefore, under the MRTU market design, the only remaining mandatory requirement to operate without a CAISO declared emergency is the Exceptional Dispatch. Such an operational need may arise for various reasons; however, an Exceptional Dispatch explicitly occurs outside the markets and therefore can only occur under certain conditions as specified in the MRTU tariff. Some stakeholders have argued that a resource owner may decline the ICPM designation because the owner of the resource may perceive that it can receive higher compensation as a non-ICPM resource through the MRTU tariff provisions regarding Exceptional Dispatch. The CAISO believes that these concerns are misplaced because further review suggests that Exceptional Dispatch compensation to a resource will be the same regardless of whether a resource accepts an ICPM designation. [8]

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7 Under MRTU, Exceptional Dispatches are similar to the current out-of-sequence and out-of-market actions that may be taken by CAISO operators to address a system or local reliability issue that cannot be resolved through the CAISO market software or dispatches to Reliability Must Run resources. There are two major potential reasons why Exceptional Dispatches may be needed for local reliability issues: forced transmission or generation outages, and local reliability constraints not modeled in market software. In such cases, the CAISO has authority to manually dispatch specific generation units to address reliability issues. Units receiving Exceptional Dispatches for energy will be paid the higher of their bid price or the Locational Marginal Price. The CAISO expects that the frequency and duration of Exceptional Dispatches will be extremely limited.

8 If there is a major change to the system due to a transmission or generation outage, it will necessitate a modification of the IFM full network model. Hence, Exceptional Dispatch in any sustained fashion is likely not to affect the IFM market clearing but rather to take place after the IFM and Residual Unit Commitment markets have cleared, meaning that both RA and ICPM resources could still be subject to Exceptional Dispatch if they had offered into those markets and not been scheduled. The only pricing issue is that of what they are eligible to be paid under Exceptional Dispatch, which is the subject of a separate CAISO stakeholder process. The ICPM payment would be made regardless of the Exceptional Dispatch payment because the payments for Exceptional Dispatch are for the energy provided versus the capacity compensation of the ICPM payment.

Reporting – Stakeholders have requested that robust reporting obligations be established to ensure that all ICPM procurement is transparent to the market and that a "feedback loop" is established to provide information to stakeholders and regulators on how well RA resources, by themselves, are meeting the various operational needs of the CAISO. It is expected that this feedback loop would, over time, lead to improvements in the RA programs and result in less reliance on ICPM procurement. The ICPM proposal includes several different types of reports, including a detailed report that would be posted within 30 days after the CAISO has procured a resource through the ICPM, a market notice that would be issued within two business days of any ICPM procurement, a monthly report that would be posted within 10 calendar days after the end of each month that would show the non-market commitments of non-RA capacity, and ICPM information that would be included in the Operations report that currently is provided to the CAISO Board of Governors at each Board meeting. The reporting obligations in this proposal are consistent with the extensive reporting that stakeholders have requested.

ICPM Procurement in RA Showings – The CAISO proposes to provide information to the CPUC and local regulatory authorities on all ICPM procurement so that capacity procured under the ICPM can be considered by the CPUC and local regulatory authorities and potentially allowed to count towards satisfying an LSE's RA requirement.[9] Stakeholders have requested, and the CAISO supports, allowing all "Type 1" ICPM capacity procurement (procurement to backstop the RA process) to be included in RA showings so that LSEs receive credit for ICPM capacity for which they have paid. However, some stakeholders have requested that all ICPM procurement be allowed to be included in RA showings. The CAISO does not support allowing "Type 2" procurement (procurement to backstop for a Significant Event) to be included in RA showings and will reflect this position to the CPUC and local regulatory authorities. The CAISO is differentiating between Type 1 and Type 2 procurement on this issue because the reason for Type 2 ICPM procurement is that the RA resources already procured by LSEs are determined by the CAISO to be insufficient to meet Applicable Reliability Criteria. Thus, allowing LSEs to include Type 2 capacity in subsequent RA showings would result in a decrease of the available RA capacity, which would only exacerbate the conditions that lead to the Significant Event and potentially cause additional ICPM procurement.

MANAGEMENT RECOMMENDATION

Management recommends that the Board of Governors approve the policy elements underlying the proposed ICPM as described in this memorandum and attachments, and authorize Management to file the conforming tariff provisions necessary to implement the new mechanism.

Attachments

Attachment A: Proposal to Board of Governors for ICPM Tariff Filing
Attachment B: MSC Final Opinion on ICPM under MRTU
Attachment C: Stakeholder Process for ICPM Tariff Filing

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9 The CPUC and local regulatory authorities determine the rules under which capacity is allowed to "count" towards an entity's RA requirement. Capacity that is determined to count towards a RA requirement is then included in a RA showing by the LSE. The CAISO does not determine the counting/crediting rules for capacity used by LSEs to fulfill a RA requirement.

Attachment C

Stakeholder Process for Interim Capacity Procurement Mechanism Tariff Filing

Summary of Submitted Comments

Stakeholders submitted five rounds of written comments to the CAISO on the following dates:

- May 25, 2007 – 12 sets of comments
- August 9, 2007 – 15 sets of comments
- October 24, 2007 – 14 sets of comments
- November 21, 2007– 7 sets of comments
- January 7, 2008– 12 sets of comments

Stakeholder comments are posted at: http://www.caiso.com/1bc5/1bc5db284cc80.html

Other stakeholder efforts include:

- Stakeholder meetings
  May 18, 2007 (22 attendees and 53 phone participants)
  June 6, 2007 (24 attendees and 31 phone participants)
  July 25, 2007 (26 attendees and 46 phone participants)
  October 15, 2007 (27 attendees and 47 phone participants)

- Stakeholder conference calls
  October 18, 2007 (69 phone participants)
  November 15, 2007 (49 phone participants)
  December 20, 2007 (47 phone participants)

* - Comments indicate the position of the parties as they were provided.

A list of abbreviations is provided at the end of this document.

Management Proposal	Load Serving Entities, Energy Service Providers, End-Use Customers, Ratepayer Groups *	Resource Suppliers *	California Public Utilities Commission *	Management Response
1. Effective Date –Allow RCST to expire by its own terms on 12/31/07, and implement ICPM on the effective date of MRTU implementation.	Conditionally Support: Six Cities - ICPM should be implemented as proposed. Oppose: TURN, PG&E, CLECA, AReM, SCE - RCST should be extended until implementation of MRTU, and then ICPM implemented at MRTU.	Oppose: Reliant, Dynegy - RCST should expire by its own terms on 12/31/07, and ICPM should be implemented on 1/1/08. Oppose: Constellation - Proposal needs to provide payment mechanism between 1/1/08 and start of MRTU.	Oppose. Support continuation of RCST until MRTU startup and/or implementation of ICPM.	On December 20, 2007 FERC ordered that ICPM need not be filed and made effective on 1/1/08 and instead preliminarily concluded that RCST should be extended until start of MRTU or an alternative backstop mechanism is filed. ICPM is designed to work under MRTU design and will not function under a pre-MRTU market structure.
2. Duration of Tariff – Automatically sunsets on 12/31/10. Revisit after progress is made at state level regarding design of long-term RA framework to create more permanent mechanism.	Support: Six Cities, PG&E, SCE, CMUA, CLECA Conditional Support: AReM - If MRTU is delayed beyond 4/1/08, consider moving sunset date to 2011.	Support: Constellation Conditional Support: Dynegy - Conditional support if CAISO commits to start stakeholder process at least 15 months prior to sunset date. Oppose: Reliant - ICPM should not sunset on a date certain. Instead should remain in effect until a capacity market is implemented in tariff.	Support: No comment on sunset date. Revisit sometime after progress is made at state level regarding design of long-term RA framework to create more permanent mechanism	Duration has been shortened from initial ICPM proposal of 5 years to current 33 months. May be appropriate to revisit ICPM sooner than 2010, depending on timing of implementation of long-term RA mechanism.

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3. Backstop to RA Process – CAISO can procure resources as a "last resort" to backstop RA programs of CPUC and LRAs if LSE does not fulfill its RAR. Each LSE is first given a chance to cure an identified deficiency.	Support: TURN, PG&E, CMUA, Support: Six Cities, CLECA, AReM, - Critical that LSEs be given opportunity to cure before CAISO procurement. Conditional Support: SCE – Chance to cure must allow effected LSE time to make necessary business decisions.	Support: Reliant - CAISO authority to backstop RA; is necessary until capacity market is implemented in tariff. Support: Dynegy - CAISO should be required to procure resources to meet RA requirements. Conditional Support: Constellation - Provided procurement is for a time duration equivalent to RA showing deficiency. IEP - Support: a single trigger and oppose bifurcated trigger between RA deficiencies and Significant Events.	Support	This authority is needed as "last resort" if LSEs do not cure identified deficiencies, and to ensure that local capacity requirements established by the CAISO tariff are met. An opportunity to cure is provided. Many features have been added to ICPM to provide transparency and checks and balances to protect against over-procurement. This authority is necessary to enable CAISO to maintain reliable grid operations.
4. Backstop for a Significant Event – CAISO can procure resources beyond RA resources provided by LSEs if an event occurs that threatens CAISO's ability to operate the grid in a manner that meets Applicable Reliability Criteria ("ARC").	Support: TURN Conditional Support: CLECA – Should be used rarely and only in extreme cases. Conditionally Support: PG&E - CAISO should have Board approve all designations longer than 30 days. Conditional Support: SCE - CAISO should revise the definition of Significant Event as proposed by SCE and, if not revised, should have Board approve all designations longer than 30 days. Conditional Support: AReM – Agree CAISO may need to procure in rare cases; disagrees with minimum term, cost allocation and denial of RA credit. Conditionally Oppose: Six Cities - Definition of Significant Event is overly broad and could allow CAISO to procure capacity when not warranted.	Support: Dynegy - CAISO should be required to procure capacity to meet reliability needs. IEP supports a single trigger and oppose bifurcated trigger between RA deficiencies and Significant Events. Oppose: Reliant - Concept of Significant Event should be stricken and replaced with straight-forward payment trigger. Oppose: Constellation – Significant Events are covered in RA Planning Reserve Margin.	Support conditionally, so long as ARC reflects NERC/WECC reliability criteria, and any further criteria are fully, effectively vetted with stakeholders and do not circumvent CPUC decisions about long-term reliability levels for California.	It has been shown historically that RA resources are not always sufficient to ensure reliable grid operations. Unexpected events of an enduring nature can affect grid facilities such that the CAISO cannot meet ARC. It is reasonable for CAISO to procure capacity from available resources to mitigate the need for declaring system emergencies and maintain reliable grid operations. This authority is necessary to enable CAISO to maintain reliable grid operations where available resources are not otherwise procured.

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Management Proposal	Load Serving Entities, Energy Service Providers, End-Use Customers, Ratepayer Groups *	Resource Suppliers *	California Public Utilities Commission *	Management Response
5. Product –Would procure a "capacity only" product, under a tariff-based schedule for service, and pay for a call option on the capacity of a resource. Would continue to engage in RMR contracting in 2008 and beyond, minimizing its use. Would not include services such as black start, dual fuel capability and voltage support in ICPM.	Support: Six Cities, CLECA, AReM Conditional Support/Oppose: Constellation - Support capacity-only product; oppose continuation of RMR. Support: PG&E - Resource should have must-offer obligation for energy, and requirement to bid available Ancillary Services. Conditional Support: SCE – Support capacity only; do not use more RMR unless cost allocation revised. Conditional Support: TURN - Do not necessarily agree that use of RMR should be minimized. CMUA - CAISO should use least cost principles in determining whether RMR or ICPM is appropriate.	Support: Reliant - Product should be capacity only for term of procurement. Support/Oppose: Dynegy – Product should be a capacity only product – buying an offer obligation. CAISO should not continue to rely on RMR as it can discourage LSE forward procurement.	Conditionally support - Do not oppose the ICPM, but believe that an energy-only backstop mechanism may make sense in light of anticipated market developments, including MRTU.	RMR contracting needs to continue to be used in 2008 and beyond due to the unique services in RMR that may be needed in certain locations, but its use will be minimized. It is not feasible to incorporate black start, dual fuel capability and voltage support services into ICPM and have ICPM available at the start of MRTU. Most entities now support the concept of ICPM including just a "pure capacity" service.
6. Designation is voluntary - Resource owner can decline a designation when offered by CAISO.	Support/Oppose: Six Cities - Support voluntary for backstop to RA process, but mandatory for Significant Events. Conditional Support: AReM – Can support voluntary, but notes it might cause need to employ RMR. Oppose: PG&E, CLECA - Resource owner should be required to accept a designation; concerned with market power and inefficiencies from voluntary, which could adversely impact reliability Oppose: SCE – Voluntary creates adverse selection problem that could raise costs to consumers. Oppose: TURN - If payment determined to be just and reasonable, no reason for voluntary.	Support: Constellation, Dynegy Support: IEP - Voluntary appropriate, but unlikely generator would decline a call. Oppose: Reliant - Declining a call from the CAISO should not be an option.	Oppose. Voluntary nature of ICPM designation fosters market power concerns and raises concerns about need for market power mitigation in the Exceptional Dispatch process, as Exceptional Dispatch would be the backstop for the ICPM/backstop mechanism.	Considered mandatory designation, but determined there are adequate incentives to accept designation, including provision where owner of resource can request payment higher than $41/kW-year if justified to FERC. FERC has ruled that there is no Must-Offer Obligation under MRTU. A voluntary approach is appropriate given there is no consensus among stakeholders – parties are extremely polarized on issue of appropriate price.

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Management Proposal	Load Serving Entities, Energy Service Providers, End-Use Customers, Ratepayer Groups *	Resource Suppliers *	California Public Utilities Commission *	Management Response
7. <u>Designation process and trigger for Type 1 procurement</u> – If LSE has deficiency in its RA showing, or portfolio of RA resources provided by LSEs is not fully effective, CAISO will give LSEs opportunity to cure; if they do not resolve it CAISO would procure.	Support: TURN, Six Cities, PG&E, Support: CLECA, AReM – And strongly support opportunity to cure before CAISO procures. Conditional Support: SCE – Chance to cure must allow effected LSE time to make necessary business decisions. CMUA – Requests clarification that procurement is driven by need only & effectiveness factors standard.	Support: Reliant - Procurement should occur timely ahead of compliance year or month. Support: Dynegy - but rate must be compensatory and not based on unattainable standard or subjective exercise of discretion. Conditional Support: Constellation – Support provided the term is equivalent to deficiency. IEP – Support a single trigger for all ICPM procurement.	Conditionally Support as long as "effectiveness" analysis is vetted and based on NERC/WECC criteria and does not circumvent CPUC decisions on long-term reliability levels.	Believes it is prudent to provide Type 1 procurement authority as "a last resort" in the event that the RAR is not met. LSEs are given opportunity to cure a deficiency. Penalty imposed on an LSE does not guarantee that capacity will be there if CAISO needs it.
8. <u>Designation process and trigger for Type 2 procurement</u> – CAISO has flexibility in determining a Significant Event and definition tied to inability to meet Applicable Reliability Criteria ("ARC"). 3-step designation process used. Step 1: procure for just 30 days, announce in market notice and issue report. Step 2: determine if extension needed and engage with stakeholders to discuss further steps to address. Step 3: if another extension is needed and stakeholders do not procure to resolve problem, extend the procurement.	Support: CLECA – Except term in step 2 should not be for 60 days; instead only as long as needed. Conditionally Support: PG&E - Stakeholder process should be used to develop alternative solutions and designations longer than 30 days should be approved by Board. Conditionally Oppose: Six Cities - Definition of Significant Event is overly broad and could allow CAISO to procure capacity when not warranted. Oppose: AReM - Term in step 2 should not be for 60 days; instead only as long as need after 30 days. Oppose: SCE – CAISO should revise the definition of Significant Event as proposed by SCE and, if not revised, should have additional reporting and oversight provisions added, including Board approve all designations longer than 30 days. CMUA would like to greater discussion on triggers and how it affects cost allocation.	Oppose: Constellation - Designation should be limited to events that reduce Planning Reserve Margin below operating reserve levels. Strongly Oppose: Dynegy - Any non-market use should trigger a designation; repeated use of non-RA capacity over period of 3 days should require report on why resource was not designated. IEP – Support a single trigger for all ICPM procurement. Reliant - Concept of Significant Event should be stricken and replaced with a straight-forward payment trigger.	Generally support, so long as ARC is based on NERC/WECC criteria and does not circumvent CPUC decisions on long-term reliability levels. Steps should be expeditiously pursued.	Discretion is necessary. It is impossible to foresee all potential events that could occur during operating year. Adequate flexibility is necessary to avoid unintended consequences of overly prescriptive approach. Lack of action to address a known problem could place CAISO in position of planning for interruption of firm load or failing to meet ARC. Do not support "hard trigger" because it would not allow CAISO to exercise prudent judgment and could lead to over-procurement to address temporary events. 3-step process is reasonable compromise and allows interaction and possible cure by LSEs.

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A list of abbreviations is provided at the end of this document.

Management Proposal	Load Serving Entities, Energy Service Providers, End-Use Customers, Ratepayer Groups *	Resource Suppliers *	California Public Utilities Commission *	Management Response
9. <u>Reporting Obligations</u> – Report posted within 30 days after procurement and market notice issued within 2 business days, monthly report posted within 10 calendar days after end of each month showing non-market commitments of non-RA capacity, and ICPM info included in Operations report to Board.	Support : TURN, CMUA, Six Cities, AReM, Support: CLECA – Support, but should include info on RMR dispatch and Exceptional Dispatch as well. Support: PG&E – Support, but should also include info on non-RA RUC commitments as well. Conditional Support: SCE – Support, but believe additional CAISO accountability is needed for extending Type 2 designation beyond initial 30 days.	Support: Constellation, Conditional Support: Dynegy – Reporting requirements are reasonable assuming the CAISO complies with them.	Support, presuming that market participants have continuing input on content of reports, which should be at least as detailed as prior RCST reports.	There is broad support for this element. The reporting obligations in this proposal are consistent with the extensive reporting that stakeholders have requested and go far beyond what was required under RCST.
10. <u>Term of Payments</u> - Varies from one month to up to 12 months depending on length and type of RAR deficiency being remedied or length of time of the Significant Event. Duration is tailored to match the actual collective RA deficiency, or the length of the Significant Event. A 3-step process specifies an iterative, phased approach for procurement to provide for interaction with market participants.	Support: TURN, PG&E, SCE, CLECA Conditional Support: Six Cities - Terms should not be any longer than need for capacity. Term for effectiveness procurement should be only for the duration of the deficiency, as opposed to a fixed 12-month term. CMUA – Does not oppose this element, but notes this issue is part of the overall compensation package and must be considered in that light. Oppose in part: AReM – Oppose the minimum procurement term for Significant Events. Term in step 2 should not be for 60 days; instead only as long as actual days needed after initial 30 days.	Conditional Support: Constellation - Term should be equivalent to duration of RA compliance showing deficiency. Oppose: Reliant - Concept of Significant Event should be stricken and replaced with straight-forward payment trigger. 3-step process should be stricken and replaced with minimum term triggered by a call to maintain ARC. Oppose: Dynegy - Forward procurement should be for RA term: 5 months (or balance of season) for system resources and full year for local resources. Real-time designation should be for a sufficient minimum term to provide meaningful fixed cost recovery - that may be far beyond the period of CAISO use.	Support	Proposal strikes a balance between the term desired by suppliers to ensure revenue adequacy and appropriate compensation for the service provided, and the LSEs' desire to not over-procure or pay what they might view as an excessive amount for the service.

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Management Proposal	Load Serving Entities, Energy Service Providers, End-Use Customers, Ratepayer Groups *	Resource Suppliers *	California Public Utilities Commission *	Management Response
11. <u>Pricing</u> - Price paid to resource would be based on Target Annual Capacity Price of $41/kW-year, with no deductions for peak energy rents, subject to an Availability Factor and a Monthly Shaping Factor. Resources with going-forward costs greater than $41/kW-year would be able to file at FERC for a price higher than $41, but owner would have to justify that price to FERC based on same types of costs that produced $41/kW-year default price.	Support: CLECA, Support: TURN – Proposal is a reasonable compromise of diverse stakeholder positions. Would ideally prefer cost based RMR compensation. Support: PG&E – Price falls within FERC-approved, and recently reaffirmed, zone of reasonableness. The removal of cost of new entry pricing and a demand curve has been a critical change to the proposal, which PG&E supports. Support: SCE – Support compensation values for Type 1 designations that are similar to those used under the current RCST mechanism. Conditional Support: AReM – Support a capacity-only price, but do not believe that CAISO has provided justification for $41/kW-year level, considering that previous proposal stated the going forward costs of generation were $22/kW-year. Conditional Support: Six Cities – Support, but showings of prices greater than $41 should be made *ex ante* as opposed to *ex post* to ensure transparency and certainty of cost outcome. CMUA - Do not oppose the $41/kW-year, no PER deduction approach. Object to policy direction that continues to not differentiate between seasonal attributes of capacity.	Oppose: IEP – Pricing should reflect existing market conditions. Proposed pricing appears to fall short of reflecting capacity backstop value. Oppose: Reliant – The proxy value of capacity should reflect vintage data for the cost of new entry. The cost of new entry value should be established by an independent party to reflect relevant up-to-date values. Oppose: Dynegy – Ability to keep energy and ancillary services is appealing, but given suppressed prices in real-time market, using a price more reflective of the real cost of new entry with a peak energy rent deduction would be more compensatory. Oppose: Constellation – Disappointed that CAISO has abandoned a market-based compensation approach. Requiring a resource to file for costs greater than $41/kW-year is burdensome and contrary to competitive markets. Proposal should specify when in process CAISO expects to know if resource will accept payment or file at FERC.	Support: Cost of new entry pricing for ICPM would interfere with CPUC jurisdiction to provide for California's long-term supply adequacy and with CPUC's RA program. Cost of new entry is not an appropriate basis for backstop capacity payments. The ICPM initiative should not get out ahead of CPUC long-term RA proceeding.	CAISO explored many pricing options, including competitive solicitations, auctions and cost-based Reliability Must-Run Agreements; however, these options were not chosen due to certain deficiencies with each option. The CAISO believes that the current ICPM proposal is superior to the other options that were considered, particularly given the concern that the CAISO not get ahead of development of the long-term RA design with this interim mechanism. The proposed $41/kW-yr. is sufficient to cover the going forward costs of most available resources. A mechanism is provided whereby an owner can file at FERC and seek a price higher than $41 if it believes that its costs are greater than $41/kW-yr.

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Management Proposal	Load Serving Entities, Energy Service Providers, End-Use Customers, Ratepayer Groups *	Resource Suppliers *	California Public Utilities Commission *	Management Response
12. Formula for Capacity Payment – Use formula in RCST, and update it to reflect the new capacity pricing methodology under ICPM that has no peak energy rent deduction. Formula is Designated Capacity times Availability Factor times Monthly ICPM Charge	Support: PG&E, Support: SCE, CLECA, AReM - CAISO should ensure that formula captures concept that CAISO may be procuring only portion of a resource (CAISO note: This change has been made in Board proposal). Conditional support. Six Cities - Payment should be based on actual capacity procured in MWs as opposed to total Net Qualifying Capacity which can be much greater. CAISO should have ability to procure less than full capacity of a unit. CMUA - Do not oppose the $41/kW-year, no PER deduction approach. Object to policy direction that continues to not differentiate between seasonal value of capacity.	Support: Dynegy, Conditional: Constellation – Do not oppose the formula, but oppose the pricing. Oppose: Reliant - The RCST formula should be modified to reflect Eligible Capacity, the proxy value of capacity should be updated to reflect 2007 vintage data and peak energy rents should align with the proxy unit technology, operational characteristics and heat rate.	No Comment	Proposal describes how formula works and has been updated from RCST formula to work with new capacity price, including no deduction for peak energy rents. Formula also revised to allow for procurement of less than the total capacity of a resource (now using "Designated Capacity" term rather than Net Qualifying Capacity). The Availability Factors from RCST have now been included in proposal, and are used because they have already been approved by FERC for RCST.
13. Formula for Monthly Capacity Charge - Use formula in RCST. Have changed the Monthly Shaping Factor so that it is a level factor throughout the year. Formula is Monthly Shaping Factor times Target Capacity Price.	Support: TURN, PG&E, SCE CMUA - Do not oppose the $41/kW-year, no PER deduction approach. Object to policy direction that continues to not differentiate between seasonal attributes of capacity. No Comment: Six Cities, CLECA, AReM	Support: Constellation, Dynegy - Levelizing capacity payment has meaning/value only if designation is actually possible. It is only appealing if market prices reflect scarcity conditions and are not artificially dampened by CAISO extra-market actions. No Comment: Reliant, IEP	Support/	The Monthly Shaping Factor has been changed from what is in the RCST to now be a level factor (i.e., Target Annual Capacity Price of $41/kW-year would be divided by 12 to determine target monthly capacity price). This works better with a level payment that is intended to cover fixed costs.

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Management Proposal	Load Serving Entities, Energy Service Providers, End-Use Customers, Ratepayer Groups *	Resource Suppliers *	California Public Utilities Commission *	Management Response
14. <u>Allocation of Costs</u> – Type 1 costs allocated only to deficient LSE (or LSEs) including any "lumpiness of procurement," except for procurement to address "effectiveness factors" which is spread among affected LSEs, with CEC forecast load used to determine load share. Type 2 costs allocated to affected LSEs in TAC area or areas, with actual load in each month from CAISO settlement system used to determine load share.	Support: PG&E, SCE Support: AReM – Support Type 1 cost allocation. Conditional Support: Six Cities – Support provided that allocation of Type 1 costs is done on basis of monthly LSE RA deficiencies. Conditional Support: CLECA - Concern about lumpiness factor. Lumps should be small as possible and cost-effectiveness assessment of procurement options should take into account minimization of procurement in excess of absolute need that would result from lumpiness. Oppose in Limited Part: TURN - Unfair to assess the cost of additional procurement for effectiveness to LSEs that have already over-procured in first instance where other LSEs were deficient. Oppose: AReM – Oppose Type 2 cost allocation. Costs should be allocated on a forecast basis, as is being done for Type 1 procurement. Believe this would improve the ability for a LSE to be able to claim a Type 2 procurement in its RA showing. CMUA requests clarification that CAISO will only procure what is necessary to meet ARC. CMUA does not oppose the write-up for the "lumpiness" issue.	Support: Constellation, Generally Support: Dynegy – For Dynegy, cost allocation is secondary to designation and payment terms, but costs should be allocated in a way to create greatest incentive to address deficiencies in RA requirements. No Comment: Reliant, IEP	Support	Broad support for overall proposal. Some were previously concerned that compliant LSEs could share in "lumpiness of procurement" costs; however have resolved this issue by revising proposal (no sharing). Proposal does not use CEC load forecast data for Type 2 procurement as actual load better follows cost causation, there is only limited support for using CEC forecast load, and use of CEC load does not solve "timing" issues related to LSEs possibly including Type 2 in RA showings (see #16).

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Management Proposal	Load Serving Entities, Energy Service Providers, End-Use Customers, Ratepayer Groups *	Resource Suppliers *	California Public Utilities Commission *	Management Response
15. <u>Selection among Multiple Resources</u> – Use same criteria as in RCST for selection. Add new ability to designate a partial unit (under RCST must procure whole unit) and use of a random selection rule to break ties if eligible resources cannot be differentiated by their physical characteristics.	Support: PG&E, SCE - Support partial unit designations. Support: CLECA – Support designation of partial units and use of auction. Conditional Support: AReM - Concerned about how tie-breaker would interact with ability of generator to request higher payment through FERC filing. Should clarify how proposal will be modified to resolve issue. PG&E - Oppose simple tie-breaker auction; instead recommend use of a random selection rule. SCE - Does not appear necessary to introduce an auction to resolve ties. CAISO should pick resources that are most effective from grid operations perspective. CMUA has no position on this issue. No Comments: TURN , Six Cities,	Dynegy - Dynegy is skeptical about how CAISO would implement partial unit designations. A designation should not occur at a level less than that required by the CAISO to operate reliably. Conditional: Constellation – Do not oppose ability to designate partial units. Oppose auction process that allows entities to bid at or below the price cap. Reliant - When CAISO calls on a Generating Unit to maintain Applicable Reliability Criteria, a term payment for all Eligible Capacity associated with the Generating Unit should be triggered, with a must-offer obligation for the term of the CAISO procurement. No Comment: IEP	No Comment	Broad support for overall proposal. Some entities were concerned with prior proposal to use a simple auction to break ties. A random selection rule is now proposed, which is supported by several entities. A "tie" is expected to be a very rare occurrence. The CAISO believes the random selection rule is a reasonable method to address a potential situation that might only rarely arise.

A list of abbreviations is provided at the end of this document.

Management Proposal	Load Serving Entities, Energy Service Providers, End-Use Customers, Ratepayer Groups *	Resource Suppliers *	California Public Utilities Commission *	Management Response
16. <u>ICPM Procurement in RA Showings</u> – Information would be provided to CPUC and LRAs on all ICPM procurement so that capacity procured can be considered by CPUC and LRAs and potentially allowed to count towards an LSE's RAR. Do not support allowing "Type 2" procurement to be included in RA showings.	Support: Six Cities, CMUA Support: PG&E, SCE, AReM – Support use of Type 1 procurement to off-set RA showings. Support: CLECA – Support, but why would Type 2 not be allowed to be included in RA showings? Oppose: PG&E, SCE – Oppose not allowing Type 2 procurement to off-set RA showings. Allowing it to count could lower collective need for system capacity. Oppose: AReM – Oppose proposal for Type 2. It should be allowed to be included in RA showings so that LSEs receive credit for ICPM capacity for which they have paid. No Comment: TURN,	Support: Dynegy - Allowing ICPM procurement to count towards meeting an LSE's RA requirements diminishes incentives to procure to meet forward showings, but it is likely that RA penalty mechanism, if effectively enforced, would counter this incentive. Support CAISO position to not allow Type 2 procurement to count in RA showings. Conditional Support: Constellation – Generally supports this feature, but Type 2 procurement for durations longer than 1 month should be potentially allowed to count in RA showings. Reliant - Allowing LSEs to count ICPM capacity against their RAR is a problem if CAISO is procuring ICPM capacity at a deep discount to cost of new entry.	Does not oppose. Does not now and is not considering giving CPUC jurisdictional LSEs RA counting "credit" for CAISO backstop procurement.	Support allowing all Type 1 procurement to be included in RA showings. Do not support allowing such treatment for Type 2 because the reason for Type 2 procurement is that the RA resources procured are insufficient to meet ARC and allowing it in RA showings would result in a decrease of available RA capacity and exacerbate conditions that lead to the procurement and potentially could cause additional ICPM procurement.

*- Comments indicate the position of the parties as they were provided.

List of Acronyms

ARC	Applicable Reliability Criteria
AReM	Alliance for Retail Energy Markets
CAISO	California Independent System Operator
CEC	California Energy Commission
CLECA	California Large Energy Consumers Association
Constellation	Constellation Energy Commodities Group, Constellation NewEnergy, Inc, and Constellation Generation Group, LLC
CPUC	California Public Utilities Commission
Dynegy	Dynegy Power Marketing, Inc.
FERC	Federal Energy Regulatory Commission
ICPM	Interim Capacity Procurement Mechanism
IEP	Independent Energy Producers Association
LCR	Locational Capacity Requirement
LRA	Local Regulatory Authority
LSE	Load Serving Entity
MORC	Minimum Operating Reliability Criteria
MRTU	Market Redesign and Technology Upgrade
MSC	Market Surveillance Committee
NERC	North American Electric Reliability Council
NRG	NRG Energy
PER	Peak Energy Rent
PGA	Participating Generator Agreement
PG&E	Pacific Gas and Electric Company
RA	Resource Adequacy
RCST	Reliability Capacity Services Tariff
Reliant	Reliant Energy, Inc.
RMR	Reliability Must-Run Agreement
RUC	Residual Unit Commitment
SCE	Southern California Edison Company
TAC	Transmission Access Charge
WECC	Western Electricity Coordinating Council

* - Comments indicate the position of the parties as they were provided.

Attachment E

Opinion on "Interim Capacity Payment Mechanism under MRTU"
by

Frank A. Wolak, Chairman
James Bushnell, Member
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Market Surveillance Committee of the California ISO

November 21, 2007

1. Introduction

The California ISO has asked the Market Surveillance Committee (MSC) to comment on its Interim Capacity Procurement Mechanism (ICPM) proposal.[1] The ICPM will replace the existing Reliability Capacity Services Tariff (RCST) when the Market Redesign and Technology Upgrade (MRTU) market is implemented. The ICPM will allow the ISO to supplement or backstop the resource adequacy (RA) procurement of load-serving entities (LSEs) to ensure there is sufficient generation capacity available to the ISO operators to maintain reliable grid operation in the California ISO control area.

The ISO proposal envisions two circumstances that will trigger purchases under the ICPM, what it calls Type 1 and Type 2 procurement. Type 1 procurement occurs before the compliance year if an LSE or group of LSEs has not purchased the full amount of their local or system-wide Resource Adequacy Requirement (RAR) by the time of the required RA showing for that year. Type 2 procurement occurs during the compliance year if the ISO determines that a "Significant Event" has occurred that creates a need to supplement LSE-procured capacity within the year.

The ISO has been undertaken an extensive stakeholder process to develop its ICPM proposal. The MSC has actively engaged in this process through both meetings and conference calls with ISO staff and stakeholders. The MSC also discussed this topic at previous MSC meetings starting with the June 6, 2007 joint MSC/stakeholder meeting. Because the ISO's ICPM proposal specifies an administrative price that the ISO will pay for capacity and the circumstances under which the ISO will pay this price, the design of the ICPM proposal has caused significant controversy among stakeholders. Generation unit owners typically favored higher prices for ICPM capacity and a commitment to pay this price for a longer period of time. Load-serving entities preferred lower prices and shorter time commitments to pay it. Virtually all parties agreed that the ISO should clearly specify in advance the circumstances under which it will make an ICPM procurement. The lack of stakeholder consensus of these issues implies that the ICPM process must strike a balance between divergent stakeholder desires and craft a proposal that all parties can live with until the current long-term RA proceedings at the California Public Utilities Commission (CPUC) have been completed.

We believe that the ISO's final ICPM proposal is a compromise solution that does not have any significant defects that are likely to harm system reliability or short-term market efficiency, or interfere with the functioning of the RA procurement process. We emphasize that

[1] This proposal is summarized in the document "Final Proposal for Interim Capacity Procurement Mechanism Tariff Filing," November 9, 2007, available at http://www.caiso.com/1c91/1c91b9f063f90.pdf

this is an interim mechanism that should be re-evaluated or even eliminated once a scarcity-pricing mechanism has been implemented and the long-term resource adequacy process at the CPUC has been resolved. We also believe that a number of features of the ICPM proposal address potential concerns we had with previous ICPM proposals. In particular, we were concerned that setting the cost of new entry (CONE) as the cap on the price of capacity for Type 1 procurement was likely to impact the price LSEs had to pay for RA capacity, particularly in areas likely to be subject to the exercise of local market power. Because the ICPM proposal may change as a result of stakeholder input before it is presented by the ISO Board, in this opinion we discuss features of the current ICPM that we would recommend retaining in the final proposal.

2. The Role of Type 1 versus Type 2 Procurement

We believe that the argument for the ISO having Type 1 procurement authority is weaker than the argument for the ISO having Type 2 procurement authority. A Type 1 procurement occurs in advance of the compliance year if an LSE fails to meet its RA capacity requirements. Because an LSE's showing of its RA capacity is made in advance of the actual compliance year, there is sufficient time for the California Public Utilities Commission (CPUC) to oversee the Type 1 procurement process, with the ISO only providing technical input on which generation capacity should be purchased. For example, if the ISO determines that there is inadequate RA capacity procured, it can request that the CPUC procure a certain amount of capacity from a group of generation units before the start of the compliance year. If the ISO is able to identify which LSE is short relative to its RA requirements, then the process could be streamlined even more. The CPUC would order the LSE that the ISO determined is short relative to its RA requirements to purchase the necessary capacity. It is difficult to see how any purchase cost savings or administrative costs savings would be realized by giving the ISO, instead of the CPUC, the authority to make these purchases. In fact, the CPUC is likely to have a stronger incentive to procure the necessary capacity shortfall at a lower total cost than the ISO because of its legal mandate to ensure that California consumers pay just and reasonable prices for electricity.

Although an effective long-term RA process at the CPUC can virtually eliminate the need for the ISO to make Type 1 procurements on behalf of CPUC-jurisdictional entities, we recognize that there is still a case for granting the ISO the authority to make them. First, there are LSEs in the California ISO control area that are not subject to the CPUC's jurisdiction, and they consume a non-trivial percentage of the annual peak demand.[2] Second, although there are safeguards and incentives in the CPUC RA procurement process, it is still possible that this process could result in the CPUC-jurisdictional entities having procured inadequate capacity in certain local areas or on a system-wide basis for the ISO to maintain grid reliability.[3] Consequently, the option for the ISO to make a Type 1 procurement must exist as a last resort if the CPUC process fails or non-jurisdictional LSEs fail to procure adequate capacity.

[2] Under the ISO tariff, all LSEs in the ISO control area are subject to its local resource adequacy requirements and can be assessed all or a portion of the costs of Type 1 and 2 procurements to address RA capacity shortfalls.

[3] The CPUC RA process provides an opportunity for LSEs to eliminate any RA deficiencies identified in their initial RA showings and subjects LSEs to penalties for non-compliance with its RA requirements.

The urgency and likely duration of a Type 2 procurement argues in favor of an ISO-dominated process for these purchases. First, an ISO determination that a "significant event" has occurred is necessary to trigger a Type 2 procurement. Second, the reliability consequences of a significant event may be so severe that the ISO cannot wait for a joint ISO and CPUC administrative process to identify the additional generation capacity needed before a CPUC-sponsored procurement can take place. The typical Type 2 procurement is also likely to be of a very short duration, because it is triggered by an unexpected event not anticipated at the time of the annual RA showing in advance of the compliance year.

The argument for an ISO-dominated Type 2 procurement process is even stronger because this procurement only occurs within the compliance year and serves a different role from the standard RA capacity product. The primary rationale for Type 2 procurement is to ensure that the generation capacity purchased continues to bid into the short-term market. Receipt of the ICPM capacity payment is conditional on the unit owner being willing to subject its unit to the ISO's must-offer obligation. For this reason, the price and duration of payment for Type 2 ICPM procurement does not provide a signal for new generation investment. This payment must only be sufficient to ensure that a supplier that has decided to offer a generation unit into the ISO markets during the compliance year without an RA contract continues to do so because of the increased reliability need for this capacity caused by a "significant event."

3. Allowing the ISO Considerable Leeway to Determine a Significant Event

Virtually all stakeholders have argued that the ISO should clearly specify the circumstances that give rise to a significant event worthy of an ICPM procurement. However, one key measure of the performance of the RA procurement process is the frequency that significant events occur. The annual RA process, which requires suppliers to procure adequate generation reserves (approximately 115 percent of peak demand), is designed to provide sufficient generation capacity to the ISO operators to manage all unexpected reliability events throughout the coming year. Clearly, it is impossible for the ISO to anticipate all possible future reliability events. For this reason, we support giving the ISO the authority to make a Type 2 procurement of additional RA capacity during the compliance year if one of these events occurs.

We also support giving the ISO operators considerable discretion to declare a significant event whenever they determine that additional RA capacity is necessary to maintain grid reliability. However, the CPUC and ISO should give serious consideration to revising the annual RA requirements for the year following any year that the ISO declares a significant event. As noted above, our expectation is that significant events should rarely, if ever, occur under a properly designed RA mechanism.

We recognize there are two competing tensions in designating a significant event: (1) the need to provide the ISO with the discretion to purchase additional RA capacity if it believes that system reliability is adversely impacted by an unexpected event, and (2) the need to provide as much clarity as possible to the process used to designate significant events so that market participants do not rely on the ICPM process to meet their RA needs. We support giving the ISO substantial discretion in making this determination because the potential reliability consequences of limiting the set of circumstances when the ISO can declare a significant event are simply too great to ignore.

4. Limit Interaction ICPM with Pricing of RA Products

The ICPM backstop price is likely to function as an upper bound on the prices that LSEs will pay for RA capacity, particularly in local areas with adequate generation capacity but inadequate competition among generation unit owners to sell it at a reasonable price. In these areas, the ICPM capacity price is likely to become the default price for RA capacity, because the LSE knows that it can purchase this capacity at the ICPM capacity price through a Type 1 procurement process. Consequently, if the ICPM price is set too high then retailers may be forced to pay this price for capacity in areas where suppliers have significant local market power, despite the fact that there is adequate generation capacity in the area to meet the ISO's RA needs.

The original ISO proposal was to make the cost-of-new-entry (CONE) the benchmark ICPM price for a Type 1 procurement. The local market power problem for RA capacity procurement was to be addressed through an administrative demand curve that reduces the price of a Type 1 capacity procurement if there is more generation capacity in the local area than is necessary to meet the LSE's RA requirement. This proposal raised a number of controversial questions about how to define the slope of the demand curve, how to set the value of CONE, and how to define local capacity areas. Although CONE may be justified in some local areas, in others there may be ample installed capacity, but local market power prevents it from being transacted at a reasonable price. Given the ongoing long-term RA process at the CPUC, we feel it is better to sort out these issues in the LT-RA proceeding, rather than in the ICPM process.

We support a capacity price significantly below CONE for Type 2 RA procurement. The consensus among MSC members is that Type 1 ICPM payments that address RA procurement deficits before the delivery year should be higher than payments made within the delivery year to address RA deficiencies stemming from a significant event. The distinction is that ICPM procurements before the delivery year may provide incentives for more generation capacity to exist at certain locations in the ISO control area. However, given the stakeholder controversy surrounding the appropriate price and market power mitigation mechanism for a Type 1 procurement and the interim nature of the ICPM procurement process, we understand the ISO's desire for simple administrative price for Type 1 procurement until long-term RA process at the CPUC is completed. .

5. Limit Price and Magnitude of Duration of ICPM Procurement

As discussed above, if the RA procurement process functions as intended, then there is likely to be little need for a Type 2 ICPM procurement as the original RA process will have adequately anticipated and accounted for "normal" contingencies. Moreover, the need for Type 1 procurement can be virtually eliminated if the CPUC ensures that all jurisdictional LSEs in the ISO control area meet their local and system-wide RA requirements. This logic implies that there should be very little Type 1 and 2 ICPM procurement each year if the RA process is properly designed. If the annual RA process is properly implemented, any ICPM procurement that does occur should be Type 2 and of very short duration.

Any capacity purchased under a Type 2 ICPM procurement is, by definition, capacity that does not have a RA capacity contract, yet has still decided to invest or remain in operation and sell into the ISO's day-ahead and real-time markets for at least part of the year. For this reason, it is worth considering what an ICPM payment is "buying" under these circumstances. The ICPM payment is buying a must-offer requirement from the generation unit. This procurement would occur when a unit that had been viewed as surplus capacity under normal conditions becomes critically needed because of a "significant event." One might expect that under these circumstances, the energy and ancillary services prices paid to this unit would rise, increasing the incentives for it to offer into these markets of its own volition (*i.e.* without a must-offer requirement). It is important to note that these units were presumably offering into the market at other times without being required to do so before the Type 2 ICPM designation. However, several possible complications could arise under the current market design that argue in favor of a positive ICPM payment for a Type 2 procurement.

It is possible that local market power mitigation combined with relatively low price caps on the ISO's energy and ancillary services markets would prevent market prices from rising to the levels necessary to induce this unit to offer sufficient capacity at critical times.[4] Certain generation units may be needed to provide services that are not fully priced by the current market design, such as a local form of a slow response time (30 to 60 minutes) operating reserve. In this circumstance, the must-offer requirement and the Type 2 ICPM payment fills the reliability and revenue gaps left by this unpriced service. One last important factor is the residual unit commitment (RUC) payment that could be earned by a non-RA unit. Under some circumstances a firm may be able to earn considerable revenues through RUC payments that stem from some form of local market power that the unit owner is endowed with as a result of the significant event. A generation unit that is not under must-offer could in theory offer only a portion of its capacity into the market. Even though the bid price of this capacity is subject to local market power mitigation, the unit's offer quantities would not be regulated. Requiring the unit to sell Type 2 ICPM capacity under these circumstances prevents the exercise of significant local market power.

As noted earlier, because the units that are at risk to be called upon to provide Type 2 ICPM capacity have already made a decision to participate in the ISO's markets without an RA payment, we believe that the payment for Type 2 ICPM capacity should at most recover the generation unit's going-forward fixed costs. If the ISO's bid caps are too low, without an ICPM capacity payment, the unit owner might not recover its going forward-fixed costs from energy and ancillary services sales.[5] The \$41/kW-year ICPM payment for Type 1 and Type 2

[4] The example of a plant that has been temporarily "mothballed" for a season has been raised as another rationale for a positive Type 2 ICPM payment, but we do not have sufficient information to determine how prevalent such circumstances are.

[5] It is important to note that the market power mitigation mechanism limits the prices *offered* into the market, rather than the market-clearing price itself. Under a fully integrated scarcity pricing scheme with a sufficiently high price cap, firms can recover their fixed costs even when they are offering their units into the market at marginal cost, as the local market power mitigation mechanism requires that they do.

procurement makes it very unlikely that a unit owner will receive revenues that do not recover its variable operating costs and going-forward fixed costs.[6]

The ISO is also considering whether to allow a unit owner to decline an ICPM designation. We support prohibiting unit owners from declining a Type 2 ICPM designation, particularly for procurements caused by local or regional capacity shortfalls where only one or a small number of generation unit owners can provide the product. We believe the case for this prohibition is much weaker for Type 2 designations made for system-wide capacity shortfalls. Providing a generation unit owner with the option to reject this designation sets up the following perverse incentive. Only those unit owners able to exercise substantial unilateral market power by not being subject to the ISO's must-offer requirement will refuse the ICPM designation. The unit owners unable to exercise much unilateral market power without a must-offer requirement will instead elect to receive the ICPM payment. These units are those most likely to be offering into the energy and ancillary services markets at reasonable pries anyway. In short, a policy that creates a special designation such as Type 2, but makes it optional to accept this designation, creates an adverse selection problem that could raise costs to consumers without significantly improving grid reliability.

Allowing parties the option to decline an ICPM designation could lead to the following costly series of events under either Type 1 or Type 2 procurement: The ISO devotes significant time and effort to determining the most appropriate generation resource for an ICPM designation, and the unit owner declines this designation for the reasons discussed above. This would unnecessarily increase the cost of the ICPM procurement process and likely result in the ISO purchasing ICPM capacity from units less able to meet its reliability needs. To address concerns that a supplier may be unable to recover the costs associated with their participation in the California market under an ICPM designation, the ISO should allow a supplier to make a cost-of-service filing at FERC to recover any annual revenue shortfalls. These incentives are likely to have far more adverse market efficiency and system reliability consequences for Type 2 procurements caused by local or regional capacity shortfalls, than those caused by system-wide shortfalls.

6. Concluding Comments

Consistent with our November 9, 2007 opinion on the long-term resource adequacy, we are concerned with the central role played by the must-offer requirement in California's resource adequacy policies. In a market with an increasing share of imported, energy limited, and intermittent energy, must-offer requirements become less meaningful, because these kinds of resources are physically unable to offer their capacity into the market a significant fraction of the hours of the year. We suspect that California policymakers and the ISO will soon need to explore what options exist for ensuring reliable grid operation beyond the currently constituted must-offer paradigm. As noted above, the authority to make a Type 1 ICPM procurement can assigned to the CPUC, which essentially eliminates the need for the ISO to engage ICPM procurement before the compliance year for all CPUC-jurisdictional entities. This leaves the Type 2 designation of previously "surplus" units under the ISO's discretion. This capacity is

6 We note that the ISO proposes to scale this annual payment to the time and duration of the ICPM procurement using monthly shaping factors which could make this statement less likely to be true.

already available to operate, so the Type 2 designation is to ensure this capacity adheres to the must-offer requirement. If the redesign of the market and RA policies allows the ISO to move beyond a must-offer requirement to focus on the provision of specific operating reserves, then the need for Type 2 ICPM procurement can also be eliminated. However, before this is done we recommend that the ISO determine what changes to its short-term operating reserve procurement process are necessary to ensure that adequate operating reserves are available for reliable grid operation in the absence of a must-offer requirement.

Attachment F

CALIFORNIA
ENERGY
COMMISSION

COMPARATIVE COSTS OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION TECHNOLOGIES

Final Staff Report

December 2007
CEC-200-2007-011-SF

STATE OF CALIFORNIA
ENERGY COMMISSION

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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ABSTRACT

This 2007 report updates the cost of generating electricity for California-located technologies. California Energy Commission staff provides levelized costs, including the cost assumptions, for 8 conventional and 20 alternative central station generation technologies. These levelized costs are useful in evaluating the financial feasibility of a generation technology and for comparing the cost of one technology against another. These cost of generation estimates represent one of the first such efforts based substantially on empirical data collected from operating facilities. The combined cycle and simple cycle costs are the result of a comprehensive survey of actual costs from the power plant developers in California who built power plants between 2001 and 2006. The other costs are based on actual costs and surveys of expected costs from experts in the field. For this reason, staff expects these estimates to have improved accuracy relative to other such estimates. The Energy Commission's Cost of Generation Model is also unique in that it has two features not commonly found in cost of generation models: screening curves and cost sensitivity analysis curves. The Energy Commission also uses the fixed-cost data of the Cost of Generation Model with the variable cost information of a production cost market simulation model to produce wholesale electricity costs, which are necessary to many related resource planning studies at the Energy Commission, including Retail Electricity Price Forecasts, Global Warming Evaluations and Electric Vehicle Studies for the AB 1007 Report.

Keywords: cost of generation, Cost of Generation Model, Model, levelized costs, instant cost, installed cost, fixed operation and maintenance, fixed O&M, variable operation and maintenance, variable O&M, heat rate, generation technology cost, annual costs, fixed cost, variable cost, alternative technologies, combined cycle, simple cycle, combustion turbine, integrated gasification combined cycle, coal cost, fuel cost, natural gas cost, nuclear fuel cost, heat rate degradation, financial variables, capital cost structure

Executive Summary

This Cost of Generation report provides levelized cost of generation estimates for various central station generation technologies. These levelized costs are useful in evaluating the financial feasibility of a generation technology and for comparing the cost of one technology against another. Since most studies involving new generation or transmission require an assessment of costs, accurate and readily available cost of generation estimates are essential to much of the California Energy Commission's (Energy Commission) work.

Care must be taken not to misuse these levelized costs. They are nominal values, not precise estimates. They are for a specific set of assumptions that might not be completely applicable for the study in question. Comparing one levelized cost against another may be useful where levelized costs are of significantly different magnitudes, but problematic where levelized costs are close. Most importantly, these estimates do not predict how the units will actually operate in an electric system, how the units will affect the operation of one another, or their effect on system costs. Such estimates require a more sophisticated model such as a market model. Finally, these cost estimates do not address environmental, system diversity or risk factors which are a vital planning aspect of all resource development.

The levelized costs herein were developed using the Energy Commission's staff Cost of Generation Model. The Energy Commission's Cost of Generation Model was first used to produce cost of generation estimates for the *2003 Integrated Energy Policy Report*, which at that time consisted of 25 separate models. Because of the usefulness of the resulting cost estimates and many requests for this type of information, the staff revised the Cost of Generation Model to be more compact, accurate and user-friendly. Staff combined the 25 separate cost of generation models of the 2003 version into one Cost of Generation Model with drop-down menus. In addition, the Cost of Generation Model has been completely reorganized to make it more flexible and more transparent.

Energy Commission staff comprehensively updated the component costs that are used as inputs to the Cost of Generation Model. Staff revised the simple cycle and combined cycle units based on a survey of the power plant developers for all units built in California since 2001. The remaining unit costs are based on a combination of actual costs collected from the power plant developers and experts in the field.

The staff added a number of analytical functions to the Cost of Generation Model, including screening curves and sensitivity curves to allow users to evaluate the effect of the various cost factors used in developing levelized costs.

The Cost of Generation Model, working together with the Marketsym model, can now develop wholesale electricity price forecasts. This feature estimates the fixed cost component and applies the variable cost factors from the production cost or market model to produce a wholesale electricity price forecast. Wholesale electricity price forecasts are necessary for many of the resource planning studies.

Energy Commission staff improved the documentation and created a comprehensive user's guide to facilitate the use of the Cost of Generation Model. Both the Cost of Generation Model and the user's guide will be made available on the web site.

The Cost of Generation Model and a June 2007 Draft Report were the subject of a June 12, 2007 workshop. Several comments were received and incorporated into the Model and this Report.

The Report is organized as follows:

- Chapter 1 reports the levelized cost estimates – the output of the Model. It provides the levelized cost estimates for 8 standard technologies and 20 alternative technologies. The levelized costs, as well as the component costs, are provided for three classes of developers: merchant, investor-owned utilities (IOU) and publicly owned utilities (POU) – often referred to as municipal utilities.

- Chapter 2 summarizes the inputs to the Model: data assumptions, and the collection and analysis process for the improved data. It also compares the effect of the present assumptions to those used in the *2003 Integrated Energy Policy Report*, *(2003 IEPR)* forecast, as well as comparing the present estimates to the EIA estimates.

- Chapter 3 provides a general description of the California Energy Commission's (Energy Commission) Model, provides instructions on how to use the Model and also describes the various unique new features of the Model, such as screening and sensitivity curves.

- Appendix A provides a list of contacts if further information about the Model is needed.

- Appendix B provides the power point slides from the June 12, 2007 workshop that describe the details of the alternative technologies, advanced nuclear and clean coal.

- Appendix C provides the comments of interested parties who reviewed the report and/or the Model, followed by staff responses to these comments.

- Appendix D provides a summary of the changes in levelized cost relative to the draft report.

- Appendix E provides a summary of the levelized fixed cost for a simple cycle unit in $/kW-Yr.

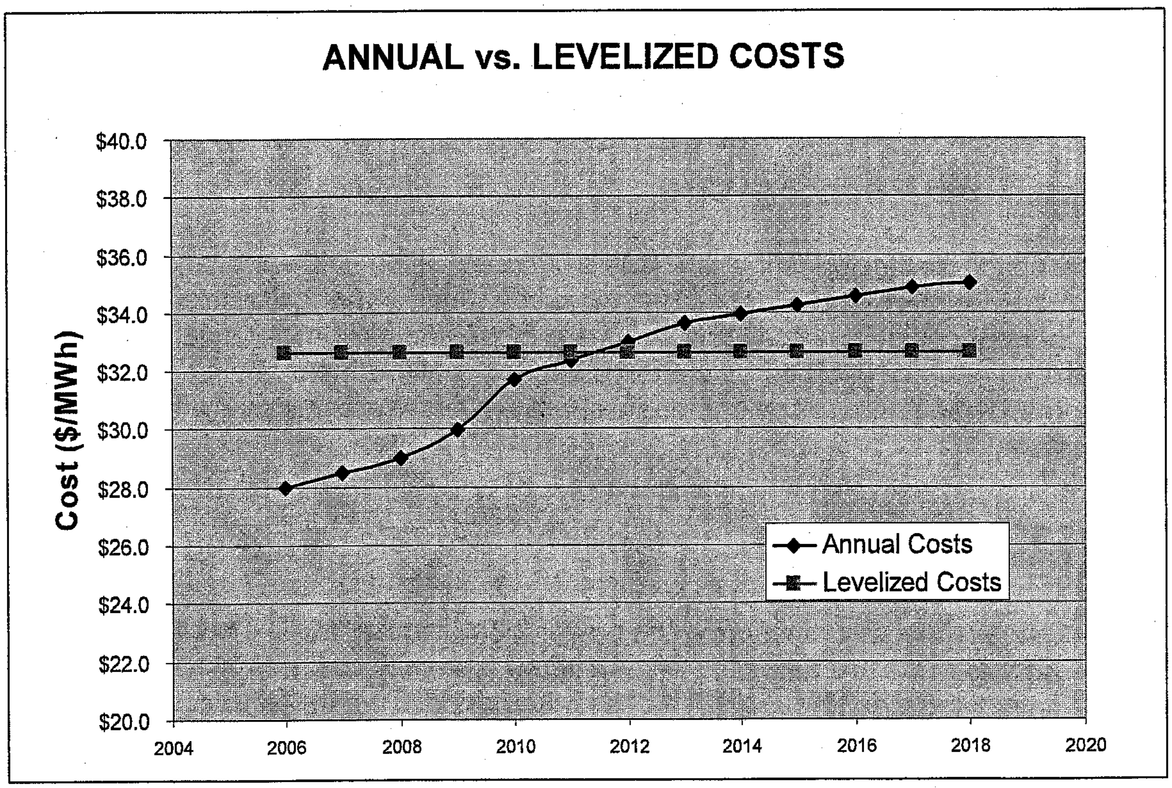
CHAPTER 1: Summary of Technology Costs

This chapter defines levelized cost, delineates the cost components of levelized cost, and summarizes the levelized costs of the technologies considered in this report. These costs are reported for nuclear, fossil fuel, and various alternative technologies.

Definition of Levelized Cost

Levelized cost is the constant annual cost that is equivalent on a present-value basis to the actual annual costs, which are themselves variable. **Figure 1** is a fictitious illustration of this relationship, which is defined by the fact that the present worth of the annualized levelized cost values is equal to the present worth of the actual annual costs. This annualized cost value allows for the comparison of one technology against the other, whereas the differing annual costs are not easily compared.

Figure 1: Illustration of Levelized Cost



Source: Energy Commission

Levelized Cost Categories

Levelized costs are reported for fixed and variable cost components as shown in **Table 1**.

Table 1: Summary of Levelized Cost Components

Fixed Cost
Capital and Financing – The total cost of construction, including financing the plant
Insurance – The cost of insuring the power plant
Ad Valorem – Property taxes
Fixed O&M – Staffing and other costs that are independent of operating hours
Variable Costs
Fuel Cost – The cost of the fuel used
Variable O&M – Operation and maintenance costs that are a function of operating hours

Source: Energy Commission

All of these costs vary depending on whether the project is a merchant facility, an IOU, or a POU. In addition, the costs can vary with location because of differing land costs, fuel costs, construction costs, operational costs, and environmental licensing costs. These costs are discussed in detail in Chapter 2, but are defined briefly as follows.

Capital and Financing Costs

The capital cost includes the total costs of construction, including land purchase, land development, permitting, interconnection, environmental control equipment, and component costs. The financing costs are those incurred through debt and equity financing and are incurred by the developer annually, similar in structure to financing a home. These annual costs, therefore, are essentially levelized by this cost structure.

Insurance Cost

Insurance is the cost of insuring the power plant, similar to the insuring of a home. The annual costs are based on an estimated first-year cost and are then escalated by nominal inflation throughout the book life period. The first-year cost is estimated as a percentage of the installed cost per kilowatt for a merchant facility and POU plant. For an IOU plant, the first-year cost is a percentage of the book value.

Ad Valorem

Ad valorem costs are annual property tax payments that are paid as a percentage of the assessed value and usually transferred to local governments. POU power plants are generally exempt from these taxes but may pay in-lieu fees. The assessed values for power plants are set by the State Board of Equalization (BOE) as a percentage of book value for an IOU and as depreciation-factored value for a merchant facility.

Fixed Operating and Maintenance

Fixed O&M costs are shown as costs that occur regardless of how much the plant operates. These are not uniformly defined by all interested parties but generally include staffing, overhead and equipment (including leasing), regulatory filings, and miscellaneous direct costs.

Corporate Taxes

Corporate taxes are state and federal taxes, which are not applicable to a POU. The calculation of these taxes is different for a merchant facility and an IOU. Neither lends itself to a simple explanation, but in general the taxes depend on depreciated values and are adjusted for interest on debt payments. The federal taxes are adjusted for the state taxes similar to adjustment rates for a homeowner.

Fuel Cost

Fuel cost is the cost of fuel, most commonly expressed in dollars per megawatt hour. For a thermal power plant, it is the heat rate (Btu/kWh) multiplied by the cost of the fuel ($/MMBtu). This includes start-up fuel costs as well as the online operating fuel usage. Allowance must be made for the degradation of the heat rate over time.

Variable Operations and Maintenance

Variable O&M costs are a function of the hours of operation of the power plant. Most importantly, this includes yearly maintenance and overhauls. Variable O&M also includes repairs for forced outages, consumables, water supply, and annual environmental costs.

Summary of Levelized Costs

Table 2 summarizes the calculated levelized costs for the various generation technologies as developed by merchant facilities, IOUs, and POUs. They are provided in the two most common formats, $/MWh and $/kW-Yr. All costs are in 2007 nominal dollars and are for a generation unit that begins operation in 2007. Although levelized costs commonly vary with location and are captured accordingly in the Model, only average California levelized costs are shown in this table and the remainder of the report. Similarly, only average California gas prices are used in reporting levelized costs for gas-fired technologies, even though the Model can produce levelized costs for each natural gas area.

Figure 2 provides this same information in graphical form. To present the information in a less busy representation, **Figure 3** shows the same data for the merchant facilities arranged in ascending order of cost.

The levelized costs include tax credits and any other benefits attributable to the technology, such as tipping fees for the biomass anaerobic digester dairy.

The IOU plants are less expensive than the merchant facilities due to lower financing costs. This is in marked contrast to the *2003 IEPR* when merchant financing costs were at least comparable to those for the IOUs. The change is a reflection of the outcome from the 2000-2001 energy crisis. The publicly owned plants are the least expensive because of lower financing costs and freedom from taxes.

Component Costs

Tables 3, **4**, and **5** show the cost components for each developer category, merchant facility, IOU and POU. **Figures 4**, **5**, and **6** show this same data graphically.

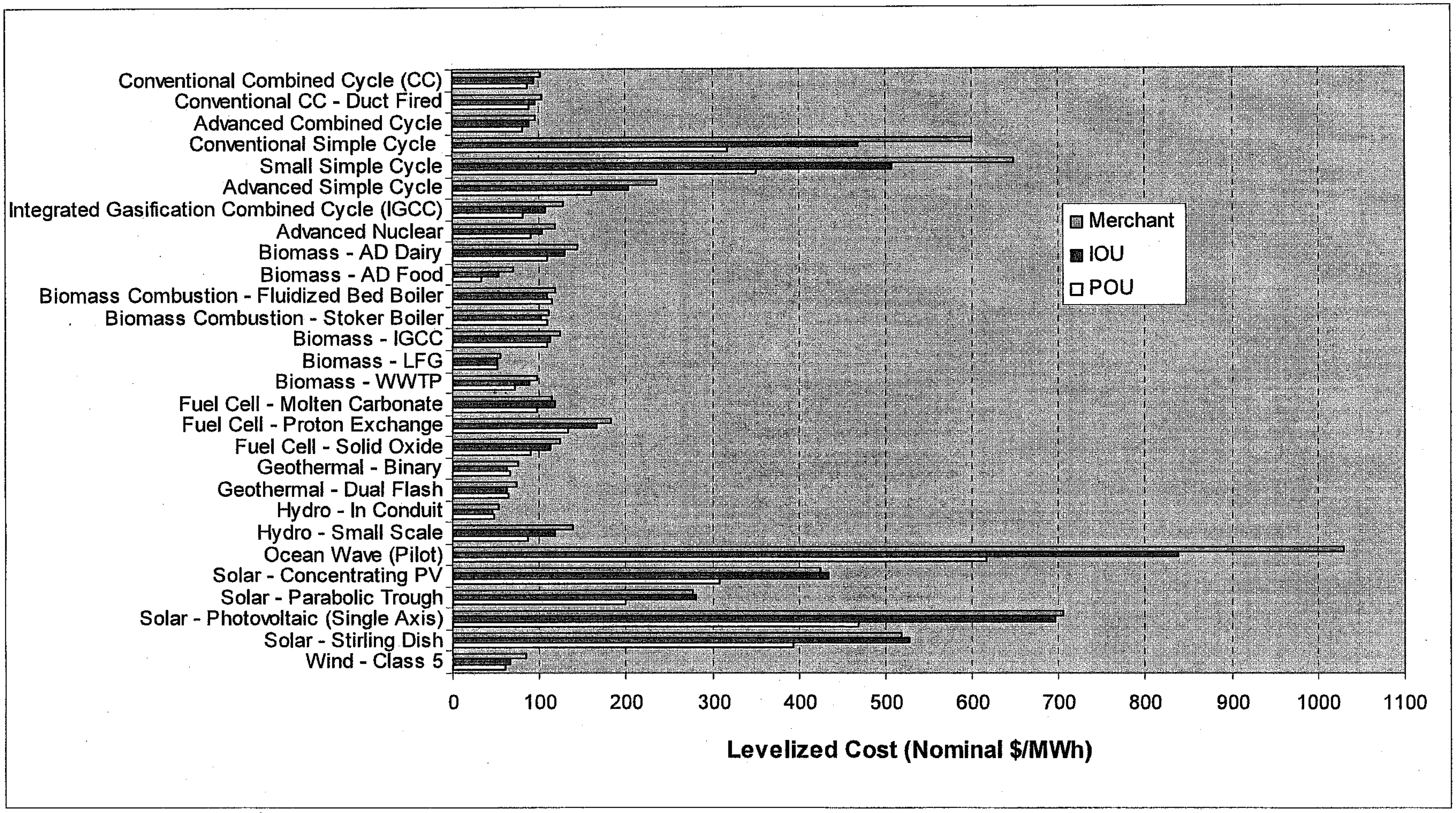
Staff has provided all the noted above levelized tables and graphs as this data is commonly used and commonly requested by various entities. It should be kept in mind, as will be explained in more detail later in the report, that all these levelized costs are nominal values based on the most likely assumptions. Since these nominal assumptions might not apply to individual studies, they are to be used with caution. In addition, these estimates show no deference to how these units will operate in a particular system or how they will affect the operation of that system and the corresponding system costs, so no conclusions should be drawn in this regard.

Table 2: Summary of Levelized Costs

In-Service Year =2007 (Nominal 2007$)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Conventional Combined Cycle (CC)	500	505.82	102.19	10.22	466.86	94.47	9.45	428.32	86.84	8.68
Conventional CC - Duct Fired	550	512.39	103.52	10.35	472.40	95.59	9.56	432.97	87.78	8.78
Advanced Combined Cycle	800	476.97	96.36	9.64	438.22	88.68	8.87	399.62	81.02	8.10
Conventional Simple Cycle	100	250.43	599.57	59.96	195.59	468.46	46.85	132.84	318.33	31.83
Small Simple Cycle	50	270.36	647.28	64.73	212.08	507.98	50.80	146.70	351.55	35.15
Advanced Simple Cycle	200	295.96	236.12	23.61	253.22	202.10	20.21	201.13	160.60	16.06
Integrated Gasification Combined Cycle (IGCC)	575	566.58	126.51	12.65	476.15	106.32	10.63	361.52	80.72	8.07
Advanced Nuclear	1000	862.70	118.25	11.83	757.78	103.87	10.39	664.78	91.12	9.11
Biomass - AD Dairy	0.25	924.52	143.61	14.36	826.57	128.39	12.84	800.93	109.77	10.98
Biomass - AD Food	2	450.97	70.05	7.00	350.30	54.41	5.44	218.82	33.99	3.40
Biomass Combustion - Fluidized Bed Boiler	25	866.25	118.72	11.87	793.99	108.82	10.88	839.92	115.12	11.51
Biomass Combustion - Stoker Boiler	25	810.99	111.15	11.12	745.45	102.17	10.22	799.74	109.61	10.96
Biomass - IGCC	21.25	849.18	123.66	12.37	768.58	111.92	11.19	744.82	108.46	10.85
Biomass - LFG	2	382.50	56.11	5.61	345.95	50.86	5.09	352.73	52.36	5.24
Biomass - WWTP	0.5	514.65	97.34	9.73	466.63	88.84	8.88	366.54	71.78	7.18
Fuel Cell - Molten Carbonate	2	886.11	114.66	11.47	910.60	117.83	11.78	754.94	97.69	9.77
Fuel Cell - Proton Exchange	0.03	1409.63	182.41	18.24	1281.28	165.80	16.58	1025.67	132.72	13.27
Fuel Cell - Solid Oxide	0.25	955.64	123.66	12.37	868.61	112.40	11.24	695.29	89.97	9.00
Geothermal - Binary	50	477.23	75.85	7.58	396.31	63.53	6.35	394.23	65.55	6.56
Geothermal - Dual Flash	50	453.91	73.66	7.37	379.23	62.07	6.21	384.36	65.26	6.53
Hydro - In Conduit	1	213.72	52.84	5.28	183.96	45.68	4.57	188.71	47.78	4.78
Hydro - Small Scale	10	567.71	138.74	13.87	481.05	118.08	11.81	347.96	87.09	8.71
Ocean Wave (Pilot)	0.75	1239.92	1030.50	103.05	1005.64	837.65	83.76	733.96	617.12	61.71
Solar - Concentrating PV	15	620.48	424.84	42.48	631.79	434.00	43.40	442.11	308.09	30.81
Solar - Parabolic Trough	63.5	497.33	277.30	27.73	504.17	281.37	28.14	355.71	199.31	19.93
Solar - Photovoltaic (Single Axis)	1	1035.07	704.98	70.50	1019.48	695.59	69.56	681.74	468.87	46.89
Solar - Stirling Dish	15	855.55	518.89	51.89	868.93	527.00	52.70	648.77	393.47	39.35
Wind - Class 5	50	245.94	84.24	8.42	196.08	67.16	6.72	179.19	61.38	6.14

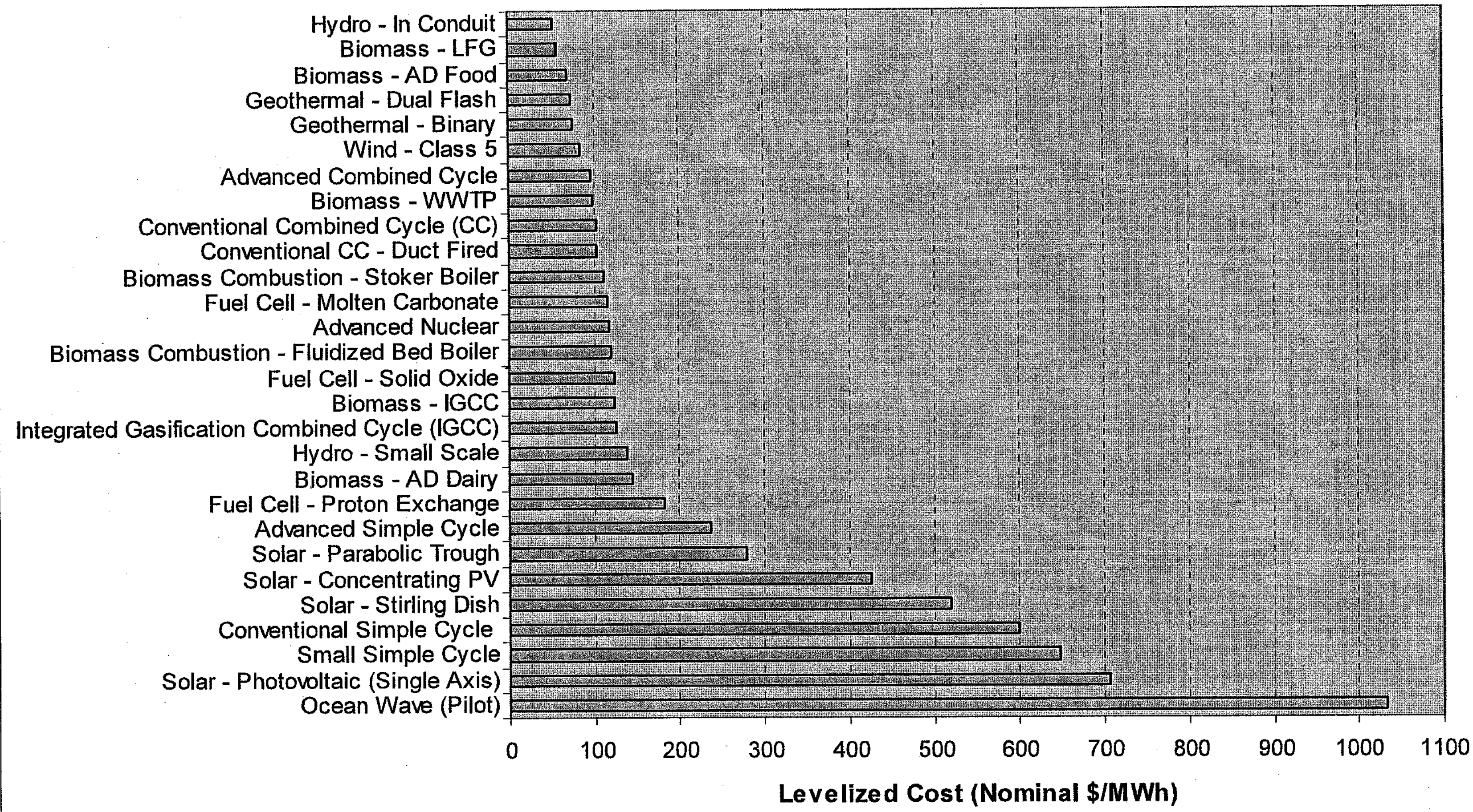
Source: Energy Commission

Figure 2: Summary of Levelized Costs



Source: Energy Commission

Figure 3: Total Levelized Costs – Merchant Plants Only



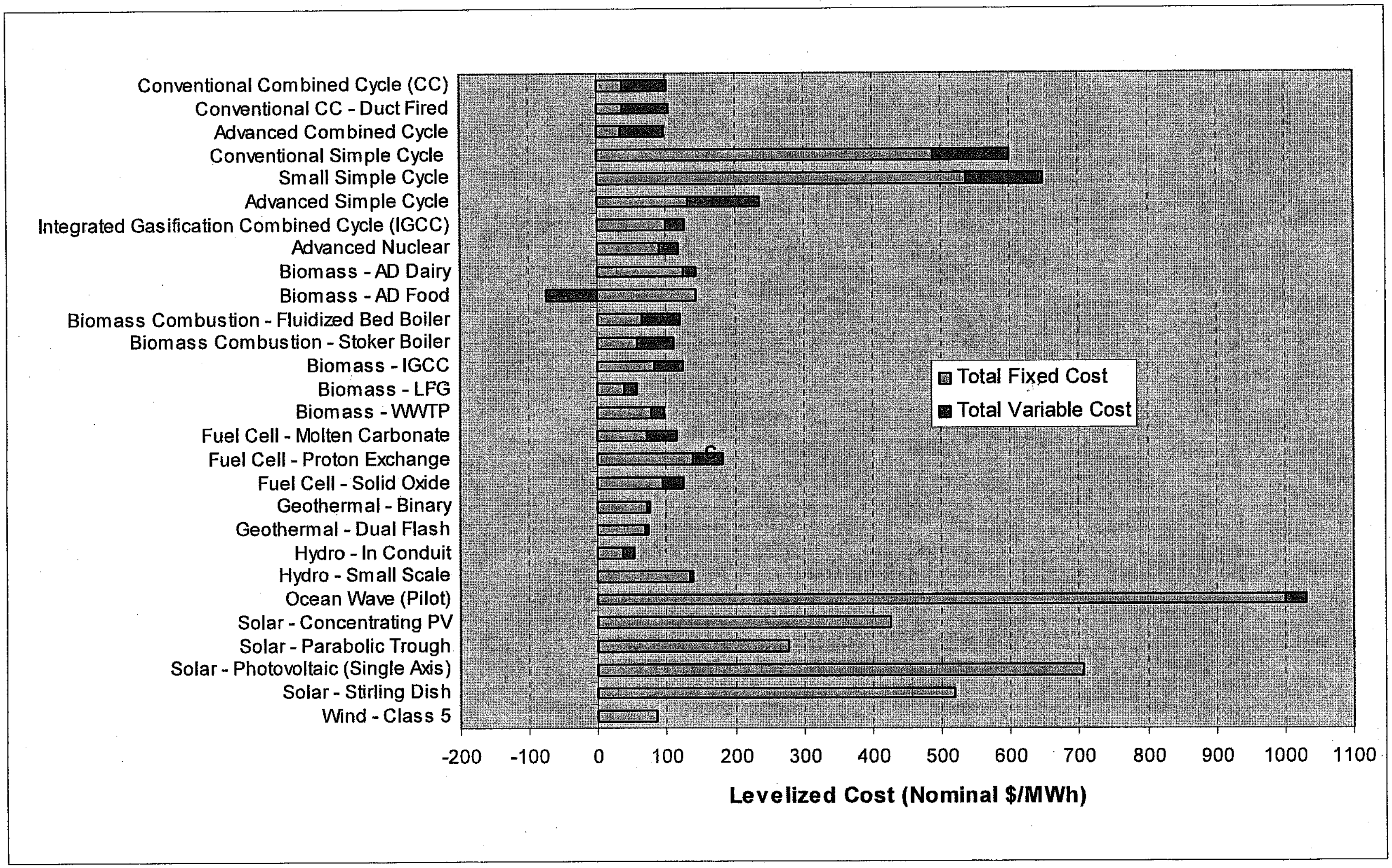
Source: Energy Commission

Table 3: Levelized Cost Components – Merchant Plants

In-Service Year =2007	Size MW	$/MWh (Nominal 2007$) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	Total Fixed Cost	Fuel	Variable O&M	Total Variable Cost	Total Levelized Cost	¢/kWh Total Levelized Cost
Conventional Combined Cycle (CC)	500	23.28	1.48	1.16	2.30	7.85	**36.07**	60.86	5.27	**66.12**	**102.19**	**10.22**
Conventional CC - Duct Fired	550	23.81	1.52	1.19	2.22	8.03	**36.77**	61.64	5.11	**66.75**	**103.52**	**10.35**
Advanced Combined Cycle	800	22.85	1.46	1.14	1.96	7.71	**35.13**	56.68	4.56	**61.24**	**96.36**	**9.64**
Conventional Simple Cycle	100	327.02	20.82	16.31	30.49	94.43	**489.08**	79.66	30.83	**110.49**	**599.57**	**59.96**
Small Simple Cycle	50	347.88	22.15	17.35	48.75	100.20	**536.33**	79.66	31.29	**110.96**	**647.28**	**64.73**
Advanced Simple Cycle	200	89.52	5.70	4.46	6.59	25.88	**132.15**	73.51	30.46	**103.97**	**236.12**	**23.61**
Integrated Gasification Combined Cycle (IGCC)	575	64.47	6.79	4.44	10.58	12.15	**98.44**	24.00	4.06	**28.07**	**126.51**	**12.65**
Advanced Nuclear	1000	56.79	5.14	3.70	24.18	0.64	**90.45**	21.50	6.30	**27.80**	**118.25**	**11.83**
Biomass - AD Dairy	0.25	110.17	7.82	6.33	9.58	-9.05	**124.84**	0.00	18.77	**18.77**	**143.61**	**14.36**
Biomass - AD Food	2	110.21	7.82	6.33	28.74	-9.05	**144.05**	0.00	-74.00	**-74.00**	**70.05**	**7.00**
Biomass Combustion - Fluidized Bed Boiler	25	48.67	4.40	3.17	25.91	-18.44	**63.72**	51.09	3.91	**55.00**	**118.72**	**11.87**
Biomass Combustion - Stoker Boiler	25	44.70	4.04	2.91	23.23	-18.74	**56.15**	51.09	3.91	**55.00**	**111.15**	**11.12**
Biomass - IGCC	21.25	53.27	4.82	3.47	28.48	-7.62	**82.42**	37.32	3.91	**41.23**	**123.66**	**12.37**
Biomass - LFG	2	40.49	2.87	2.33	3.62	-11.70	**37.61**	0.00	18.50	**18.50**	**56.11**	**5.61**
Biomass - WWTP	0.5	63.60	4.51	3.65	4.67	2.41	**78.84**	0.00	18.50	**18.50**	**97.34**	**9.73**
Fuel Cell - Molten Carbonate	2	72.48	5.14	4.16	0.34	-10.63	**71.50**	0.00	43.17	**43.17**	**114.66**	**11.47**
Fuel Cell - Proton Exchange	0.03	116.92	8.30	6.71	2.87	4.44	**139.24**	0.00	43.17	**43.17**	**182.41**	**18.24**
Fuel Cell - Solid Oxide	0.25	79.28	5.63	4.55	1.60	3.01	**94.06**	0.00	29.60	**29.60**	**123.66**	**12.37**
Geothermal - Binary	50	67.75	4.78	3.87	13.73	-19.84	**70.30**	0.00	5.55	**5.55**	**75.85**	**7.58**
Geothermal - Dual Flash	50	64.12	4.53	3.67	16.02	-20.12	**68.21**	0.00	5.45	**5.45**	**73.66**	**7.37**
Hydro - In Conduit	1	43.02	3.97	2.86	0.00	-13.97	**35.88**	0.00	16.96	**16.96**	**52.84**	**5.28**
Hydro - Small Scale	10	113.39	10.47	7.54	4.14	-0.71	**134.83**	0.00	3.91	**3.91**	**138.74**	**13.87**
Ocean Wave (Pilot)	0.75	777.27	54.07	43.81	30.77	93.75	**999.65**	0.00	30.85	**30.85**	**1030.50**	**103.05**
Solar - Concentrating PV	15	414.12	0.00	25.88	39.14	-54.30	**424.84**	0.00	0.00	**0.00**	**424.84**	**42.48**
Solar - Parabolic Trough	63.5	252.23	0.00	16.77	43.65	-35.34	**277.30**	0.00	0.00	**0.00**	**277.30**	**27.73**
Solar - Photovoltaic (Single Axis)	1	726.35	0.00	47.29	21.31	-89.97	**704.98**	0.00	0.00	**0.00**	**704.98**	**70.50**
Solar - Stirling Dish	15	422.09	0.00	28.06	128.97	-60.23	**518.89**	0.00	0.00	**0.00**	**518.89**	**51.89**
Wind - Class 5	50	75.51	6.83	4.92	13.40	-16.41	**84.24**	0.00	0.00	**0.00**	**84.24**	**8.42**

Source: Energy Commission

Figure 4: Fixed and Variable Costs – Merchant Plants



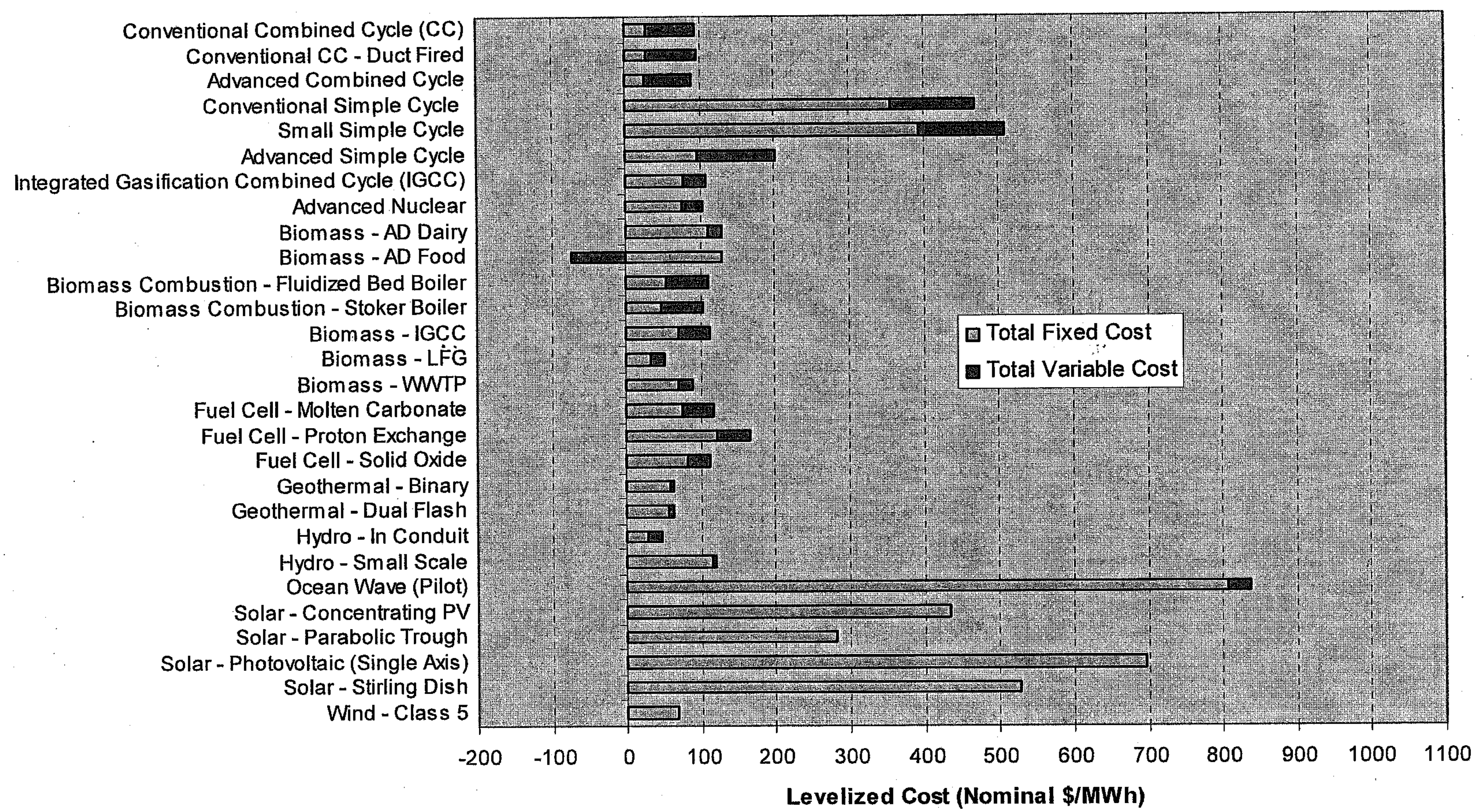
Source: Energy Commission

Table 4: Levelized Cost Components – IOU Plants

		$/MWh (Nominal 2007$)										¢/kWh
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	**Total Levelized Cost**	**Total Levelized Cost**
Conventional Combined Cycle (CC)	500	18.23	1.18	0.66	2.35	4.03	**26.46**	62.63	5.38	**68.02**	**94.47**	**9.45**
Conventional CC - Duct Fired	550	18.65	1.21	0.68	2.27	4.13	**26.93**	63.44	5.23	**68.66**	**95.59**	**9.56**
Advanced Combined Cycle	800	17.90	1.16	0.65	2.01	3.97	**25.68**	58.33	4.66	**62.99**	**88.68**	**8.87**
Conventional Simple Cycle	100	254.22	16.45	9.23	31.13	44.08	**355.10**	81.89	31.47	**113.36**	**468.46**	**46.85**
Small Simple Cycle	50	270.43	17.50	9.82	49.77	46.62	**394.14**	81.89	31.95	**113.84**	**507.98**	**50.80**
Advanced Simple Cycle	200	69.59	4.50	2.53	6.72	12.10	**95.44**	75.56	31.10	**106.66**	**202.10**	**20.21**
Integrated Gasification Combined Cycle (IGCC)	575	52.71	4.59	2.58	10.77	6.94	**77.59**	24.59	4.14	**28.72**	**106.32**	**10.63**
Advanced Nuclear	1000	47.31	3.69	2.07	24.46	-2.12	**75.41**	22.08	6.37	**28.46**	**103.87**	**10.39**
Biomass - AD Dairy	0.25	97.97	6.30	3.54	9.63	-7.93	**109.52**	0.00	18.88	**18.88**	**128.39**	**12.84**
Biomass - AD Food	2	98.01	6.30	3.54	28.90	-7.93	**128.83**	0.00	-74.42	**-74.42**	**54.41**	**5.44**
Biomass Combustion - Fluidized Bed Boiler	25	41.42	3.23	1.81	26.21	-19.46	**53.22**	51.65	3.96	**55.60**	**108.82**	**10.88**
Biomass Combustion - Stoker Boiler	25	38.03	2.97	1.67	23.50	-19.60	**46.56**	51.65	3.96	**55.60**	**102.17**	**10.22**
Biomass - IGCC	21.25	45.15	3.52	1.98	28.81	-9.23	**70.23**	37.73	3.96	**41.68**	**111.92**	**11.19**
Biomass - LFG	2	36.08	2.32	1.30	3.65	-11.09	**32.26**	0.00	18.61	**18.61**	**50.86**	**5.09**
Biomass - WWTP	0.5	56.89	3.66	2.05	4.72	2.91	**70.24**	0.00	18.61	**18.61**	**88.84**	**8.88**
Fuel Cell - Molten Carbonate	2	64.34	4.14	2.32	0.34	3.29	**74.42**	0.00	43.41	**43.41**	**117.83**	**11.78**
Fuel Cell - Proton Exchange	0.03	103.77	6.68	3.75	2.89	5.30	**122.39**	0.00	43.41	**43.41**	**165.80**	**16.58**
Fuel Cell - Solid Oxide	0.25	70.36	4.53	2.54	1.61	3.59	**82.63**	0.00	29.77	**29.77**	**112.40**	**11.24**
Geothermal - Binary	50	59.41	3.84	2.16	13.92	-21.39	**57.95**	0.00	5.58	**5.58**	**63.53**	**6.35**
Geothermal - Dual Flash	50	56.22	3.64	2.04	16.25	-21.56	**56.59**	0.00	5.48	**5.48**	**62.07**	**6.21**
Hydro - In Conduit	1	37.30	2.92	1.64	0.00	-13.33	**28.53**	0.00	17.15	**17.15**	**45.68**	**4.57**
Hydro - Small Scale	10	98.31	7.70	4.32	4.21	-0.43	**114.12**	0.00	3.96	**3.96**	**118.08**	**11.81**
Ocean Wave (Pilot)	0.75	672.25	43.49	24.41	31.01	35.47	**806.62**	0.00	31.02	**31.02**	**837.65**	**83.76**
Solar - Concentrating PV	15	362.76	0.00	14.65	39.63	16.96	**434.00**	0.00	0.00	**0.00**	**434.00**	**43.40**
Solar - Parabolic Trough	63.5	217.94	0.00	9.58	44.18	9.66	**281.37**	0.00	0.00	**0.00**	**281.37**	**28.14**
Solar - Photovoltaic (Single Axis)	1	619.97	0.00	27.16	21.60	26.87	**695.59**	0.00	0.00	**0.00**	**695.59**	**69.56**
Solar - Stirling Dish	15	364.38	0.00	16.02	130.44	16.16	**527.00**	0.00	0.00	**0.00**	**527.00**	**52.70**
Wind - Class 5	50	64.25	5.01	2.81	13.55	-18.47	**67.16**	0.00	0.00	**0.00**	**67.16**	**6.72**

Source: Energy Commission

Figure 5: Fixed and Variable Costs – IOUs



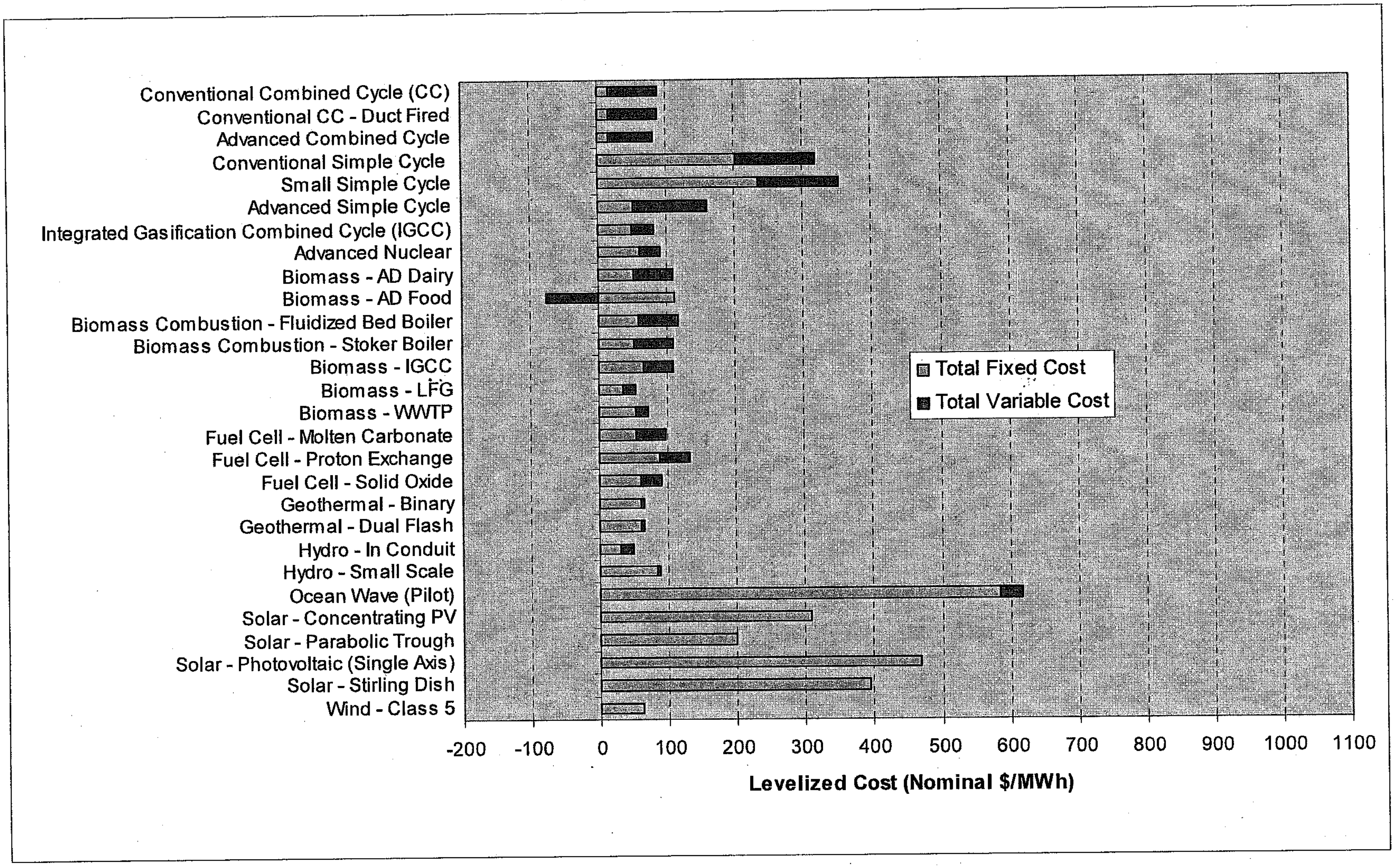
Source: Energy Commission

Table 5: Levelized Costs – Publicly Owned Plants

		$/MWh (Nominal 2007$)										¢/kWh
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**	Fuel	Variable O&M	**Total Variable Cost**	**Total Levelized Cost**	**Total Levelized Cost**
Conventional Combined Cycle (CC)	500	11.98	1.00	1.11	2.41	0.00	**16.50**	64.82	5.52	**70.34**	**86.84**	**8.68**
Conventional CC - Duct Fired	550	12.27	1.03	1.14	2.33	0.00	**16.77**	65.65	5.36	**71.01**	**87.78**	**8.78**
Advanced Combined Cycle	800	11.74	0.98	1.09	2.06	0.00	**15.88**	60.36	4.78	**65.14**	**81.02**	**8.10**
Conventional Simple Cycle	100	144.11	12.08	13.39	31.88	0.00	**201.47**	84.62	32.23	**116.86**	**318.33**	**31.83**
Small Simple Cycle	50	155.71	13.05	14.47	50.97	0.00	**234.20**	84.62	32.72	**117.34**	**351.55**	**35.15**
Advanced Simple Cycle	200	37.21	3.12	3.46	6.89	0.00	**50.67**	78.09	31.85	**109.93**	**160.60**	**16.06**
Integrated Gasification Combined Cycle (IGCC)	575	28.96	3.77	4.36	11.71	0.00	**48.80**	27.42	4.50	**31.92**	**80.72**	**8.07**
Advanced Nuclear	1000	27.62	3.04	3.46	25.73	0.00	**59.84**	24.58	6.70	**31.28**	**91.12**	**9.11**
Biomass - AD Dairy	0.25	24.21	2.66	3.04	24.82	-3.32	**51.41**	54.19	4.18	**58.36**	**109.77**	**10.98**
Biomass - AD Food	2	69.01	5.79	6.41	29.59	-0.60	**110.20**	0.00	-76.21	**-76.21**	**33.99**	**3.40**
Biomass Combustion - Fluidized Bed Boiler	25	26.32	2.89	3.29	27.57	-3.31	**56.77**	54.19	4.16	**58.35**	**115.12**	**11.51**
Biomass Combustion - Stoker Boiler	25	24.17	2.66	3.02	24.72	-3.31	**51.26**	54.19	4.16	**58.35**	**109.61**	**10.96**
Biomass - IGCC	21.25	28.25	3.11	3.53	30.30	-0.47	**64.72**	39.58	4.16	**43.74**	**108.46**	**10.85**
Biomass - LFG	2	25.61	2.15	2.38	3.77	-0.60	**33.31**	0.00	19.05	**19.05**	**52.36**	**5.24**
Biomass - WWTP	0.5	41.09	3.44	3.82	4.98	-0.60	**52.73**	0.00	19.05	**19.05**	**71.78**	**7.18**
Fuel Cell - Molten Carbonate	2	44.94	3.77	4.18	0.35	0.00	**53.23**	0.00	44.46	**44.46**	**97.69**	**9.77**
Fuel Cell - Proton Exchange	0.03	72.49	6.08	6.74	2.96	0.00	**88.26**	0.00	44.46	**44.46**	**132.72**	**13.27**
Fuel Cell - Solid Oxide	0.25	49.15	4.12	4.57	1.64	0.00	**59.48**	0.00	30.49	**30.49**	**89.97**	**9.00**
Geothermal - Binary	50	41.83	3.51	3.89	14.78	-4.17	**59.84**	0.00	5.72	**5.72**	**65.55**	**6.56**
Geothermal - Dual Flash	50	39.56	3.32	3.68	17.25	-4.17	**59.64**	0.00	5.61	**5.61**	**65.26**	**6.53**
Hydro - In Conduit	1	24.09	2.65	3.01	0.00	0.00	**29.75**	0.00	18.03	**18.03**	**47.78**	**4.78**
Hydro - Small Scale	10	63.49	6.98	7.94	4.51	0.00	**82.93**	0.00	4.16	**4.16**	**87.09**	**8.71**
Ocean Wave (Pilot)	0.75	473.75	39.72	44.02	32.04	-4.17	**585.37**	0.00	31.76	**31.76**	**617.12**	**61.71**
Solar - Concentrating PV	15	243.29	0.00	26.76	41.69	-3.65	**308.09**	0.00	0.00	**0.00**	**308.09**	**30.81**
Solar - Parabolic Trough	63.5	138.58	0.00	17.35	46.68	-3.31	**199.31**	0.00	0.00	**0.00**	**199.31**	**19.93**
Solar - Photovoltaic (Single Axis)	1	399.33	0.00	49.96	22.90	-3.31	**468.87**	0.00	0.00	**0.00**	**468.87**	**46.89**
Solar - Stirling Dish	15	230.77	0.00	28.87	137.14	-3.31	**393.47**	0.00	0.00	**0.00**	**393.47**	**39.35**
Wind - Class 5	50	40.84	4.49	5.11	14.26	-3.31	**61.38**	0.00	0.00	**0.00**	**61.38**	**6.14**

Source: Energy Commission

Figure 6: Fixed and Variable Costs – Publicly Owned Plants



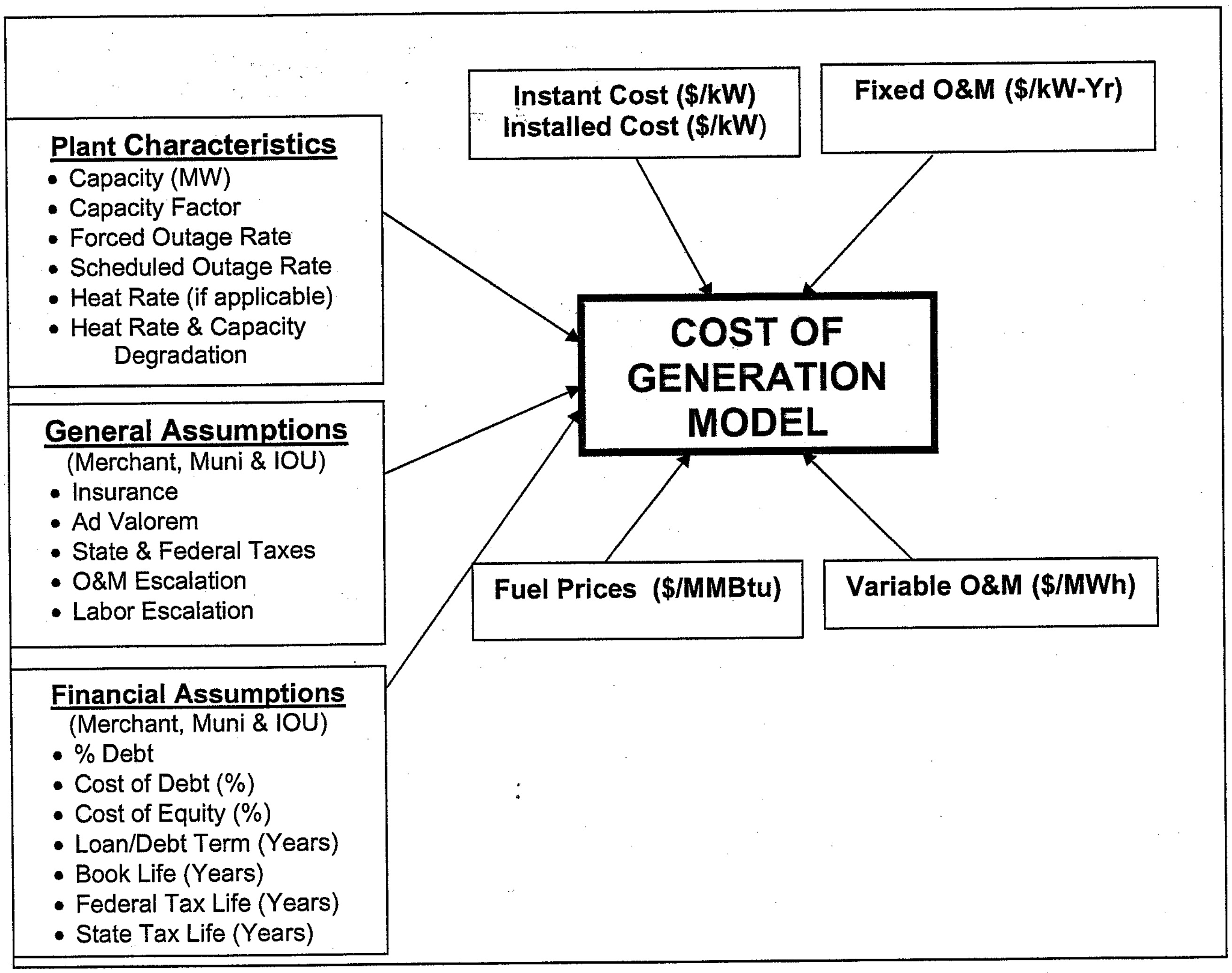
Source: Energy Commission

CHAPTER 2: Assumptions

This chapter summarizes the assumptions, the data collection and interpretation process, and a comparison to *2003 IEPR* assumptions.

Figure 7 shows a simplified block diagram of the Model's input assumptions.

Figure 7: Flow Chart of Cost of Generation Model Inputs



Source: Energy Commission

Summary of Assumptions

Tables 6 and **7** summarize the most common input assumptions. All costs are for 2007 and are in nominal dollars.

Table 6: Common Assumptions

Technology (All costs in Nominal 2007$)	Gross Capacity (MW)	Capacity Factor (%)	HHV Heat Rate (Btu/kWh)	Instant Cost ($/kW)	Installed Cost ($/kW)			Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
					Merchant	IOU	Muni		
Conventional Combined Cycle (CC)	500	60.00%	6,990	781	844	849	779	9.86	4.42
Conventional CC - Duct Fired	550	60.00%	7,080	798	863	868	798	9.53	4.28
Advanced Combined Cycle	800	60.00%	6,510	766	828	834	763	8.42	3.83
Conventional Simple Cycle	100	5.00%	9,266	925	1000	1000	793	11.00	25.72
Small Simple Cycle	50	5.00%	9,266	974	1053	1053	846	17.65	26.10
Advanced Simple Cycle	200	5.00%	8,550	756	817	817	610	7.13	25.57
Integrated Gasification Combined Cycle (IGCC)	575	60.00%	8,979	2,198	3,007	2,941	2,569	36.27	3.11
Advanced Nuclear	1000	85.00%	10,400	2,950	3,754	3,662	3,177	140.00	5.00
Biomass - AD Dairy	0.25	75.00%	12,407	5,800	5,923	5,911	5,837	51.81	15.77
Biomass - AD Food	2	75.00%	17,060	5,803	5,925	5,913	5,840	155.44	-62.18
Biomass Combustion - Fluidized Bed Boiler	25	85.00%	15,509	3,156	3,223	3,217	3,177	150.26	3.11
Biomass Combustion - Stoker Boiler	25	85.00%	15,509	2,899	2,960	2,954	2,917	134.72	3.11
Biomass - IGCC	21.25	85.00%	10,663	3,121	3,320	3,301	3,181	155.44	3.11
Biomass - LFG	2	85.00%	11,566	2,254	2,302	2,296	2,263	20.73	15.54
Biomass - WWTP	0.5	75.00%	12,407	2,743	2,801	2,794	2,748	20.73	15.54
Fuel Cell - Molten Carbonate	2	90.00%	8,322	4,488	4,678	4,659	4,546	2.18	36.27
Fuel Cell - Proton Exchange	0.03	90.00%	13,127	7,239	7,545	7,515	7,332	18.65	36.27
Fuel Cell - Solid Oxide	0.25	90.00%	8,530	4,908	5,116	5,096	4,972	10.36	24.87
Geothermal - Binary	50	95.00%	N/A	3,093	3,548	3,501	3,227	72.54	4.66
Geothermal - Dual Flash	50	93.00%	N/A	2,866	3,287	3,244	2,988	82.90	4.58
Hydro - In Conduit	1	51.40%	N/A	1,547	1,612	1,606	1,567	0.00	13.47
Hydro - Small Scale	10	52.00%	N/A	4,125	4,299	4,282	4,178	13.47	3.11
Ocean Wave (Pilot)	0.75	15.00%	N/A	7,203	7,662	7,617	7,342	31.09	25.91
Solar - Concentrating PV	15	23.00%	N/A	5,156	5,372	5,352	5,222	46.63	0.00
Solar - Parabolic Trough	63.5	27.00%	N/A	4,021	4,190	4,175	4,073	62.18	0.00
Solar - Photovoltaic (Single Axis)	1	22.14%	N/A	9,611	9,678	9,672	9,632	24.87	0.00
Solar - Stirling Dish	15	24.00%	N/A	6,187	6,446	6,423	6,266	168.92	0.00
Wind - Class 5	50	34.00%	N/A	1,959	2,000	1,997	1,972	31.09	0.00

Source: Energy Commission

Table 7: Emission Factors

Technology	Emission Factors (Lbs/MWh)					
	NOx	VOC	CO	CO2	SOx	PM10
Conventional Combined Cycle (CC)	0.056	0.017	0.049	817.62	0.007	0.035
Conventional CC - Duct Fired	0.064	0.018	0.050	828.14	0.007	0.028
Advanced Combined Cycle	0.046	0.016	0.046	761.47	0.007	0.026
Conventional Simple Cycle	0.093	0.023	0.093	1083.84	0.009	0.065
Small Simple Cycle	0.093	0.023	0.093	1083.84	0.009	0.065
Advanced Simple Cycle	0.076	0.019	0.053	886.63	0.008	0.053
Integrated Gasification Combined Cycle (IGCC)	0.530	0.000	0.000	1928.00	0.300	0.000
Advanced Nuclear	0.000	0.000	0.000	0.000	0.000	0.000
Biomass - AD Dairy	1.700	0.000	0.000	0.000	0.390	0.000
Biomass - AD Food	1.700	0.000	0.000	0.000	0.420	0.000
Biomass Combustion - Fluidized Bed Boiler	1.240	0.000	0.000	0.000	0.700	0.000
Biomass Combustion - Stoker Boiler	1.240	0.000	0.000	0.000	0.700	0.000
Biomass - IGCC	0.850	0.000	0.000	0.000	0.700	0.000
Biomass - LFG	1.700	0.000	0.000	0.000	0.340	0.000
Biomass - WWTP	1.700	0.000	0.000	0.000	0.390	0.000
Fuel Cell - Molten Carbonate	0.010	0.000	0.000	0.000	0.003	0.000
Fuel Cell - Proton Exchange	0.100	0.000	0.000	0.000	0.000	0.000
Fuel Cell - Solid Oxide	0.050	0.000	0.000	0.000	0.000	0.000
Geothermal - Binary	0.000	0.000	0.000	0.000	0.000	0.000
Geothermal - Dual Flash	0.000	0.000	0.000	60.000	0.350	0.000
Hydro - In Conduit	0.000	0.000	0.000	0.000	0.000	0.000
Hydro - Small Scale	0.000	0.000	0.000	0.000	0.000	0.000
Ocean Wave (Pilot)	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Concentrating PV	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Parabolic Trough	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Photovoltaic (Single Axis)	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Stirling Dish	0.000	0.000	0.000	0.000	0.000	0.000
Wind - Class 5	0.000	0.000	0.000	0.000	0.000	0.000

Source: Energy Commission

Capacity Factor

The capacity factor (CF) is a measure of how much the power plant operates. More precisely, it is equal to the energy generated by the power plant during the year divided by the energy it could have generated if it had run at its dependable capacity throughout the entire year (8,760 hours).

Instant Cost

Instant cost, sometimes referred to as overnight cost, is the initial expenditure, which does not include the costs incurred during construction (see installed cost) – that is, it assumes that the plant could have been constructed in an instant requiring no construction loan or associated expenses. Instant costs include the component cost, land cost, development cost, permitting cost, linears, and environmental control costs.

Installed Cost

Installed cost is the total cost of building a power plant. It includes not only the instant costs, but also the costs associated with the fact that it takes time to build a power plant. Thus, it includes a building loan, sales taxes, and the costs associated with escalation of costs during construction.

Fixed Operations and Maintenance

Conceptually, fixed O&M comprises those costs that occur regardless of how much the plant operates. What is included in this category is not always consistent from one assessment to the other but always includes labor costs and the associated overhead. Other costs that are not consistently included are equipment (and leasing of equipment), regulatory filings, and miscellaneous direct costs. The Energy Commission staff recently changed to a convention that includes all of these components in the fixed O&M costs.

Variable Operations and Maintenance

Operations and maintenance are a function of the operation of the power plant and includes:

- Scheduled outage maintenance – annual maintenance and overhauls
- Forced outage maintenance
- Water supply costs
- Environmental costs

Scheduled outage maintenance, which includes annual maintenance and overhaul costs, is by far the largest expenditure.

Capital and Financing Assumptions

Capital and financing assumptions cover the entire cost of building and financing the construction of the power plant. These costs include the amortization of the loan, both principal and interest. These costs vary depending upon the developer because of the different interest rates available for IOUs, POUs, and merchants. Capital costs are described later in the report. **Table 8** summarizes the financial assumptions being used in the Model. Note that the debt to equity split is different for merchant gas-fired plants than non gas-fired plants (clean coal, advanced nuclear, and alterative technologies). The financial assumptions for gas-fired plants are available from the BOE and are known with a high degree of certainty. The corresponding assumption for the other plants is based on Navigant Consulting Inc. (Navigant) estimates.

Table 8: Financial Assumptions

	Merchant Gas-Fired	Merchant Non Gas-Fired	IOU	POU
% Debt	40.0%	60.0%	50.0%	100.0%
% Equity	60.0%	40.0%	50.0%	0.0%
Cost of Debt (%)	6.5%	6.5%	5.73%	4.35%
Cost of Equity (%)	15.19%	15.19%	11.74%	0.0%

Source: Energy Commission

Insurance

Insurance is calculated differently depending on the type of developer. For an IOU, the cost is based on the book value. For a merchant facility or publicly owned plant, the cost is calculated as a fraction of the installed cost. The fraction used in the Model is 0.6 percent, and the annual cost then escalates with nominal inflation.

Ad Valorem

In California, ad valorem (property tax) is different depending on the developer. The merchant-owned facility tax is based on the market value assessed by the BOE. The value reflects the market value of the asset but may not increase in value at a rate faster than 2 percent per annum per Proposition 13. The Model assumes an initial rate of 1.07 multiplied by the installed cost of the power plant and a property tax depreciation factor. The utility-owned plant tax is based on the value assessed by the BOE and is set to the net depreciated book value. The Model assumes an initial cost of $1.07 multiplied by the book value. Counties are allocated property tax revenues based on the share of rate base within each county. Publicly owned plants are exempt from paying property taxes but may pay a negotiated in-lieu fee.

Corporate Taxes

Corporate taxes are state and federal taxes. Again, these taxes depend on the developer type. A POU is exempt from state and federal taxes. The calculation of taxes for a merchant facility or IOU power plant is based on the taxable income. The rates are shown in **Table 9**.

Table 9: Tax Rates

Tax	Rate
Federal Tax	35.0%
CA State Tax	8.84%
Total Tax Rate	40.7%

Source: Energy Commission

Fuel Prices

The fuel prices used in this report are summarized in **Table 10**. The natural gas prices are a preliminary estimate developed from the *2005 IEPR* gas prices by modifying the first two years using forward gas prices. As of this time, there is no official *2007 IEPR* gas price series. The nuclear and coal fuel prices were developed from *2007 IEPR* data, and biomass fuel prices were developed by Navigant.

Description of Data Gathering and Analysis

Staff conducted two separate data gatherings: one for the combined cycle and simple cycle (combustion turbines) and one for the alternative technologies, clean coal, and nuclear.

Combined and Simple Cycle Data Collection

Initially, staff attempted to gather the modeling input information using the Energy Commission's Application for Certification (AFC) filings but discovered that the available capital cost data from AFC filings were inadequate. Cost estimates appeared to be inconsistent with one another and unrealistically low. Based on a preliminary assessment, the actual capital costs for building new combined cycle power plants over the last five years were approximately 25 percent higher than the estimated capital costs in recent AFC filings. Simple cycle estimates appeared to be even more inadequate. Additionally, the AFC filings did not contain useful operating cost data.

Table 10: Fuel Prices

Deflator Series 2007=1	Year	PG&E	SCE	SDG&E	SMUD	LADWP	IID	CA - Avg.	Uranium	Coal	Biomass
1.00	2007	8.30	8.23	8.74	8.50	8.50	8.50	8.34	0.63	1.47	2.57
1.02	2008	6.72	6.76	7.32	6.81	7.07	7.07	6.82	0.75	1.68	2.63
1.04	2009	6.80	6.80	7.11	6.92	7.06	7.06	6.87	0.89	1.70	2.69
1.07	2010	5.46	5.71	6.20	5.42	6.09	6.09	5.69	1.05	1.72	2.74
1.09	2011	7.04	7.25	7.74	7.05	7.66	7.66	7.26	1.26	1.71	2.80
1.11	2012	6.69	6.84	7.25	6.72	7.22	7.22	6.87	1.50	1.83	2.85
1.13	2013	8.08	8.28	8.59	8.04	8.57	8.57	8.26	1.77	1.90	2.91
1.15	2014	7.39	7.57	7.88	7.36	7.86	7.86	7.56	2.11	1.97	2.97
1.17	2015	8.52	8.61	8.65	8.57	8.90	8.90	8.63	2.58	2.04	3.02
1.20	2016	8.58	8.72	8.82	8.59	9.01	9.01	8.72	2.63	2.12	3.08
1.22	2017	8.63	8.82	8.99	8.60	9.12	9.12	8.80	2.68	2.19	3.14
1.24	2018	9.16	9.42	9.62	9.12	9.77	9.77	9.38	2.73	2.27	3.20
1.26	2019	9.71	10.04	10.28	9.65	10.45	10.45	9.98	2.78	2.35	3.25
1.29	2020	9.91	10.21	10.41	9.87	10.60	10.60	10.16	2.83	2.43	3.32
1.31	2021	10.12	10.38	10.54	10.09	10.75	10.75	10.34	2.89	2.52	3.38
1.34	2022	10.58	10.91	11.10	10.54	11.33	11.33	10.86	2.94	2.59	3.44
1.36	2023	11.06	11.47	11.69	11.00	11.94	11.94	11.39	3.00	2.70	3.51
1.39	2024	11.53	11.87	12.01	11.47	12.28	12.28	11.81	3.05	2.73	3.57
1.41	2025	12.01	12.28	12.35	11.95	12.63	12.63	12.23	3.11	2.83	3.64
1.44	2026	12.44	12.72	12.80	12.37	13.09	13.09	12.67	3.17	2.94	3.71
1.47	2027	12.91	13.21	13.28	12.83	13.58	13.58	13.15	3.23	3.02	3.78
1.49	2028	13.44	13.75	13.79	13.35	14.12	14.12	13.68	3.29	3.12	3.85
1.52	2029	13.96	14.28	14.30	13.87	14.65	14.65	14.21	3.35	3.23	3.92
1.55	2030	14.48	14.80	14.78	14.38	15.16	15.16	14.73	3.41	3.33	3.99
1.58	2031	15.05	15.36	15.31	14.94	15.71	15.71	15.28	3.48	3.44	4.07
1.61	2032	15.65	15.97	15.89	15.53	16.31	16.31	15.89	3.54	3.56	4.14
1.64	2033	16.27	16.59	16.47	16.15	16.92	16.92	16.50	3.61	3.67	4.22
1.67	2034	16.91	17.21	17.05	16.78	17.52	17.52	17.13	3.67	3.77	4.30
1.70	2035	17.57	17.87	17.66	17.43	18.16	18.16	17.78	3.74	3.90	4.38
1.73	2036	18.26	18.55	18.30	18.10	18.83	18.83	18.46	3.81	3.97	4.46
1.77	2037	18.97	19.26	18.96	18.80	19.52	19.52	19.16	3.88	4.04	4.54
1.80	2038	19.72	20.00	19.65	19.53	20.25	20.25	19.90	3.96	4.12	4.63
1.83	2039	20.49	20.77	20.36	20.29	20.99	20.99	20.66	4.03	4.20	4.72
1.87	2040	21.29	21.56	21.09	21.08	21.76	21.76	21.44	4.11	4.27	4.80
1.90	2041	22.12	22.38	21.86	21.90	22.56	22.56	22.26	4.18	4.35	4.89
1.94	2042	22.99	23.24	22.65	22.75	23.39	23.39	23.12	4.26	4.44	4.99
1.97	2043	23.90	24.13	23.47	23.64	24.25	24.25	24.00	4.34	4.52	5.08
2.01	2044	24.83	25.05	24.31	24.56	25.13	25.13	24.92	4.42	4.60	5.17
2.05	2045	25.80	26.01	25.19	25.51	26.06	26.06	25.87	4.51	4.69	5.27

Source: Energy Commission

Staff then decided to request this information directly from the power plant developers. All the combined cycle (but not cogeneration) and simple cycle power plants that were certified by the Energy Commission starting in 1999 and on-line since 2001 through the first quarter of 2006 received a data request. These plants are summarized in **Table 11**, together with the in-service year and county location.

Table 11: Surveyed Power Plants

Combined Cycle Plants (19)			Simple Cycle Plants (15)		
Plant Name	**County**	**Operating**	**Plant Name**	**County**	**Operating**
Los Medanos	Contra Costa	2001	Wildflower Larkspur [2]	San Diego	2001
Sutter	Sutter	2001	Wildflower Indigo [2]	Riverside	2001
Delta	Contra Costa	2002	Drews Alliance [2]	San Bernardino	2001
Moss Landing	Monterey	2002	Century Alliance [2]	San Bernardino	2001
La Paloma	Kern	2003	Hanford [2]	Kings	2001
High Desert	San Bernardino	2003	Calpeak Escondido [2]	San Diego	2001
MID Woodland [1,2]	Stanislaus	2003	Calpeak Border [2]	San Diego	2001
Sunrise	Kern	2003	Gilroy [2]	Santa Clara	2002
Blythe I	Riverside	2003	King City [2]	Monterey	2002
Elk Hills	Kern	2003	Henrietta	Kings	2002
Von Raesfeld [1]	Santa Clara	2005	Los Esteros	Santa Clara	2003
Metcalf	Santa Clara	2005	Tracy Peaker	San Joaquin	2003
Magnolia [1]	Los Angeles	2005	Kings River Peaker [1,2]	Fresno	2005
Malburg [1]	Los Angeles	2005	Ripon	San Joaquin	2006
Pastoria	Kern	2005	Riverside	Riverside	2006
Mountainview [3]	San Bernardino	2006			
Palomar	San Diego	2006			
Cosumnes	Sacramento	2006			
Walnut	Stanislaus	2006			

Notes:
1 – Muni-owned facility
2 – Emergency Siting or SPPE Cases
3 – IOU-owned facility

Source: Energy Commission

Capital cost information was requested from all 34 plants, while operating costs were requested from plants that began regular operations in 2005 or earlier. The data requests for the combined cycle and simple cycle units were divided into capital costs and operating and maintenance costs, as summarized in **Table 12.**

Table 12: Summary of Requested Data

Capital Cost Parameters	Operating & Maintenance Cost Parameters
Gas Turbine and Combustor Make/Models	Total Annual Operating Costs
Steam Turbine Make/Model	Operating Hours
Total Capital Cost of Facility	Startup/Shutdown Hours
Gas Turbine Cost	Natural Gas Sources
Steam Turbine Cost	Duct Burner Natural Gas Use
Air Inlet Treatment Cost	Water Supply Source/Cost/Consumption
Cooling Tower/Air Cooled Condenser Cost	Labor (Staffing and Cost)
Water Treatment Facilities	Non-Fuel Annual Operating Costs (Consumables, etc.)
Site Footprint and Land Cost	Annual Regulatory Costs (Filings, Consumables, etc.)
Total Construction Costs (Labor/Equipment/etc.)	Major Scheduled Overhaul Frequency/Cost
Cost of Site Grading	Normal Annual Maintenance Costs
Cost of Pipeline Linear Construction	Reconciliation of QFER data (MW generation and total fuel use)
Cost of Transmission Linear Construction	
Cost of Licensing/Permitting Project	
Air Pollution Control Costs	
Cost of Air Quality Offsets	

Source: Energy Commission

Each power plant received an information request tailored according to the design of that plant. For example, simple cycle facilities did not receive questions about steam turbines and duct burners.

The responses were reviewed, and additional data or clarification of data was requested, as appropriate for each power plant, to complete and validate the information to the extent possible. As much of this data was gathered under confidentiality agreements, the details can be presented and discussed only in general, collective terms.

Spreadsheet analysis and comparison of relative costs as a function of various variables enabled determination of a suitable base cost plus adders to atypical configurations for the following four categories.

Combined Cycle Capital Costs

By making cost adjustments to each of the combined cycle cost components, all the units could be reduced to a common base case configuration, which is shown in **Table 13.**

Table 13: Base Case Configuration - Combined Cycle

Combined Cycle Base Configuration
1) 500 MW Plant W/O Duct Firing
2) 2 Turbines W/ 1 Steam Generator
3) GE 7F Gas Turbines
4) Wet Cooling
5) Greenfield Site
6) Non-Urban Land Cost
7) Reclaimed Water Source
8) Evaporative Coolers/Foggers
9) Selective Catalytic Reduction (SCR) & Oxidation Catalyst
10) Zero Liquid Discharge (ZLD)
11) Not Co-Located W/ Other Power Facilities
12) 12-Month Licensing Process

Source: Energy Commission

These base case costs were then averaged to develop the base installed costs shown in **Table 14**. These costs include equipment, land, development, air emission control equipment, water treatment, and water cooling costs. The total installed costs are then calculated by estimating the linears (transmission, gas supply, water, and sewer), permits (building and environmental) and emission reduction credits (ERCs). The linear and the permit costs are estimated from the survey data. The ERC costs are based on emission factors developed by Energy Commission staff and are calculated by the Model for each of the California air districts. The value shown here is an average California value, calculated by the Model.

Table 14: Base Case Installed Costs for Combined Cycles

500 MW Combined Cycle Unit (Nominal 2007$)	Merchant ($/kW)	IOU ($/kW)	Muni ($/kW)
Base Installed Cost	747	753	716
Linears	66	66	33
Permits	11	11	11
ERCs (California Average)	20	20	20
Total Installed Cost	844	849	779

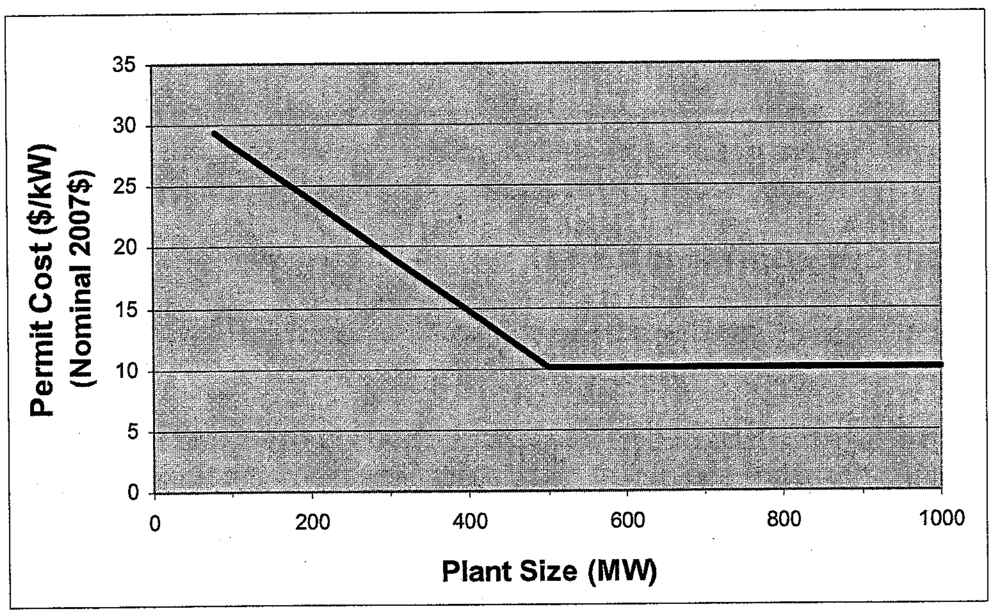
Source: Energy Commission

The above adders are shown as single values, however, permit and ERC costs are variable. Permits were found to be a function of plant size ($Size_{MW}$) and are entered in the Model accordingly:

- 500 MW and above: ***10.2***
- Below 500 MW: ***(33 – 0.0456*$Size_{MW}$)***

Figure 8 shows this graphically.

Figure 8: Combined Cycle Permit Costs



Source: Energy Commission

The ERCs in the table above are a single average California value but are a function of the location of the power plant. The cost of ERCs is constantly changing for all areas in California, but ERCs are clearly more costly in some areas than others. The staff anticipates that these costs will increase disproportionately over time and need to be critically evaluated regularly. One particular issue is the impact of the priority reserve credit costs for the South Coast Air Basin when the South Coast Air Quality Management District finalizes the priority reserve Rule 1309.1.

Table 15 shows the total installed costs for the standard combined cycle configurations available in the Model, including the above 500 MW unit. As before, it assumes permit costs and California average ERCs.

Table 15: Total Installed Costs for All Combined Cycle Units

Various Combined Cycle Units (Nominal 2007$)	**Merchant ($/kW)**	**IOU ($/kW)**	**Muni ($/kW)**
Conventional 500 MW CC without Duct Firing	844	849	779
Conventional 550 MW CC with Duct Firing	863	868	798
Advanced 800 MW CC without Duct Firing	828	834	763

Source: Energy Commission

The base installed costs are for a 2-on-1 configuration – two turbines and one steam generator, but the survey determined that the cost was dependent on the configuration. The Model has a selection option to incorporate survey data, which reduces cost approximated at $81/kW for each additional turbine and increases cost by $81/kW for a single turbine plant.

Cost adders for less common component costs were also calculated from the survey data that are not incorporated directly into the Model, but can be entered exogenously into the Model. These adders are shown in **Table 16**.

Combined Cycle Operating Costs

The operating costs consist of three components: fixed O&M, variable O&M, and fuel. Fuel costs were discussed earlier.

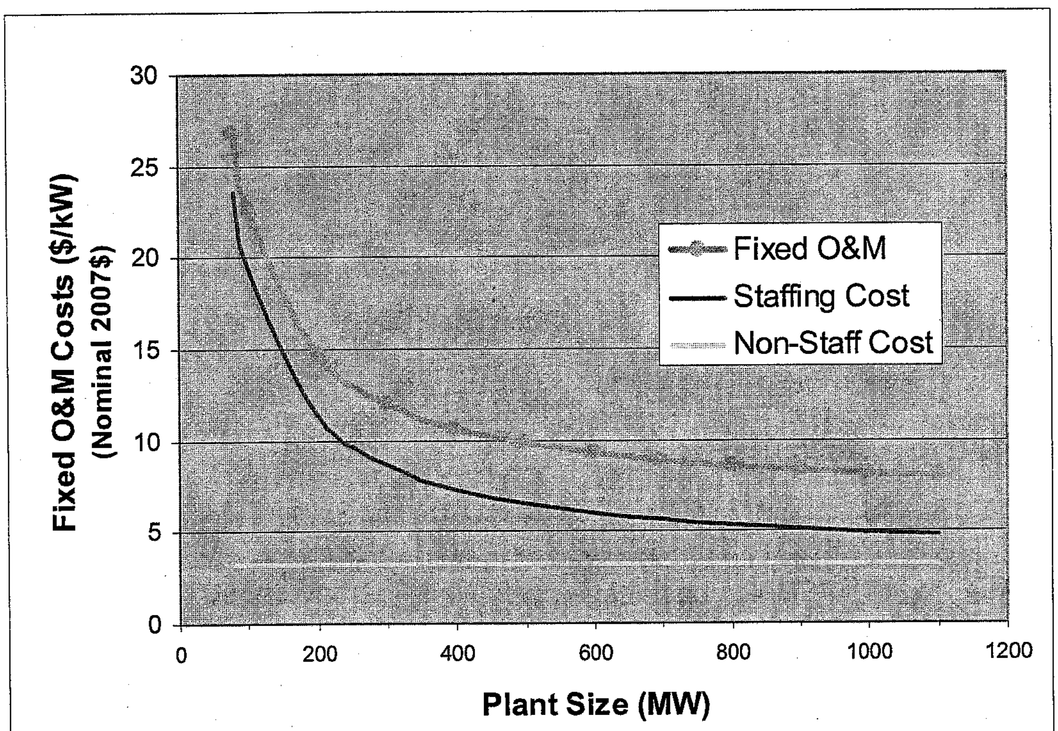
Fixed O&M is composed of two components: staffing costs and non-staffing costs. Non-staffing costs are equipment, regulatory filings, and other direct costs. The staffing cost, and thus the total fixed cost, varies with plant size as shown in **Figure 9**.

Table 16: Installed Cost Adders for Combined Cycles

Combined Cycle Units (Nominal 2007$)	**$/kW**
Dry Cooling	48
Chillers	11
Plume Abated Cooling Tower	6
No Oxidation Catalyst	-4
Urban Site	11
Co-located facility (Muni only)	-43
Alternative Gas Turbine Type	
SW 501	-32
Alstom GT-24	21
GE 7E	48
Alstom GTX100	53
GE LM6000	16

Source: Energy Commission

Figure 9: Combined Cycle Fixed O&M Costs



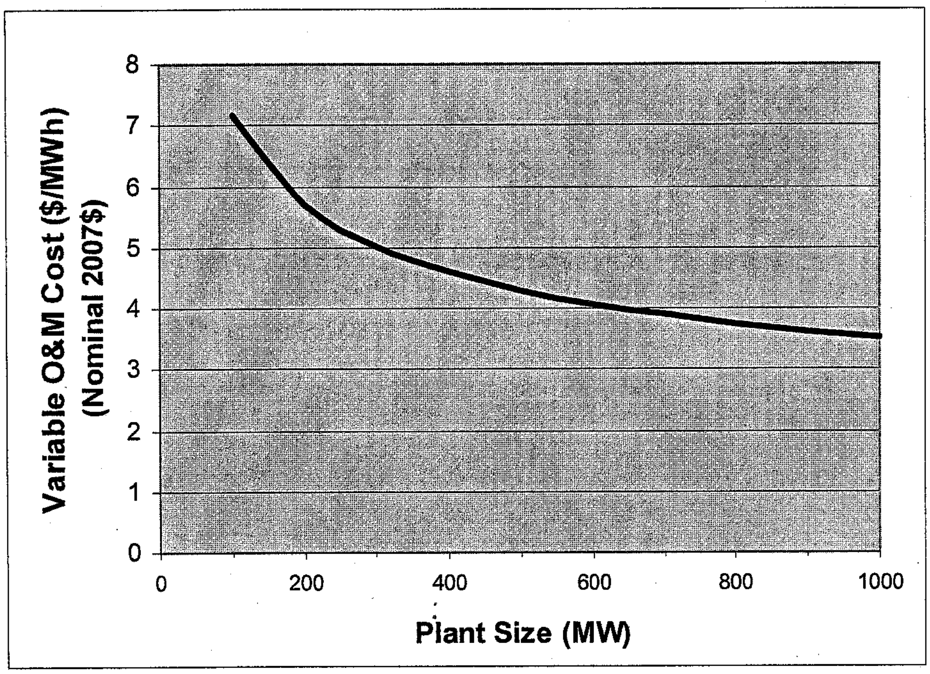
Source: Energy Commission

Variable O&M is composed of the following components:

- Scheduled outage maintenance – annual maintenance and overhauls
- Forced outage maintenance
- Consumables maintenance
- Water supply costs
- Environmental costs

Figure 10 shows the total variable O&M as a function of plant size. Of all the components, the scheduled and overhaul maintenance is the largest: about 75 to 90 percent of the total cost, depending on the year in question.

Figure 10: Combined Cycle Variable O&M



Source: Energy Commission

Simple Cycle Capital Costs

Similar to the combined cycle units, adjustments were made to each of the simple cycle units so that they could be reduced to a common base configuration, which is shown in **Table 17**. These base case costs were then averaged to develop the base installed costs shown in **Table 18**. These costs include equipment, land, development, air emission control equipment, water treatment, and water cooling costs.

The total installed costs are then calculated by estimating the linears (transmission, gas supply, water, and sewer), permits (building and environmental) and ERCs.

The linears and the permits are estimated from the survey data; permits were estimated at $21/kW except for units under 50 MW, which were estimated as $11/kW. The ERC costs are based on data developed by Energy Commission staff and calculated by the Model based on that information. The Model is able to calculate ERCs for each of the California air districts. The value shown here is an average California value, calculated by the Model.

Table 17: Base Case Configuration – Simple Cycle

1) 100 MW Merchant Plant
2) 2 LM6000 Turbines
3) Wet Cooling Or Dry Cooling
4) Brownfield Site
5) Non-Urban Land Cost
6) Potable Water Source
7) Evaporative Coolers/Foggers
8) Oxidation Catalyst Used
9) ZLD
10) Not Co-Located W/ Other Power Facilities

Source: Energy Commission

Table 18: Base Case Installed Costs for Simple Cycle

100 MW Simple Cycle Unit (Nominal 2007$)	**Merchant ($/kW)**	**IOU ($/kW)**	**Muni ($/kW)**
Base Installed Cost	**942**	**942**	**735**
Linears	34	34	34
Permits	21	21	21
ERCs (California Average)	3	3	3
Total Installed Cost	**1000**	**1000**	**793**

Source: Energy Commission

Table 19 shows the total installed costs for the standard simple cycle configurations available in the Model, including the above 100 MW unit. As before, this includes permit costs and California average ERCs.

Table 19: Total Installed Costs for Simple Cycle Units

Various Simple Cycle Units (Nominal 2007$)	Merchant ($/kW)	IOU ($/kW)	Muni ($/kW)
Conventional 50 MW SC	1053	1053	846
Conventional 100 MW SC	1000	1000	793
Advanced 200 MW SC	817	817	610

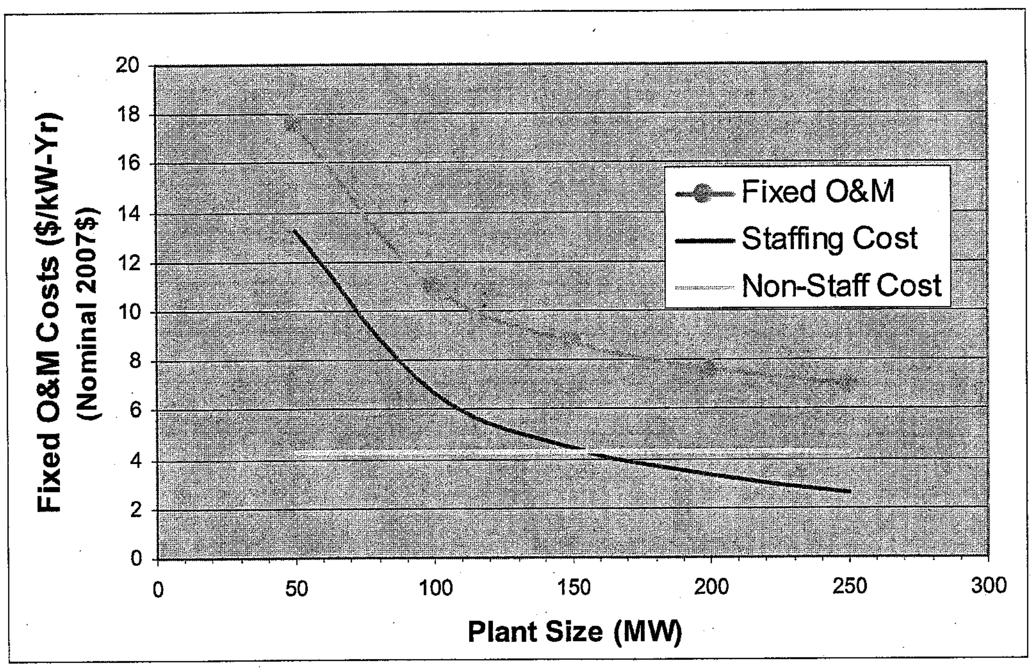
Source: Energy Commission

Simple Cycle Operating Costs

The operating costs consist of two components: fixed O&M and variable O&M.

Fixed O&M is composed of two components: staffing costs and non-staffing costs. Non-staffing costs are comprised of equipment, regulatory filings, and other direct costs. As with the combined cycle fixed costs, staffing costs for simple cycle units, and thus total fixed O&M, were found to vary with plant size as shown in **Figure 11.**

Figure 11: Simple Cycle Fixed O&M Costs



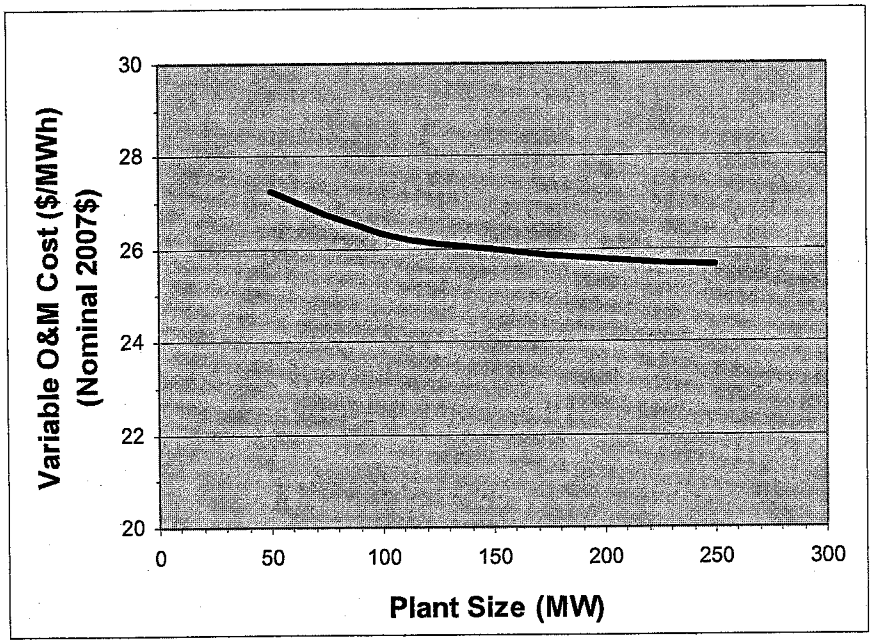
Source: Energy Commission

Variable O&M is composed of the following components:

- Scheduled outage maintenance – annual maintenance and overhauls
- Forced outage maintenance
- Consumables maintenance
- Water supply costs
- Environmental costs

Figure 12 shows the total Variable O&M as a function of plant size. Of the three components, the scheduled and overhaul maintenance is the largest: about 75 to 90 percent of the total cost, depending on the year in question.

Figure 12: Simple Cycle Variable O&M Cost



Source: Energy Commission

Miscellaneous Operating Variables

Heat Rate – Heat rates are a measure of the efficiency of a power plant. An imagined power plant with 100 percent efficiency would have a heat rate of 3413 Btu/KWh. The efficiency of a real power plant can be calculated as 3413 divided by the plant's heat rate. In this report, heat rates are estimated for four categories of thermal power plants:

- Conventional combined cycle
- Advanced combined cycle
- Conventional simple cycle
- Advanced simple cycle

The heat rates for all of these plant types were estimated based on actual data taken from the Energy Commission's Quarterly Fuels and Energy Report (QFER) database. The conventional units were developed by running a statistical regression of the monthly QFER data from 2001 to 2005 for 10 combined cycle and 12 simple cycle facilities. The advanced units were taken from the Energy Information Administration (EIA) 2006 forecast. **Table 20** summarizes the resulting formulas and heat rates for capacity factors of 60 percent for conventional and advanced combined cycles and 5 percent for conventional simple cycle units and 15 percent for advanced simple cycle units.

Table 20: Summary of Heat Rates

Technology	Heat Rate Formulas	Heat Rate (Btu/kWh)
Conventional Combined Cycle (CC)	*HR =8871+1050*0+2209*CF-4140*CF^.5*	6990
Conventional CC W/ Duct Firing	*HR =8871+1050*.091+2209*CF-4140*CF^.5*	7080
Advanced Combined Cycle	*HR= Conventional CC Heat Rate * (6333/6800)*	6510
Conventional Simple Cycle (SC)	*HR = Regression of QFER data*	9266
Advanced SC	*HR = 2006 EIA estimate*	8550

Source: Energy Commission

Heat Rate Degradation – Heat rate degradation is the percentage that the heat rate will increase per year. For this report, the heat rate degradation estimates are:

- For simple cycle units: 0.05 percent per year.
- For combined cycle units: 0.2 percent per year.

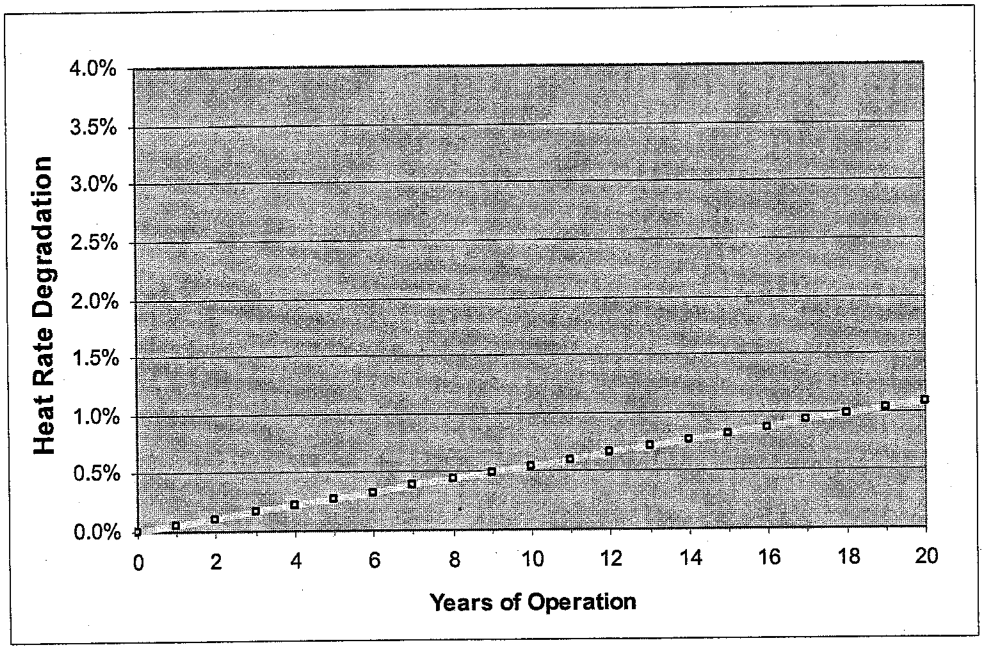
These values were estimated using General Electric data provided under the Aspen data survey. The rule for simple cycle units (combustion turbines) is that they degrade 3 percent between overhauls, which is every 24,000 hours. The actual time between overhauls, therefore, is a function of capacity factor as shown in **Table 21**. The staff elected to use a 5 percent capacity factor based on the capacity factors observed in the survey data and calculated degradation of 0.05 percent per year. **Figure 13** shows the results, designated as "Equivalent SC Degradation."

Table 21: Annual Heat Rate Degradation vs. Capacity Factor

Technology	Assumed Capacity Factor	Years Between Overhauls
Simple Cycle Units	5%	55
Simple Cycle Units	10%	27
Combined Cycle Units	50%	5.5
Combined Cycle Units	60%	4.6
Combined Cycle Units	70%	3.9
Combined Cycle Units	80%	3.4

Source: Energy Commission

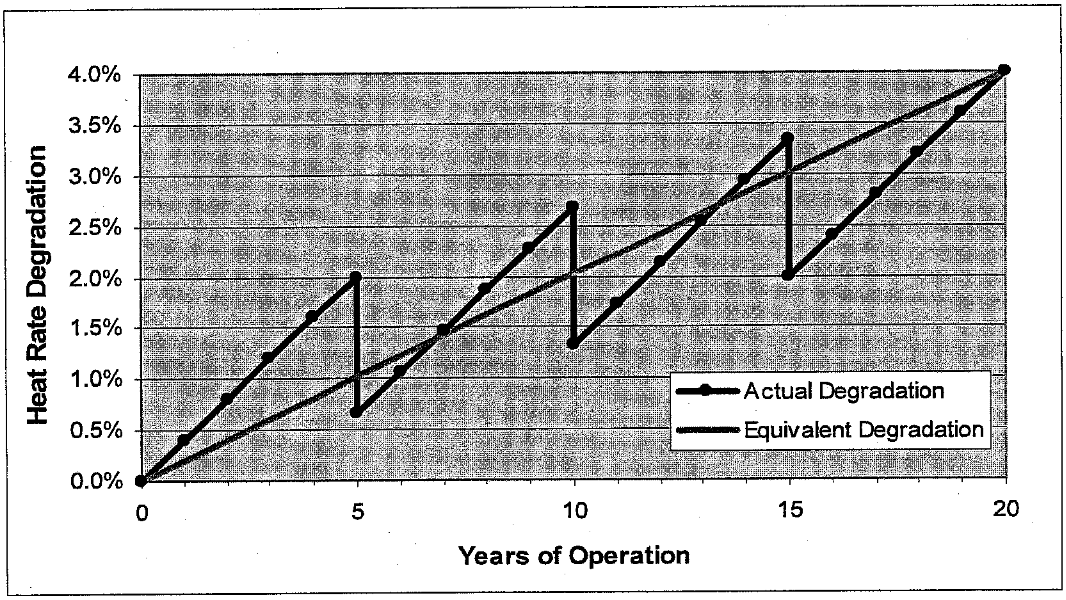
Figure 13: Simple Cycle Heat Rate Degradation



Source: Energy Commission

The computation for the combined cycle units is more complex due to its higher capacity factor, estimated herein to be roughly 60 percent based on the QFER data and other historical information. The 60 percent capacity factor calls for an overhaul every 4.6 years. The staff simplified this assumption by using five years. This results in three major overhauls during its 20-year book life, as shown in **Figure 14**. Since the steam generator portion remains essentially stable, the overall system deteriorates two-thirds of the 3 percent of the simple cycle during the five-year period, which is 2 percent; and recovers two-thirds of its deterioration during the overhaul, which is four-thirds of 1 percent. The details of this can be found in the Model User's Guide.

Figure 14: Combined Cycle Heat Rate Degradation



Source: Energy Commission

Parasitic Losses – These are sometimes defined as "station service losses." This is the power consumed by the power plant as a part of its normal operation. It can also be defined as the difference between the power generated and the power that arrives at the bus bar. The QFER database was used to estimate parasitic losses, which for combined cycle units was estimated to be 2.7 percent.

Transmission and Transformer Losses – Transformer losses are the losses in uplifting the power from the low voltage side of the transformer (generator voltage) to the high voltage side of the transformer (transmission voltage). Transmission losses represent the power lost in getting the power from the high side of the transformer to the load center (hearing designation is "GMM to Load Center"). Staff used assumptions established in the California Public Utility Commission (CPUC) 2005/2006 market price referents (MPRs), which are summarized in **Table 22.**

Table 22: Transformer and Transmission Losses Assumptions

LOCATION	LOSSES (%)	POWER (MW)	ENERGY (GWh)
Busbar	--	1.0000	8.059200
High-side of Transformer	0.5%	0.9950	8.018904
Load Center	1.43%	0.9808	7.904234

Source: Energy Commission

Nuclear, Clean Coal, and Alternative Technologies

This data was gathered by Navigant, based on earlier work, document searching, and phone calls to knowledgeable people in the field. The source of the data and other questions can be answered by contacting the expert noted in Appendix A.

Navigant provided input data for 22 technologies, 20 alternative technologies, nuclear, and integrated gasification combined cycle. The staff processed this data for use in the Model. The processed data is summarized in Chapter 2, and the resulting levelized costs are summarized in Chapter 1.

Navigant's instant costs are inherently incomplete, in that Navigant is not including ERC costs. Navigant provided the estimated emission factors (lbs/MWh) applicable to each technology. The staff used estimated cost of emissions ($/ton) in the Model to calculate the cost in dollars. These costs are added to the instant cost provided by Navigant to calculate the total instant cost. The Model converts the instant cost to installed cost and calculates the levelized cost. **Table 23** summarizes the Navigant instant costs and Energy Commission staff instant cost calculation.

Table 23: Instant Cost Adjustments

Technology (All costs in Nominal 2006$)	Gross Capacity (MW)	Navigant Instant Cost w/o ERCs ($/kW)	CEC Total Instant Cost ($/kW)
Integrated Gasification Combined Cycle (IGCC)	575	2050	2198
Advanced Nuclear	1000	2400	2950
Biomass - AD Dairy	0.25	5300	5800
Biomass - AD Food	2	5300	5803
Biomass Combustion - Fluidized Bed Boiler	25	2750	3156
Biomass Combustion - Stoker Boiler	25	2500	2899
Biomass - IGCC	21.25	2800	3121
Biomass - LFG	2	1850	2254
Biomass - WWTP	0.5	2400	2743
Fuel Cell - Molten Carbonate	2	4350	4488
Fuel Cell - Proton Exchange	0.03	7000	7239
Fuel Cell - Solid Oxide	0.25	4750	4908
Geothermal - Binary	50	3000	3093
Geothermal - Dual Flash	50	2750	2866
Hydro - In Conduit	1	1500	1547
Hydro - Small Scale	10	4000	4125
Ocean Wave (Pilot)	0.75	6985	7203
Solar - Concentrating PV	15	5000	5156
Solar - Parabolic Trough	63.5	3900	4021
Solar - Photovoltaic (Single Axis)	1	9321	9611
Solar - Stirling Dish	15	6000	6187
Wind - Class 5	50	1900	1959

Source: Energy Commission

Effect of Tax Credits on Cost

Table 24 shows the cost of technologies with and without tax credits. The difference between these quantifies the tax credit. The last column shows the tax credit as a percentage of the cost (in the absence of the tax credit). **Figure 15** shows this same data graphically.

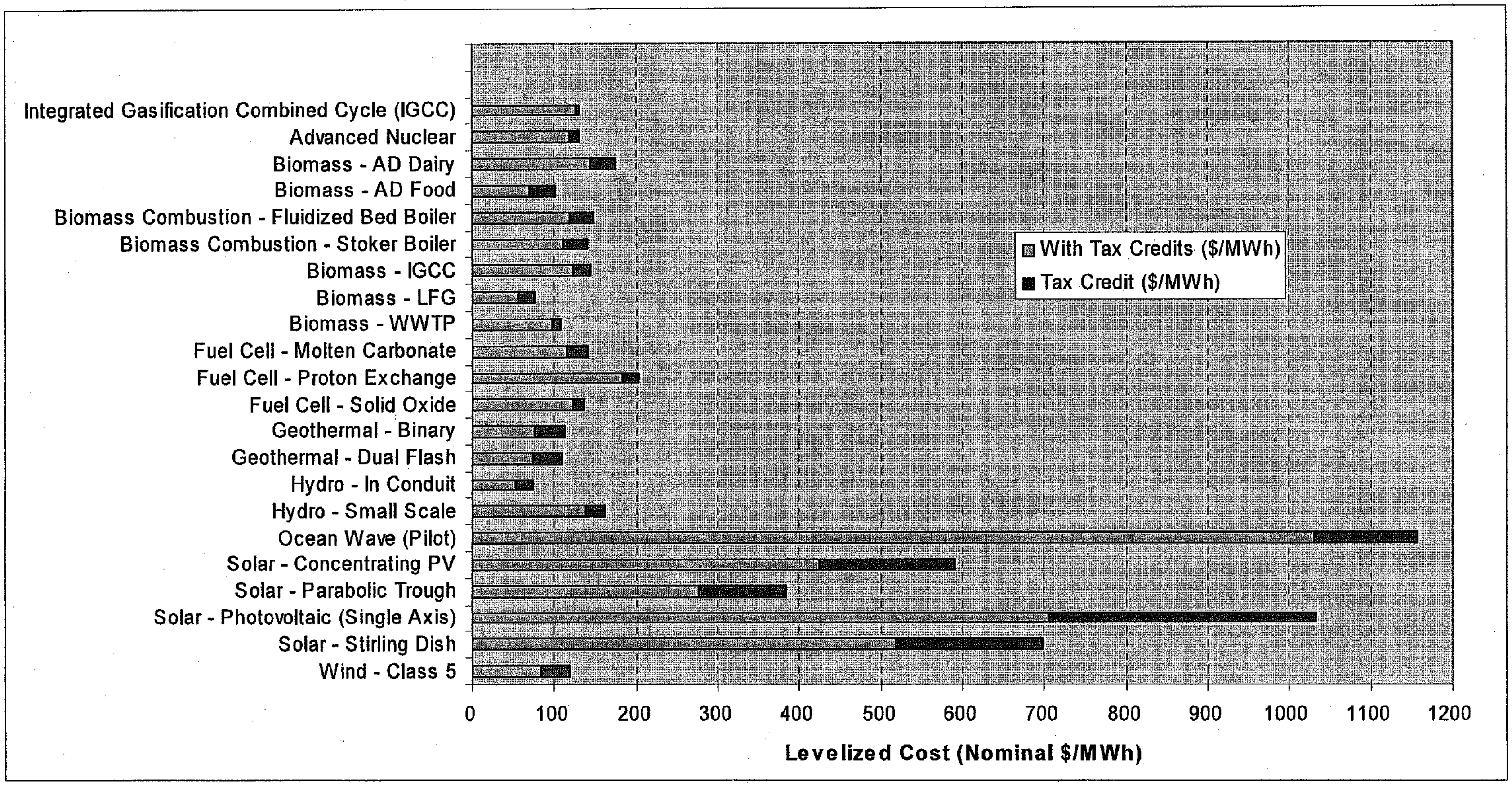
Table 24: Effect of Tax Credits on Costs

Levelized Costs (2007$)	With Tax Credits ($/MWh)	W/O Tax Credits ($/MWh)	Tax Credit ($/MWh)	As a % of Cost
Integrated Gasification Combined Cycle (IGCC)	126.51	130.43	3.92	3%
Advanced Nuclear	118.25	130.81	12.56	10%
Biomass - AD Dairy	143.61	175.09	31.49	18%
Biomass - AD Food	70.05	101.89	31.84	31%
Biomass Combustion - Fluidized Bed Boiler	118.72	148.57	29.84	20%
Biomass Combustion - Stoker Boiler	111.15	140.36	29.21	21%
Biomass - IGCC	123.66	143.74	20.08	14%
Biomass - LFG	56.11	76.18	20.07	26%
Biomass - WWTP	97.34	108.08	10.74	10%
Fuel Cell - Molten Carbonate	114.66	140.28	25.62	18%
Fuel Cell - Proton Exchange	182.41	202.15	19.74	10%
Fuel Cell - Solid Oxide	123.66	137.05	13.39	10%
Geothermal - Binary	75.85	112.22	36.37	32%
Geothermal - Dual Flash	73.66	109.43	35.77	33%
Hydro - In Conduit	52.84	74.95	22.11	30%
Hydro - Small Scale	138.74	160.81	22.07	14%
Ocean Wave (Pilot)	1030.50	1158.06	127.56	11%
Solar - Concentrating PV	424.84	590.06	165.22	28%
Solar - Parabolic Trough	277.30	383.45	106.14	28%
Solar - Photovoltaic (Single Axis)	704.98	1032.72	327.74	32%
Solar - Stirling Dish	518.89	697.59	178.70	26%
Wind - Class 5	84.24	118.54	34.30	29%

Source: Energy Commission

The tax credits for the alternative technologies were taken from the Database of State & Federal Incentives for Renewables & Efficiency. The link to the website is: http://www.dsireusa.org/Index.cfm?EE=0&RE=1

Figure 15: Effect of Tax Credits on Costs – Merchant Plants



Source: Energy Commission

Comparison to *2003 IEPR* Assumptions

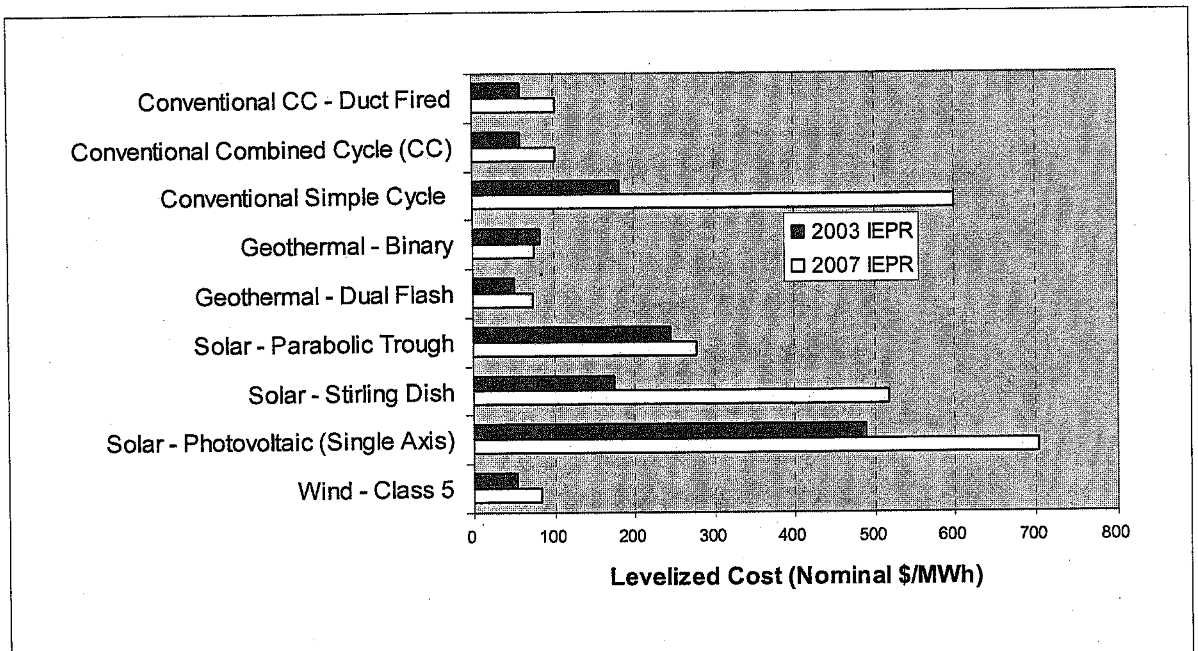
The staff compared the preliminary *2007 IEPR* costs to the *2003 IEPR* costs to see how the estimates have changed and to see if the differences are reasonable. **Table 25** makes this comparison of the total levelized costs. **Figure 16** presents the levelized cost data graphically.

Table 25: 2007 IEPR vs. 2003 IEPR

Technology (Costs in Nominal 2007$)	2003 IEPR			2007 IEPR			2003 IEPR		2007 IEPR	
	Gross Capacity (MW)	Levelized Cost ($/MWh)	Capacity Factor (%)	Gross Capacity (MW)	Levelized Cost ($/MWh)	Capacity Factor (%)	Instant Cost ($/kW)	Installed Cost ($/kW)	Instant Cost ($/kW)	Installed Cost ($/kW)
Conventional CC - Duct Fired	550	$59.73	91.6	550	$103.52	60.0	608	664	798	863
Conventional Combined Cycle (CC)	500	$59.50	91.6	500	$102.19	60.0	620	677	781	844
Conventional Simple Cycle	100	$182.62	9.4	100	$599.57	5.0	477	522	925	1000
Geothermal - Binary	35	$83.40	98.5	50	$75.85	95.0	3673	4140	3089	3562
Geothermal - Dual Flash	50	$51.85	96.0	50	$73.66	93.0	2435	2758	3093	3548
Solar - Parabolic Trough	110	$246.40	22.0	63.5	$277.30	27.0	2975	3203	4021	4190
Solar - Stirling Dish	15	$175.86	36.3	15	$518.89	24.0	3742	4028	6187	6446
Solar - Photovoltaic (Single Axis)	50	$488.84	23.8	1	$704.98	22.2	7614	8197	9611	9678
Wind - Class 5	100	$52.93	36.3	50	$84.24	34.0	1015	1093	1959	2000

Source: Energy Commission

Figure 16: Levelized Cost 2007 IEPR vs. 2003 IEPR



Source: Energy Commission

For some of the technologies, the differences in levelized cost were so dramatic that staff undertook a study to rationalize these differences. An exact comparison is difficult since so many factors have changed since the *2003 IEPR*, but staff was able in general to show that these differences can be explained. Staff selected three technologies that were comparable between the two IEPRs and had dramatic differences in costs: combined cycle, simple cycle, and solar stirling dish.

Combined Cycle with Duct Firing[1]

The *2007 IEPR* levelized cost is approximately 70 percent higher than that in the *2003 IEPR*. **Table 26** and the equivalent graphical representation in **Figure 17** show the cumulative effect on the levelized cost of changing present assumptions to match those of the *2003 IEPR* assumptions.

If the capacity factor in the *2007 IEPR* (60 percent) is adjusted to the *2003 IEPR* value (91.6 percent), the levelized cost decreases from $103.52/MWh to $89.54/MWh, which is a reduction of 13 percent. Additionally, if the *2007 IEPR* gas prices, which are about 40 percent higher, are replaced with the *2003 IEPR* gas prices, the levelized cost decreases from $88.54/MWh to $74.79, which is an additional 17 percent reduction. If the *2007 IEPR* installed cost, which is 27 percent higher than the 2003 cost, is adjusted to the 2003 value, then the levelized cost decreases from $74.79/MWh to $69.29/MWh, which is another 7 percent. The correction for the capital cost structure and fixed and variable O&M accounts for only a small percentage of difference. The remaining difference is to be expected due to modeling improvements made since the *2003 IEPR*, mostly in tax accounting.

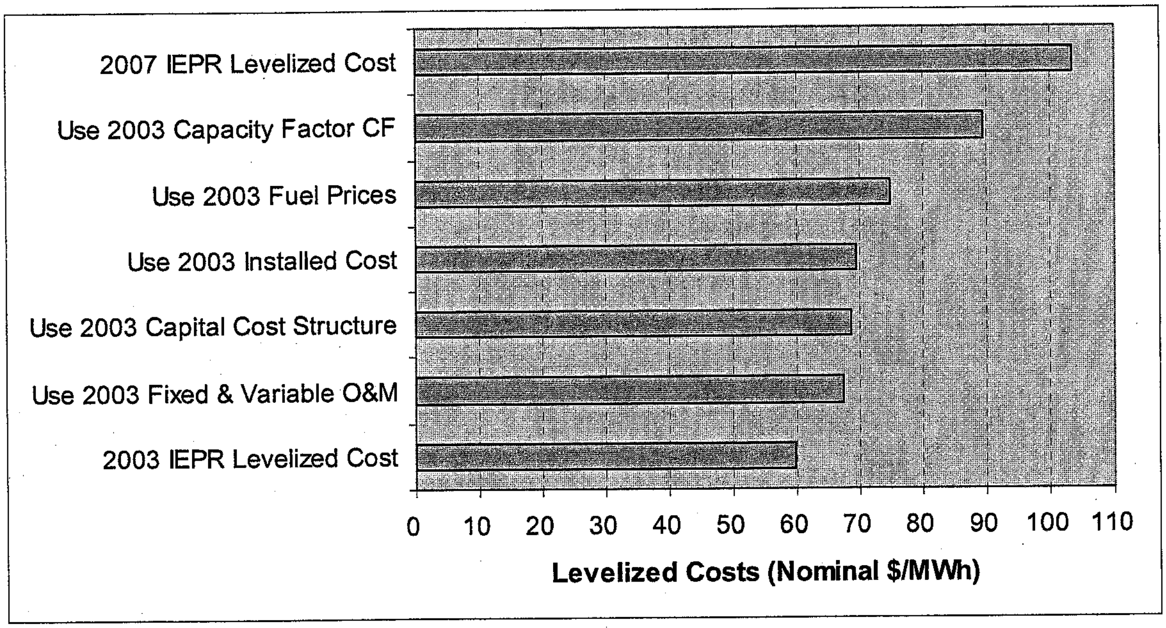
Table 26: 2007 IEPR vs. 2003 IEPR – Combined Cycle W/ DF

Effect of Change (Nominal 2007$)	$/MWh
2007 IEPR Levelized Cost	103.52
Use 2003 Capacity Factor CF	89.54
Use 2003 Fuel Prices	74.79
Use 2003 Installed Cost	69.29
Use 2003 Capital Cost Structure	68.71
Use 2003 Fixed & Variable O&M	67.48
2003 IEPR Levelized Cost	59.73

Source: Energy Commission

[1] Duct Firing: A combined cycle plant peaking technology that adds heat to the heat recovery steam generator section of a combined cycle plant to increase steam and power output. Duct burners can be small adding less than 5 percent additional load or very large adding 20 percent or more to the base load power output.

Figure 17: 2007 IEPR vs. 2003 IEPR – Combined Cycle



Source: Energy Commission

Simple Cycle

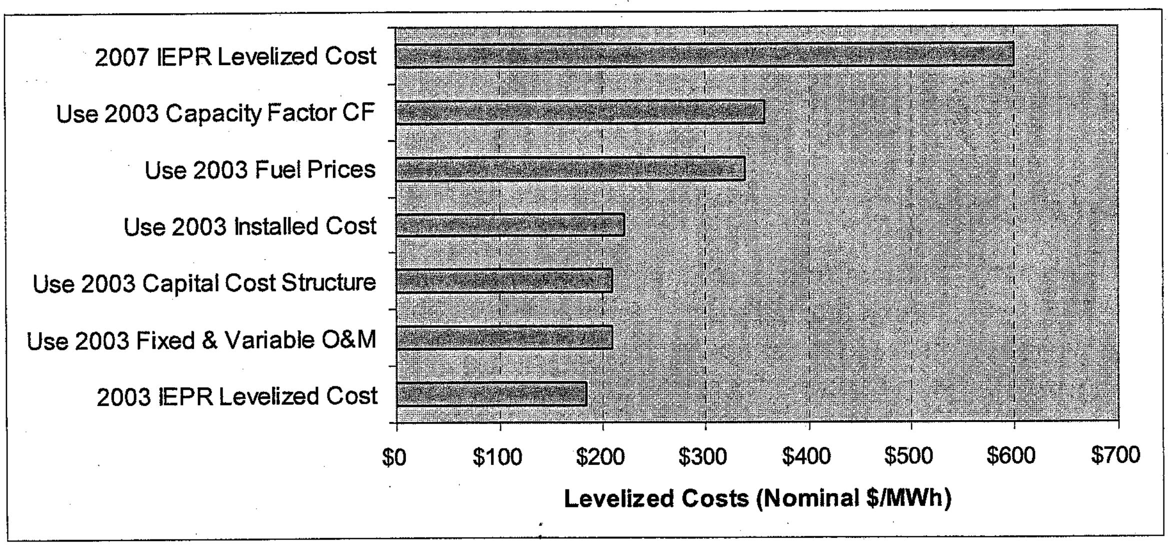
The *2007 IEPR* levelized cost is more than three times (3.3) higher than in the *2003 IEPR*. At first blush this difference seems inexplicable, but the difference can also be explained similar to the combined cycle unit above as shown in **Table 27** and **Figure 18.** If the capacity factor in the *2007 IEPR* emulation (5 percent) is adjusted to the *2003 IEPR* value (9.4 percent), the levelized cost decreases about 40 percent. Additionally, if the *2007 IEPR* gas prices, which are about 40 percent higher, are replaced with the *2003 IEPR* gas prices, the levelized cost decreases by another 5 percent – the difference is small due to the small amount of gas used at these lower capacity factors. If the *2007 IEPR* installed cost ($1,000/kW) is replaced with the 2003 cost ($522/kW), the levelized cost decreases another 35 percent. Using the 2003 financial assumptions and the fixed and variable O&M assumptions bring the levelized cost within 12 percent of the target *2003 IEPR* levelized cost, which again is to be expected due to the new modeling structure, most importantly the handling of taxes.

Table 27: 2007 IEPR vs. 2003 IEPR – Simple Cycle

Effect of Change (Nominal 2007$)	$/MWh
2007 IEPR Levelized Cost	599.57
Use 2003 Capacity Factor CF	357.01
Use 2003 Fuel Prices	337.94
Use 2003 Installed Cost	220.67
Use 2003 Capital Cost Structure	208.67
Use 2003 Fixed & Variable O&M	207.92
2003 IEPR Levelized Cost	182.62

Source: Energy Commission

Figure 18: 2007 IEPR vs. 2003 IEPR – Simple Cycle



Source: Energy Commission

Solar Stirling Dish

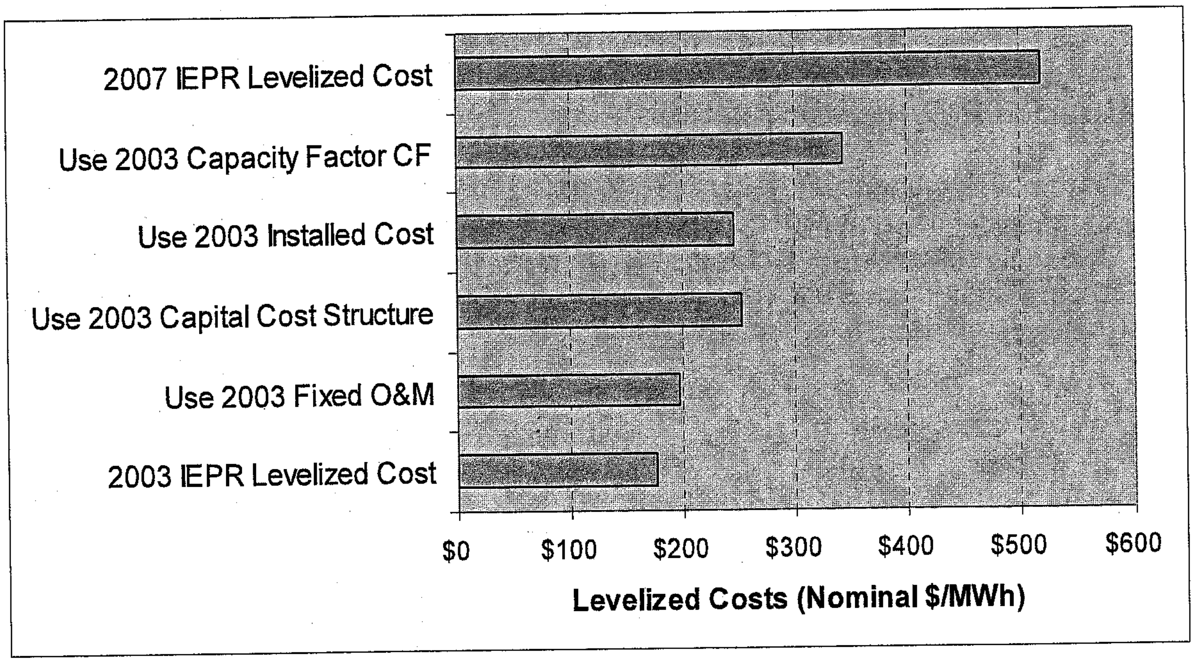
The *2007 IEPR* levelized cost is almost three times (2.95) that of the *2003 IEPR*. **Table 28** and **Figure 19** rationalize the differences similarly to the above analyses. If the capacity factor in the *2007 IEPR* (24 percent) is adjusted to the *2003 IEPR* value (36.3 percent), the levelized cost decreases 34 percent. If the 2007 installed cost $6446/kW is replaced by the 2003 installed cost of $4,028/kW (Both in 2007$), the levelized cost decreases 28 percent. If the 2003 cost of capital are used, the levelized cost increases slightly. If the *2007 IEPR* fixed O&M cost ($169/kW-Yr) is replaced by the *2003 IEPR* fixed cost ($53/kW-Yr), it reduces the levelized cost another 23 percent. The remaining 10 percent difference seems small considering the differences in tax credits and the modeling improvements.

Table 28: 2007 IEPR vs. 2003 IEPR – Solar Stirling Dish

Effect of Change (2007$)	$/MWh
2007 IEPR Levelized Cost	518.89
Use 2003 Capacity Factor CF	342.85
Use 2003 Installed Cost	245.99
Use 2003 Capital Cost Structure	253.02
Use 2003 Fixed O&M	196.07
2003 IEPR Levelized Cost	175.86

Source: Energy Commission

Figure 19: 2007 vs. 2003 IEPR – Solar Stirling Dish



Source: Energy Commission

Comparison to Energy Information Administration Assumptions

To gain additional perspective on the *2007 IEPR* levelized forecast, staff compared the input assumptions against those of the 2007 EIA estimate. **Table 29** makes this comparison for the main assumptions.

In general, the staff cost data is significantly higher than EIA information, with the notable exception of fixed O&M and some variable O&M. For example, EIA is estimating an instant cost for simple cycle units at $447/kW, which is much lower than staff's $925/kW estimate – approximately one-half of staff's estimate. Some of these differences can be explained by the higher construction costs in California compared to the nationwide costs used by the EIA. Also, EIA is not accounting for California's ERC costs, and staff believes that they are not accounting for linears. However, staff feels that part of this difference is that EIA is simply underestimating the instant cost of some of these technologies.

Staff also feels that the EIA estimates for capacity factors are not reasonable for California. The EIA is estimating an 87 percent capacity factor for conventional combined cycles and 30 percent for simple cycles, where staff is estimating 60 and 5 percent respectively. Staff also feels that the EIA heat rate of 10,450 Btu/kWh for a simple cycle unit is much too high compared to the staff estimate of 9,266 Btu/kWh based on actual operating statistics.

On the other hand, staff has ultimately deferred to the EIA estimated advanced simple cycle heat rate of 8550 Btu/kWh and has incorporated it into this final report. Staff, however, has not incorporated the corresponding EIA capacity factor of 30 percent but has elected to use a smaller capacity factor of 15 percent based on Energy Commission Marketsym simulations.

Table 29: 2007 IEPR vs. EIA Assumptions

Technology	Size (Gross MW)		Instant Cost ($/kW)			Fixed O&M ($/kW-Yr)			Variable O&M ($/MWh)			Capacity Factor (%)		Heat Rate (Btu/kWh)	
(Nominal 2007$)	CEC	EIA	CEC	EIA	Ratio	CEC	EIA	Ratio	CEC	EIA	Ratio	CEC	EIA	CEC	EIA
Combined Cycle (CC)	500	250	781	641	1.22	9.86	12.49	0.79	4.42	2.07	2.91	60%	87%	6,990	6,800
Advanced CC	800	400	766	632	1.21	8.42	11.70	0.72	3.83	2.00	2.70	60%	87%	6,510	6,333
Simple Cycle (SC)	100	160	925	447	2.07	11.00	12.12	0.9	25.72	3.57	13.5	5%	30%	9,266	10,450
Advanced SC	200	230	756	423	1.79	7.13	10.53	0.7	25.57	3.17	13.8	15%	30%	8,550	8,550
IGCC	575	550	2192	1585	1.38	36.27	38.68	0.2	3.11	2.92	14.5	60%	85%	8,979	6,800
Adv Nuclear	1000	1350	2950	2213	1.33	140.00	67.92	0.8	5.00	0.49	2.5	85%		10,400	10,400
Fuel Cell (Molten Carbonate)	2	10	4488	5085	0.88	2.18	5.65	0.4	36.27	47.95	0.8	90%		8,322	8,832
Geothermal - Binary	50	50	3093	1999	1.55	72.54	164.72	0.4	4.66	0.00	-	95%	90%		
Wind	50	50	1959	1282	1.53	31.09	30.31	1.0	0.00	0.00	-	34%	34.1%		
Photovoltaic	1	5	9678	5051	1.92	24.87	11.68	1.1	0.00	0.00	-	17.3%			

Source: Energy Commission

CHAPTER 3: Cost of Generation Model

This chapter describes:

- Model overview
- Model structure
- Model improvements since *2003 IEPR*
- Model limitations
- The Model's screening curve function
- The Model's sensitivity curve function
- The Model's wholesale electricity price forecast function

Model Overview

A simplified flow chart of the Model is shown in **Figure 20.**

Using the inputs on the left side of the flow chart, which are described in detail later in this chapter, the Model can produce the outputs shown on the right side of the flow chart. The top set of output boxes show the levelized costs:

- Levelized fixed costs
- Levelized variable costs
- Total levelized costs (Fixed + Variable)

These are typical results from most cost of generation models. These results are used in almost any study that involves the cost of generation technologies. They can be used to evaluate the cost of a generation technology as a part of a feasibility study or to compare the differences between generation technologies. They also can be used for system generation or transmission studies.

This Model is more unique than the traditional model since it can create three other outputs not commonly provided:

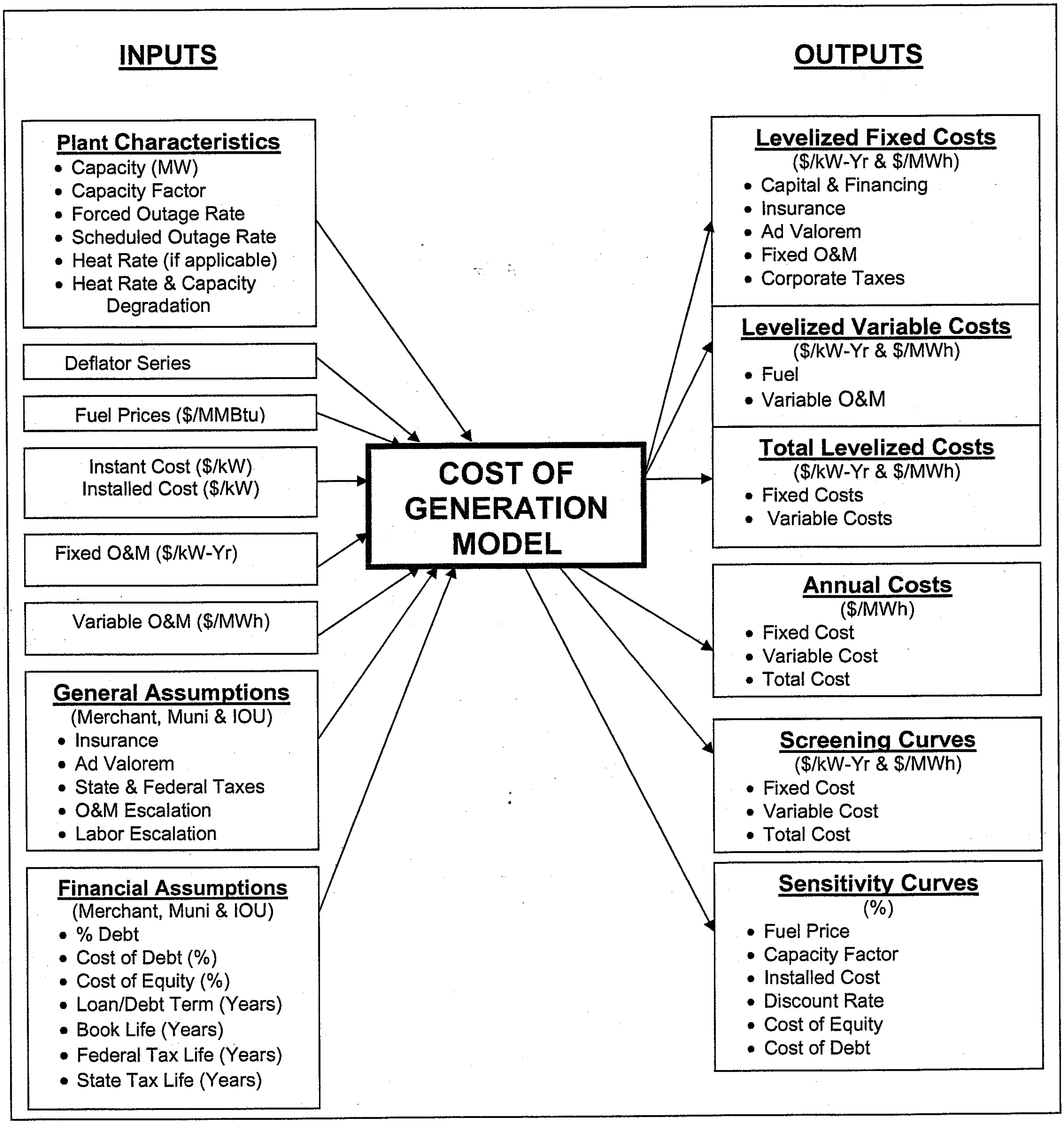
- Annual costs, which are not traditionally displayed in both a table and a graph.

- Screening curves, which show the relationship between levelized cost and capacity factor – an addition that makes the Model much more useful in evaluating cost of generation costs and comparing different technologies.

- Sensitivity curves, which show the percentage change in outputs (levelized cost) as various input variables are changed.

The fixed cost portion of the Model also can be used to forecast the cost of wholesale electricity, which is explained later in the chapter.

Figure 20: Flow Chart for Cost of Generation Model



Source: Energy Commission

Model Structure

The Model is a spreadsheet model that calculates levelized costs for 28 different technologies. These include nuclear, combined cycle, integrated gasification combined cycle, simple cycle and various alternative technologies. The Model is designed to accommodate additional technologies and includes a function for storing the results of scenario runs for these technologies.

The Model is contained within a single Excel file or workbook using Microsoft terminology. This workbook consists of 18 spreadsheets or worksheets using Microsoft terminology, but 4 of these are informational and do not contribute to the calculations.

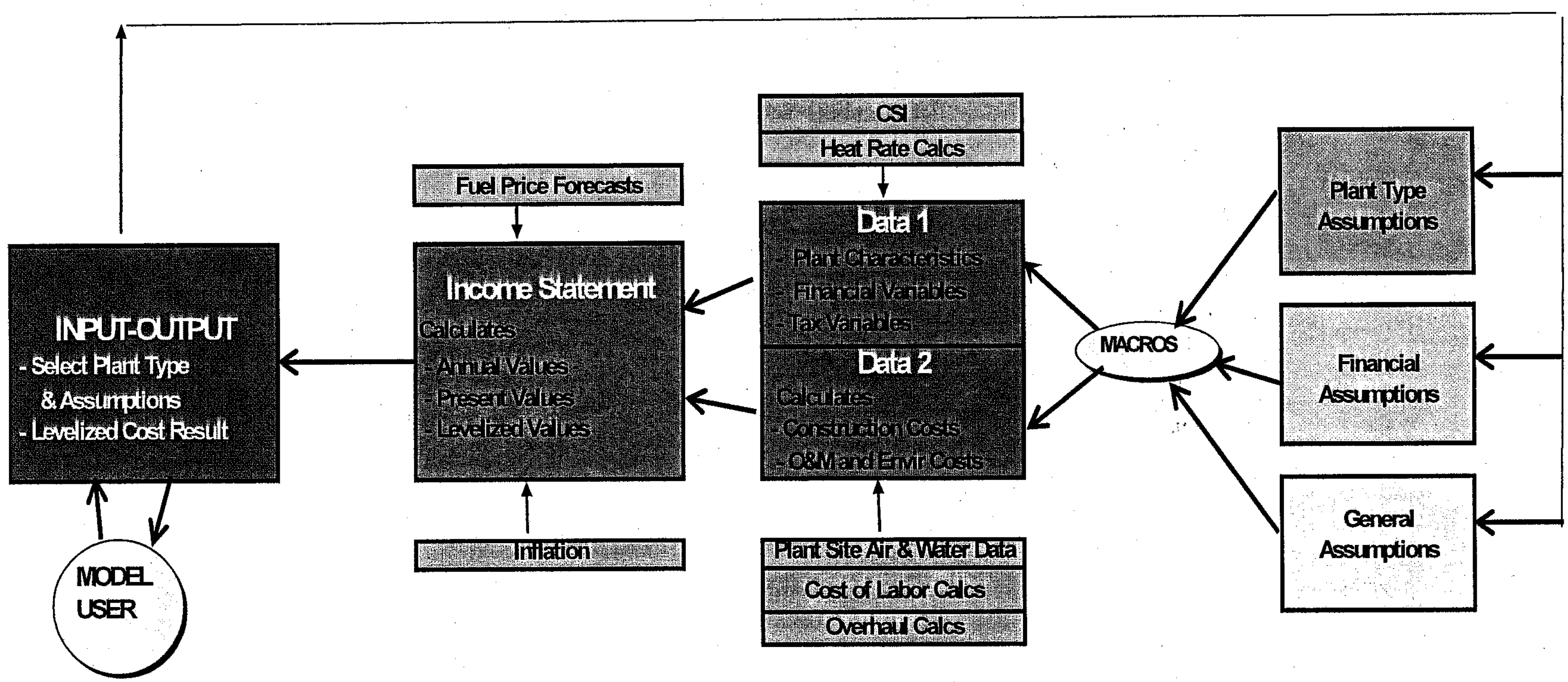
Changes	Tracks Model modifications using version numbers.
Instructions	General Instructions & Model Description.
WEP Forecast	Estimates Wholesale Electric Price Forecast
Adders	Provides Adder Costs that can be entered exogenously for the combined cycle & simple cycle units.
Input-Output	User selects Assumptions - Levelized Costs are reported along with some key data values.
Data 1	Plant, Financial & Tax Data are summarized - User can override data for unique scenarios.
Data 2	Construction, O&M Costs are calculated in base year dollars.
Income Statement	Calculates Annual Costs and Levelizes those Costs - Shows Annual Cash Flows of Costs & Revenues.
Plant Type Assumptions	Data Assumptions summary for each Plant Type.
Financial Assumptions	Data Assumptions summary of all Financial Data.
General Assumptions	General Assumptions summary such as Inflation Rates & Tax Rates.
Plant Site Air & Water Data	Regional Air Emissions & Water Costs - Used by Data 2 Worksheet.
Overhaul Calcs	Calculates Overhaul & Equipment Replacement Costs - Used by Data 2 Worksheet.
Inflation	Calculates Historical & Forward Inflation Rates based on GDP Price Deflator Series - Used by Income Statement Worksheet.
Fuel Price Forecasts	Fuel Price Forecast - Used by the Income Statement Worksheet.
Heat Rate Table	Shows the regression and provides the Heat Rate factors.
Labor Table	Calculates the Labor Cost components.
CSI	Shows the California Solar Initiative.

Source: Energy Commission

The relationship of these worksheets is illustrated in **Figure 21**.

One way to better understand the Model is to visualize the "Income Statement Worksheet" as the Model, the "Input-Output Worksheet" as the control module, which also summarizes the results, and the remaining worksheets as data inputs. Data 1 and 2 could be considered the data set (broken into two parts) that is derived from the "Assumptions Worksheets" and the remaining worksheets (auxiliary data).

Figure 21: Block Diagram for Cost of Generation Model



Source: Energy Commission

Input-Output Worksheet

Figure 22 shows the key interface worksheet, where the user selects the generation technology and characteristics and reads the final result. Through the use of drop-down windows, the user selects the power plant type, the financial assumptions, the general assumptions, fuel price, and regional location of the power plant. The user enters the start year.

Figure 22: Technology Assumptions Selection Box

Plant Type Assumptions (Select)	Combined Cycle Standard - 2 Turbines, No Duct Firing
Financial (Ownership) Assumptions (Select)	**Merchant Gas-Fired**
Ownership Type For Scenarios	**Merchant**
General Assumptions (Select)	**Default**
Base Year (All Costs In 2005 Dollars)	**2005**
Fuel	**Natural Gas**
Data Source	*CEC 2007 IEPR Survey (Will Walters, Aspen)*
Start (Inservice) Year (Enter)	**2007**
Fuel Price Forecast (Select)	**CA - Avg.**
Plant Site Region (Air & Water) (Select)	**CA - Avg.**
Study Perspective (Select)	**At Load Center**
Reported Construction Cost Basis (Select)	**Installed**
Turbine Configuration (Select)	**2**

Source: Energy Commission

The remaining options are more complex and require further description. The study perspective sets the location of the calculation (busbar or load center) – that is, the load center option allows for transformer and transmission losses incurred getting to the delivery point. All data reported in this Model are based on load center. The reported construction cost basis allows the user to enter the data as instant or installed. The turbine configuration allows for non-standard configurations for the combined cycle units. The standard configuration is two combustion turbine units and one steam generator – thus the number "2."

The Model collects the relevant data as directed by the selection box and delivers it to the data worksheets. The income statement then uses the data worksheets to calculate the levelized costs and reports those costs back to the input-output worksheet to the table shown in **Figure 23**.

Figure 23: Levelized Cost Output

SUMMARY OF LEVELIZED COSTS Combined Cycle Standard - 2 Turbines, No Duct Firing		
Start Year = 2007 (2007 Dollars)	**$/kW-Yr**	**$/MWh**
Capital & Financing - Construction	$115.21	$22.69
Insurance	$5.75	$1.13
Ad Valorem Costs	$7.34	$1.44
Fixed O&M Costs	$11.58	$2.28
Corporate Taxes (w/Credits)	$35.38	$6.97
Fixed Costs	**$175.25**	**$34.52**
Fuel Costs	$309.57	$60.98
Variable O&M	$26.27	$5.17
Variable Costs	**$335.85**	**$66.15**
Total Levelized Costs	**$511.10**	**$100.67**

Source: Energy Commission

Figure 24 also shows the annual costs both in tabular and graphical form.

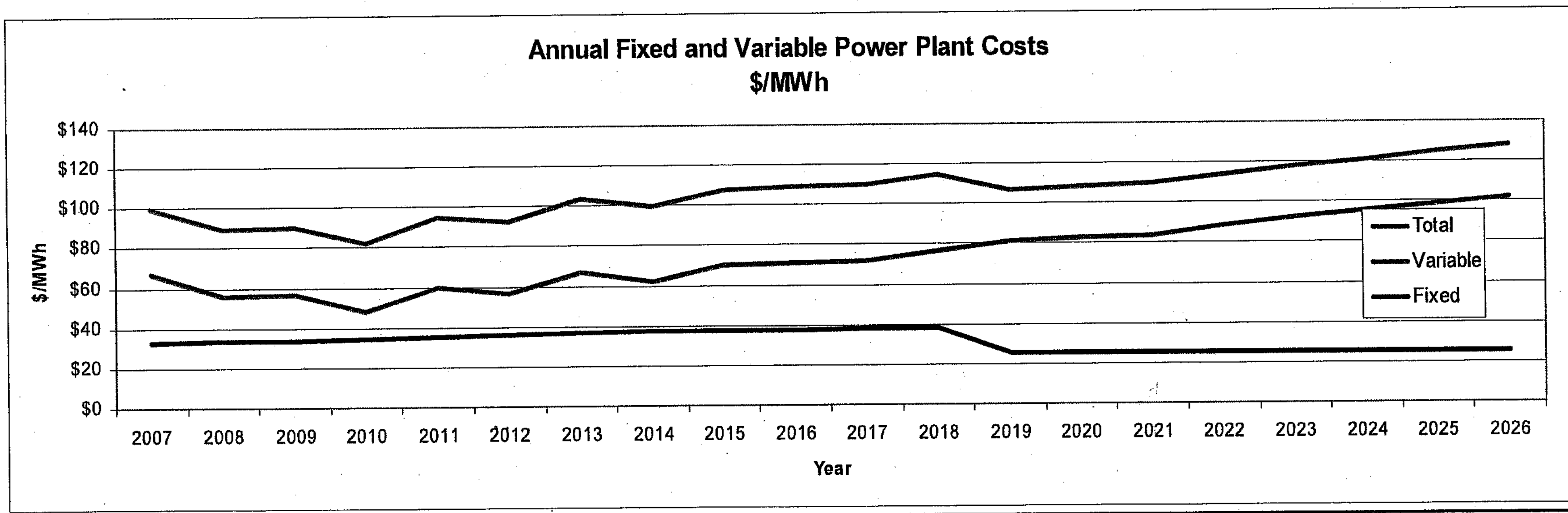
Assumptions Worksheets

Most of the data used in the Model are compiled into these three worksheets. These worksheets store the data for the multitude of technologies and data assumptions that give the Model its flexibility.

Plant Type Assumptions – This worksheet stores all of the power plant-specific data, such as plant size, fuel use, plant performance characteristics, construction costs, operation and maintenance costs, environmental costs, and water usage costs. There are over 200 of these items, but the most important, at least for thermal units, are the fuel costs (fuel price and heat rate) and capital costs. These account for 70 to 90 percent of the cost of a fossil-fueled power plant.

Financial Assumptions - This worksheet stores the capital structure and cost of capital data for the three main categories of ownership: merchant, IOU, and publicly owned. The worksheet provides the relative percentages of equity as opposed to long term debt, as well as the cost of capital for these two basic financing mechanisms. It also provides data on eligibility for tax credits.

Figure 24: Annual Costs – Merchant Combined Cycle Plant



	Levelized	NPV	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Fixed Costs	$33.35	$272	$32.2	$33.0	$33.8	$34.5	$35.2	$35.9	$36.6	$37.1	$37.4	$37.7	$38.0	$38.3	$25.6	$25.6	$25.7	$25.7	$25.7	$25.7	$25.8	$25.8
Variable Costs	$66.78	$544	$67.1	$55.8	$56.2	$47.5	$59.4	$56.6	$67.2	$62.0	$70.2	$71.0	$71.7	$76.3	$80.9	$82.4	$83.9	$87.9	$92.1	$95.4	$98.7	$102.2
Total Costs	$100.13	$816	$99.3	$88.8	$90.0	$82.0	$94.6	$92.5	$103.8	$99.2	$107.6	$108.7	$109.7	$114.6	$106.6	$108.0	$109.6	$113.6	$117.8	$121.1	$124.5	$128.0

Source: Energy Commission

General Assumptions – These are a multitude of assumptions that are common to all power plant types, such as inflation rates, tax rates, tax credits, as well as transmission losses and ancillary service rates.

Based on the user selections in the input-output worksheet, the relevant data in these assumptions worksheets is gathered by a macro and sent to the data worksheets.

Indicates area for data modification
Plant Type Assumptions
Financial Assumptions
General Assumptions

Data Worksheets

This is where the macro stores the data selected from the assumptions worksheets, and basic calculations are made to prepare data for the income statement worksheet. Data 1 and Data 2 worksheets can be envisioned as two parts of the main dataset to be used in the income statement. These are separated solely to keep the worksheets to a reasonable size. Data 1 and 2 also provide the opportunity for the user to modify or replace the data that came from the assumptions worksheets. Care should be taken to modify only those areas that are shaded in color.

Data 1 – This worksheet summarizes key data: plant capacity size and energy data, fuel use (such as heat rate and generation), operational performance data (such as forced outage rate and scheduled outage factor), key financial data (such as inflation rates and capital structure), and tax information (such as tax rates and tax benefits). It also does some calculations in order to calculate certain necessary variables. The following sheet sends data to the Data 1 worksheet.

Heat Rate Table – This worksheet shows the regression that created the heat rate formula as a function of capacity factor in the Data 1 worksheet.

Data 2 – This worksheet calculates construction, operation, maintenance, water use and environmental costs. These calculations depend on data from the following worksheets:

Plant Site Air and Water Data – These are emission and water costs on regional basis that are located outside the Data 2 worksheet.

Overhaul Calculations – These costs are calculated outside the Data 2 worksheet since they are non-periodic overhaul costs that require special treatment to derive the necessary base-year costs needed by the Data 2 worksheet.

Keep in mind that all the data in these worksheets are for base year dollars. These costs are used by the income statement worksheet to calculate the yearly values and account for inflation.

Labor Table – This worksheet calculates the labor costs that are used in the fixed O&M cost calculations in the Data 2 worksheet.

Fuel Price Forecasts – This worksheet provides the fuel prices ($/MMBtu) to the income statement worksheet. For the natural gas price forecast, it provides prices by utility service area, as well as a California average value. It allows storage of different forecasts if needed to conduct various scenario studies. These forecasts should be updated regularly to represent the most recent Energy Commission forecasts. The inflation factors used in this worksheet come from and must absolutely be consistent with the inflation worksheet.

Inflation – This worksheet provides inflation factors used by the income statement worksheet, needed to inflate the various capital and O&M costs. This worksheet calculates two inflation values to simplify the income statement calculations: a historical inflation rate, used for the period from the base year to the start year, and a forward inflation rate, used for the period from the start year to the end of the study.

Income Statement Worksheet

This worksheet takes the data from the above data sources and calculates the fixed and variable cost components of total levelized cost. It develops the yearly values, present values, and levelized costs necessary for the cash-flow and revenue calculations.

Model Improvements Since *2003 IEPR*

The Model has undergone numerous changes since the *2003 IEPR*, both in structure and data inputs.

Improvements in User Interface

One of the major intents was to improve the transparency and usability of this Model because some considered it to be confusing and at times inscrutable. Toward that end, staff made dramatic improvements in the user interface and developed a comprehensive user's guide. The following is a delineation of the most significant improvements in this regard:

- **Combined the Many Workbooks into a Singular Workbook with Drop-Down Menus** – The 2003 version consisted of about 25 separate workbooks, one for each technology and two common workbooks (natural gas prices and financial variables). All of these spreadsheets have been reduced to a singular workbook.

- **Improved Documentation in the Model** – Previously, there was very little documentation, so it was difficult to understand the various components and the source of the data. This new version has over a hundred explanatory comments that pop up in response to the cursor.

- **Created a User's Guide** – Previously, there was no written descriptive material. The staff has completed an extensive user's guide that explains how to use the Model and the Model mechanics. It also provides a definitions section that defines all relevant terminology both in narrative and with formulas.

- **Added the Ability to Do Scenarios** – The Model now has the ability to save scenarios for future use. After a technology has been temporarily modified for a specific case, it can be saved with the "Save as New Scenario" button for future use.

- **Added More Detail to Levelized Cost Output** – The levelized costs are now shown in detail in both $/MWh and $/kW-Yr.

- **Added Graphical Summary Data** – The levelized costs are shown graphically as well as numerically, which makes it easier to see the relevant importance of the various components of the costs.

- **Added Annual Costs Output** – So that the levelized costs can be better interpreted, the annual costs that produced those levelized costs are shown as an output in both numerical and graphical format.

Improvements in Model Mechanics

The Model's mechanics have also been improved to be more complete, more accurate, and more flexible.

- **Added Year-by-Year Inflation Values** – Previously, the Model used one inflation rate, 2 percent, for all years. This is simplistic and not consistent with the inflation factors used for the fuel price forecast. The Model has been modified to accept year-by-year inflation factors that are linked forward to the inflation of fuel prices to ensure consistency.

- **Added Real Escalation Factors** – Previously, the Model had only nominal inflation. The Model now captures both nominal (or general) inflation and real-cost escalation for individual components.

- **Incorporated GADS Definitions** – The Model has been modified to incorporate standard North American Reliability Council (NERC)/Generating Availability Data System (GADS) definitions for the reliability and output factors, most notably for scheduled and forced (unscheduled) outage. This is important within itself to ensure standardization of definitions but can become more important if an attempt to use NERC/GADS data in the future or even attempts to just benchmark Energy Commission values against NERC/GADS data.

- **Modified the Model to Develop Screening Curves** – The Model is limited in its ability to compare one generation against another because it uses a singular assumed capacity factor for each technology. This is a serious limitation. This feature, its importance, and its limitations are described in a separate section below.

- **Corrected the Definitions for Capacity Factor and Availability Factors** – The definitions of capacity and availability factors in the old model were simply wrong and inconsistent with common practices at the Energy Commission. This is important in itself but becomes essential when the Model is used to create screening curves.

- **Improved Heat Rates**– Since fuel cost can be as much as 80 percent of the levelized cost for a combined cycle unit, it is important to have accurate heat rates. The heat rates in the Model have been improved to reflect actual operation rather than manufacturer estimates. Energy Commission staff used actual QFER fuel consumption and electric output data to develop heat rates to reflect actual operation.

- **Miscellaneous Improvements in Calculations** – Improved the calculation of installed cost, weighted average cost of capital (WACC), taxes, depreciation, and ad valorem.

Improvements in Data Inputs

Most of the data in the Model has been updated:

- **Power Plant Data** – All power plant cost data has been revised through data requests to reflect actual as-built data.

- **Natural Gas Prices** – The Model has been updated to reflect the Energy Commission's most current forecast. It also provides optional forecasts.

- **Inflation Values** – Inflation factors have been updated.

- **Tax Rates, Tax Deductions, and Tax Credits –** These variables were reviewed and updated as necessary.
- **Capital Structure –** Cost of equity and long-term debt were updated along with the debt to equity ratios, discount rate, and weighted average cost of capital.
- **Degradation Factors –** Heat rate degradation factors have been added.

Model Limitations

Models are inherently limited because a number of assumptions must be made for each generation technology. The most important assumptions are:

- Capital costs
- Fuel costs
- Capacity factors
- Heat rates – for thermal plants

Capital Costs

Deriving capital costs is challenging, particularly for alternative technologies since costs tend to drop with increased development over time. Even for well-developed technologies, such as combined cycle and simple cycle plants, it is difficult because of varying location and situational costs. Developers generally keep this information confidential to maintain a competitive edge over other developers.

Fuel Costs

Fuel cost is highly unpredictable and difficult to forecast with a high degree of accuracy. The only safeguard against the unpredictability of fuel cost forecasts is to have alternative forecasts for comparison or to use uncertainty analysis. The Model thereby has the ability to compare the implications of different forecasts.

Capacity Factors

Models are inherently limited because the user must assume a specific capacity factor, which may or may not be applicable to the power plant under consideration. This is a common problem for combined cycle and simple cycle power plants. Combined cycle units are all too commonly modeled as having capacity factors in the vicinity of 90 percent, but the historical information on California power plants, as summarized in **Table 30,** shows that the average is closer to 60 percent or less. The

Model attempts to deal with this problem using the screening curve function, as described below.

Table 30: Actual Historical Capacity Factors

Power Plant	QFER 2004	QFER 2005
Moss Landing Power Plant	55.5%	52.6%
Los Medanos	74.3%	74.7%
Sunrise Power	62.1%	65.7%
Elk Hills Power, LLC	79.9%	72.4%
High Desert Power Project	51.9%	50.3%
Sutter	72.0%	51.3%
Delta Energy Center	72.6%	69.5%
Blythe Energy LLC	26.8%	19.6%
La Paloma Generating	57.2%	46.4%
Von Raesfeld	nd	31.6%
Woodland	nd	51.5%
Average	61.3%	53.2%

Source: Energy Commission

Heat Rates

An actual thermal power plant being considered, such as a combined cycle unit, may operate at an entirely different capacity factor than that selected for the Model. In fact, these plants typically operate at different capacity factors from month to month and even day to day. These varying capacity factors result in differing heat rates. A combined cycle unit has most efficient (lowest) heat rate at full power, or in the case of a duct-fired plant, at near full power since the duct-firing process provides additional power at the cost of lower efficiency. Operation at lower power levels produces less efficient operation (higher heat rates). Two identical power plants with the same capacity factor can have widely different average annual heat rates. For example, both could have 50 percent capacity factors if one operated at full power for half of the year and the other operated at half power for the entire year. Obviously, the latter unit would have a much higher heat rate. The staff's Model attempts to deal with this problem with the screening curve function, as described below.

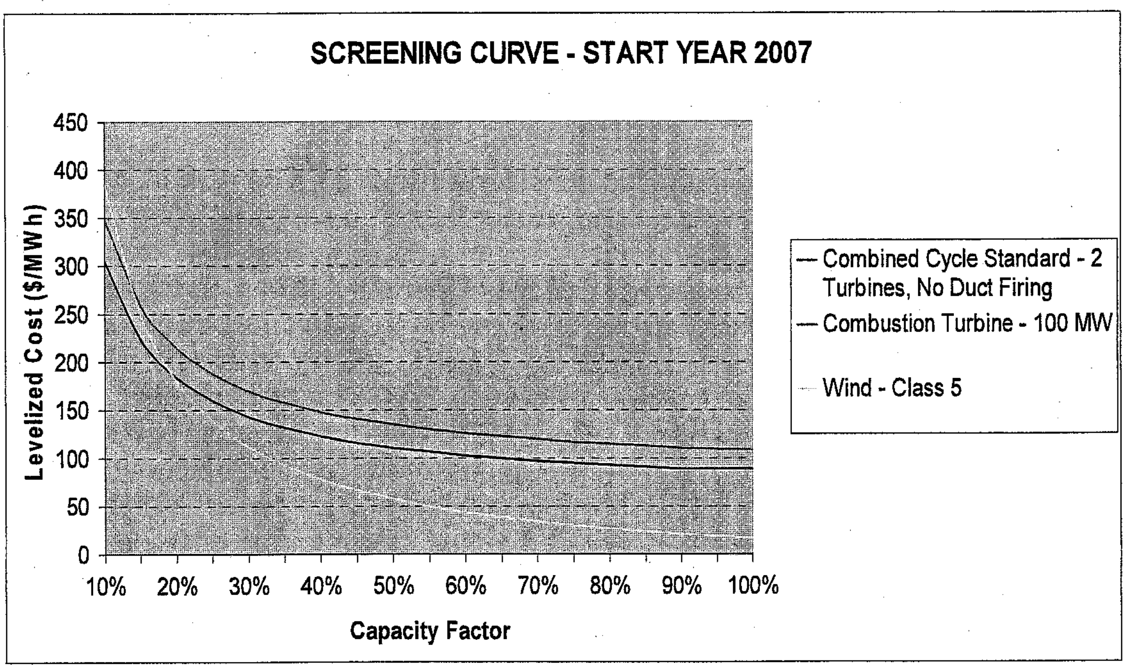
Model's Screening Curve Function

Screening curves allow one to estimate the levelized cost for various capacity factors, rather than the singular capacity factor that is typical of models. This is useful in many ways. The most obvious is that it allows the user to estimate levelized costs for its specific assumption of capacity factor. It also allows the user to assess the cost risk of incorrectly estimating the capacity factor. It allows for the comparison of various technologies as a function of capacity factor – that is, at what capacity factor one technology becomes less costly than another.

The Energy Commission's Model is somewhat unique in that it recognizes the reality that heat rate is a function of capacity factor, and corrects for this in the screening curve. By analyzing historical data from operating power plants in California (Energy Commission's QFER database), it was possible to find a relationship between capacity factor and heat rate that has a high statistical level of confidence – and that formula (through regression) has been embedded in the Model.

The levelized cost can be shown as $/MWh or $/kW-Year. **Figure 25** is an illustrative example of a $/MWh screening curve.

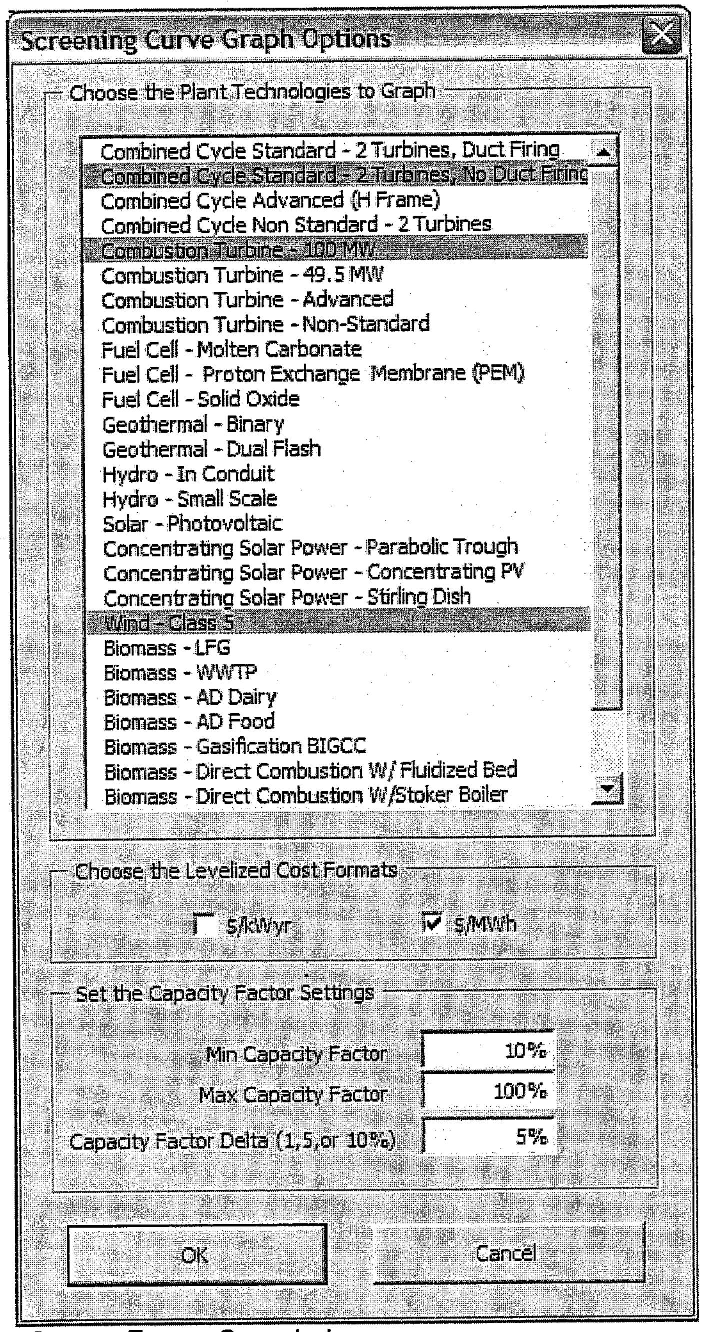
Figure 25: Screening Curve in Terms of Dollars per Megawatt Hour



Source: Energy Commission

Figure 26 shows the corresponding interface window.

Figure 26: Interface Window for Screening Curve



Source: Energy Commission

Misuse of Screening Curves

Care must be taken to not misuse the screening curves. The curves estimate only the relative costs. This is a good starting point, which is why they are called "screening curves." For those cases where costs are close, additional and more detailed economic analysis is necessary.

It is also essential to use these curves in proper perspective. If the study is to simply compare the costs, the screening curves are useful. If the study is to determine the least cost to the system where the unit will be operating, then the screening curves are of less value and should be very carefully applied.

First of all, the assumed capacity factor is just that, an assumption. The actual capacity factor will depend on its economic viability once it is actually operating in the system. Furthermore, that capacity factor will vary over the seasons of the year and from year to year. In addition, screening curves do not reveal how a unit will affect the system operations. This is where a production cost or market model becomes important since they can capture these kinds of interactions. A production cost or a market model can emulate the system, how the generation unit will operate and how the unit will likely affect the rest of the system. Different generation technologies offer different system attributes and services.

All of this, however, ignores environmental, risk, and diversity factors, which may in the final analysis be the determining factors.

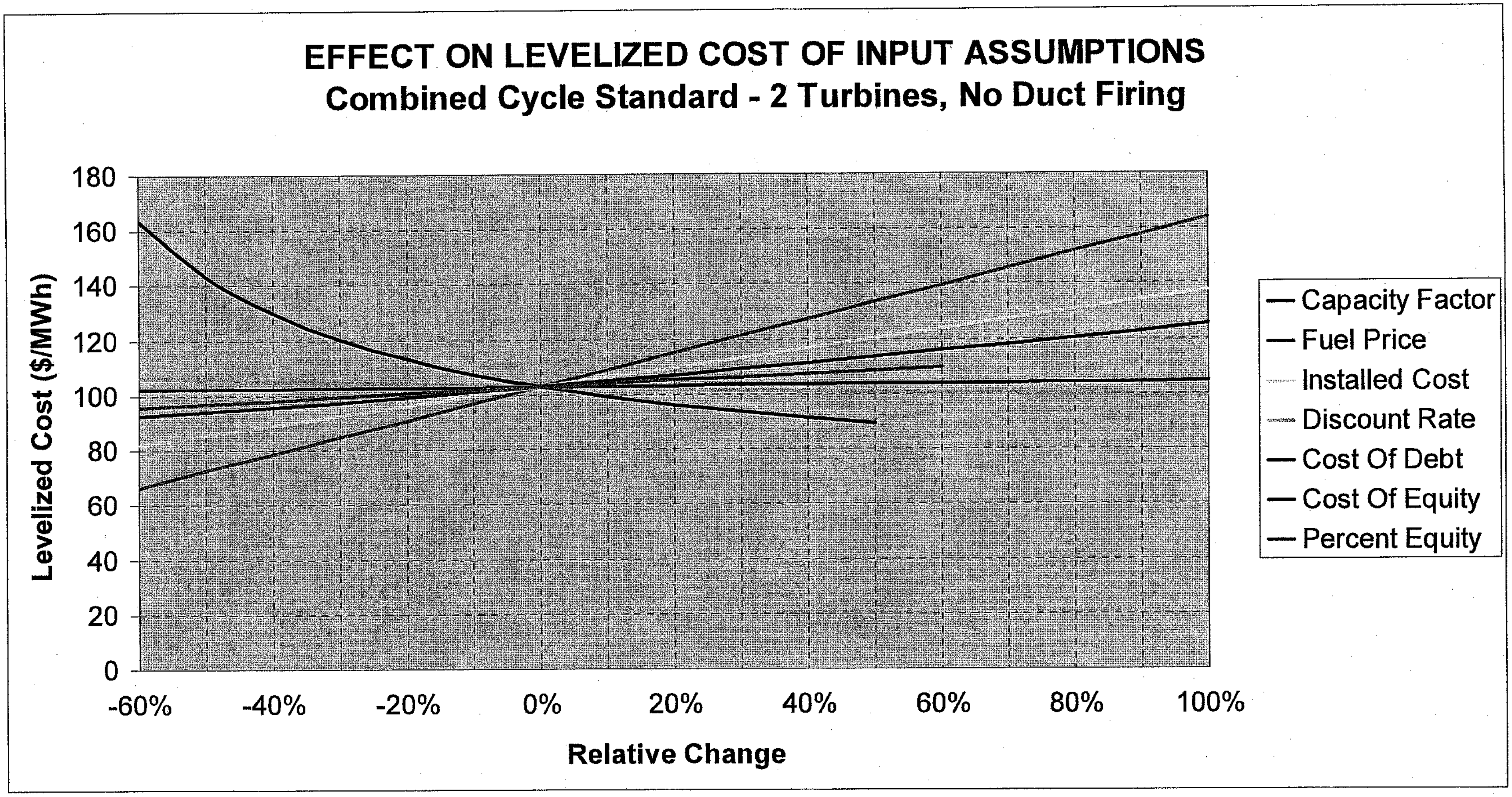
Model's Sensitivity Curve Function

Although the screening curves can prove useful, they address only one variable to the base case assumptions when estimating levelized costs – the capacity factor. Staff's new sensitivity curves address a multitude of assumptions: capacity factor, fuel prices, installed cost, discount rate (WACC), percent equity, cost of equity, cost of debt, and any other variable that should be considered. Sensitivity curves show the effect on total levelized cost by varying any of these parameters in three formats:

- Levelized cost ($/MWh or $/kW-Yr)
- Change in levelized cost as a percent
- Change in levelized cost as incremental levelized cost from the base value ($/MWh or $/kW-Yr).

Figure 27 shows an illustrative example of a sensitivity curve.

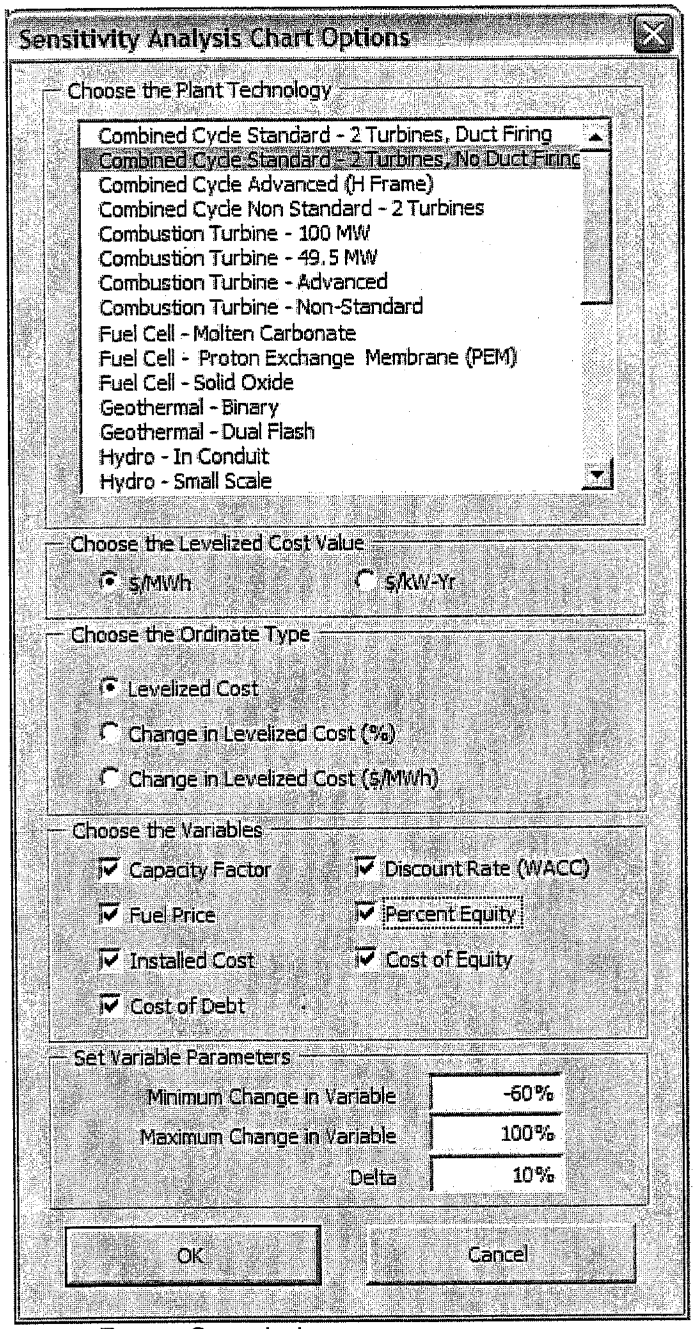
Figure 27: Sample Sensitivity Curve



Source: Energy Commission

Figure 28 shows the interface window for the above sensitivity curve.

Figure 28: Interface Window for Screening Curves



Source: Energy Commission

Model's Wholesale Electricity Price Forecast Function

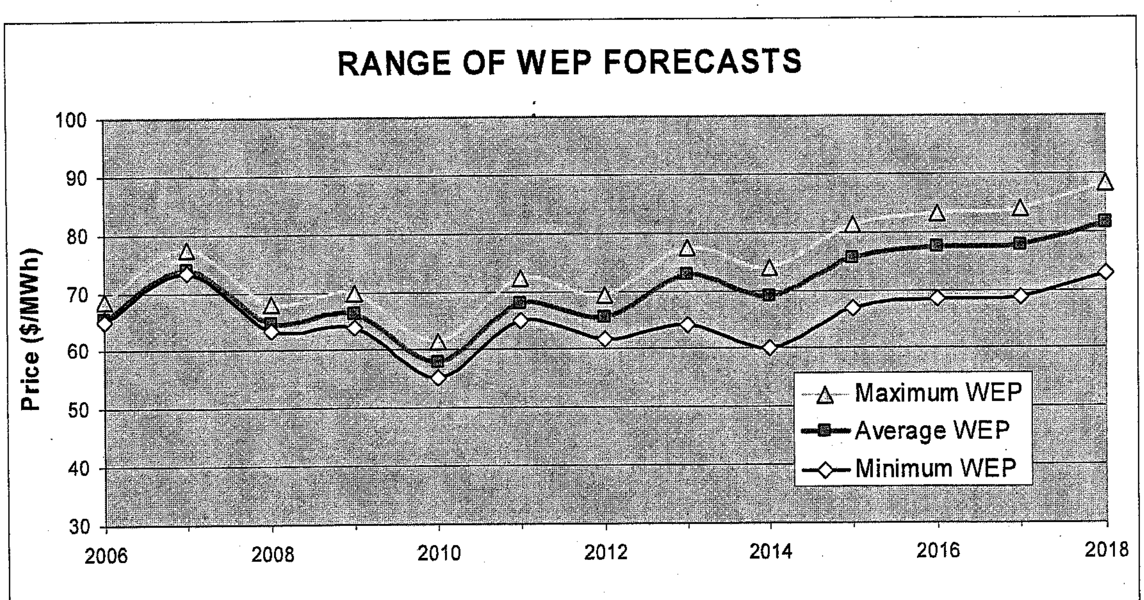
The Model can be used in conjunction with the Marketsym model – or some other production cost model – to forecast wholesale electricity prices. The Model can calculate the fixed cost portion of the wholesale electricity prices (WEP), but not the variable portion. The Marketsym model, on the other hand, can calculate the variable portion of the WEP, but not the fixed portion.

The details of this process are complicated and outside the scope of this report but can briefly be explained as follows. To estimate the fixed portion, the Model must be run to emulate the fixed cost for each of the combined cycles online during the period from 2001 to the end of the forecast period. These annual costs are then analyzed to find the following for each year of the forecast period: the most expensive unit in each year, the least expensive unit in each year and the average cost of all the generating units.

The Marketsym model is run in the cost-based mode for all the years of the forecast using all the above identified resource additions. The fixed costs from the Model are then added to the variable costs from the Marketsym model to get the WEP forecast.

Figure 29 is an illustrative example of the resulting wholesale electricity price forecast. The maximum wholesale electricity price is the most expensive generating unit in each year. The minimum wholesale electricity price is the least expensive generating unit in each year. The average wholesale electricity price is the average of all the generating units operating in that year.

Figure 29: Illustrative Example for Wholesale Electricity Price Forecast



Source: Energy Commission

APPENDIX A: Contact Personnel

The following is a list of the Energy Commission and contractor personnel who participated in the development of the Model, the data gathering process and the computer simulations, along with their phone numbers and e-mail addresses. This list is intended to facilitate information requests related to this report. If you are in doubt as to whom to contact, you can contact the authors, who will direct you to the appropriate source. Copies of this report and the Model are available on the website at:

http://www.energy.ca.gov/2007_energypolicy/documents/index.html#061207

A User's Guide for the Model will be available at this website within the next month.

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Source: Energy Commission

APPENDIX B: Alternative Technology Data

COMPARATIVE COSTS OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION TECHNOLOGIES: APPENDIX B RENEWABLE ENERGY COST OF GENERATION INPUTS

CONSULTANT REPORT

Prepared For:
California Energy Commission

Prepared By:
Navigant Consulting Inc.

NAVIGANT CONSULTING

August 2007
CEC-200-2007-011 APB

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Table of Contents

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INTRODUCTION

Renewable energy technologies are constantly changing and evolving. Renewables are fairly immature technologies, and there is significant research and development activities taking place. As more investment is made and more is learned, there will be reductions in the capital and operating costs. This research attempts to capture some of these dynamics.

Not as much attention was placed on renewable energy in the 2003 Integrated Energy Policy Report, IEPR, and not as much was being actually put in the field, especially in the United States. But since then, renewable and clean energy is in the paper and on the news almost every day. California is regarded as a leader in this area, and is becoming a more central part of generation strategies. In most cases, costs have continued to decrease and performance has improved for these technologies. But in some cases, some of the costs have actually increased. Just looking at wind and solar, wind capital cost was approximately $1,200 a kilowatt back in 2003, but today it is closer to $2,000. This is because of high demand for turbines, insufficient skilled labor for installation, and increasing steel prices as a result of worldwide demand. All these things contribute to the price increases.

In the solar photovoltaic, PV, area, silicon costs have risen because there has not been an increase in silicon manufacturing capacity. In addition, it takes two to three years to build plants and bring them on-line. These factors have driven up costs on the PV side.

To develop the inputs for renewable energy technology for the Cost of Generation Model, the consultant first reviewed relevant literature. This included studies such as those performed by the Electric Power Research Institute, EPRI, the California Energy Commission, Energy Commission, and other published data. This provided a better understanding of the best published data that was available, as well as insight into the types of facilities that could be built in California.

For example, looking at the potential landfill gas sites in California suggests that there might be more new facilities with a capacity of about one megawatt, rather than larger capacities of existing facilities, which can range up to five or megawatts. Navigant Consulting also reviewed their internal database, comprised of published literature, and consulting work performed for utilities, venture capital firms and others.

The consultant developed "straw man data" that reflected current data appropriate for California. That data was distributed to the people in respective industries that would have a good sense of what the California market is today. The consultant conducted interviews with those industry representatives and asked them if the assumptions were appropriate. This resulted in more refined data that was reviewed with Energy Commission staff. After Energy Commission staff review, the data was reviewed once more by other experts within Navigant, and then the data was submitted for presentation at the June 12, 2007 workshop.

The June 12 workshop provided the public review necessary to validate the data. The entire workshop, including the agenda, distributed materials, audio recording, and transcript is available at the Energy Commission's website, at:
http://www.energy.ca.gov/2007_energypolicy/documents/index.html#061207

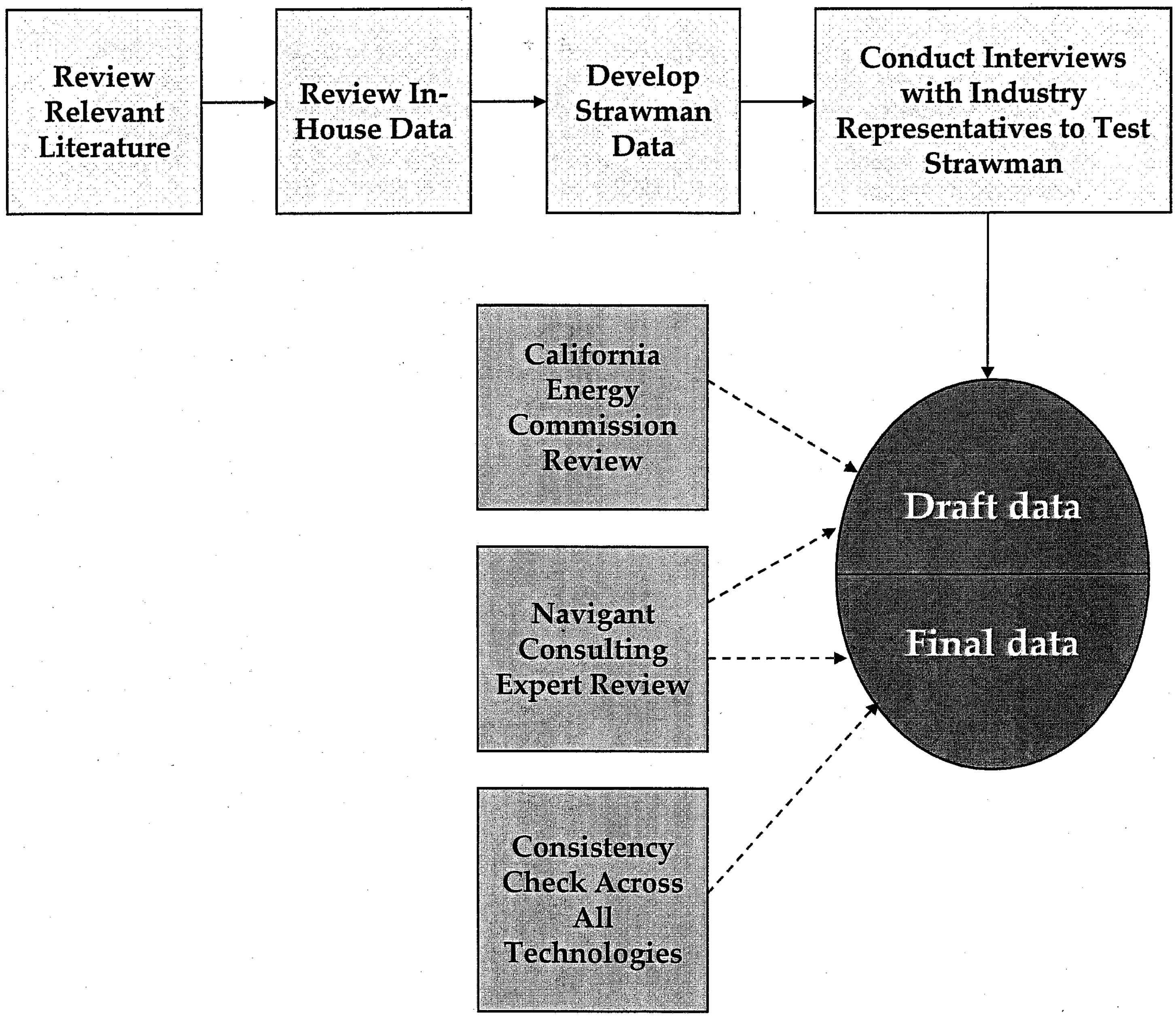
Readers should keep in mind that not all of these technologies are at the same level of maturity. Some technologies, such as utility-scale wind, are well understood. It is a fairly mature technology, even though there is still a significant amount of potential for cost reductions. There are other technologies that are maybe just as, or even more mature, such as landfill gas. But the cost data that is publicly available is sometimes several years old. The data does not always reflect costs that are required based on emission regulations. A higher gas cleanup cost or emission control cost might be necessary.

For technologies that are not as mature, engineering cost estimates or pilot plant costs may be available. These too require review. An engineering cost estimate might be optimistic, or it might not capture some of the difficulties that are often encountered when making a technology commercial and operational. This could be influenced by linear costs or financing costs. Conversely, a pilot plant might suggest higher costs. Some pilot plants can be over-engineered in order to test several functionalities. In reality, when actually built, capital costs could be lower. The Energy Commission process and the modeling approach attempted to insure that this type of data was being taken into consideration.

In the pages that follow, the first page provides the basic description for each technology. There may be several different forms regarding one technology, and this information describes the particular technology under consideration. Following is a page listing the economic assumptions made for the technology. Third is a page presenting performance data for the technology. On each page, the sources of information are listed. The final page provides a brief explanation of key assumptions that were made to finalize the economic and performance estimates.

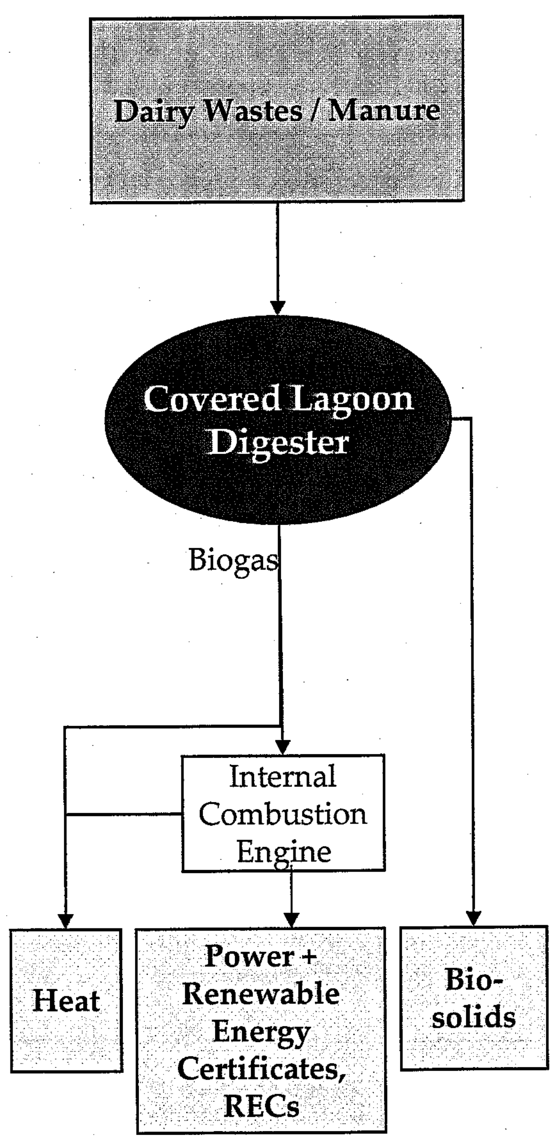
Navigant Consulting Process for Inputs to Integrated Energy Policy Report Model

Navigant Consulting, NCI, reviewed existing literature and in-house data to develop strawman information that was then vetted with industry.



An anaerobic digester treats dairy manure to produce biogas that can be used to produce electricity, heat, and bio-solids.

Schematic of the Technology



Description

- An anaerobic digester, AD, utilizes the natural process of anaerobic decomposition to treat waste (for example dairy cow manure), produce biogas that can be used to power electricity generators, provide heat and produce soil improving material.
- Anaerobic digestion power production with an internal combustion engine is an established technology.
- These cost estimates assume a combined heat and power internal combustion engine.
- Costs can vary depending on the digester being deployed. These cost estimates are for a **covered lagoon**, which is the cheapest and most suitable for warm climates.
- Other conventional digester technologies are Plug-Flow (rectangular flow-through tank, 11% - 13% solids), and Complete Mix (large tanks, 10% solids, most expensive).
- Other more advanced digester technologies use "multi-stage" digesters or "flow" designs with the use of "thermophillic" (high temperature) bacteria.

Economic Assumptions: Anaerobic Digesters – Dairy

	Anaerobic Digesters – Dairy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity, kilowatts, (kW)	250	A 250 kW system is the expected size of new single-farm, covered lagoon anaerobic digester in California. Sizes may increase over time if other types of organic wastes are added.
Project Life (years)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$5,300	Overnight costs includes development fees, interconnection, but not interest during construction. The cost breakdown between engine/generator, digester and other is an approximation, and is performed differently by each source. The digester component could also be considered installation.
Electrical Facilities ($/kW)	$2,000	From Navigant Consulting sources and estimates.
Digester ($/kW)	$2,600	From Navigant Consulting sources and estimates.
Other ($/kW)	$700	Other includes manure storage, liquids separation, and varies depending on system design.
Fixed operations and maintenance (O&M) ($/kW-yr)	$50	O&M costs are estimated to be near $250/kW-yr in California based on cost estimates at actual facilities. These costs are not typically separated into fixed and variable. NCI estimates that 80% of the costs are variable. These numbers have been confirmed by interviews.
Variable O&M ($/MWh)	$15	

Sources: Navigant Consulting Estimates 2007, Cornell Manure Management Program, California Dairy Power Production Program, Wisconsin Anaerobic Digester Casebook – 2004 Update, NCI Interviews with equipment and digester manufacturers.

Performance Data: Anaerobic Digesters – Dairy

	Anaerobic Digesters – Dairy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	75%	Capacity factors can vary significantly by dairy and can be dependent on the owner's motivation or amount paid for an O&M service contract.
Fuel Cost ($/MMBtu)	n/a	
Economic benefits from by-products sales (heat, digester solids) ($/kW-yr)	$100	Economic benefits can vary significantly, but based on historical data can amount to $20,000/yr for a 200 kW system.
Higher Heating Value Efficiency, HHV, (%)	20%	HHV efficiency is based on the feedstock to electricity. Feedstock to methane is typically 60% to 70% efficient and the internal combustion engine ~30%.
CO_2 (lb/MWh)	AD – Dairy is assumed to be CO_2 neutral. Senate Bill, SB, 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	NO_x can vary widely. Figures shown assume 60 parts per million by volume, ppmv, @15% O_2 in exhaust, which complies with the California Air Resources Board, ARB guidelines for best available control technology, BACT.
SO_x (lb/MWh)	0.39	Sulfur content can vary. Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2.

Sources: Navigant Consulting Estimates 2007, Cornell Manure Management Program, California Dairy Power Production Program, Wisconsin Anaerobic Digester Casebook – 2004 Update, NCI Interviews with equipment and digester manufacturers.

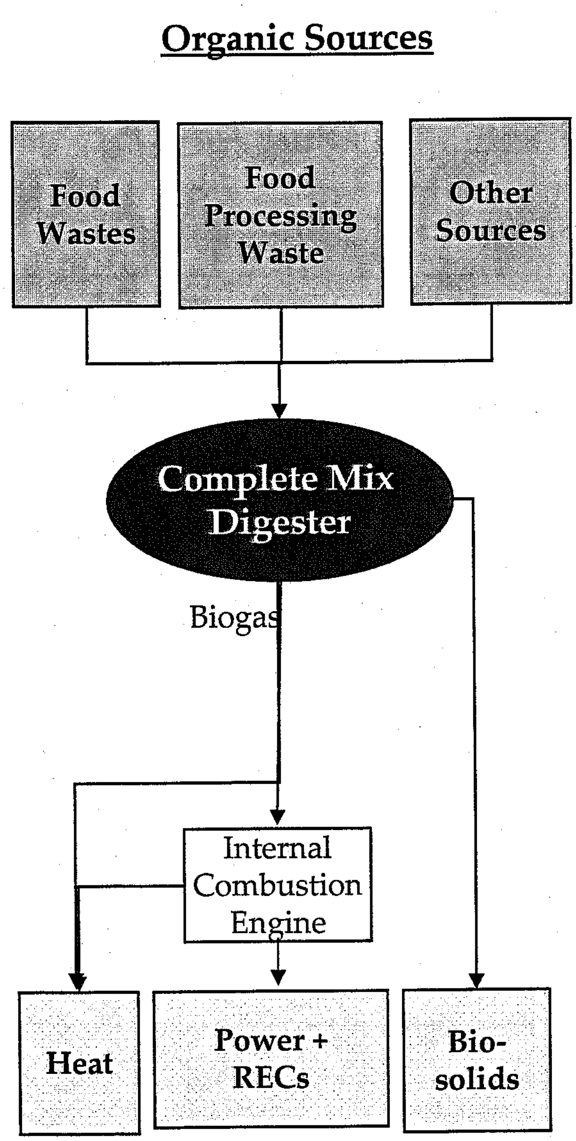
Methodology and Key Assumptions: Anaerobic Digesters – Dairy

Methodology & Key Assumptions

- The costs are for a standard covered lagoon digester. Most systems in California use a covered lagoon. In the future, more and more systems will utilize a complete mix system or other technology that allows multiple feedstocks to be placed in the digester. This technology is described in the "Anaerobic Digester – Food Waste"
- NCI surveyed costs from public– California's Dairy Power Production Program, California's Western United Dairymen, Wisconsin's Agricultural Biogas Casebook, and Cornell University's Manure Management Program. We developed installed cost and O&M based on these sources and confirmed these estimates with interviews with system designers, installers, and equipment providers. Installed costs in California are likely to be higher than the Midwest due to higher labor costs for the construction of the digester and installation of the equipment.
- Actual costs for a covered lagoon digester can vary by 25% depending on foundation and lining requirements for the digester as well as local labor rates.
- Costs for complete mix systems with concrete-lined digesters can cost approximately $700/kW more. These systems are more common on the east coast where manure is scraped into the digesters. In California, it is much more common to wash manure away with water. A covered lagoon system is more adequate for these systems given the moisture content.
- Costs for larger, 1 MW systems can cost 25% less due to economies of scale.
- Future costs are not expected to decrease in real terms as the total cost is driven primarily by installation costs and materials. Future cost declines for both installed costs and O&M are driven by reduced costs for the IC engine.

An anaerobic digester treats food wastes manure to produce biogas that can be used to produce electricity, heat, and bio-solids.

Schematic of the Technology



Description

- An anaerobic digester utilizes the natural process of anaerobic decomposition to treat waste (for example, food wastes), produce biogas that can be used to power electricity generators, provide heat and produce soil improving material.
- These cost estimates assume a combined heat and power internal combustion engine.
- Food wastes could include:
  - Food wastes, from large food retail establishments
  - Fats, oils, and grease, such as Yellow Grease or trap greases
  - Food processing wastes
- Costs can vary depending on the digester being deployed. These cost estimates are for a **Complete Mix,** which deploys large tanks, has 10% solids, and is the most expensive of the conventional digester technologies.

Economic Assumptions: Anaerobic Digesters - Food Waste

	Anaerobic Digesters - Food Waste Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	2,000	The Plant Capacities will vary widely. There is the potential for capacities to increase in the future as technology advances allow for additional types of feedstocks to be combined and utilized.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$5,300	Total installed costs will vary widely depending on size, number and type of feedstocks, type and use of electricity generating equipment. In many applications, the biogas may be used for process heat or for pipeline quality natural gas.
Electrical Facilities ($/kW)	$1,750	From Navigant Consulting sources and estimates.
Digester ($/kW)	$2,100	
Other ($/kW)	$1,450	
Fixed O&M ($/kW-yr)	$150	Fixed O&M is estimated to be approximately $150/kW-yr. Variable O&M estimated to be $200/MWh, reduced by an economic benefit from a **tipping fee**, or soil amendment credit, estimated to be $3.70/MMBtu. (Assumes $20/ton tipping fee, 70% food waste moisture content). Since no statistical or operating experience, tipping fee is assumed to remain constant.
Variable O&M ($/MWh)	-$60	

Sources: Navigant Consulting Estimates 2007, NCI Estimates for Anaerobic Digester-Dairy, NCI Interview with Dave Konwinski – Onsite Power Systems, NCI interviews with European project developers, owners, and technology providers; *Characterization of Food and Green Waste as Feedstock for Anaerobic Digesters, Interim Report*, 2005, Zhang et. al., California Energy Commission.

Performance Data: Anaerobic Digesters - Food Waste

	Anaerobic Digesters – Food Waste Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	75%	Capacity Factors can vary significantly by plant and are largely dependent on the type of feedstock.
HHV Efficiency (%)	18%	HHV efficiency is based on the feedstock to electricity. Feedstock to methane is typically 60% to 70% efficient and the IC engine ~30%. There is about a 10% loss in energy output to power the digester and mixing equipment.
CO_2 (lb/MWh)	AD – Food Waste is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	NO_x can vary widely. Figures shown assume 55 ppmv @15% O_2 in exhaust, which complies with the ARB guidelines for BACT.
SO_x (lb/MWh)	0.42	Sulfur content can vary. Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2.

Sources: Navigant Consulting Estimates 2007, NCI Estimates for Anaerobic Digester-Dairy, NCI Interviews with industry players.

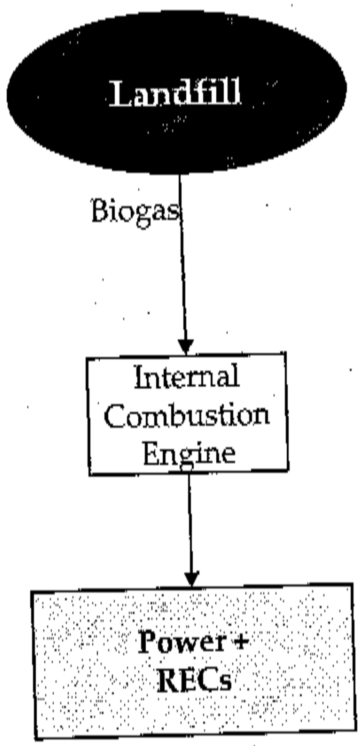
Methodology and Key Assumptions: Anaerobic Digesters - Food Waste

Methodology & Key Assumptions

- The cost estimates are for a complete-mix digester that could utilize a variety of organic wastes. Several different designs and technologies can be used, and the assumption for this technology is that one or two sources of primarily urban wastes are being used, for example food wastes from restaurants, organic waste separated at the landfill, or food processing wastes.
- The added complexity of the system requires additional staff to operate the facility and added capital equipment for preparation of the waste.
- Due to the increased size, the system benefits from economies of scale for the generation equipment and the digesters themselves.
- Future costs are expected to decline as designers and manufacturers of the digesters learn and optimize the design. As designs improve, an increased amount of organic waste may be included, and sizes could increase. These cost estimates assume a constant 2 MW size.
- Actual installed costs for existing facilities are not published in detail. Dave Konwinski from Onsite Power Systems provided guidance on cost data. NCI based its cost estimates on relative costs to a covered lagoon system, published costs for complete-mix systems, historical analysis based on systems in Europe, and input from Dave Konwinski.

A landfill gas fuel to energy, LFGFTE, utilizes the biogas from a landfill to power an electricity generator.

Schematic of the Technology



Description

- A LFGFTE utilizes the biogas produced by decomposing organic waste in landfills to power an electricity generator.
- Since most applications use an internal combustion engine, these cost estimates assume a power-only internal combustion engine (no heat capture/Combined heat and power [CHP]).
- IC Engines are more forgiving of the typically poor fuel quality that comes from a landfill.
- Costs can vary significantly based on the size of the application and the amount of front-end gas clean-up and tail-end emission clean-up. These cost estimates assume both front-end gas clean-up and tail-end emission clean-up due to the increasing stringency of California air emission regulations.

Economic Assumptions: Landfill Gas Fuel to Energy (LFGFTE)

	Landfill Gas to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Plant Capacity (kW)	2,000	The average size of existing facilities in CA is 4 MW. 32 of 51 of existing facilities in 2002 used a reciprocating engine, averaging 3.5 MW. The average size of future facilities using reciprocating engines is 2 MW.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kWpac)	$1,850	Total Installed Costs for landfill gas have increased significantly over the past 5 years. According to Energy Commission reports, historical costs as of 2002 were between $1,100/kW and $1,300/kW. Based on interviews installed costs in 2006 are estimated to be 50% higher, primarily due to the increased cost in permitting costs and increased capital costs for emissions control. Gas collection facilities are required to be in place for municipal solid waste facilities with design capacities over 2.75 million tons. If they need to be added, they typically cost $500/kW.
Non-Fuel Fixed O&M ($/kW-yr)	$20	Historical O&M costs are based on historical costs at existing facilities as obtained from Energy Velocity as well as interviews with industry. The variable O&M includes only the maintenance of the generating equipment and not the maintenance of the landfill collection system, which is estimated to be about $50/kW-yr (10% of the installed cost of the gas collection system each year).
Non-Fuel Variable O&M ($/MWh)	$15	

Sources: Navigant Consulting Estimates 2007. *Landfill Gas-to-Energy Potential in California*, CEC 500-02-041V1; *Economic and Financial Aspects of Landfill Gas to Energy Project Development in California*, Apr 2002, CEC-500-02-020; NCI Interviews; *Energy Velocity*; Gas-fired Distributed Energy Resource Technology Characterizations, DOE/NREL/GTI, October 2003.

Performance Data: Landfill Gas Fuel to Energy (LFGFTE)

	Landfill Gas Fuel to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Scheduled Outage Factor (%)	6%	Forced outage rates and typical capacity factors are based on historical data at existing plants as reported by Energy Velocity.
Forced Outage Rate (%)	7%	
Typical Net Capacity Factor (%)	85%	
Fuel Cost ($/MMBtu)	-	
HHV Efficiency (%)	29.5%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	LFGFTE is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	Figures shown assume 65 ppmv @15% O_2 in exhaust, which complies with the ARB guidelines for BACT.
SO_x (lb/MWh)	0.34	Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2.

Sources: Navigant Consulting Estimates 2007. *Landfill Gas-to-Energy Potential in California,* CEC 500-02-041V1; *Economic and Financial Aspects of Landfill Gas to Energy Project Development in California,* Apr 2002, CEC-500-02-020; NCI Interviews; *Energy Velocity;* "Gas-fired Distributed Energy Resource Technology Characterizations", DOE/NREL/GTI, October 2003.

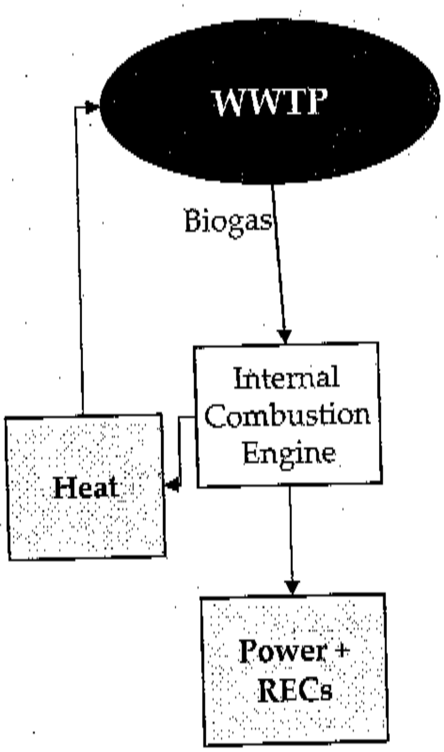
Methodology and Key Assumptions: Landfill Gas Fuel to Energy (LFGFTE)

Methodology & Key Assumptions

- Landfill gas to energy systems come in a wide variety of sizes and use a variety of different generating equipment. For the purpose of this analysis, the costs are based on a 2 MW reciprocating engine, which has been a common common system historically, and many of the planned systems are expected to be similar. Fuel cells and microturbines may become more pervasive as emission requirements become more stringent and the cost of these technologies decreases.
- The costs of landfill gas to energy facilities in California have increased from about $1,200/kW in 2002 to about $1,850/kW in 2006. Actual costs for installed systems varies widely due to the differences in technology, size, accounting, and cost overruns. NCI based its estimates for installed costs on its own historical cost estimates, historical costs published by the Energy Commission, as well as interviews with owners and developers of landfill gas to energy projects.
- The increase in cost has been driven by more stringent permitting requirements that has increased the development costs and increased capital costs for emission control equipment.
- Costs for the electric generating equipment, such as reciprocating engines, are expected to decline by about 1%/yr based on interviews as well as DOE/NREL projections. Development costs and installation costs are expected to remain constant in real terms as these are driven more by labor and permitting.
- The variable O&M includes only the maintenance of the generating equipment and not the maintenance of the landfill collection system, which is estimated to be about $50/kW-yr (10% of the installed cost of the gas collection system annually, or approximately $50/kW-yr).

A waste water treatment fuel to energy (WWTFTE) facility utilizes the biogas produced at a waste water treatment facility to power an electricity generator and produce heat.

Schematic of the Technology



Description

- A waste water treatment fuel to energy (WWTFTE) facility utilizes the biogas produced by decomposing organic waste in a waste water treatment facility to power an electricity generator and produce heat.
- Since most applications use an internal combustion engine, these cost estimates assume a combined heat and power internal combustion engine.
- IC Engines are more forgiving of the typically poor fuel quality that comes from a waste water treatment facility.
- Costs for a WWTFTE facility are typically higher than a LFGTE due to the smaller size of the engine, and the additional costs of the heat capture/CHP. These cost estimates assume both front-end gas clean-up and tail-end emission clean-up due to the increasing stringency of California air emission regulations.

Economic Assumptions: Waste Water Treatment Fuel to Energy (WWTFTE)

	Waste Water Treatment Fuel to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	500	From Navigant Consulting sources and estimates.
Project Life (yrs)	20	
Overnight Cost ($/kWpac)	$2,400	Costs for a WWTFTE facility are typically higher than a LFGTE due to the smaller size of the engine, and the additional costs of the heat capture/CHP.
Fixed O&M ($/kW-yr)	$22	Historical O&M costs are based on historical costs at existing facilities as obtained from Energy Velocity as well as interviews with industry. O&M costs are higher for the WWTFTE than the LFGTE due to the decreased scale.
Variable O&M ($/MWh)	$18	

Sources: Navigant Consulting Estimates 2007. NCI cost estimates 2002-2006, NCI Interviews; *Energy Velocity*; Gas-fired Distributed Energy Resource Technology Characterizations, DOE/NREL/GTI, October 2003.

Performance Data: Waste Water Treatment Fuel to Energy (WWTFTE)

	Waste Water Treatment Fuel to Energy Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	6%	Forced outage rates and typical capacity factors are based on historical data at existing plants as reported by Energy Velocity.
Forced Outage Rate (%)	7%	
Typical Net Capacity Factor (%)	85%	
Fuel Cost ($/MMBtu)	-	
HHV Efficiency (%)	27.5%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	WWTFTE is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.7	Figures shown assume 65 ppmv @15% O_2 in exhaust, which complies with the ARB guidelines for BACT.
SO_x (lb/MWh)	0.39	Sulfur content of waste water treatment plants can vary. Figures shown assume SO_2 in exhaust of 10 ppmv @ 15% O_2. For SO_x this value is consistent with some H_2S removal prior to combustion.

Sources: Navigant Consulting Estimates 2007. Navigant Consulting Estimates 2007. NCI cost estimates 2002-2006, NCI Interviews; *Energy Velocity;* Gas-fired Distributed Energy Resource Technology Characterizations, DOE/NREL/GTI, October 2003.

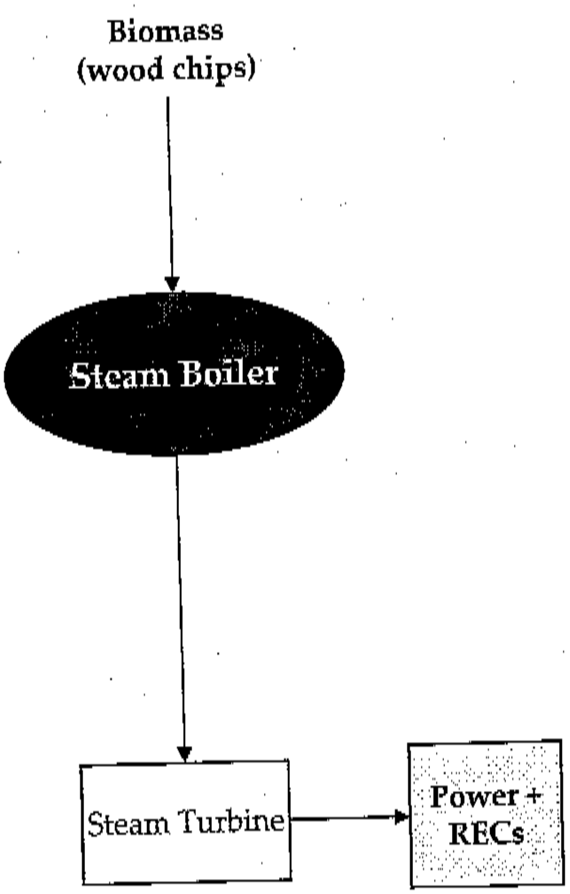
Methodology and Key Assumptions: Waste Water Treatment Fuel to Energy (WWTFTE)

Methodology & Key Assumptions

- The costs of a WWTFTE system will be very similar to that of a LFGFTE system. The configurations are fairly similar, but the WWTFTE system will have higher installed costs because it is a smaller system and it is a CHP application.
- The O&M for a WWTFTE system does not include the O&M for the gas collection system.
- There are limited sources for historical costs of WWTFTE systems. The estimates are based on historical NCI estimates and interviews. The difference in capital costs due to CHP and size were confirmed with DOE/NREL estimates.

Biomass is combusted in a boiler that generates the steam that drives a steam turbine

Schematic of the Technology



Description

- In a *stoker boiler*, biomass is added in a thin layer on a grate near the bottom of the boiler. This provides a more even distribution of feed material.
  - Mature, most commonly used technology. Incremental improvements being made to increase steam temperature and pressure
- In a *fluidized-bed boiler*, combustors burn biomass fuel in a bed of hot granular material. Air is injected at a high-rate underneath the bed to create the appearance of a boiling liquid. This helps to evenly distribute the fuel.
  - Relatively mature technology - fluidized bed combustors are becoming the systems of choice for biomass fuels, due to good fuel flexibility and good emissions characteristics.

Economic Assumptions: Biomass Combustion – Fluidized Bed Boiler

	Biomass Combustion - Fluidized Bed Boiler Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	25	From Navigant Consulting sources and estimates.
Project Life (yrs)	25	
Overnight Cost ($/kW)	$2,750	Overnight costs for 2006 are based on the NREL and Oak Ridge National Lab study. Includes all development costs, such as permitting, inventory capital and start-up costs.
Fixed O&M ($/kW-yr)	$145	Fixed O&M costs for 2006 are based on the NREL and OAK Ridge National Lab study. Includes operating, labor and maintenance costs.
Variable O&M ($/MWh)	$3	Non-Fuel Variable O&M costs for 2006 are based on the NREL and Oak Ridge National Lab study. Includes chemicals, water, ammonia, and ash disposal.
Fuel Cost ($/MMBtu)	$2.5	Fuel costs assume wood chips at $40/dry ton

Source: *Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report* published by the Energy Research and Development Division, California Energy Commission, June 2005; *BioPower Technical Assessment – State of the Industry and the Technology* published by the National Renewable Energy Lab and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews.

Performance Data: Biomass Combustion – Fluidized Bed Boiler

	Biomass Combustion – Fluidized Bed Boiler Performance Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Scheduled Outage Factor (%)	4%	Scheduled Outage based on approximately 2 weeks/year. This includes a major turbine/generator overhaul every six years lasting one month, 5-7 days of annual for cleaning, tube repairs, etc and 2 days for inspections. 6% forced outage based on interviews.
Forced Outage Rate (%)	6%	
Net Capacity Factor (%)	85%	Based on the California Energy Commission Biomass Strategic Value Analysis, In Support of the 2005 Integrated Energy Policy Report .
HHV Efficiency (%)	22%	NCI estimate based on review of above mentioned studies and interviews.
Annual Output Degradation (%/yr)	0.4%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	Biomass Combustion is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.24	Based on NO_x emissions of 0.08 lbs/MMBtu fuel input as indicated by equipment suppliers. This is better than the ARB recommended BACT guidelines of a limit for NO2 in exhaust of 70 ppm at 12% CO_2 (0.128 lbs/MMBtu) for solid biomass fuel firing. See (http://www.arb.ca.gov/drdb/sac/curhtml/r411.pdf) Page 6.
SO_x (lb/MWh)	0.70	Based on sulfur content in the biomass of 0.03%. Only 60% of the sulfur is converted to SO_2 due to the addition of SO_x control minerals in the fluidized bed. This is lower than typical requirements in California for sulfur dioxide emissions from the combustion of solid and solid-derived fuels for power generation. See (http://www.arb.ca.gov/drdb/sd/curhtml/r260-43a.htm)

Source: *Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report* published by the Energy Research and Development Division, California Energy Commission, June 2005; *BioPower Technical Assessment – State of the Industry and the Technology* published by the National Renewable Energy Lab and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews.

Economic Assumptions: Biomass Combustion – Stoker Boiler

	Biomass Combustion – Stoker Boiler Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	25	From Navigant Consulting sources and estimates.
Project Life (yrs)	25	
Overnight Cost ($/kW)	$2,500	Based on the Energy Commission study, assumed capital costs are marginally lower than for the fluidized bed boiler case.
Fixed O&M ($/kW-yr)	$130	Based on the Energy Commission study, assumed that Fixed O&M costs for a stoker boiler are 10% lower than for a fluidized bed boiler.
Variable O&M ($/MWh)	$3	Non-Fuel Variable O&M are assumed to be the same for a stoker boiler system as for a fluidized bed boiler system
Fuel Cost ($/MMBtu)	$2.5	Fuel costs assume wood chips at $40/dry ton.

Source: *Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report* published by the Energy Research and Development Division, California Energy Commission, June 2005; *BioPower Technical Assessment – State of the Industry and the Technology* published by the National Renewable Energy Laboratory and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews

Performance Data: Biomass Combustion – Stoker Boiler

	Biomass Combustion – Stoker Boiler Performance Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Scheduled Outage Factor (%)	4%	Scheduled Outage based on approximately 2 weeks/year. This includes a major turbine/generator overhaul every six years lasting one month, 5-7 days of annual for cleaning, tube repairs, etc and 2 days for inspections. 6% forced outage based on interviews.
Forced Outage Rate (%)	6%	
Net Capacity Factor (%)	85%	Based on the Energy Commission Biomass Strategic Value Analysis, In Support of the 2005 Integrated Energy Policy Report .
HHV Efficiency (%)	21.5%	NCI estimate based on review of above mentioned studies and interviews. 0.5% lower than for fluidized bed boiler based on discussions with technology providers.
Annual Output Degradation (%/yr)	0.4%	Based on a total output degradation over the lifetime of the project (25 years) of ~2% (same for fluidized bed boiler). Based on NCI estimates, interviews and review of the following documents: http://www.cpuc.ca.gov/Published/Comment_resolution/54445.htm and http://www.calwea.org/Attached%20Documents/Recd%2004Mar05/CALWEA-CBEA-%20CCC%20comments%20on%20the%20MPR%20Staff%20Report%202-28-05.pdf.
CO_2 (lb/MWh)	Biomass Combustion is assumed to be CO_2 neutral. This is SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	1.24	Based on NO_X emissions of 0.08 lbs/MMBtu fuel input as indicated by equipment suppliers. This is better than the ARB recommended BACT guidelines of a limit for NO_2 in exhaust of 70 ppm at 12% CO_2 (0.128 lbs/MMBtu) for solid biomass fuel firing. See (http://www.arb.ca.gov/drdb/sac/curhtml/r411.pdf) Page 6.
SO_x (lb/MWh)	1.10	Based on sulfur content in the biomass of 0.03%. All the sulfur is converted to SO_2. Also see Slide 21.

Source: *Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report* published by the Energy Research and Development Division, California Energy Commission, June 2005; *BioPower Technical Assessment – State of the Industry and the Technology* published by the National Renewable Energy Laboratory and Oak Ridge National Lab, June 2003; NCI estimates based on DOE/EPRI Technology Characterizations and NCI multi-client study and interviews.

Methodology and Key Assumptions: Biomass Combustion

Methodology & Key Assumptions

- For all years we are profiling a 25 MW_E steam boiler fueled by wood chips and associated steam turbine for power generation.

- Capital Costs:
  - For a fluidized bed boiler system, the NREL and Oak Ridge National Laboratory reports capital costs of $2,426/kW for 2001. NCI adjusted this figure for inflation (inflator of 1.15), that resulted in $2,750/kW for 2006.
  - The California Energy Commission study indicates that capital costs for a stoker boiler system are 15% lower than for a fluidized bed boiler system in 2006. Based on interviews, estimate cost differential to be 10%, or ~$250/kW in 2006.

- Fixed O&M Costs:
  - For a fluidized bed boiler, the NREL and Oak Ridge National Laboratory study reports total yearly costs of $3.1M in 2001, or $125/kW-yr. Applying the above-mentioned inflator to 2006, calculates to $145/kW-yr.
  - Based on the California Energy Commission study, assumed that Fixed O&M costs for a stoker boiler are 10% lower than estimates for a fluidized bed boiler throughout the timeframe.

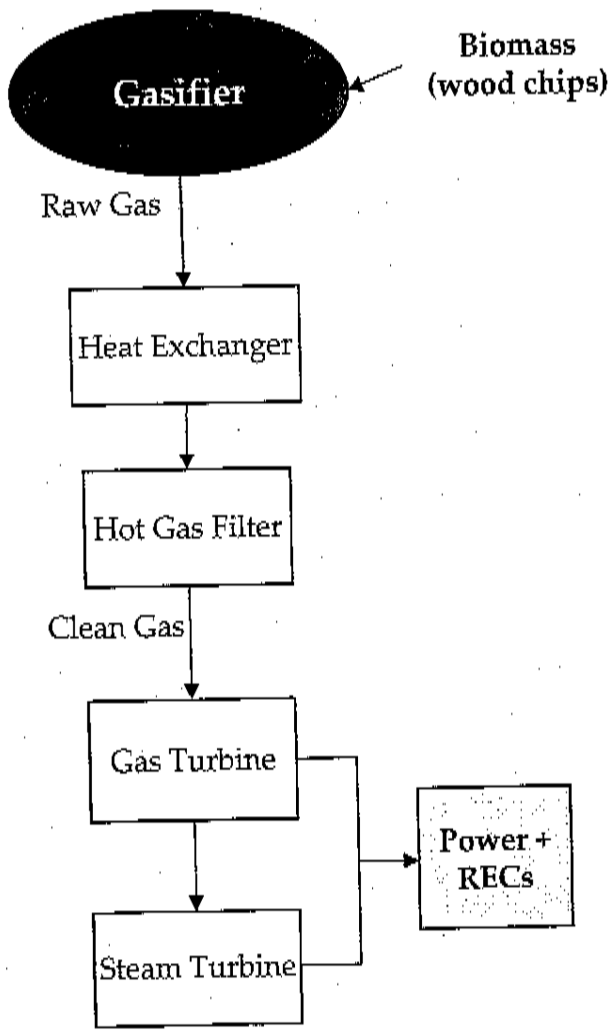
Methodology and Key Assumptions: Biomass Combustion

Methodology & Key Assumptions

- Non-Fuel Variable O&M Costs: The NREL and Oak Ridge National Lab study reports total yearly costs of $560k in 2001, or $3/MWh. Used this same assumption for fluidized bed boilers and stoker boilers alike.
- System HHV Efficiency. NCI estimate. The efficiencies in the California Energy Commission study appear low for the state-of-the-art technologies in the short-term. The NREL and Oak Ridge National Lab study projects higher efficiencies that reflect the use of a biomass drier and steam cycle efficiencies improvements, for example higher pressure, higher temperature and reheat (these make sense only for larger plant sizes). Based on interviews, NCI estimates an efficiency of 22% for a 25 MW_E plant in 2006 that will improve only marginally as the technology is mature. Stoker boilers are assumed to have a slightly lower efficiency due to a lower carbon burnout
- Compared to a stoker boiler system a fluidized-bed boiler:
  - Achieves a higher carbon burn-out.
  - Ensures more fuel flexibility due to the good mixing that occurs on the fluidized bed.
  - The relatively low combustion temperature ensures reduced NO_x emissions, and the CFB process allows for the addition of certain minerals into the bed to control SO_x emissions. We estimate a 40% reduction in SO_x emissions compared to the stoker boiler system.

Biomass is gasified to produce a syngas that fuels a combined cycle power generation facility.

Schematic of the Technology



Description

- This technology gives biomass access to the higher efficiencies of gas fired power generation and combined cycles.
- Key characteristics of the profiled system:
  - Direct (single stage and autothermal), pressurized, fluidized bed gasifier.
  - Heat exchanger to 400C prior to hot gas filter for dust removal (tar removal is not necessary).
  - Cleaned gas is a combusted in a gas turbine, which also supplies the gasifier with pressurized air from the compressor.
  - Residual heat is used in a steam cycle.
- Commercial deployment of the technology has not occurred. One demonstration BIGCC unit has been built in Europe but it is no longer in operation.
  - Information on actual capital and operating costs is limited.

Economic Assumptions: BIGCC

	BIGCC Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Plant Capacity (MW)	20	From Navigant Consulting sources and estimates.
Project Life (yrs)	25	
Overnight Cost ($/kW)	$2,800	
Fixed O&M ($/kW-yr)	$150	
Non-Fuel Variable O&M ($/MWh)	$3	
Fuel Cost ($/MMBtu)	$2.50	

Sources: *Handbook Biomass Gasification* edited by H. Knoef and published by the Biomass Technology Group, BTG; *Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report*, Energy Research and Development Division, California Energy Commission; *Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems* by K. Craig and M. Mann, National Energy Renewable Lab; *Fuels and Electricity from Biomass with and without CO_2 Capture and Storage* by E. Larson, R. Williams, H. Jin; *Integrated Gasification Combined Cycle and Steam Injection Gas Turbine Powered by Biomass Joint-Venture Evaluation* by G. Sterzinger at the Economics, Environment and Regulation; *Biomass-Gasifier/Aeroderivative Gas Turbine Combined Cycles: Part A – Technologies and Performance Modeling* by E.D. Larson and S. Consonni; *Renewable Energy Technology Characterizations* TR-109496 Topical Report. Prepared by Office of Utility Technologies, Energy Efficiency and Renewable Energy, U.S. Department of Energy and EPRI; Interviews with Richard Bain, NREL and Mark Paisley, Taylor Biomass Energy

Performance Data: BIGCC

	BIGCC Performance Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Scheduled Outage Factor (%)	6%	Based on the BTG study, assumed a total downtime of 12%.
Forced Outage Rate (%)	6%	
Net Capacity Factor (%)	85%	From Navigant Consulting sources and estimates.
HHV Efficiency (%)	32%	
Annual Output Degradation (%/yr)	0.4%	
CO_2 (lb/MWh)	BIGCC is assumed to be CO_2 neutral. SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.	
NO_x (lb/MWh)	0.85	See comments on section on biomass combustion technologies (stoker boiler and fluidized bed boiler) for further details.
SO_x (lb/MWh)	0.75	

Sources: *Handbook Biomass Gasification* edited by H. Knoef and published by BTG; *Biomass Strategic Value Analysis – In Support of the 2005 Integrated Energy Policy Report*, Energy Research and Development Division, California Energy Commission; *Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems* by K. Craig and M. Mann, National Energy Renewable Lab; *Fuels and Electricity from Biomass with and without CO_2 Capture and Storage* by E. Larson, R. Williams, H. Jin; *Integrated Gasification Combined Cycle and Steam Injection Gas Turbine Powered by Biomass Joint-Venture Evaluation* by G. Sterzinger at the Economics, Environment and Regulation; *Biomass-Gasifier / Aeroderivative Gas Turbine Combined Cycles: Part A – Technologies and Performance Modeling* by E.D. Larson and S. Consonni; *Renewable Energy Technology Characterizations* TR-109496 Topical Report. Prepared by Office of Utility Technologies, Energy Efficiency and Renewable Energy, U.S. Department of Energy and EPRI; Interviews with Richard Bain, NREL and Mark Paisley, Taylor Biomass Energy

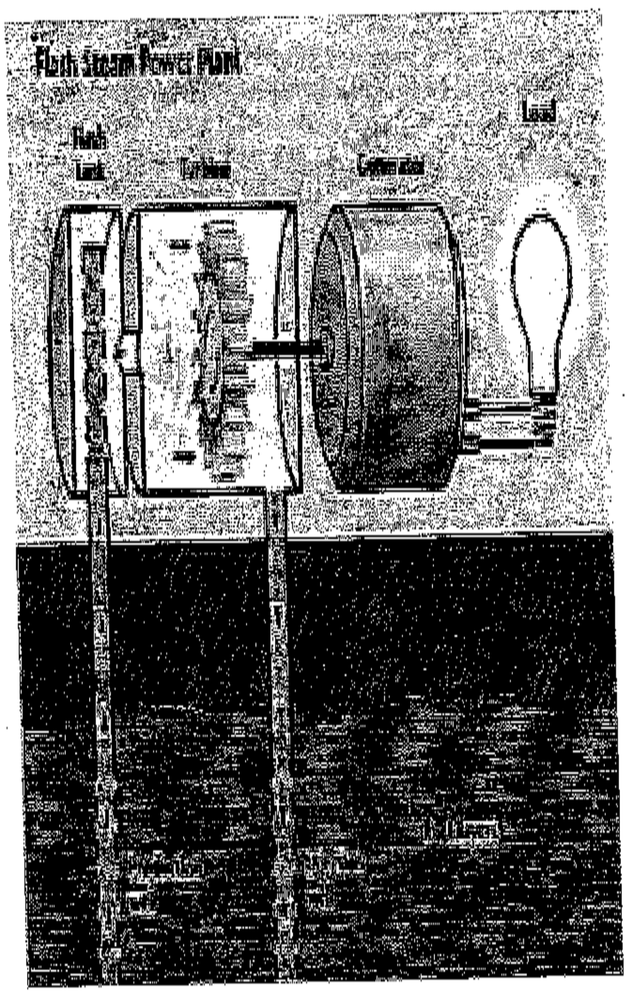
Methodology and Key Assumptions: BIGCC

Methodology & Key Assumptions

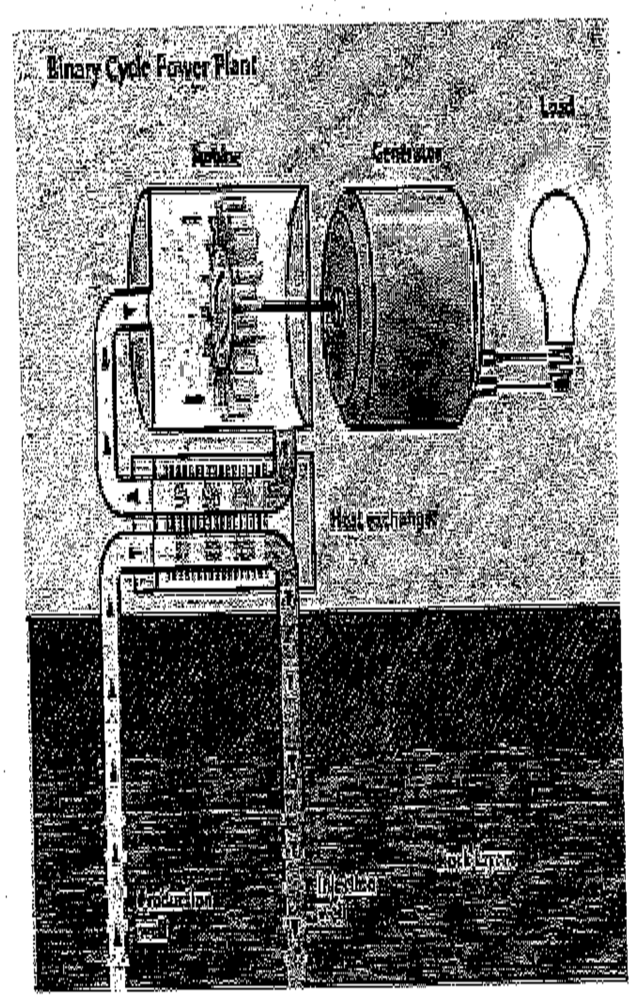
- BIGCC is not a commercial technology. In addition to the direct, pressurized, fluidized bed gasifier, other advanced biomass gasification designs are being studied. Promising options include two-stage (indirect) gasifiers and oxygen-blown gasifiers. It is unclear which variant will prove most cost-competitive in the long-term.
- The reference used for 2006 is a collaborative study conducted by BTG biomass technology group BV, a European firm specializing in bioenergy technologies. Other studies indicate lower capital and operating costs but refer to longer-term economics that incorporate learning curves and other improvements in the technology. The BTG study incorporates the experience of the few operating demonstration units to estimate the current cost for a turnkey BIGCC facility.
  - Unit has 20 MW_E capacity, a capacity factor of 85% and a HHV of 32% (lower than what is assumed in the study based on result of the interviews NCI conducted).
  - Capital costs estimated at $2,800/kW. Major cost items are the gasification island, inclusive of the gasifier, gas cleaning, heat exchangers, etc.. ($1,200/kW) and the gas turbine ($600/kW).
  - Fixed O&M, estimated at $150/kW-yr, include labor (18 people, $50/kW-yr) and maintenance (2% investment, $50/kW-yr).
  - Non-fuel variable O&M, estimated at $3/MWh, include chemicals, water consumption and disposal of residues.
  - Fuel costs of $2.5/MMBtu reflects a cost of $40/ton of wood chips.

Dual Flash systems typically use steam above 400 F and Binary Steam systems use steam below 400 F.

Dual Flash Schematic



Binary Steam Schematic



Source: National Renewable Energy Lab

Economic Assumptions: Geothermal – Dual Flash

	Geothermal – Dual Flash Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Plant Capacity (MW)	50	Current California installations range from .5 to 90 MW in size. 50 is an average.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Installed Cost ($/kW)	$2,750	
Exploration ($/kW)	$10	
Confirmation Drilling ($/kW)	$290	
Equipment/Installation ($/kW)	$2,345	
Transmission ($/kW)	$105	
Fixed O&M ($/kW-yr)	$80	
Variable O&M ($/MWh)	$5	Water for cooling condensers is the largest component of Variable O&M. Water access issues in California could balance out any gains in water usage efficiency.

Sources: Navigant Consulting Estimates 2007, *Geothermal Strategic Value Analysis,* CEC-500-2005-105-SD June 2005, Potential Improvements to Existing Geothermal Facilities in California, *GRC Transactions*, Vol. 30, 2006, J. Lovekin, S. Sanyal, A. Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007, Jim Lovekin of Geothermex, February 2007 and Vince Signorotti of Cal Energy, March 2007.

Performance Data: Geothermal – Dual Flash

	Geothermal – Dual Flash Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	95%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
Heat Rate (HHV)	n/a	
HHV Efficiency (%)	n/a	
Annual Output Degradation (%/yr)	4%	
CO_2 (lb/MWh)	60	CO_2 and SO_x are emitted from the geothermal resource. See page 115 of the Geothermal Resource Council Bulletin May-June '05.
NO_x (lb/MWh)	0	
SO_x (lb/MWh)	0.35	

Sources: Navigant Consulting Estimates 2007, *Geothermal Strategic Value Analysis,* CEC-500-2005-105-SD June 2005; *Potential Improvements to Existing Geothermal Facilities in California*, GRC Transactions, Vol. 30, 2006, J. Lovekin, S. Sanyal, A, Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007. Geothermal Resource Council Bulletin May-June 2005.

Methodology and Key Assumptions: Geothermal – Dual Flash

Methodology & Key Assumptions

- Output and overnight costs can very significantly by site, depending on resource quality. Average values for California are reported.
- NCI surveyed cost and performance data from recent CEC reports on geothermal technology in California. NCI also used internal sources and Energy Velocity. This data was verified by an interview with Vince Signorotti of Cal Energy.
- Future costs are highly uncertain. Costs are assumed to remain constant in real terms as technology advances are balanced by the increased costs of developing relatively less attractive sites.

Economic Assumptions: Geothermal – Binary Steam

	Geothermal – Binary Steam Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	50	Current California installations range from .5 to 90 MW in size. 50 is an average.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Installed Cost ($/kW)	$3,000	From Navigant Consulting sources and estimates.
Exploration ($/kW)	$8	
Confirmation Drilling ($/kW)	$327	
Equipment/Installation ($/kW)	$2,560	
Transmission ($/kW)	$105	
Fixed O&M ($/kW-yr)	$70	
Variable O&M ($/MWh)	$4.5	Water for cooling condensers is the largest component of Variable O&M. Water access issues in California could balance out any gains in water usage efficiency.

Sources: Navigant Consulting Estimates 2007, *Geothermal Strategic Value Analysis* CEC-500-2005-105-SD June 2005, Potential Improvements to Existing Geothermal Facilities in California, GRC Transactions, Vol. 30, 2006, J. Lovekin, S. Sanyal, A, Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007

Performance Data: Geothermal – Binary Steam

	Geothermal – Binary Steam Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	95%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
Heat Rate (HHV)	n/a	
HHV Efficiency (%)	n/a	
Annual Output Degradation (%/yr)	4%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	0	Binary steam systems do not emit CO_2, NO_x, or SO_x because the geothermal steam is in a closed loop system and is not vented to the atmosphere.
NO_x (lb/MWh)	0	
SO_x (lb/MWh)	0	

Sources: Navigant Consulting Estimates 2007; *Geothermal Strategic Value Analysis*, CEC-500-2005-105-SD June 2005, *Potential Improvements to Existing Geothermal Facilities in California*, GRC Transactions, Vol. 30, 2006, J. Lovekin, S. Sanyal, A. Caner Sener, V. Tiangco, and P. Gutierrez-Santana, Interview with Dan Schochet, Vice President of ORMAT Technologies, January 2007

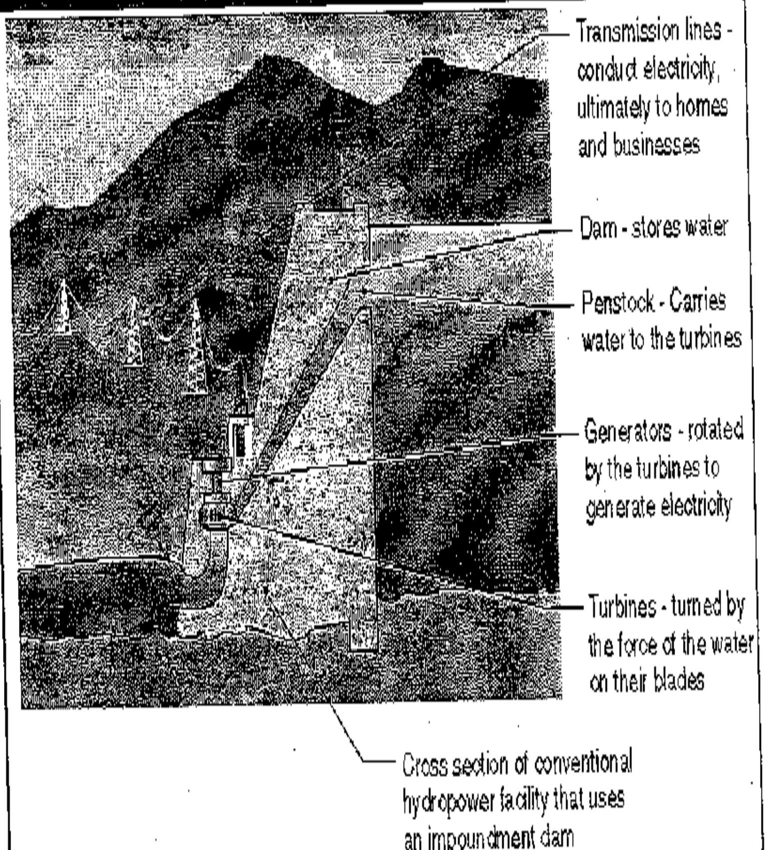
Methodology and Key Assumptions: Geothermal – Binary

Methodology & Key Assumptions

- Output and overnight costs can vary significantly by site, depending on resource quality. Average values for California are reported.
- NCI surveyed cost and performance data from recent CEC reports on geothermal technology in California. NCI also used internal sources and Energy Velocity. This data was verified by an interview with Dan Schochet of ORMAT, Inc. ORMAT is one of the key companies installing plants in California.
- Future costs are highly uncertain. Costs are assumed to remain constant in real terms as technology advances are balanced by the increased costs of developing relatively less attractive sites. Further development in California will require more wells and new drilling techniques to utilize the lower temperature steam.

A small-scale hydropower facility captures the energy of falling water to generate electricity.

Schematic of the Technology



Description

- The most common type of hydroelectric power plant is an impoundment facility. An impoundment facility, typically a large hydropower system, uses a dam to store river water in a reservoir. Water released from the reservoir flows through a turbine, spinning it, which in turn activates a generator to produce electricity. The water may be released either to meet changing electricity needs or to maintain a constant reservoir level.
- Small Scale Hydropower facilities are impoundment facilities that generate between .01 to 30 MW of electricity.

Sources: Idaho National Laboratory, http://hydropower.inel.gov/hydrofacts/hydropower_facilities.shtml

Economic Assumptions: Small-Scale Hydropower

	Small-Scale Hydropower Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	10	According to Idaho National Engineering and Environmental Laboratory, INEEL, the average MW potential at sites with developed dams without hydropower is 14 MW.
Project Life (yrs)	30	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$4,000	Actual installed costs vary widely based on the amount of civil works and mitigation required. NCI cost estimates are based on Idaho National Laboratory and RETScreen™ estimates for a 10MW facility where the dam is already in place.
Equipment & Construction ($/kW)	$1,800	
Licensing & Mitigation ($/kW)	$2,200	
Non-Fuel Fixed O&M ($/kW-yr)	$13	Median cost for plants 8-11 MWs with Dams and No Power in INEEL Hydropower Resource Economics Database, IHRED, Database is $13/kW-yr.
Non-Fuel Variable O&M ($/MWh)	$3	Median cost for plants 8-11 MWs with Dams and No Power in IHRED Database is $14.5/kW-yr.
Typical Net Capacity Factor (%)	52%	Idaho National Laboratory estimates.
Annual Output Degradation (%/yr)	2%	From Navigant Consulting sources and estimates.

Sources: Navigant Consulting Estimates 2007. Idaho National Laboratory, *Estimation of Economic Parameters of U.S. Hydropower Resources*, June 2003; INEEL Hydropower Resource Economics Database, IHRED; *California Small Hydropower and Ocean Wave Energy Resources*; 2005 IEPR, April 2005; Natural Resources Canada RETScreen™ Energy Model - Small Hydro Project; INL State Resource Assessment.

Methodology and Key Assumptions: Small-Scale Hydropower

Methodology & Key Assumptions

- The costs of a small-scale hydropower facility vary widely depending on the amount of civil works, licensing, and mitigation required.
- The Idaho National Laboratory, INL, as well as the Natural Resources Canada, NRC, both have online tools that help estimate the costs for hydropower.
- The INL has a database of prospective sites that: 1) already have power, 2) are developed with a dam, but do not have power, and 3) are not developed. This analysis focuses on estimating costs for the sites that are developed, but do not have power. The median size of these sites in California is approximately 10 MW.
- Both online tools from the INL and NRC estimate that installed costs in 2002/3 would be approximately $1,500/kW for equipment and construction. INL also estimates costs for mitigation and licensing, which run about $1,750/kW. Based on NCI experience, NCI assumes a 30% increase in costs to arrive at a $4,000/kW installed costs in 2006.
- According to INL, "Estimated costs included in the database including licensing, construction, mitigation, and O&M were not developed by performing individual site analyses. They are general cost estimates based on a collection of historical experience for similar facilities. Therefore, the costs presented in this study should not be interpreted as precise engineering estimates. Actual costs for any specific site could vary significantly from these generalized estimates".

In-Conduit Hydropower facility.

Schematic of the Technology

Description

- In-conduit hydro is that developed within man-made conduits instead of natural streams, rivers, or creeks.
- Key advantages of in-conduit hydropower include no impact on wildlife, reduced O&M due to the cleanliness of the water, more streamlined permitting processes, and often less civil works.
- "Man-made conduits" include pipelines, aqueducts, irrigation ditches, and canals.
- In-conduit hydro can use impoundment, run-of-river, or diversion to generate electricity.

Economic Assumptions: In-Conduit Hydropower

	In-Conduit Hydropower Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Plant Capacity (MW)	1	According to the June 2006 PIER report, the median size is approximately 1 MW for small hydropower.
Project Life (yrs)	30	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$1,500	Actual installed costs vary widely NCI cost estimates are based on Table 7 of the CEC PIER report *Statewide Small Hydropower Resource Assessment*; and adjusted to $2006.
Non-Fuel Fixed O&M ($/kW-yr)	-	
Non-Fuel Variable O&M ($/MWh)	$13	
Typical Net Capacity Factor (%)	49%	
Annual Output Degradation (%/yr)	1%	From Navigant Consulting sources and estimates.

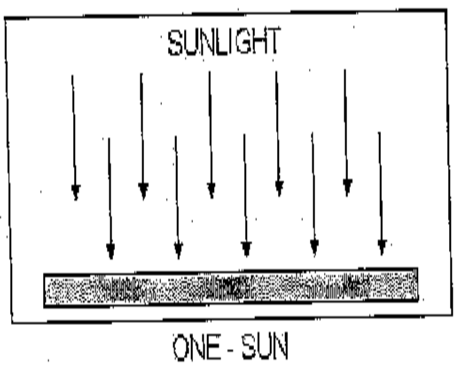
Sources: Navigant Consulting Estimates 2007. *Statewide Small Hydropower Resource Assessment*; California Energy Commission PIER Final Project Report, June 2006.

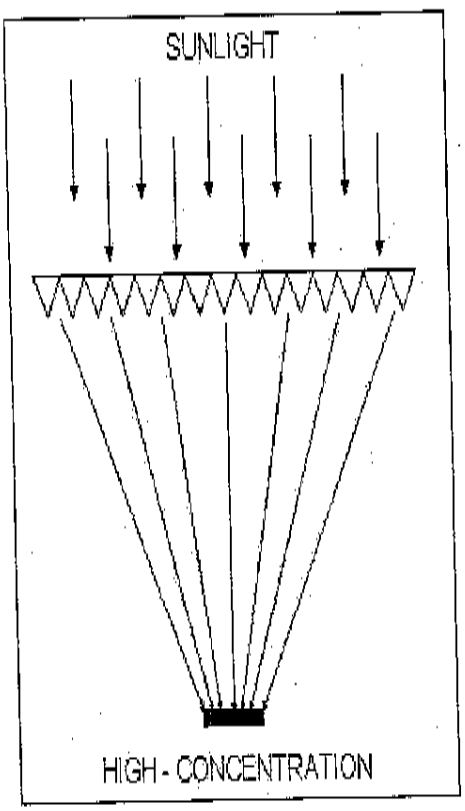
Methodology and Key Assumptions: In-Conduit Hydropower

Methodology & Key Assumptions

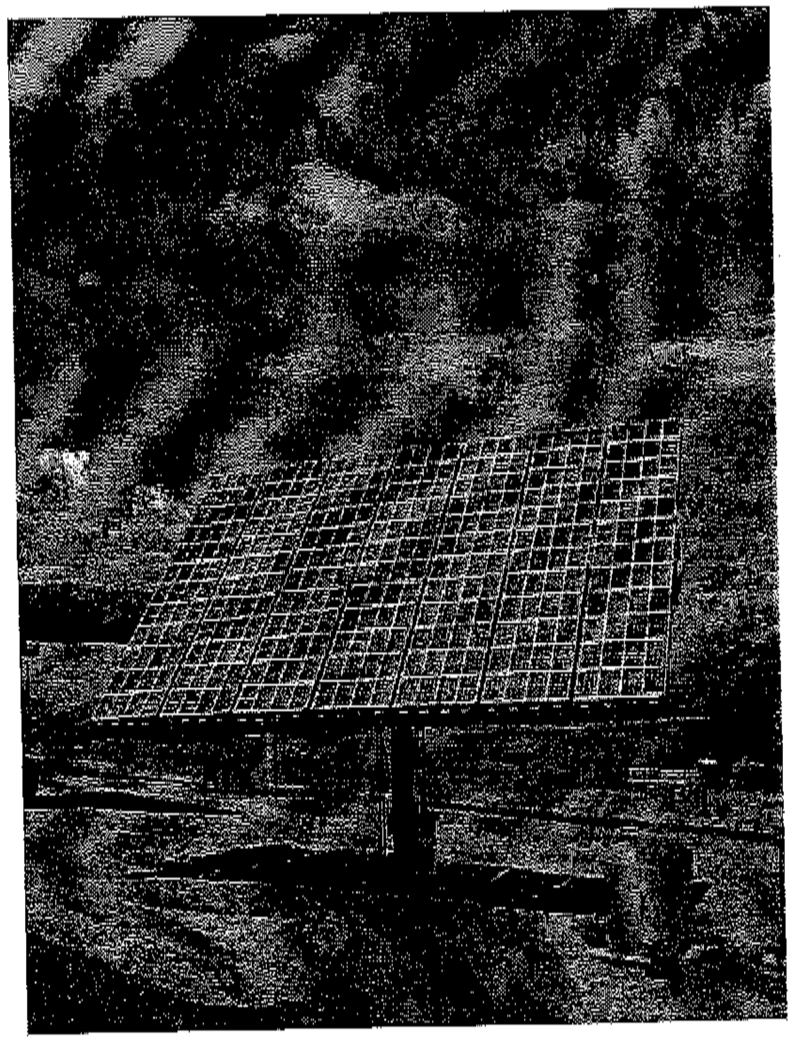
- The costs of a In-Conduit Hydropower were estimated by Navigant Consulting in 2006. *Statewide Small Hydropower Resource Assessment*; California Energy Commission, PIER Final Project Report; June 2006; http://www.energy.ca.gov/2006publications/CEC-500-2006-065/CEC-500-2006-065.PDF)
- These estimates are based on that report as well as analysis performed by NCI using the RETScreen™ cost estimator model developed by Natural Resources Canada.

Concentrating photovoltaics, CPV, use lenses or reflective collectors to focus solar energy (typically > 100 suns) on a reduced area of solar cell material that is more efficient.





From www.amonix.com



Arizona Public Service photo: Prescott 35 kW, dual axis tracking system.

Installed system costs for concentrating PV are high due to small production volumes.

	Concentrating PV Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Net Plant Capacity (kW)	15,000	Navigant Consulting, Inc. estimates based on *Arizona Solar Electric Roadmap*, Full Report, Prepared by Navigant Consulting, Inc. for the Arizona Department of Commerce, January 2007 and interview with Vahan Garboushian, President, Amonix, March 7, 2007.
Annual Output Degradation (%/yr)	1%	Interview with Vahan Garboushian, President, Amonix, March 7, 2007. 1% per year up to a maximum of 10% for a system.
Project Life (yrs)	25	Navigant Consulting, Inc. estimates based on *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc. for the Arizona Department of Commerce, January 2007 and interview with Vahan Garboushian, President, Amonix, March 7, 2007.
Overnight Cost ($/kWp)	$5,000	
Fixed O&M ($/kW-yr)	$45	
Variable O&M ($/MWh)	NA	
Development Time (months)	12	Interview with Vahan Garboushian, President, Amonix, March 7, 2007.

Sources: *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc, Jan 2007; interview with Vahan Garboushian, President, Amonix, March 7, 2007.

Capacity factors for concentrating PV is estimated around 23% for key areas in Southern California.

	Concentrating PV Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Typical Net Capacity Factor (%)	23%	The systems do not shut down all at once and units are fixed one at a time. Availability is estimated at 98%. Interview with Vahan Garboushian, President, Amonix, March 7, 2007. 1% per year up to a maximum of 10% for a system. Capacity factors based on *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc. for the Arizona Department of Commerce, January 2007 and interview with Vahan Garboushian, President, Amonix, March 7, 2007. Capacity factor estimate is typical of Imperial Valley area of Southern California.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

Sources: *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc, Jan 2007; interview with Vahan Garboushian, President, Amonix, March 7, 2007.

Below are some additional key assumptions and sources used for the Concentrating PV analysis.

Methodology & Key Assumptions

- Companies such as Amonix claim to need 10MW of production volumes to be competitive
  - Arizona Public Service and Amonix have worked together since 1995 and have >600 kW operating in Arizona with 26% efficient cells/250x solar concentration.
- The solar rebates that are applicable to flat plate PV in California are not currently applicable to concentrating PV.

A dish/engine uses a mirrored dish (similar to a large satellite dish) that collects and concentrates the sun's heat onto a receiver, which absorbs the heat and transfers it to fluid within the engine.

The heat causes the fluid to expand against a piston or turbine to produce mechanical power. The mechanical power is then used to run a generator or alternator to produce electricity.

Solar Dish engine economics are still somewhat unknown, and vary widely.

	Dish Engine Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Net Plant Capacity (kW)	15,000	From Navigant Consulting sources and estimates.
Annual Output Degradation (%/yr)	NA	Not Available. No commercial systems have been operational enough to provide an estimate.
Project Life (yrs)	25	From Navigant Consulting sources and estimates.
Overnight Cost ($/kWp)	$6,000	
Fixed O&M ($/kW-yr)	$125 - $200	
Variable O&M ($/MWh)	NA	
Development Time (months)	12	From Navigant Consulting sources and estimates.

Sources: *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc, Jan 2007; NCI Interviews. National Renewable Energy Laboratory web site, March 2007.

The capacity factors for Dish Engines are expected to be between 23% – 25% in good solar resource areas in California.

	Dish Engine Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	23% - 25%	Systems may have about 10% of the units not being used because they are in repair. There is expected to be limited forced outage in the near term. Assuming installation near Imperial Valley (Southern California). Low end from interview with NREL and high end based on *Arizona Solar Electric Roadmap, Full Report*, Prepared by Navigant Consulting, Inc. for the AZ Department of Commerce, January 2007.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_2 (lb/MWh)		

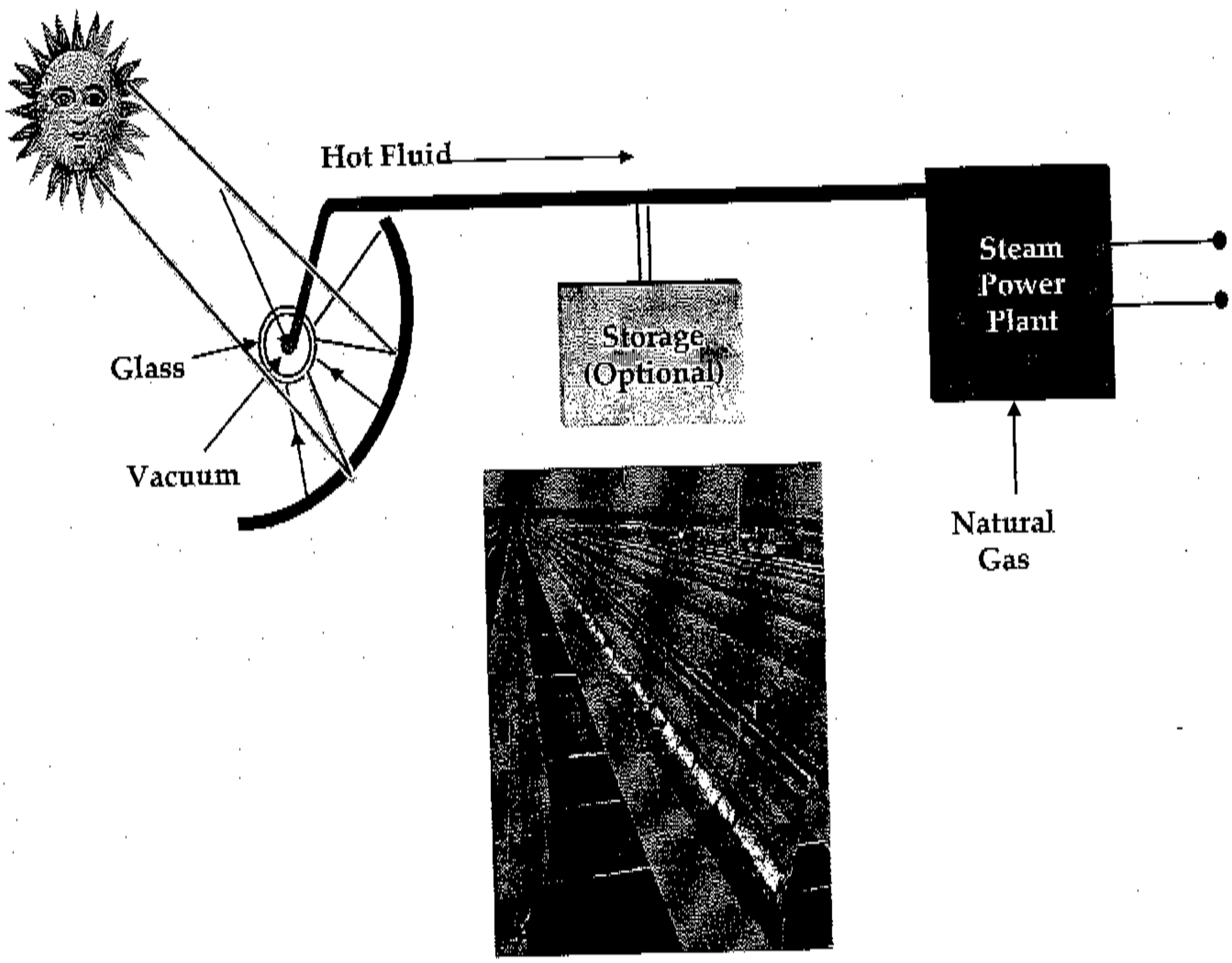
Sources: *Arizona Solar Electric Roadmap, Full Report,* Prepared by Navigant Consulting, Inc, Jan 2007; NCI Interviews.

Methodology and key assumptions and sources used for the Dish Engine analysis:

Methodology & Key Assumptions

- There is limited operational experience for dish Engine technology. Six dishes are in demonstration mode at Sandia and one 25 kW system is operating at the University of NV at Las Vegas.
- SES has a PPA with Southern California Edison for 500 MW with a 350 MW option and a PPA with San Diego Gas & Electric for 300 MWs with a 600 MW option (total potential for 1,750 MW).
- Land use is about 5 acres per MW
- Dish Engines qualify for 5-yr accelerated depreciation and 30% investment tax credit until the end of 2008 when the tax credit amount will reduce to 10%.

Parabolic trough systems use concentrated solar energy to raise the temperature of a heat transfer fluid. Co-firing with natural gas or storage can sometimes be used to ensure dispatch capability.



Parabolic Trough

Parabolic-trough systems concentrate the sun's energy through long rectangular, curved (U-shaped) mirrors. The mirrors are tilted toward the sun, focusing sunlight on a pipe that runs down the center of the trough. This heats the oil flowing through the pipe. The hot oil then is used to boil water in a conventional steam generator to produce electricity. (NREL web site, March 2007.)

Typical system sizes range are expected to increase, and overnight costs are currently too expensive for more widespread adoption.

	Parabolic Trough Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Gross Plant Capacity (kW)	63,500	NCI estimate based on Solargenix report reference in the source listed below, page 52, and discussions with NREL.
Net Plant Capacity (kW)	50,000	
Annual Output Degradation (%/yr)	0.2%	Based on discussions with NREL.
Project Life (yrs)	30	From Navigant Consulting sources and estimates.
Overnight Cost ($/kWp)	$3,900	Assumes 6 hours of molten salt storage starting in 2010. Navigant Consulting estimates are for overnight costs based on Black and Veatch report, and discussions with NREL. Data also from report prepared by NCI, Arizona Solar Electric Roadmap Study. Increasing the plant capacity to 100 MW reduces costs ~10%.
Fixed O&M ($/kW-yr)	$60.0	Solar field O&M assumed to be 35% of total O&M and of that 25% is assumed to be for solar field parts and materials (most of which is receiver replacement. Mirror breakage is only 15% of the total parts cost. NCI estimate based on Interview with NREL, Solargenix report, NCI Solar Electric Roadmap for AZ.
Variable O&M ($/MWh)	NA	
Development Time (months)	20	From Navigant Consulting sources and estimates.
Construction Time (months)	12	

Sources: *Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California*, Solargenix Energy, November 2005, CEC-500-2005-175. NCI Interviews with Hank Price and Mark Mehos, NREL. *Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California*, Black and Veatch for the National Renewable Energy Laboratory, April 2006. NREL/SR-550-39291; *Arizona Solar Electric Roadmap Study*, NCI, Arizona Department of Commerce, January 2007 Interview with Bob Lawrence of Sunray Energy, Inc. March 2007.

The solar field that includes the mirrors and the metal support structure is the most costly part of the trough system.

Year	2010
Plant Size	100 MW
Site Work and Infrastructure	1%
Solar Field	45%
Heat Transfer Fluid System	2%
Thermal Energy Storage (6 hrs)	13%
Power Block	8%
Balance of Plant	5%
Contingency	6%
Indirect Costs	20%

Source: Navigant Consulting, Inc. analysis based on Black and Veatch, *Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California*, April 2006.

Trough systems currently do not include storage, but by 2010 storage is expected to be an economic option that will increase capacity factors.

	Parabolic Trough Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Factor (%)	NA	Defined as solar output less than 75% of maximum during the top 100 hours of peak demand hours. See pg. 36 of Solargenix report. Outage includes 1 week of scheduled outage every year and a 5 week major overhaul every 5 years. Solar plants have the advantage that they can take outages at night or on cloudy days.
Forced Outage Rate (%)	6%	
Typical Net Capacity Factor (%)	27%	A 50 MW system with 6 hrs of storage is being installed in Spain and should be operational by the end of 2007. Assumes 6 hours of molten salt storage starting in 2010. Capacity factors based on discussion with Hank Price, NREL, February 2007.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

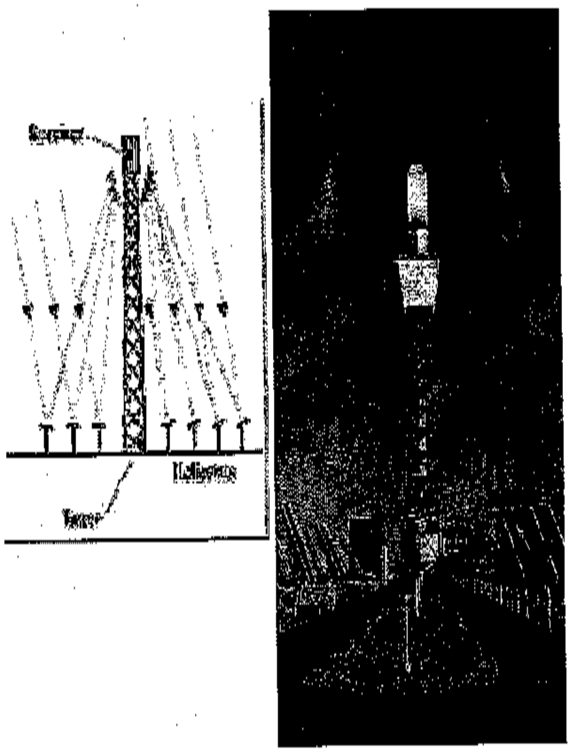
Sources: NCI Estimates 2007. *Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California*, Solargenix Energy, California Energy Commission, November 2005, CEC-500-2005-175. NCI Interviews with Hank Price, NREL.

Methodology, key assumptions, and sources used for the trough analysis:

Methodology & Key Assumptions

- Trough technology is well proven (without storage).
- Requires high direct normal solar (DNI).
- Overnight cost includes cost of heat collection element, mirrors, metal support structure, heat transfer fluid system, thermal energy storage, and thermal energy storage fluid. Currently, heat collection elements produced in Germany and Israel; and mirrors produced in Germany.
- May require water consumption at a rate of 103 million gallons per year. This is for steam cycle, cooling, and washing mirrors. Source: *Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California*, Solargenix Energy, November 2005, CEC-500-2005-175. Page 52.
- 63.5 MW max gross output and 55.5 MW gross output. Net output is 50 MW. Source: *Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California*, Solargenix Energy, November 2005, CEC-500-2005-175. Page 46.
- Construction times at the site are about 1 year. The longest lead time has been the turbine, but from order to on-line for 64 MWe plant is about 20 months. A 100 MW plant will be similar. Component supply can be an issue for large projects, but more receiver and mirror manufacturing facilities are being built. Source: Hank Price, NREL February 26, 2007.

A power tower system uses a large field of mirrors to concentrate sunlight onto the top of a tower, where a receiver sits.



Power Tower

Sunlight heats the molten salt flowing through the receiver. Then, the salt's heat is used to generate electricity through a conventional steam generator. Molten salt retains heat efficiently, so it can be stored for days before being converted into electricity. That means electricity can be produced on cloudy days or even several hours after sunset.

It is unlikely that Power Tower technology can be up and running by 2010, as development time is about 3 – 4 years.

	Power Tower Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Net Plant Capacity (kW)	NA	Based on discussions with NREL March 6,2007. No full scale plants are in operation.
Annual Output Degradation (%/yr)	NA	NCI estimates based on discussions with NREL, 2006; Osuna, et. Al. *PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain* 2006; Ortega, et. al. *Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid*, 2006; and Sargent and Lundy, *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts* 2003; and interview with Mark Mehos, NREL, March 6, 2007.
Project Life (yrs)	NA	
Overnight Cost ($/kWp)	NA	Interview with Mark Mehos, NREL, March 6, 2007.
Fixed O&M ($/kW-yr)	NA	NCI estimates based on discussions with NREL, 2006; Osuna, et. Al. *PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain 2006*; Ortega, et. al. *Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid*, 2006; and Sargent and Lundy, *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts*, 2003; and interview with Mark Mehos, NREL, March 6, 2007.
Variable O&M ($/MWh)	NA	
Development Time (Months)	NA	
Construction Time	NA	

Sources: Osuna, et. Al. PS10, *Construction of A 11MW Solar Thermal Tower Plant in Seville*, Spain 2006; Ortega, et. al. *Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid*, 2006; and Sargent and Lundy, *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts*, 2003; NCI Interviews.

Power Tower technology will likely incorporate 15 hours of storage by 2020 to result in capacity factors of 75%.

	Power Tower Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Forced Outage Rate (%)	NA	Interview with Mark Mehos, NREL March 6, 2007.
Typical Net Capacity Factor for Southern CA (%)	NA	The only plant in construction is the PS10 that is being built in Seville, Spain where the capacity factor in 20%. The Solar Tres plant is designed with 15 hours of storage that is likely to result in capacity factors of 64%. NCI estimates based on Osuna, et. al. *PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain*, 2006; Ortega, et. al. *Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid*, 2006; and Sargent and Lundy, *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts*, 2003.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	No Emissions	
NOx (lb/MWh)	No Emissions	
SO_2 (lb/MWh)	No Emissions	

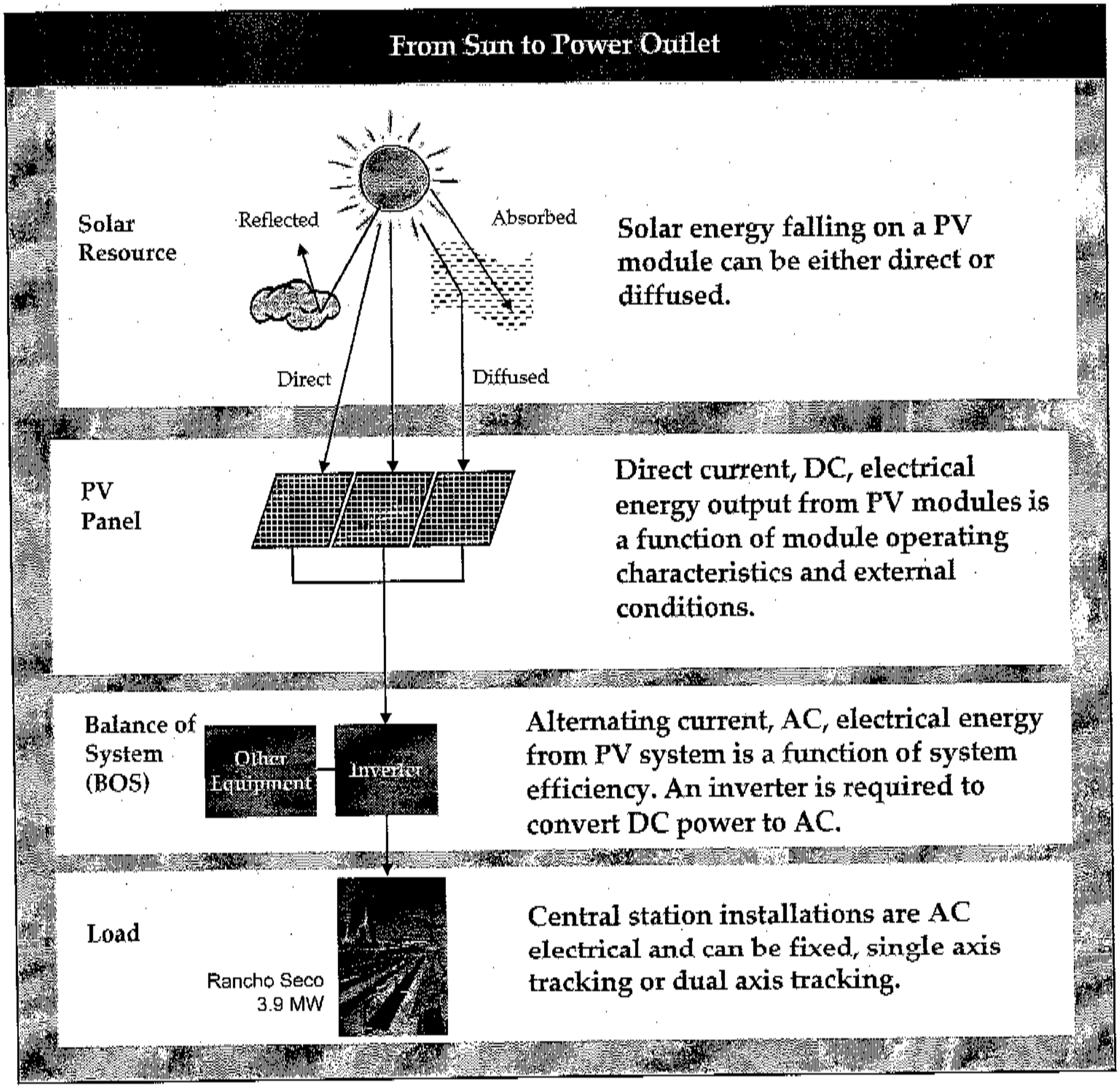
Sources: Osuna, et. al. *PS10, Construction of A 11MW Solar Thermal Tower Plant in Seville, Spain*, 2006; Ortega, et. al. *Central Receiver System (CRS) Solar Power Plant Using Molten Salt as Heat Transfer Fluid*, 2006; and Sargent and Lundy, *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts*, 2003; NCI Interviews.

Below are some additional key assumptions and sources used for the power tower analysis.

Methodology & Key Assumptions

- Power Tower technology has limited field performance experience. The 10 MW Solar One plant operated in Barstow, California from 1982 to 1988. It was retrofitted with a molten salt receiver and renamed Solar Two from 1998 to 1999.
- Pacific Gas and Electric, PG&E, announced plans to buy 500 MW from towers build by LUZ II which are scheduled to be on line in 2010, but there is only a memorandum of understanding in place.
- Scales of 50 MW or greater are needed to obtain favorable economics.
- The 30% Investment Tax Credit is applicable until the end of 2008, when it will revert back to 10%.
- The 5-year accelerated depreciation applies to Power Tower technology.
- The degradation is associated with the reflectors and turbines.
- The 11 MW plant in Seville, Spain has only ½ hour of full load storage resulting in about a 25% capacity factor.

PV technology converts solar energy into usable electrical energy.



NCI has provided business as usual price reductions for central station PV.

	Central Station Single Axis Photovoltaics (PV) Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Plant Capacity (kWdc)	1,000	From Navigant Consulting sources and estimates.
Annual Output Degradation (%/yr)	0.4%	
Project Life (yrs)	30	
Overnight Cost ($/kWpac)	$9,320	
Development Costs ($/kW)	NA	
Module ($/kWpac)	$4,370	
Inverter ($/kWpac) includes replacements at years 10 & 20	$603.8	
Installation ($/kWpac)	$1,495	
Other BOS ($/kWpac)	$402.5	
Marketing/Sales/Taxes ($/kWpac)	$230	
Gross Margin ($/kWpac)	$2,219.5	
Non-Fuel Fixed O&M ($/kW-yr)	$24	
Non-Fuel Variable O&M ($/MWh)	NA	

Sources: Annual degradation from Tom Hansen, Tucson Electric, February 10, 2007. Overnight costs: provided by several industry representatives: Barry Cinnamon, Akeena Solar; Les Nelson, California Solar Energy Industries Association, CaLSEIA, and Bill Rever, BP Solar, January 2007. Note: Prices can vary significantly depending on variables such as location, type of owner, and volume of purchase. NCI assumed 80% loss going from DC to AC. Inverter replacement needed every 10 years in out years.

Performance information was based upon an average single axis installation.

	Central Station Single Axis PV Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Scheduled Outage Rate (%)	NA	
Forced Outage Rate (%)	.25%	Inverter is likely to be replaced every 10 years. Source of data is Tom Hansen, Tucson Electric, February 10, 2007. Based on the assumption that the utility will use a sophisticated control systems and therefore forced outages are lower than residential or commercial.
Typical Net Capacity Factor	22.4%	Assumes single axis installation for average insolation levels. Based on output from Clean Power Estimator model.
Fuel Cost ($/MMBtu)	NA	
HHV Efficiency (%)	NA	
CO_2 (lb/MWh)	0.00	
NO_x (lb/MWh)	0.00	
SO_2 (lb/MWh)	0.00	

Sources: Annual degradation from Tom Hansen, Tucson Electric, February 10, 2007. Overnight costs: provided by several industry representatives: Barry Cinnamon, Akeena Solar; Les Nelson, CalSEIA, and Bill Rever, BP Solar, January 2007. Note: Prices can vary significantly depending on variables such as location, type of owner, and volume of purchase. NCI assumed 80% loss going from DC to AC. Inverter replacement needed every 10 years in out years.

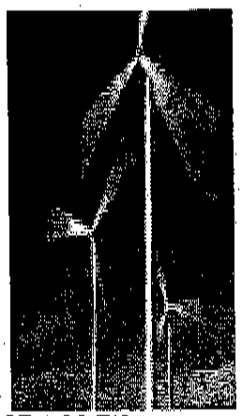
Below are some additional key assumptions and sources used for the single axis PV analysis.

Methodology & Key Assumptions

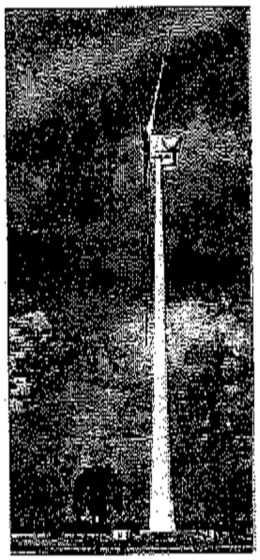
- The primary technology installation in 2006 was crystalline silicon technology and therefore some of the early year costs are based on this technology.
- NCI converts all $/Wpdc (direct current) estimates to $/Wpac (alternating current) using a .80 conversion factor to account for module mismatch, inverter efficiency, dust and other losses. This was derived from PVWatts web site and a presentation by Ed Kern, President of Irradiance, *PV Downstream*, presented in January 2007.
- PV system cost reductions are mostly associated with module efficiency improvements, increased manufacturing capacity, and reductions in inverter prices.
- The net capacity factors factor in dust loss and account for expected hours of output. These estimates were pulled from the Clean Power Estimator model.
- Loan period is 20 years.
- There is currently a 30% Investment Tax Credit for commercial installations that will reduce to 10% after 2008. A 5 year MACRs accelerated depreciation should also be applied to all years of analysis as well as a property tax exemption.
- The 30% ITC does not apply to utility owned systems, however, many utility companies negotiate with third parties to own, operate, and lease land for the projects (similar to independent power producers' [IPP] structure).
- Interest during construction is minimal. A 1 MWpdc system could be installed by a crew of eight people in less than eight weeks, based on data from Tucson Electric, February 10, 2007.
- Balance of System other equipment includes mounting structure, switches & fuses, meters, wires & conduits, isolation transformers/ automatic lock-out switches, controls, communication, data acquisition, feeder line connection, and fencing.

Large, utility wind developments convert wind energy into electricity, and can range from 50 MW to 150 MW in size in California.

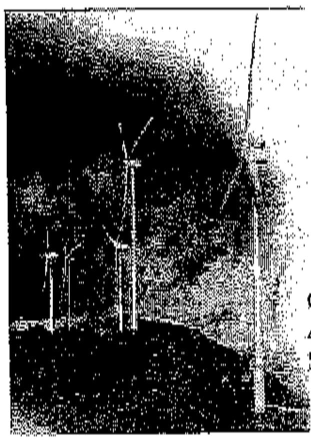
Schematic of the Technology



GE 1.5 MW Turbines
Source: GE



GE 3.6 MW Turbines
Source: DOE



Gatun, Spain
49.5 MW wind farm
Source: GE

Description

- A 50 MW wind development consisting of multiple wind turbines atop steel towers. Typical facilities today consist of 1.5 to 2.5 MW turbines atop 80m towers.
- In the future, wind farms are likely to see a continued evolution towards larger rotors, turbine sizes, and tower heights.
- Since installed costs and performance vary with turbine size, tower height and site conditions. NCI assumes some typical turbine sizes, tower heights, and site conditions to develop the cost estimates, recognizing that actual wind farm configurations will see a wider range.
- The expected or typical wind regime is uncertain as new wind developments are likely to be in poorer wind regimes, but re-powering at existing good wind sites like Altamont and Tehachapi is also likely.

Economic Assumptions: Utility Wind

	Utility Wind Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Plant Capacity (MW)	50	Based on current proposed projects in California. Source: AWEA.
Turbine Size (range) (MW)	2.0 (1.5-2.5)	From Navigant Consulting sources and estimates.
Tower Height (range) (meters)	80 (60 – 80)	
Project Life (yrs)	30	
Overnight Cost ($/kW)	$1,900	Overnight Costs can vary widely depending on the several factors. Key assumptions include: turbine prices on a $/kW basis decrease asymptotically by 1.5%/yr to 0.5%/yr due to technological improvements and learning; commodity prices increase ; turbine original equipment manufacturers, OEMs, profit margins decrease due to increased competition; balance of plant cost increases due to interconnection and increased civil works are mitigated by decreased cost per kW due to increased scale (turbine rating per tower).
Turbine ($/kW)	$1,250	
Balance of Plant / Installation ($/kW)	$500	
Permitting / Development ($/kW)	$150	
Fixed O&M ($/kW-yr)	$30	O&M costs are based on historical performance at existing sites as well as interviews with industry. Costs per unit of capacity and energy are expected to decline as machine size and output increase.

Sources: Navigant Consulting Estimates 2007. AWEA, NCI interviews with leading turbine OEMs, project developers, energy maintenance providers, and wind farm owners.

Performance Data: Utility Wind

	Utility Wind Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Scheduled Outage Factor (%)	0.3%	Forced outage rates and typical capacity factors are based on historical data at existing plants.
Forced Outage Rate (%)	1.3%	
Typical Net Capacity Factor – Class 5 (%)	34%	Wind class definition based on wind speed at 50m: Class 5 = 7.5-8 m/s (16.8-17.9 mph). Capacity factors are net of all losses at the plant, such as blade soiling, and aerodynamic losses. Expected capacity factors for a given wind regime are expected to remain relatively constant over time. The improvements in turbine design and increased tower heights (factors that increase the capacity factors) are expected to be partially offset by the use of larger machines, which have lower capacity factors.
Annual Output Degradation (%/yr)	0.25%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	No Air Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

Sources: Navigant Consulting Estimates 2007, AWEA. NCI estimates validated by NCI interviews with leading turbine OEMs, project developers, energy maintenance providers, and wind farm owners.

Methodology and Key Assumptions: Utility Wind

Methodology & Key Assumptions

- NCI based its cost estimates on its knowledge of historical installed costs in the U.S. and California as well as its own internal model of wind installed costs.
- Several leading market participants commented on the NCI cost estimates and helped Navigant refine its numbers.
- Installed costs can vary widely depending on the scale of the project, civil works and interconnection requirements, permitting requirements, and buying power of the owner.
- Future costs are based on a defined wind development size, turbine sizes and tower height, but actual system configurations could differ, which would affect costs and performance.
- Key assumptions include:
  - Turbine prices on a $/kW basis decrease asymptotically due to technological improvements and learning.
  - Commodity prices increase by 3%/yr in real terms.
  - Turbine OEM profit margins will decrease due to increased competition.
  - Balance of plant costs remain constant on a $/kW basis as improvements in scale (capacity rating per tower), are balanced by an increase in cost for interconnection, roads, and the absolute cost per tower.
  - Tower heights increase from 80m to 100m.
  - Typical turbine sizes increase from 2 MW to 3.5 MW.
- O&M costs are based on historical performance at existing sites as well as interviews with industry. Costs per unit of capacity and energy are expected to decline as machine size and output increase.

Fuel cells convert hydrogen or a hydrogen-rich gas directly to electricity through a clean, efficient electrochemical reaction.

- The main characteristic that distinguishes fuel cell types is the electrolyte. The four principal types being developed for commercial markets are: proton exchange membrane (PEM), phosphoric acid (PAFC), molten carbonate (MCFC), and solid oxide (SOFC).
- Balance of system components include: fuel processor to convert primary fuel to hydrogen or hydrogen rich gas, air handling, water purification / management, power conditioning (to convert DC electricity to AC), heat recovery equipment (for cogeneration applications or hybrid power cycles), and the enclosure.
- Emissions are negligible because fuels are not combusted. Typically, a small portion of the unconverted fuel is burned, but with very low emissions.
- High efficiency is possible, even at very small scales.

Source: Fuel Cells 2000. representation of the Fuel Cell Energy MCFC Fuel Cells at Sierra Nevada Brewery in California

Broad application of fuel cells is expected to be several years off, but there are some near term opportunities to demonstrate the technology.

- Fuel cells can either use natural gas or carbon-based renewable fuels provided that the gas is properly treated, that is, contaminants are removed, and reformed into a hydrogen-rich gas.
  - Often have more stringent fuel purity requirements than gas turbines or reciprocating engines.
- Renewable fuels include hydrocarbon-based fuels such as landfill gas, biogas from anaerobic digestion, syngas from biomass gasification and liquid fuels such as ethanol and methanol derived from renewable feedstocks. Hydrogen produced from renewable resources can also be used.
- Low-temperature fuel cells (PEM and PAFC) can also use pure hydrogen. High temperature fuel cells (MCFC and SOFC) are less suited to operation on pure hydrogen and typically internally reform natural gas or other hydrocarbon fuels.
- Key advantages over other small prime movers are low emissions and high efficiency. However, the efficiency advantage is largely lost in landfill gas and biogas applications because the fuel cost is low or zero.
- United Technologies, UT Fuel Cells, has successfully operated several PC25 200kW PAFC on landfill gas and biogas from wastewater treatment, and offered a standard package for this type of fuel.
  - However, the cost of the PC25 has remained high (>$4,000/kW) and UT Fuel Cells has decided not to invest further in the technology.
- PEM fuel cells are not receiving much attention for biogas or landfill gas markets.
  - Product sizes are too small for these applications (generally less than 50 kW) and are currently being designed for residential, small commercial and automotive applications.

Technology Description: Molten Carbonate Fuel Cell

- Assumed to be a fuel cell located at a LFGFTE facility. The 2 MW size was chosen so as to be consistent with the LFGFTE technology that uses a reciprocating engine.
- MCFCs are high-temperature fuel cells that use an electrolyte composed of a molten carbonate salt mixture suspended in a porous, chemically inert ceramic matrix of beta-alumina solid electrolyte. Since they operate at extremely high temperatures of 650°C (roughly 1,200°F) and above, non-precious metals can be used as catalysts at the anode and cathode, reducing costs.
- MCFC systems are high temperature technology (operating temperature 650°C). Uses a liquid alkali carbonate mixture to form the electrolyte layer, nickel based catalyst material and stainless steel cell use for other hardware.
- They have the potential to reach higher electrical efficiencies than that of PEMFC or PAFC.
- Unlike alkaline, phosphoric acid, and polymer electrolyte membrane fuel cells, MCFCs don't require an external reformer to convert more energy-dense hydrocarbons to hydrogen. Due to the high temperatures at which MCFCs operate, these fuels are converted to hydrogen within the fuel cell itself by a process called internal reforming, which also reduces cost.
- Molten carbonate fuel cells are not prone to carbon monoxide "poisoning" - making them more attractive for fueling with gases made from coal.
- The primary disadvantage of current MCFC technology is short stack lifetime. The high temperatures at which these cells operate and the corrosive electrolyte used accelerate component breakdown and corrosion, decreasing cell life. Scientists are currently exploring corrosion-resistant materials for components as well as fuel cell designs that increase cell life without decreasing performance.

Economic Assumptions: Molten Carbonate Fuel Cell

	Molten Carbonate Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	2,000	Assumes the fuel cell is sized for a landfill gas site and utilizes the methane from the landfill.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$4,350	From Navigant Consulting sources and estimates.
Equipment ($/kW)	$3,600	Based on cost estimates from NREL. Assumes costs decline asymptotically from 3.5% to 1.5%.
Gas Treatment ($/kW)	$300	Similar cost requirements as for a LFGFTE facility using a reciprocating engine.
Balance of Plant & Installation ($/kW)	$450	
O&M ($/kW-yr)	$2.10	Based on cost estimates from NREL. Assumes costs decline asymptotically from 3.5% to 1.5%.
Variable O&M ($/MWh)	$35	
Service Contract ($/MWh)	$6	
Stack Replacement ($/MWh)	$29	

Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations,* DOE/NREL/GTI, October 2003. Fuel Cell Energy 2006 Annual Report. NCI Interviews with fuel cell manufacturers. *Lessons Learned from the World's Largest Digester Gas Fuel Cell. Washington State Recycling Association –Spokane,* May, 2006, Greg Bush -King Co.

Performance Data: Molten Carbonate Fuel Cell

	Molten Carbonate Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	90%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
HHV Efficiency (%)	40%	Based on NREL projections and reported efficiencies at King County 1MW Fuel Cell demonstration project.
CO_2 (lb/MWh)	Assumed to be CO_2 Neutral	SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.
NO_x (lb/MWh)	0.01	Based on Case Studies cited by Art Soinski, CEC.
SO_x (lb/MWh)	0.003	

Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003. Fuel Cell Energy 2006 Annual Report. NCI Interviews with fuel cell manufacturers. *Lessons Learned from the World's Largest Digester Gas Fuel Cell. Washington State Recycling Association –Spokane*, May, 2006, Greg Bush -King Co.

Methodology and Key Assumptions: Molten Carbonate Fuel Cell

Methodology & Key Assumptions

- The Molten Carbonate Fuel Cell (MCFC) is modeled after a Fuel Cell Energy product placed in operation at a Landfill Gas Fuel To Energy (LFGFTE) facility. Fuel Cell Energy is the largest manufacturer of Molten carbonate fuel cells. The company's Direct Fuel Cell (DFC) products range from 300 kW in size to 2.4 MW.
- Since IEPR assumes a 2MW size for the LFGFTE using a reciprocating engine, a similar size was assumed for the MCFC. The costs for the MCFC equipment would be higher for system sizes <2MW.
- The MCFC would have similar needs for gas treatment and preparation as well as installation, but it would not require emissions treatment.
- Cost and performance estimates are based on prior NCI experience with fuel cell technology as well as cost and performance estimates published in a 2003 DOE/NREL study: *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003.
- Installed costs for the fuel cell equipment at a landfill are estimated to be higher than one utilizing natural gas due to an approximate 10% de-rating of the output.
- Due to the technological maturity of fuel cells, these cost and performance estimates should be considered within +/- 25% of actual future numbers.

Technology Description: Proton Exchange Membrane Fuel Cell

- Assumed to be a 30kW system at a Wastewater Treatment Fuel to Energy (WWTFTE) facility.
- The proton exchange membrane fuel cell (PEMFC) is also known as the solid polymer or polymer electrolyte fuel cell. A PEMFC contains an electrolyte that is a layer of solid polymer (usually a sulfonic acid polymer, whose commercial name is Nafion™) that allows protons to be transmitted from one face to the other. PEMFCs require hydrogen and oxygen as inputs, though the oxidant may also be ambient air, and these gases must be humidified. PEMFCs operate at a temperature much lower than other fuel cells, because of the limitations imposed by the thermal properties of the membrane itself. The operating temperatures are around 90°C. The PEMFC can be contaminated by CO, reducing the performance and damaging catalytic materials within the cell. A PEMFC requires cooling and management of the exhaust water to function properly.

Economic Assumptions: Proton Exchange Membrane Fuel Cell

	Proton Exchange Membrane Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (kW)	30	Assumes the fuel cell is sized for a small wastewater treatment site and utilizes the biogas from the digester.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$7,000	
Equipment ($/kW)	$6,000	Based on cost estimates from NREL.
Gas Treatment ($/kW)	$550	High level estimate. Actual costs are difficult to determine as PEMs are not typically considered for such applications.
Balance of Plant & Installation ($/kW)	$450	From Navigant Consulting sources and estimates.
Fixed O&M ($/kW-yr)	$18	Based on cost estimates from NREL.
Variable O&M ($/MWh)	$35	
Service Contract ($/MWh)	$13	
Stack Replacement ($/MWh)	$20	

Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Performance Data: Proton Exchange Membrane Fuel Cell

	Proton Exchange Membrane Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Typical Net Capacity Factor (%)	90%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
HHV Efficiency (%)	26%	Assumes a reduction in efficiency as a result of the use of wastewater treatment biogas.
CO_2 (lb/MWh)	Assumed to be CO_2 Neutral	SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.
NOx (lb/MWh)	<0.1	Based on NREL 2003 report.
SO_2 (lb/MWh)	negligible	

Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations,* DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Methodology and Key Assumptions: Proton Exchange Membrane Fuel Cell

Methodology & Key Assumptions

- Several companies manufacture Proton Exchange Membrane (PEM) fuel cells, including Plug Power, United Technologies, Nuvera, and Hydrogenics. Most products are sized at approximately 10 kW to 50 kW. PEM fuel cells are not typically being developed for stationary commercial or industrial power. Instead, manufacturers are targeting the residential and automotive markets.
- In California, potential markets for a stationary PEM fuel cell is a small wastewater treatment facility or a small animal waste anaerobic digester.
- The cost characteristics here are modeled after a 30 kW PEM fuel cell placed in a WWTFTE facility.
- IEPR assumes a 500 kW size for the WWTFTE facility, but many smaller facilities exist that could be appropriate for a PEM fuel cell. The economics are not as attractive and these markets are not as likely to be targeted by developers, owners, or fuel cell manufacturers.
- Cost and performance estimates are based on prior NCI experience with fuel cell technology as well as cost and performance estimates published in a 2003 DOE/NREL study: *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003.
- Due to the technological maturity of fuel cells, these cost and performance estimates should be considered within +/- 25% of actual future numbers.

Technology Description: Solid Oxide Fuel Cell, SOFC.

- Assumed to be a 250 kW system at a WWTFTE facility.
- Solid oxide fuel cells are intended mainly for stationary applications with an output from 100 kW to 2 MW. They work at very high temperatures, typically between 700 and 1,000ºC. In these cells, oxygen ions are transferred through a solid oxide electrolyte material at high temperature to react with hydrogen on the anode side. Due to the high operating temperature of SOFC's, they have no need for expensive catalyst, which is the case of proton-exchange fuel cells (platinum). This means that SOFCs do not get poisoned by carbon monoxide and this makes them highly fuel-flexible. Solid oxide fuel cells have so far been operated on methane, propane, butane, fermentation gas, gasified biomass and paint fumes. However, sulfur components present in the fuel must be removed before entering the cell, but this can easily be done by an activated carbon bed or a zinc absorbent.
- Thermal expansion demands a uniform and slow heating process at startup. Typically, 8 hours or more are to be expected. Micro-tubular geometries promise much faster start up times, typically 13 minutes.
- Unlike most other types of fuel cells, SOFCs can have multiple geometries. The planar geometry is the typical sandwich type geometry employed by most types of fuel cells, where the electrolyte is sandwiched in between the electrodes. SOFCs can also be made in tubular geometries where either air or fuel is passed through the inside of the tube and the other gas is passed along the outside of the tube. The tubular design is advantageous because it is much easier to seal and separate the fuel from the air compared to the planar design. The performance of the planar design is currently better than the performance of the tubular design however, because the planar design has a lower resistance compared to the tubular design.

Economic Assumptions: Solid Oxide Fuel Cell

	Solid Oxide Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Plant Capacity (KW)	250	Assumes the fuel cell is sized for a small wastewater treatment site and utilizes the biogas from the digester.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Cost ($/kW)	$4,750	Based on cost estimates from NREL.
Equipment ($/kW)	$3,900	
Gas Treatment ($/kW)	$400	High level estimate. Actual costs are difficult to determine as few SOFCs have been designed for such applications.
Balance of Plant & Installation ($/kW)	$450	From Navigant Consulting sources and estimates.
Fixed O&M ($/kW-yr)	$10	Based on cost estimates from NREL.
Variable O&M ($/MWh)	$24	
Service Contract ($/MWh)	$11	
Stack Replacement ($/MWh)	$13	

Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Performance Data: Solid Oxide Fuel Cell

	Solid Oxide Fuel Cell Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	90%	From Navigant Consulting sources and estimates.
Fuel Cost ($/MMBtu)	n/a	
HHV Efficiency (%)	40%	Assumes a reduction in efficiency as a result of the use of wastewater treatment biogas.
CO_2 (lb/MWh)	Assumed to be CO_2 Neutral[2]	SB 1368 contains provisions recognizing the net emission, whole-fuel cycle character of Biomass.
NO_x (lb/MWh)	<0.05	Based on NREL 2003 report.
SO_x (lb/MWh)	negligible	Based on NREL 2003 report.

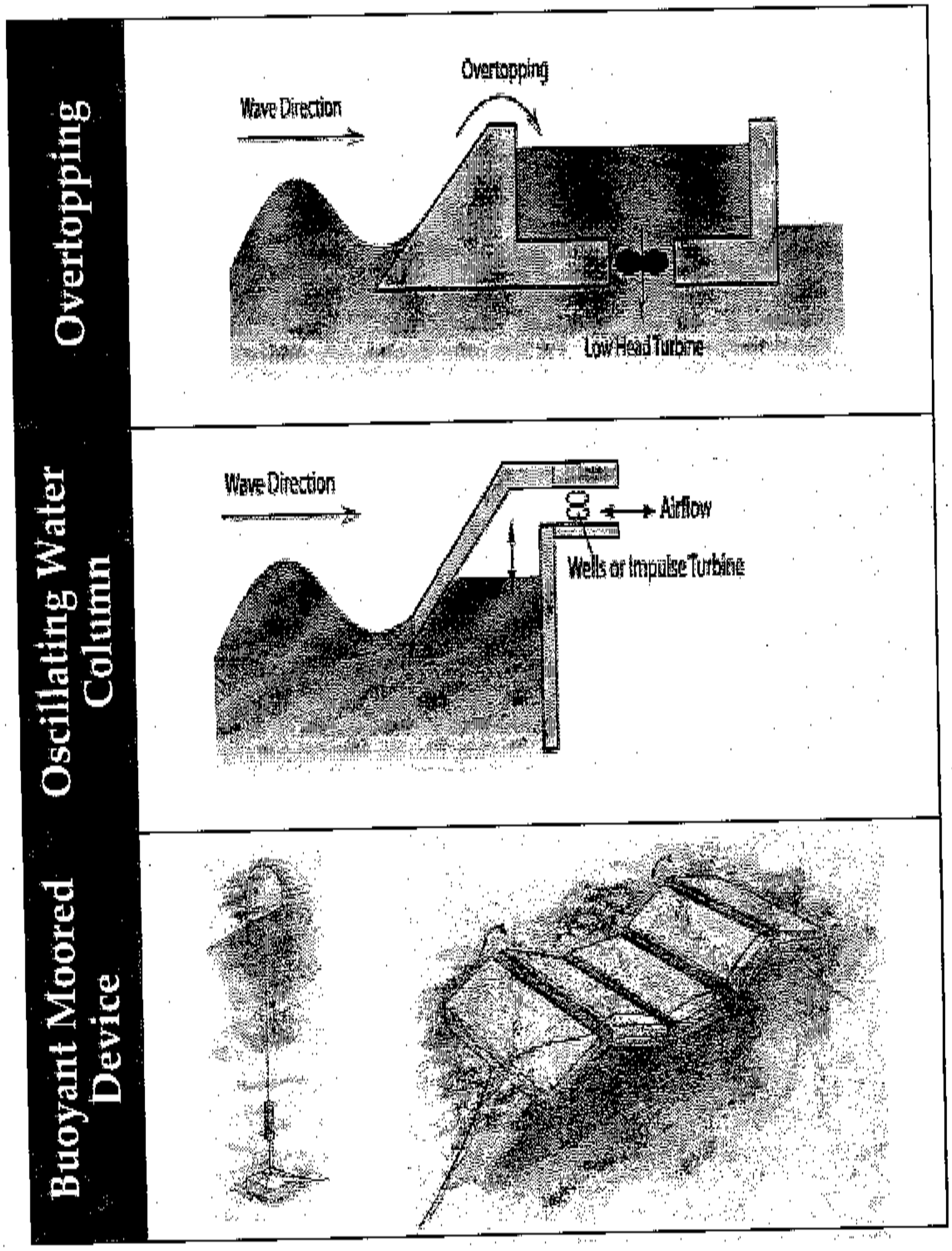
Sources: Navigant Consulting Estimates 2007. *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003. NCI Interviews with fuel cell manufacturers.

Methodology and Key Assumptions: Solid Oxide Fuel Cell

Methodology & Key Assumptions

- Several companies manufacture SOFCs, including GE Power Systems, Rolls Royce, Mitsubishi, Acumentrics, and Siemens/Westinghouse. Most all products are sized at approximately 250 kW, although many of the test products are under 100 kW.
- In California, potential renewable fuels markets for a stationary SOFC is a small wastewater treatment facility or a small animal waste anaerobic digester.
- The cost characteristics here are modeled after a 250 kW SOFC placed in a WWTFTE facility.
- IEPR assumes a 500 kW size for the WWTFTE facility, but many smaller facilities exist that could be appropriate for a SOFC.
- Cost and performance estimates are based on prior NCI experience with fuel cell technology as well as cost and performance estimates published in a 2003 DOE/NREL study: *Gas-fired Distributed Energy Resource Technology Characterizations*, DOE/NREL/GTI, October 2003

Wave Energy Conversion devices convert wave motion to electricity.



Sources: Electric Power Research Institute

Economic Assumptions: Wave Energy Conversion

	Wave Energy Conversion Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	.75	The 2006 number assumes a small 750 kW pilot plant.
Project Life (yrs)	20	From Navigant Consulting sources and estimates.
Overnight Installed Cost ($/kW)	$6,970	Assumes pilot plant.
Transmission and undersea cables	$1,340	From Navigant Consulting sources and estimates.
Equipment	$4,000	
Facilities	0	
Installation	$990	
Construction Management and Permitting	$640	
Fixed O&M ($/kW-yr)	$30	
Non-Fuel Variable O&M ($/MWh)	$25	

Sources: Navigant Consulting Estimates, 2007

Performance Data: Wave Energy Conversion

	Wave Energy Conversion Economic Assumptions for Given Year of Installation (2006$)	
	2006	Notes
Typical Net Capacity Factor (%)	15%	Capacity factors will vary with site conditions.
Fuel Cost ($/MMBtu)	n/a	
Heat Rate (HHV)	n/a	
HHV Efficiency (%)	n/a	
Annual Output Degradation (%/yr)	1%	From Navigant Consulting sources and estimates.
CO_2 (lb/MWh)	0	Wave energy conversion technologies have no emissions.
NO_x (lb/MWh)	0	
SO_2 (lb/MWh)	0	

Sources: Navigant Consulting Estimates, 2007

Methodology and Key Assumptions: Wave Energy Conversion

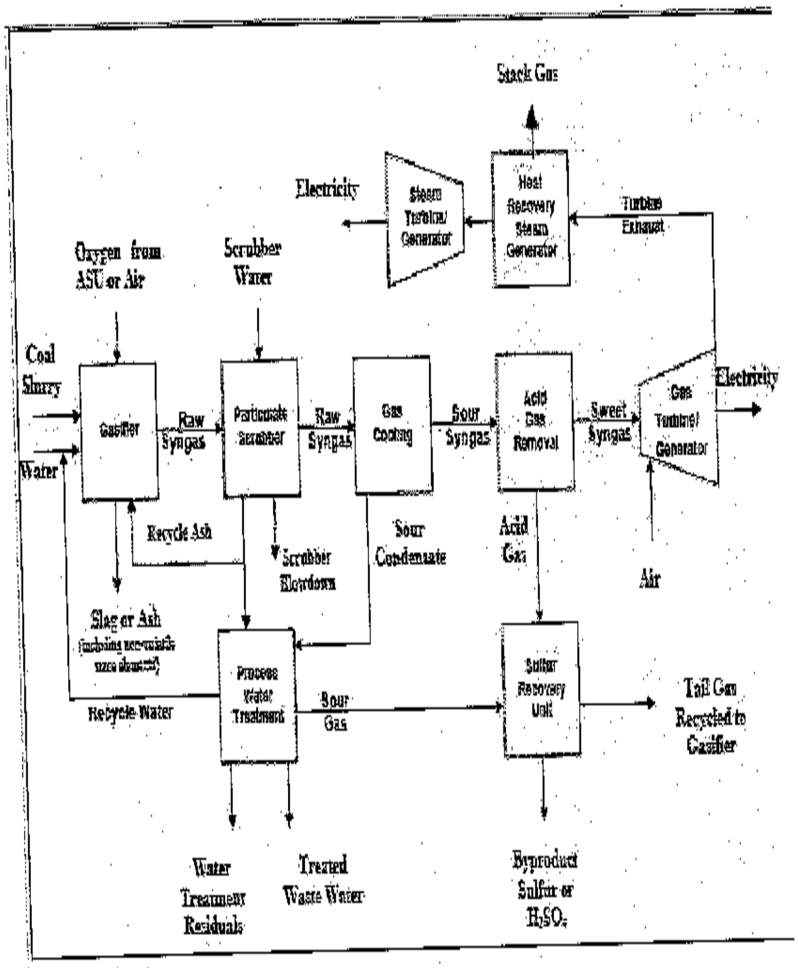
Methodology & Key Assumptions

- No commercial Wave Energy Conversion facilities exist anywhere in the world. NCI analyzed a pilot facility for 2006.
- The 2006 estimates reflect the current technology status and market for wave energy. Assumed that a large scale plant (with greater capacity and lower costs) could not be built at this time.
- System output varies significantly during the year and from year to year. NCI took yearly total outputs and averaged them over the year.
- NCI reviewed data from studies done by EPRI for Wave Energy Conversion facilities built off the Oregon coast. The wave climate closely matches the Northern California locations where PG&E has applied to the FERC for permits.
  - Cost estimates and capacity factors also were reviewed for 2010 and beyond, based primarily on the *System Level Design, Performance and Costs – Oregon State Offshore Wave Power Plant*, EPRI, 2004. These estimates are in agreement with the comments received from Ocean Power Delivery, Wavebob, Community Environmental Council, Mirko Previsic, and Ocean Power Technology. The estimates for 2010, are a plant capacity of 90 MW, a project life of 20 years, an overnight installed cost of $2,700/kW in (2006$), with a 38% capacity factor.
  - The EPRI paper calculated costs for 100 MW worldwide production capability and an 82% progress ratio for learning curves (based upon wind power, PV, and offshore oil and gas).
  - NCI held transmission, facility, and permitting costs constant for a commercial facility over time.

Integrated Gasification Combined Cycle is a power plant using syngas (developed from coal) as a source of clean fuel.

- Integrated Gasification Combined Cycle, or IGCC, is a power plant using synthetic gas (syngas) as a source of clean fuel. Syngas is produced in a gasification unit built for Combined Cycle purposes. Steam generated by waste heat boilers of the gasification process is utilized to help power steam turbines. Heavy petroleum residues, coal, and even biomass are possible feeds for gasification process.
- IGCC is now being considered since it may offer a low-cost long-term option for the reduction of carbon dioxide emissions (through capture and storage).
- The main inhibiting factor for IGCC is high capital cost, but reliability must also be proven before widespread deployment can occur.

Schematic of Generic IGCC Power Plant



Source: *Advanced Fossil Power Systems Comparison Study – Final Report*, National Energy Technologies Laboratory, US Department of Energy.

Economic Assumptions: IGCC

	IGCC Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	500	From Navigant Consulting sources and estimates.
Project Life (yrs)	40	
Overnight Cost ($/kW)	$2,050	The Wisconsin Public Utilities Commission estimate is $1,885/kW for Wisconsin. NCI assumes $2,050, which reflects a cost adjustment for California. Approximately 1%/yr cost improvement is achieved due to learning and technical change.
Fixed O&M ($/kW-yr)	$35	2006 estimates reflect 2006 Wisconsin Public Service Commission IGCC Report estimates, which are more representative of a test facility.
Variable O&M ($/MWh)	$3	

Sources: Navigant Consulting Estimates 2007. EPRI Technical Assessment Guide; Maurstad, O. (2005), *An Overview of Coal-Based Integrated Gasification Combined Cycle (IGCC) Technology*, Laboratory for Energy and the Environment, Massachusetts Institute of Technology; *Annual Energy Outlook 2006, With Projections to 2030*, Energy Information Administration, February 2006; Parsons, E., Shelton, W. Lyons, L. (2002), *Advanced Fossil Power Systems Comparison Study – Final Report*, National Energy Technologies Laboratory, US Department of Energy; *Integrated Gasification Combined-Cycle Technology Draft Report: Benefits, Costs, and Prospects for Future Use in Wisconsin*, June 2006, Wisconsin Department of Natural Resources and the Public Service Commission of Wisconsin; *Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions*, August 31, 2006, John Lyons.

Performance Data: IGCC

	IGCC Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	80%	Based on Wisconsin Public Service Commission and Department of Natural Resources IGCC Study for IGCC plants using western coal.
Fuel Cost ($/MMBtu)	$1.55	Based upon Energy Commission staff conversations with Global Energy Decisions, Sacramento office, May 2007.
HHV Efficiency (%)	38%	Based on Wisconsin Public Service Commission and Department of Natural Resources IGCC Study for IGCC plants using western coal. Due to its higher moisture content, western coal requires more heat to convert energy into electricity.
CO_2 (lb/MWh)	1,928	Based on Wisconsin Public Service Commission and Department of Natural Resources IGCC Study for IGCC plants using western coal. NCI Emissions Calculator.
NO_x (lb/MWh)	0.53	
SO_x (lb/MWh)	0.30	

Sources: Navigant Consulting Estimates 2007. EPRI Technical Assessment Guide; Maurstad, O. (2005), *An Overview of Coal-Based Integrated Gasification Combined Cycle (IGCC) Technology*, Laboratory for Energy and the Environment, Massachusetts Institute of Technology; *Annual Energy Outlook 2006, With Projections to 2030*, Energy Information Administration, February 2006; Parsons, E., Shelton, W. Lyons, L. (2002), *Advanced Fossil Power Systems Comparison Study – Final Report*, National Energy Technologies Laboratory, US Department of Energy; *Integrated Gasification Combined-Cycle Technology Draft Report: Benefits, Costs, and Prospects for Future Use in Wisconsin*, June, 2006, Wisconsin Department of Natural Resources and the Public Service Commission of Wisconsin; *Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions*, August,, 2006, John Lyons.

Methodology and Key Assumptions: IGCC

Methodology & Key Assumptions

- The costs of IGCC power plants using coal have been documented in numerous studies, with estimates for installed costs ranging from $1,400/kW to $2,300/kW. Some of the lower estimates were performed over 5 years ago prior to the recent increase in commodity and steel prices.
- NCI used 4 primary sources for its cost estimates:
  - *Integrated Gasification Combined-Cycle Technology Draft Report: Benefits, Costs, and Prospects for Future Use in Wisconsin,* dated June 2006 prepared by the Wisconsin Department of Natural Resources and the Public Service Commission of Wisconsin.
  - *2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions,* Avista, August 31, 2006, John Lyons.
  - *Annual Energy Outlook 2006, With Projections to 2030,* Energy Information Administration, February 2006.
  - *EPRI Technical Assessment Guide.*
- NCI cost estimates for 2006 reflect the higher end of the cost estimates, and are representative of initial test facilities.

Future nuclear power plants in California could be one of several competing designs, and NCI developed cost estimates for a generic advanced nuclear technology.

Generic Description of Nuclear Power Technology

- Nuclear power is the controlled use of nuclear reactions to release energy for the generation of electricity. Nuclear energy is produced when a fissile material, such as uranium-235, 235U, is concentrated such that nuclear fission takes place in a controlled chain reaction and creates heat — which is used to boil water, produce steam, and drive a steam turbine.

Nuclear Power Technology in California

- Currently, there are three different consortia who are leading efforts to build new nuclear power plants in the United States. None of these consortia have any plans to build a new plant in California.
- Several manufacturers are developing advanced nuclear technology designs. The cost estimates for these designs vary widely. IEPR cost estimates are for a generic advanced nuclear technology.

Advanced Nuclear Design Types and Manufacturers

Design	Manufacturer	Size & Type
US APWR	Mitsubishi	1,700 MWe Advanced Pressurized Water Reactor, PWR
US EPR	AREVA	1,600 MWe Evolutionary Power Reactor
ABWR	GE	1,350 MWe Boiling Water Reactor, BWR
ESBWR	GE	1,380 MWe BWR with passive safety features
SWR 1000	Framatome ANP	1,013 MWe BWR
AP600	BNFL – Westinghouse	610 MWe PWR with passive safety features
AP1000	BNFL – Westinghouse	1090 MWe PWR with passive safety features
IRIS	Westinghouse	100-300 MWe PWR
PBMR	ESKOM	110 MWe modular pebble bed gas-cooled reactor
GT-MHR	General Atomics	288 MWe prismatic graphite moderated gas-cooled reactor
ACR 700	AECL	730 MWe heavy water reactor

Economic Assumptions: Advanced Nuclear

	Advanced Nuclear Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Plant Capacity (MW)	1,000	*Nuclear Power Joint Fact-Finding*, June 2007, The Keystone Center. See page 42, Summary of Construction Cost Estimates, High Case.
Project Life (yrs)	30	
Overnight Cost ($/kW)	$2,865	2007 costs presented in Keystone report adjusted to 2006. See page 34. Assumes some standardization of design and learning from commercial deployment in the U.S.
Fixed O&M ($/kW-yr)	$136	Fixed O&M includes grid integrations costs of $20/kW/yr.
Variable O&M ($/MWh)	$4.86	

Sources: *Nuclear Power Joint Fact-Finding*, June 2007, The Keystone Center; Navigant Consulting Estimates 2007. *The Future of Nuclear Power. An Interdisciplinary MIT Study*, Massachusetts Institute of Technology, 2003; *Annual Energy Outlook 2006, With Projections to 2030*, Energy Information Administration, February 2006; *Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions*, August, 2006, John Lyons; *EIA Electric Power Annual*, Table 8.2. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1994 through 2005; Press Release for Finnish Utility TVO, December 18, 2003.

Performance Data: Advanced Nuclear

	Advanced Nuclear Economic Assumptions for Given Year of Installation (2006$)	
	2006	**Notes**
Typical Net Capacity Factor (%)	85%	*Nuclear Power Joint Fact-Finding*, June 2007, The Keystone Center, compromise between low and high case scenarios.
Fuel Cost ($/MMBtu)	$0.54	Based upon Energy Commission staff conversations with Global Energy Decisions, Sacramento office, May 2007.
HHV Efficiency (%)	32.8%	
CO_2 (lb/MWh)	No Emissions	
NO_x (lb/MWh)		
SO_x (lb/MWh)		

Sources: *Nuclear Power Joint Fact-Finding*, June 2007, The Keystone Center; Navigant Consulting Estimates 2007. *The Future of Nuclear Power. An Interdisciplinary MIT Study*, Massachusetts Institute of Technology, 2003; *Annual Energy Outlook 2006, With Projections to 2030*, Energy Information Administration, February 2006; *Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions*, August, 2006, John Lyons; *EIA Electric Power Annual*, Table 8.2. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1994 through 2005; Press Release for Finnish Utility TVO, December 18, 2003.

Methodology and Key Assumptions: Advanced Nuclear

Methodology & Key Assumptions

- Cost estimates are based on the recent *Nuclear Power Joint Fact-Finding*, June 2007, The Keystone Center. This report reflects the most up to date cost estimates and reflects recent increases in commodity and labor prices.
- Other sources of information include:
  - *The Future of Nuclear Power. An Interdisciplinary MIT Study*, Massachusetts Institute of Technology, 2003;
  - *Annual Energy Outlook 2006, With Projections to 2030*, Energy Information Administration, February 2006;
  - *Avista 2007 Electric Integrated Resource Plan - IRP Modeling Overview: Resource Options and Cost Assumptions*, August 2006, John Lyons;
  - A Press Release for Finnish Utility TVO, December 18, 2003.
- The Keystone and Massachusetts Institute of Technology studies compiled cost statistics from numerous sources, and analyzed the costs of several recent new nuclear power plants in South Korea and Japan.
- Other cost and operational data are very consistent across sources. NCI used the Massachusetts Institute of Technology or Energy Information Administration data except where there definitions were not consistent with the California IEPR approach. For example, the Avista O&M costs fit the IEPR definition more closely.

Glossary

AC	Alternating current
AD	Anaerobic digesters
ARB	California Air Resources Board
BACT	Best available control technology
BOS	Balance of System
BIGCC	Biomass gasification combined cycle
BWR	boiling water reactor
California ISO	California Independent System Operator
CalSEIA	California Solar Energy Industries Association
CHP	Combined heat and power
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
CPV	concentrating photovoltaic
DC	Direct current
DWR	Department of Water and Power
EAO	Electricity Analysis Office
Energy Commission	California Energy Commission
GW	gigawatt
HHV	Higher heating value
IC	Internal combustion
IEPR	Integrated Energy Policy Report
IGCC	Integrated Gasification Combined Cycle
INEEL	Idaho National Engineering and Environmental Laboratory
kV	kilovolt
LFGFTE	Landfill gas fuel to energy
mmBTU	million British Thermal Units
MCFC	molten carbonate fuel cell

MW	megawatt
NCI	Navigant Consulting
NO_x	oxides of nitrogen
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
PG&E	Pacific Gas and Electric Company
PAFC	phosphoric acid fuel cell
PIER	Public Interest Energy Research
PEM	proton exchange membrane
ppmv	Parts per million by volume
PV	photovoltaic
PWR	pressurized water reactor
RD&D	research, development and demonstration
REC	Renewable Energy Certificates
RPS	Renewable Portfolio Standard
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SMUD	Sacramento Municipal Utility District
SO_x	oxides of sulfur
SOFC	solid oxide fuel cell
WWTFTE	Waste water treatment fuel to energy

APPENDIX C: Comments on Report

This appendix summarizes all docketed comments on staff's report and Model, as well as staff's responses to these comments.

Pacific Gas & Electric Company (Received 6/22/07)

PG&E Comment 1:
Anaerobic Digesters (AD): The Navigant report shows dairy and food digesters. Similarly priced, but the staff report shows an almost 3-to-1 difference in Tables 2 and 24 while Navigant costs are used in Table 23.

Staff Response to Comment 1:
There is roughly a 2-to-1 difference in levelized cost for AD dairy relative to AD food. However, the dairy and food digesters are similarly priced only in regard to installed cost. Both the variable and fixed O&M costs are quite different for the two technologies. The single biggest factor driving the 2-to-1 difference in levelized cost is the tipping fee of $20/ton for AD food that is not applicable to AD dairy. This tipping fee is captured in the variable O&M which changes the AD food variable O&M levelized cost to become a net savings of $60/MWh compared to the AD dairy which is a net cost of $15.22/MWh. Even though the fixed O&M and corporate taxes of the AD food are higher than the AD dairy, the effect of the tipping fee makes the total levelized cost of AD food significantly lower.

PG&E Comment 2:
Anaerobic Digester Food: Table 24 shows a 94 percent tax credit without derivation, which can explain some of the difference, but this result is inconsistent with Figure 15.

Staff Response to Comment 2:
The 94 percent tax credit derived in Table 24 is using the data in Table 24, but was calculated using a base cost that is confusing to the reader. It was calculated by dividing the difference between the cost without the savings ($97.65) and the cost with the savings ($50.27) by the cost with savings: ($97.65 - $50.27)/$50.27 * 100% = 94.3%. It probably makes more sense to calculate this percentage by dividing the difference by the cost without savings: ($97.65 - $50.27) / $97.65 * 100% = 48.5%. This is corrected in this final report.

PG&E Comment 3:
Biomass Costs: Costs shown in Table 10 for biomass are extremely low and not differentiated between "free" fuel, such as landfill gas, and more expensive fuel, such as wood waste.

Staff Response to Comment 3:
Biomass costs were $40/dry ton for fluidized bed and stoker boiler. "Free" fuels were used for the Biomass landfill gas and waste water treatment plant technologies. Staff believes the costs in the Report are reasonable. Without quantitative data, we cannot make any adjustments.

PG&E Comment 4:
Combined Cycle and Combustion Turbine: Combined cycle costs compared to combustion turbine costs changed from 30 percent higher in the *2003 IEPR* to 15 percent lower in the *2007 IEPR*. In addition, the installed costs of a simple cycle unit almost doubled (see table below). It is unclear why the combined cycle costs are not increased proportionately.

Instant Cost	2003 IEPR ($/kW)	2007 IEPR ($/kW)	% Increase
Combined Cycle Base Load	$ 620	$ 784	126%
Simple Cycle	$ 477	$ 925	194%

These counterintuitive results need to be reviewed. Possible reasons could be that many of the combustion turbines were developed under emergency siting or small power plant exemption (SPPE) cases, which potentially reflects a market premium.

Staff Response to Comment 4:
The differences between the *2003* and *2007 IEPRs* are misleading. The simple cycle cost of *2003 IEPR* was simply too low, making the comparison meaningless. It is important to keep in mind that the 2003 estimates were simply rough estimates. The *2007 IEPR* estimates were developed based on a survey of actual costs. The difference really illustrates the necessity to develop estimates based on actual costs rather than relying on publicly available data as was done in the *2003 IEPR*.

PG&E Comment 5:
Regarding escalation rates, PG&E does not have access to escalation rates used in the analysis but suggests that capital costs be escalated with a construction cost escalation index, as construction materials costs have recently increased significantly faster than inflation.

Staff Response to Comment 5:
Real escalation for fixed and variable costs was assumed to be 0.5 percent per year. Real escalation for capital costs has been assumed to be zero. Nominal escalation is shown in the report in Table 10. Based on the data collected in the survey, staff was unable to discern any long-term pattern in cost escalation beyond nominal inflation. Furthermore, recent history shows costs falling relative to nominal price levels and the more recent construction cost increases only tend to offset the falling trend.

PG&E Comment 6:
Advance Simple Cycle Technology: The advanced simple cycle heat-rate improvement to 7580 BTU/kWh is too optimistic (p. 33) compared to the referenced Energy Information Administration (EIA) heat rate of 8550 BTU/kWh (p. 43). If this 7580 BTU/kWh low heat rate were achieved, the expected capacity factor should be higher than 5 percent.

Staff Response to Comment 6:
Staff agrees with PG&E that the 7580 Btu/kWh estimate is probably unrealistic for actual operation and has decided to use the EIA estimate of 8550 Btu/kWh instead. Staff also concurs that the capacity factor should be greater than 5 percent – even for the EIA estimate – and is changing this value to 15 percent based on Marketsym simulations.

PG&E Comment 7:
Advanced Simple Cycle Technology: The Energy Commission's instant cost of $756/kW for this new technology appears too low. For comparison, the Energy Commission's forecasted cost of a simple cycle unit is $925/kW. PG&E believes the cost of an advanced simple cycle unit will likely be higher.

Staff Response to Comment 7:
The model did assume a small incremental cost increase for advanced turbines using EIA data; however, that cost increase is offset by the fact that the base advanced CT facility is twice the size in MW of the conventional CT facility, thus an economy of scale.

PG&E Comment 8:
Capacity Factors: Use of historical capacity factors during the 2001- 2006 post-energy crises may not be a good estimate for future operation.

Staff Response to Comment 8:
The projected capacity factors are based in part on the Energy Commission's Marketsym modeling and in part on the judgment of the Aspen consultant. At this point, both the 60 percent capacity factor assumed for combined cycle units and the 5 percent capacity factor assumed for simple cycle units may be slightly high, but our best estimates have been rounded up to these approximate values in deference to the uncertainties inherent in this type of estimating.

PG&E Comment 9:
Base Combined Cycle Configuration: Consistent with the *2003 IEPR*, the base case configuration should include costs of dry cooling.

Staff Response to Comment 9: Dry cooling was not used in the base configuration for the *2007 IEPR* as it is relatively uncommon in the existing combined cycle units.

PG&E Comment 10:
Chillers: The effects of chillers on heat rate, capacity degradation, and parasitic load should be considered.

Staff Response to Comment 10:
These effects are considered to an extent by using actual heat rate and generation data from QFER. Chillers are used as peakers during hot periods only. Their overall effect during the year is not enough to significantly affect the COG model results.

PG&E Comment 11:
PG&E recommends that variable costs be excluded in the $kW-yr columns of Table 2: Summary of Levelized Costs, which presents calculated levelized costs that appear to include both fixed and variable costs.

Staff Response to Comment 11:
Staff's intention is to show the total levelized cost in both $/kW-Year and $/MWh as a convenience to future users and sees no purpose in excluding the variable cost portion.

PG&E Comment 12:
Solar Dish Engine: The cost is more than 50 percent higher than solar trough, which is inconsistent with SCE and SDG&E contracts under the MPR.

Staff Response to Comment 12:
The 2006 numbers that were included in the report reflect the current technology status and market for solar dish and solar trough plants from publicly available sources. In the future, larger production volumes are expected to lower overnight costs for solar dish, and storage is expected to be an economic option that will initially increase overnight costs and also increase capacity factors for solar trough. For this project, 2006 costs and capacity factors were used. Staff believes the costs in the report are reasonable. Without quantitative data, we cannot make adjustments.

PG&E Comment 13:
Geothermal: Binary and dual flash technologies appear to be too similarly priced compared to current market prices.

Staff Response to Comment 13:
Staff believes these costs are reasonable. The levelized cost between these two technologies is very close because the capital costs and net capacity factors are very similar. Without quantitative data, we cannot make adjustments.

PG&E Comment 14:
Solid Oxide Fuel Cell: Capital costs appear low, although variable costs for service contract and stack replacement may make up for it.

Staff Response to Comment 14:
Staff believes these costs are reasonable. Without quantitative data, we cannot make any adjustments.

PG&E Comment 15:
Wave: Capital costs are on the high side, and capacity factor appears too low. Integrated Gasification Combined Cycle (IGCC): Costs for this technology should include CO_2 sequestration costs to account for further reductions in greenhouse gas emissions.

Staff Response to Comment 15:
The 2006 numbers included in the report reflect the current technology status and market for wave energy. We did not think it was realistic that a large-scale plant (with considerably greater capacity and lower costs) could have been built at that time, and the analysis reflected this. Cost estimates and capacity factors were estimated for 2010 and beyond based primarily on the *EPRI System Level Design, Performance and Costs – Oregon State Offshore Wave Power Plant* report. These estimates are in agreement with the comments received from Ocean Power Delivery, Wavebob, Community Environmental Council, Mirko Previsic, and Ocean Power Technology. The estimates for 2010 are for a plant capacity of 90 MW, a project life of 20 years, an overnight installed cost of $2,700/kW in (2006$) and with a 38 percent capacity factor. The footnote is correct in this final report. CO_2 sequestration costs are not included as they are beyond the present scope of the model.

PG&E Comment 16:
Advanced Nuclear: Capital costs appear low.

Staff Response to Comment 16:
Staff agrees. New costs have recently become available in the June 2007 Keystone Report, *Nuclear Power Joint Fact Finding*. This is corrected in this final report.

NRDC & UCS (Received 6/27/07)

NRDC Comment 1
The Model will be more valuable to policy makers if it presents the results of sensitivity analysis on cost of greenhouse gas emissions and allows the user to vary the cost of greenhouse gas emissions in the model.

Staff Response to Comment 1:
The requested study is beyond the present scope of the Cost of Generation report. However, staff intends to consider this in subsequent Cost of Generation reports.

NRDC Comment 2
The emission rate for IGCC should be changed from 1,928 pounds of CO_2 per MWh to 1,100 pounds of CO_2 per MWh to conform to the SB 1368 Performance Standard, which has been adopted by the Energy Commission (07-0523-7) and the CPUC (CPUC D.07-01-039, January 25, 2007).

Staff Response to Comment 2:
Navigant agrees that the Energy Commission and CPUC adopted rules and regulations need to be considered. The plant that was profiled would not meet current regulations. Under the current adopted rules and regulations, additional capital investment and operating costs would be needed to meet emission requirements. These changes could also affect plant efficiency.

NRDC Comment 3
The Model should be modified to capture carbon cost of IGCC, as it will increase cost about $14/MWh. Suggests adding $450/kW to capital cost and $3/MWh for variable cost.

Staff Response to Comment 3:
Carbon capture is not sufficiently defined and it implies other things such as carbon tax, which are beyond the present scope of the model.

NRDC Comment 4
Nuclear levelized costs are too low for nuclear power. The Model assumes an installed cost of nuclear of $2,433/kW, whereas the Keystone Center estimates that cost as between $3,600/kW and $4,000/kW.

Staff Response to Comment 4:
Staff agrees. New costs have recently become available in the June 2007 Keystone report *Nuclear Power Joint Fact Finding*. This is corrected in this final report.

NRDC Comment 5
Assuming a forward price for IGCC is inconsistent with the other technologies. Capital costs may be too low. Mesba Unit 1 in northern Minnesota had an instant cost of $3,000/kW ($3600/KW installed).

Staff Response to Comment 5:
The point made by Navigant in the presentation was that many of these technologies will not be built today as there is lead time required for permitting and other approvals. It was assumed that the technologies would be installed in 2006 when creating the estimates. Therefore, Navigant did not assume that one technology was using 2010 technology and the other 2007.

NRDC Comment 6
Wind costs ($99/MWh for Merchant and $67/MWh for IOU) are unreasonably high in that 2006 MPR is set at $84.24 per MWh. Thinks this is due to using cost of equity of 15.19 percent.

Staff Response to Comment 6:
Staff considers the cost of equity to be reasonable but has reconsidered the debt to equity ratio. This is corrected in this final report.

NRDC Comment 7
Solar prices are high due to incomplete or bad assumptions. Does not explain the large difference between Merchant and IOU owned plants – illogical since IOU is not eligible for investment tax credits (ITCs). The Report assumes that the 30 percent ITC will not extend beyond 2008 but Congress is considering an eight-year extension – at a minimum five years should be assumed.

Staff Response to Comment 7:
The difference in merchant and IOU costs comes from the financing mechanisms. Staff considers the cost of equity to be reasonable but has reconsidered the debt to equity ratio. The cost estimates are not impacted by the incentives assumed in future years as the incentives apply based on the time of plant construction. Therefore the assumption of the ITC being extended does not affect the results. Staff agrees that ITC is not applicable to the IOUs and has modified the Model and report accordingly. Navigant did take into consideration the economies of scale that are achieved by combining modular units.

Southern California Edison (Rec'd 6/29/07)

SCE Comment 1:
The Energy Commission report uses a commercial grade LM6000 as the base configuration for the simple cycle combustion turbine. SCE believes that the GE Frame 7x configuration is a more appropriate standard. SCE recommends an additional scenario based on a two-unit or four-unit Frame 7x peaker configuration be incorporated.

Staff Response to Comment 1:
The simple and combined cycle base cases were based on the normal type and number of turbines that have been licensed in the recent past and that are currently undergoing licensing. There are a large number of potential selections for these base cases; however, we believe that the use of siting cases since 2001 provides the most reasonable and typical design. Staff doesn't believe that Frame 7 turbines are a reasonable simple cycle case as staff has seen only two such cases be licensed Tracy (2-7E turbines), and Pastoria expansion project (1-7F turbine with three existing 7F combined cycle turbines); while more than half of the cases were LM6000 turbines. The simple cycle cases under construction or currently under review, not including the LMS100 advanced turbine cases, also are predominately LM6000 turbines and cases outside of Energy Commission jurisdiction would typically have to be LM6000 or smaller turbines (as is the case with the four LM6000 SCE projects in construction in the SCAB and the one LM6000 project proposed in Oxnard). While staff is aware of these five LM6000 cases proposed/being built by SCE, staff is not aware that SCE is proposing any Frame 7 turbines for simple cycle operation.

SCE Comment 2:
The combined cycle scenario as currently described appears to be inefficiently sized by using a 500 MW 2x1 configuration (2 CTs into one steam turbine). SCE believes a scenario similar to the Mountainview plant is more appropriate at approximately 1000 MW, using a 4x2 configuration.

Staff Response to Comment 2:
Four turbine combined cycle projects are not the norm. Of the 15 7F combined cycle projects surveyed (that is, licensed and built since 2001) only three were four turbine projects. The most prevalent, eight cases, were two turbine cases (with one turbine occurring once and three turbines occurring three times). The combined cycle cases under construction or currently under review are predominately two turbine 7F configurations as well.

SCE Comment 3:
Chapter 2. Assumptions, Summary of Assumptions, page 16: The paragraph indicates that Tables 6 and 7 summarize the most common input assumptions and that all costs are for year 2007 nominal dollars. However, Table 6 and 7 presents the same emissions factors for the various technologies, no other assumptions are provided, and no costs are provided. Is the information provided by Tables 6 and 7 the correct information presentation (same data in both tables and no costs)? Please review.

Staff Response to Comment 3:
This was a typographical error. Table 6 should have shown the common input assumptions, not the emission factors. This is corrected in this final report.

SCE Comment 4:
Clean Coal (IGCC) & Nuclear Section, Advanced Nuclear Design Types and Manufacturers Table, page 101: Two (2) major suppliers of advanced nuclear plant designs are not listed in the table but should be considered.

Design	Mfgr.	Size & Type
US APWR	Mitsubishi	1,700 MWe Advanced Pressurized Water Reactor
US EPR	AREV A	1,600 MWe Evolutionary Power Reactor

Staff Response to Comment 4:
These suppliers are added in this final report.

SCE Comment 5:
ADDERS Sheet: It is understood that the Plants Survey Information was used to develop the "Linears" costs indicated in the Model Adjustment Factors tables. Recent Southern California Edison experience indicates that the "Linears" cost used for the simple cycle plant is approximately fifty (50) percent low when compared to actual construction costs for transmission, gas supply, etc.

Staff Response to Comment 5:
Again relying on the data gathered, staff has no evidence to support a higher value. In the absence of specific information, staff can only keep SCE's admonition in mind during future data gathering efforts.

SCE Comment 6:
INPUT-OUTPUT Sheet, INPUT SELECTION Table: For Advanced Nuclear and IGCC Plant Types, selecting a Start (in-service) year other than 2007 produces a "#N/A" indication in the OUTPUT RESULTS Table Fuel Costs columns. It this the intended result for the fuel cost for these Plant Types and Start Year selection? Please review.

Staff Response to Comment 6:
Selecting Advanced Nuclear with a book life of 40 years extends the algorithm beyond its present structure. This is correct in the final version of the Model.

SCE Comment 7:
INPUT-OUTPUT Sheet, INPUT SELECTION Table: After selecting Fuel Cell Plant Types, methane fuel is indicated as the fuel. However, a **"$0"** fuel cost is indicated in the OUTPUT RESULTS Table Fuel Costs columns. It this correct, that no fuel costs are included in the variable costs? If not, how is the fuel cost accounted for. Please review.

Staff Response to Comment 7:
The fuel cost is intentionally set to zero based on the assumption that the fuel cell is sized for a landfill gas site and uses the methane from the landfill.

SCE Comment 8:
INPUT-OUTPUT Sheet, KEY DATA VALUES Table. Fuel Use Summary: The row name "Natural Gas Price ($/MMBtu)" remains the same even when other fuels (coal, nuclear, etc.) are indicated in the INPUT SELECTION Table. However, the selected fuel costs are listed. Is this the intended presentation result for indicating fuel types costs? Please review.

Staff Response to Comment 8:
This is an error in the coding. This is corrected to say Fuel Price, rather than Natural Gas Price in the final version of the Model.

SCE Comment 9:
INPUT-OUTPUT Sheet, KEY DATA VALUES Table. Instant and Installed cost: The Installed Costs generated by the Model are indicated as LESS than the Instant Costs. Is this correct? It would seem that the Installed Costs should be more than the Instant Costs. Please review.

Staff Response to Comment 9:
Staff cannot replicate this concern. The confusion is no doubt generated by the Instant/Installed option in cell C19 on the input-Output worksheet, which allows the user to tell the model whether the cost data in Data 2 worksheet are Instant Costs or Installed Costs. If the Installed option is used, the data in G27 is identical to the cost in G26, which signifies that there is no Instant cost being used. Staff has modified Instructions on the Input-Output worksheet along with a reference adjacent to the cell C19 that should eliminate this confusion.

SCE Comment 10:
FUEL PRICE FORECASTS Sheet: The column header "Natural Gas, $/MMBtu" (left hand side of Sheet) remains the same even when other fuels (coal, nuclear, etc.) are indicated in the INPUT-OUTPUT Sheet, INPUT SELECTION Table. However, the selected fuel costs are listed in the column. Is this the intended header presentation for indicating fuel types costs? Please review.

Staff Response to Comment 10:
This is an error in the coding. It has been corrected to read "Fuel Price," rather than "Natural Gas Price" in the final version of the Model.

SCE Comment 11:
INPUT-OUTPUT Sheet. KEY DATA VALUES Table. Capacity & Energy Summary, Etc.: For Combined Cycle Advanced (H Frame) Plant Type--when the Turbine Configuration is changed from 2 (default) to 1, there is no change to the power output numbers in the Capacity & Energy Summary, no change in Fuel Use, etc. The Levelized Costs, Instant Costs, Installed Costs, etc. change but the values are questionable since the Capacity does not change. Please review.

Staff Response to Comment 11:
In order for the Model to work correctly, the user must refresh the Plant Type Assumptions, Instruction 10.

Wave Energy (Received 6/20/07)
Ocean Power Delivery (Received 6/22/07)
Community Environmental Council (Received 6/22/07)
Ocean Power Technologies, Inc (Received 6/22/07)
Wavebob (Received 6/29/07)

Summary of these 5 comments:
All of these public entities commented that capital costs were too high and capacity factors were too low, resulting in unrealistically high levelized cost.

Staff response to these 5 comments:
The 2006 numbers that were included in the report reflect the current technology status and market for wave energy. We did not think it was realistic that a large scale plant (with considerably greater capacity and lower costs) could have been built at that time and the analysis reflected this. Cost estimates and capacity factors were estimated for 2010 and beyond based primarily on the EPRI System Level Design, Performance and Costs – Oregon State Offshore Wave Power Plant report. These estimates are in agreement with the comments received from Ocean Power Delivery, Wavebob, Community Environmental Council, Mirko Previsic, and Ocean Power Technologies. The estimates for 2010, are a plant capacity of 90 MW, a project life of 20 years, an overnight instant cost of $2,700/kW in (2006$), with a 38 percent capacity factor. The footnote in the final report will be corrected accordingly.

APPENDIX D: Changes Since Draft Report

This Appendix summarizes the changes since the June 12, 2007 draft report. The significant changes are:

- Advanced simple cycle heat rate and capacity factors changed from 7580 Btu/kWh and 5 percent to 8550 Btu/kWh and 15 percent.
- Nuclear costs were increased to reflect the recently released 2007 Keystone Report. The corresponding changes from the draft report are as follows:
    - Instant cost: From $2509 to $2950 /kW
    - Fixed O&M: From $57 to $140 /kW-Yr
    - Variable O&M: From $1.24 to $5 /MWh
    - Construction period: From five to six years
- The variable cost for Biomass AD-Food's was reduced to reflect a correction in the estimated tipping fee.
- The BETC tax credit for solar concentrating PV was removed for IOU ownership as it is not applicable.
- CSI and SGIP tax credits were removed as not being applicable for central station technologies.
- Debt-to-equity ratio for merchant non-gas fired technologies was changed from 40 percent/60 percent to 60 percent/40percent resulting in reductions in levelized cost between 5 and 18 percent depending on the technology – not accounting for the other updates to the report.
- Tax credits and tax credit accounting revised such that levelized costs decreased for all ownerships and all technologies but most significantly for technologies with tax credits – changes range from 1 percent to 20 percent depending on the technology and ownership.

Table D-1 shows the levelized costs presented in the draft report. **Table D-2** shows the resulting changes in levelized costs due to the above delineated revisions. **Table D-3** shows the resulting change as a percent of draft report's levelized cost.

Table D-1: Draft Report Levelized Costs

In-Service Year =2007 (Nominal 2007$)	Size	Merchant		IOU		POU	
	MW	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh
Conventional Combined Cycle (CC)	500	514.56	101.35	476.31	93.97	443.68	87.79
Conventional CC - Duct Fired	550	521.49	102.72	482.14	95.12	448.59	88.77
Advanced Combined Cycle	800	485.30	95.59	447.16	88.22	413.91	81.90
Conventional Simple Cycle	100	250.81	586.36	196.68	460.01	133.90	313.42
Small Simple Cycle	50	270.85	633.21	213.36	499.02	147.98	346.37
Advanced Simple Cycle	200	205.06	479.40	160.83	376.17	106.18	248.52
Integrated Gasification Combined Cycle (IGCC)	575	678.11	131.66	492.79	95.68	384.74	74.70
Advanced Nuclear	1000	728.50	99.86	538.03	73.75	488.88	67.01
Biomass - AD Dairy	0.25	937.69	145.65	723.65	112.41	636.95	98.94
Biomass - AD Food	2	323.64	50.27	80.72	12.54	-51.00	-7.92
Biomass Combustion - Fluidized Bed Boiler	25	915.59	125.49	793.72	108.78	855.28	117.22
Biomass Combustion - Stoker Boiler	25	854.32	117.09	745.23	102.14	814.95	111.69
Biomass - IGCC	21.25	929.64	127.41	781.13	107.06	771.37	105.72
Biomass - LFG	2	370.07	54.49	294.14	43.66	317.72	47.86
Biomass - WWTP	0.5	458.23	87.35	361.82	70.59	296.38	60.36
Fuel Cell - Molten Carbonate	2	933.83	120.84	774.10	100.17	672.03	86.96
Fuel Cell - Proton Exchange	0.03	1289.91	166.91	1026.94	132.89	858.56	111.10
Fuel Cell - Solid Oxide	0.25	776.26	100.45	615.21	79.61	531.28	68.75
Geothermal - Binary	50	573.15	91.82	400.34	66.10	384.60	67.18
Geothermal - Dual Flash	50	542.03	88.67	383.07	64.58	375.70	67.01
Hydro - In Conduit	1	256.67	63.36	183.90	46.09	185.71	48.01
Hydro - Small Scale	10	700.93	171.03	480.62	119.06	338.23	86.43
Ocean Wave (Pilot)	0.75	1440.72	1201.48	1006.79	846.40	716.79	611.59
Solar - Concentrating PV	15	495.96	271.96	334.48	185.55	204.88	116.23
Solar - Parabolic Trough	63.5	671.03	294.54	497.90	219.23	349.47	154.86
Solar - Photovoltaic (Single Axis)	1	1117.12	608.42	723.14	396.30	461.81	256.29
Solar - Stirling Dish	15	1121.75	544.27	859.49	417.02	643.25	312.10
Wind - Class 5	50	289.10	99.03	195.24	66.88	177.44	60.78

Table D-2: Levelized Cost Changes from Draft to Final Report

In-Service Year =2007 (Nominal 2007$)	Size	Merchant		IOU		POU	
	MW	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh
Conventional Combined Cycle (CC)	500	-8.74	0.84	-9.46	0.50	-15.37	-0.96
Conventional CC - Duct Fired	550	-9.10	0.80	-9.75	0.48	-15.62	-0.98
Advanced Combined Cycle	800	-8.34	0.78	-8.95	0.46	-14.29	-0.88
Conventional Simple Cycle	100	-0.38	13.21	-1.09	8.46	-1.06	4.91
Small Simple Cycle	50	-0.49	14.07	-1.28	8.95	-1.28	5.18
Advanced Simple Cycle	200	90.90	-243.28	92.38	-174.07	94.95	-87.92
Integrated Gasification Combined Cycle (IGCC)	575	-111.54	-5.16	-16.64	10.64	-23.22	6.02
Advanced Nuclear	1000	134.20	18.39	219.74	30.12	175.90	24.11
Biomass - AD Dairy	0.25	-13.17	-2.05	102.92	15.99	163.98	10.83
Biomass - AD Food	2	127.33	19.78	269.57	41.87	269.82	41.91
Biomass Combustion - Fluidized Bed Boiler	25	-49.34	-6.76	0.27	0.04	-15.37	-2.11
Biomass Combustion - Stoker Boiler	25	-43.33	-5.94	0.22	0.03	-15.21	-2.09
Biomass - IGCC	21.25	-80.46	-3.76	-12.55	4.86	-26.55	2.74
Biomass - LFG	2	12.43	1.63	51.80	7.21	35.01	4.50
Biomass - WWTP	0.5	56.42	9.99	104.81	18.25	70.16	11.42
Fuel Cell - Molten Carbonate	2	-47.72	-6.18	136.51	17.66	82.91	10.73
Fuel Cell - Proton Exchange	0.03	119.72	15.49	254.34	32.91	167.11	21.62
Fuel Cell - Solid Oxide	0.25	179.39	23.21	253.40	32.79	164.01	21.22
Geothermal - Binary	50	-95.93	-15.98	-4.03	-2.57	9.64	-1.63
Geothermal - Dual Flash	50	-88.11	-15.00	-3.83	-2.51	8.66	-1.75
Hydro - In Conduit	1	-42.95	-10.52	0.06	-0.41	3.00	-0.23
Hydro - Small Scale	10	-133.22	-32.29	0.44	-0.99	9.73	0.66
Ocean Wave (Pilot)	0.75	-200.80	-170.98	-1.15	-8.76	17.16	5.53
Solar - Concentrating PV	15	124.52	152.88	297.32	248.46	237.22	191.86
Solar - Parabolic Trough	63.5	-173.71	-17.24	6.27	62.14	6.24	44.45
Solar - Photovoltaic (Single Axis)	1	-82.05	96.56	296.34	299.30	219.93	212.58
Solar - Stirling Dish	15	-266.20	-25.38	9.43	109.98	5.61	81.37
Wind - Class 5	50	-43.17	-14.79	0.84	0.29	1.75	0.60

Table D-3: Change as a Percent of Draft Report Levelized Costs

In-Service Year =2007 (Nominal 2007$)	Size	Merchant		IOU		POU	
	MW	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh
Conventional Combined Cycle (CC)	500	-1.7%	0.8%	-2.0%	0.5%	-3.5%	-1.1%
Conventional CC - Duct Fired	550	-1.7%	0.8%	-2.0%	0.5%	-3.5%	-1.1%
Advanced Combined Cycle	800	-1.7%	0.8%	-2.0%	0.5%	-3.5%	-1.1%
Conventional Simple Cycle	100	-0.2%	2.3%	-0.6%	1.8%	-0.8%	1.6%
Small Simple Cycle	50	-0.2%	2.2%	-0.6%	1.8%	-0.9%	1.5%
Advanced Simple Cycle	200	44.3%	-50.7%	57.4%	-46.3%	89.4%	-35.4%
Integrated Gasification Combined Cycle (IGCC)	575	-16.4%	-3.9%	-3.4%	11.1%	-6.0%	8.1%
Advanced Nuclear	1000	18.4%	18.4%	40.8%	40.8%	36.0%	36.0%
Biomass - AD Dairy	0.25	-1.4%	-1.4%	14.2%	14.2%	25.7%	10.9%
Biomass - AD Food	2	39.3%	39.3%	333.9%	333.9%	-529.1%	-529.1%
Biomass Combustion - Fluidized Bed Boiler	25	-5.4%	-5.4%	0.0%	0.0%	-1.8%	-1.8%
Biomass Combustion - Stoker Boiler	25	-5.1%	-5.1%	0.0%	0.0%	-1.9%	-1.9%
Biomass - IGCC	21.25	-8.7%	-2.9%	-1.6%	4.5%	-3.4%	2.6%
Biomass - LFG	2	3.4%	3.0%	17.6%	16.5%	11.0%	9.4%
Biomass - WWTP	0.5	12.3%	11.4%	29.0%	25.9%	23.7%	18.9%
Fuel Cell - Molten Carbonate	2	-5.1%	-5.1%	17.6%	17.6%	12.3%	12.3%
Fuel Cell - Proton Exchange	0.03	9.3%	9.3%	24.8%	24.8%	19.5%	19.5%
Fuel Cell - Solid Oxide	0.25	23.1%	23.1%	41.2%	41.2%	30.9%	30.9%
Geothermal - Binary	50	-16.7%	-17.4%	-1.0%	-3.9%	2.5%	-2.4%
Geothermal - Dual Flash	50	-16.3%	-16.9%	-1.0%	-3.9%	2.3%	-2.6%
Hydro - In Conduit	1	-16.7%	-16.6%	0.0%	-0.9%	1.6%	-0.5%
Hydro - Small Scale	10	-19.0%	-18.9%	0.1%	-0.8%	2.9%	0.8%
Ocean Wave (Pilot)	0.75	-13.9%	-14.2%	-0.1%	-1.0%	2.4%	0.9%
Solar - Concentrating PV	15	25.1%	56.2%	88.9%	133.9%	115.8%	165.1%
Solar - Parabolic Trough	63.5	-25.9%	-5.9%	1.3%	28.3%	1.8%	28.7%
Solar - Photovoltaic (Single Axis)	1	-7.3%	15.9%	41.0%	75.5%	47.6%	82.9%
Solar - Stirling Dish	15	-23.7%	-4.7%	1.1%	26.4%	0.9%	26.1%
Wind - Class 5	50	-14.9%	-14.9%	0.4%	0.4%	1.0%	1.0%

APPENDIX E: Summary of Simple Cycle Cost

This appendix is provided at the request of the California ISO. It summarizes the fixed cost components for simple cycle generating units (combustion turbines) in \$/kW-Yr. It is consistent with the summary of levelized costs provided in Tables 2 – 5 of this report.

Table E-1: Simple Cycle Fixed Costs - Merchant

		\$/kW-Yr (Nominal 2007\$)					
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Conventional Simple Cycle	100	136.59	8.70	6.81	12.74	39.44	**204.28**
Small Simple Cycle	50	145.30	9.25	7.25	20.36	41.85	**224.01**
Advanced Simple Cycle	200	112.21	7.14	5.60	8.25	32.44	**165.64**

Table E-2: Simple Cycle Fixed Costs - IOU

		\$/kW-Yr (Nominal 2007\$)					
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Conventional Simple Cycle	100	106.14	6.87	3.85	13.00	18.40	**148.26**
Small Simple Cycle	50	112.91	7.30	4.10	20.78	19.47	**164.55**
Advanced Simple Cycle	200	87.19	5.64	3.17	8.42	15.16	**119.58**

Table E-3: Simple Cycle Fixed Costs - POU

		\$/kW-Yr (Nominal 2007\$)					
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Conventional Simple Cycle	100	60.14	5.04	5.59	13.30	0.00	**84.08**
Small Simple Cycle	50	64.98	5.45	6.04	21.27	0.00	**97.74**
Advanced Simple Cycle	200	46.60	3.91	4.33	8.62	0.00	**63.46**

Levelized costs, including all cost components thereof, can be converted from \$/MWh to \$/kW-Yr by multiplying the \$/MWh value by the load center energy (GWh) and dividing by the gross capacity (MW). Alternatively, the same result can be obtained by using Table 2. Multiply the \$/MWh levelized cost by the corresponding \$/kW-Yr and divide by the \$/MWh. Care must be taken to use the corresponding technology and developer.

Attachment G

COMPARATIVE COSTS OF CALIFORNIA CENTRAL STATION ELECTRICITY GENERATION TECHNOLOGIES

(COST OF GENERATION MODEL)

ISO Stakeholders Meeting

Interim Capacity Procurement Mechanism

Joel Klein

Date: October 15, 2007

TODAY

- Overview of the Cost of Generation Model.
- Summary of Levelized Costs – Output.
  - Has not yet received final approval.
- Summary of Assumptions – Input.
- Data Collection, Processing & Results.

FIRST ITEM

- Overview of the Cost of Generation Model.
- Summary of Levelized Costs - Output.
- Review the Assumptions – Input.
- Data Collection , Processing & Results.

OVERVIEW OF MODEL

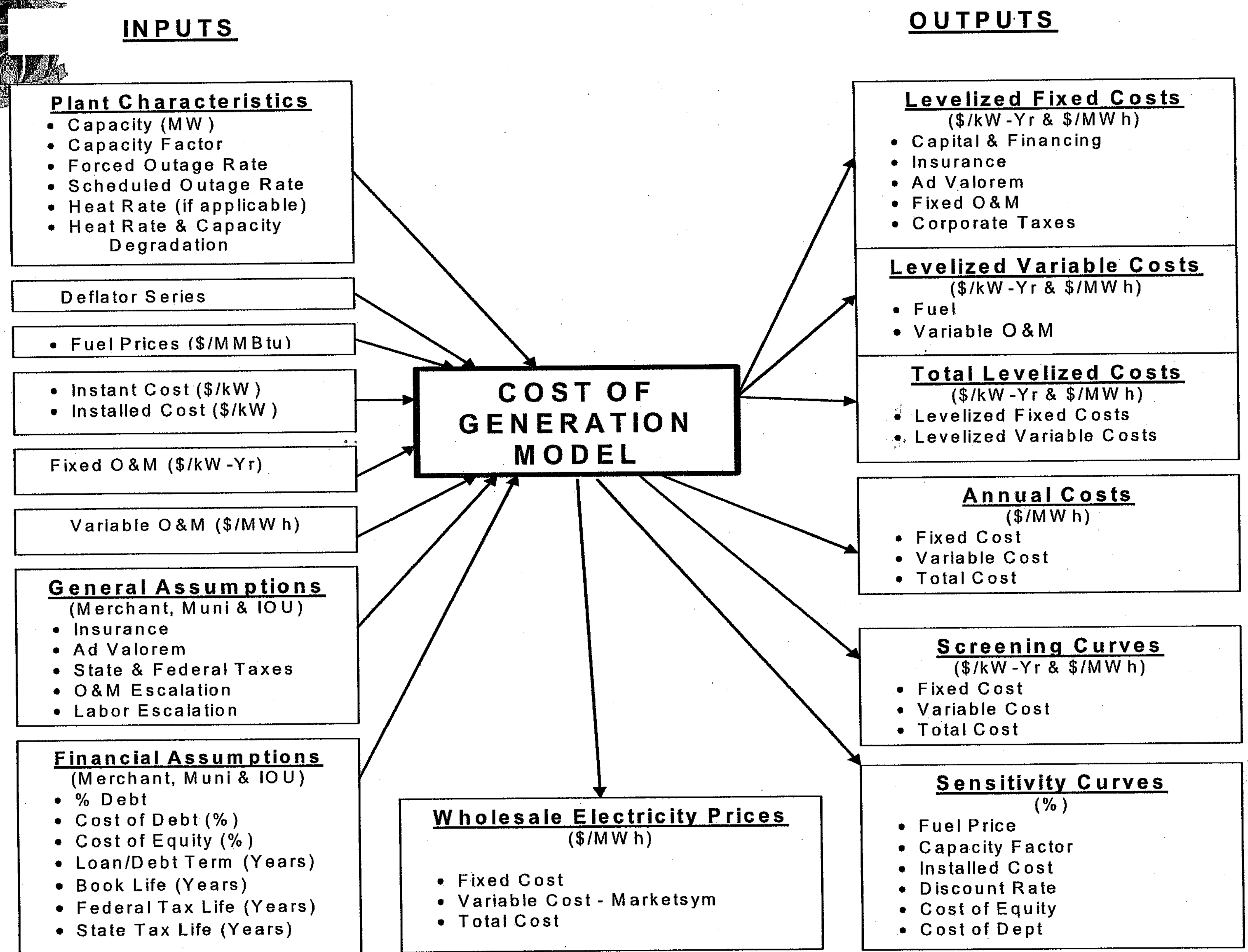
- Cost of Generation (COG) models.
  - What do they do?
  - Who uses them?
- CEC Model Structure.
- Model Demonstration.

WHAT DO THEY DO?

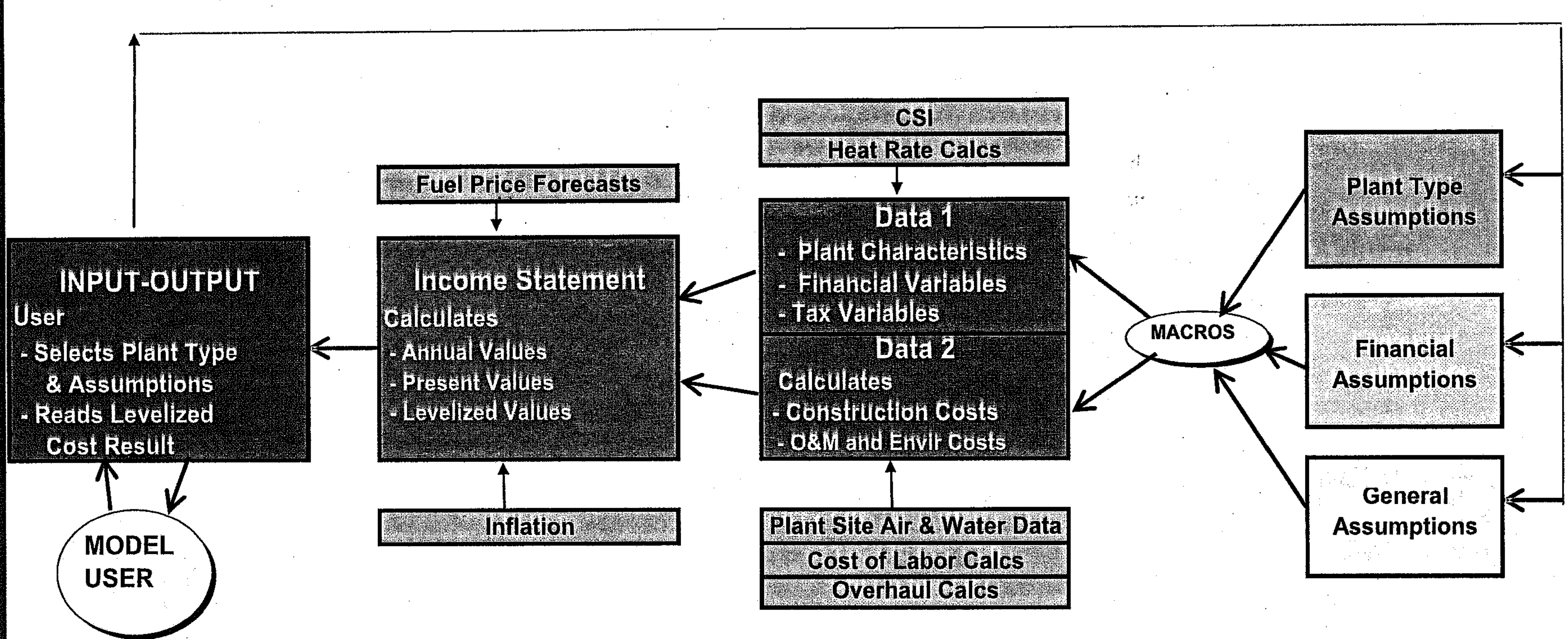
- Estimate the levelized cost of a technology.
- Compare cost of one technology to another – commonly misused.
- CEC Model also generates:
  - Annual Costs.
  - Screening Curves.
  - Sensitivity Curves.
  - Wholesale Electricity Prices.

WHO USES THEM?

- Within the Energy Commission
  - Scenario & Portfolio Projects of the IEPR.
  - Retail Electricity Prices.
  - Technology summaries (Renewables Energy Office).
  - Transmission studies (Engineering Office).
  - Title 24: Value of conservation measures (Buildings and Appliances Office).
- Outside the Energy Commission
  - Requests from Legislature.
  - Board of Equalization (Property Taxes).
  - CPUC – Provide Modeling, Model Evaluation Or Data:
    - Computation of the Market Price Referent (MPR).
    - Computation of Qualifying Facilities (QF) Payments.
    - Valuing IOU Conservation Programs.
  - Requests from consultants and graduate students.


INPUTS
Plant Characteristics
• Capacity (MW)
• Capacity Factor
• Forced Outage Rate
• Scheduled Outage Rate
• Heat Rate (if applicable)
• Heat Rate & Capacity Degradation
Deflator Series
• Fuel Prices ($/MMBtu)
• Instant Cost ($/kW)
• Installed Cost ($/kW)
Fixed O&M ($/kW-Yr)
Variable O&M ($/MWh)
General Assumptions
(Merchant, Muni & IOU)
• Insurance
• Ad Valorem
• State & Federal Taxes
• O&M Escalation
• Labor Escalation
Financial Assumptions
(Merchant, Muni & IOU)
• % Debt
• Cost of Debt (%)
• Cost of Equity (%)
• Loan/Debt Term (Years)
• Book Life (Years)
• Federal Tax Life (Years)
• State Tax Life (Years)
COST OF GENERATION MODEL
OUTPUTS
Levelized Fixed Costs
($/kW-Yr & $/MWh)
• Capital & Financing
• Insurance
• Ad Valorem
• Fixed O&M
• Corporate Taxes
Levelized Variable Costs
($/kW-Yr & $/MWh)
• Fuel
• Variable O&M
Total Levelized Costs
($/kW-Yr & $/MWh)
• Levelized Fixed Costs
• Levelized Variable Costs
Annual Costs
($/MWh)
• Fixed Cost
• Variable Cost
• Total Cost
Screening Curves
($/kW-Yr & $/MWh)
• Fixed Cost
• Variable Cost
• Total Cost
Sensitivity Curves
(%)
• Fuel Price
• Capacity Factor
• Installed Cost
• Discount Rate
• Cost of Equity
• Cost of Dept
Wholesale Electricity Prices
($/MWh)
• Fixed Cost
• Variable Cost - Marketsym
• Total Cost

CEC MODEL STRUCTURE



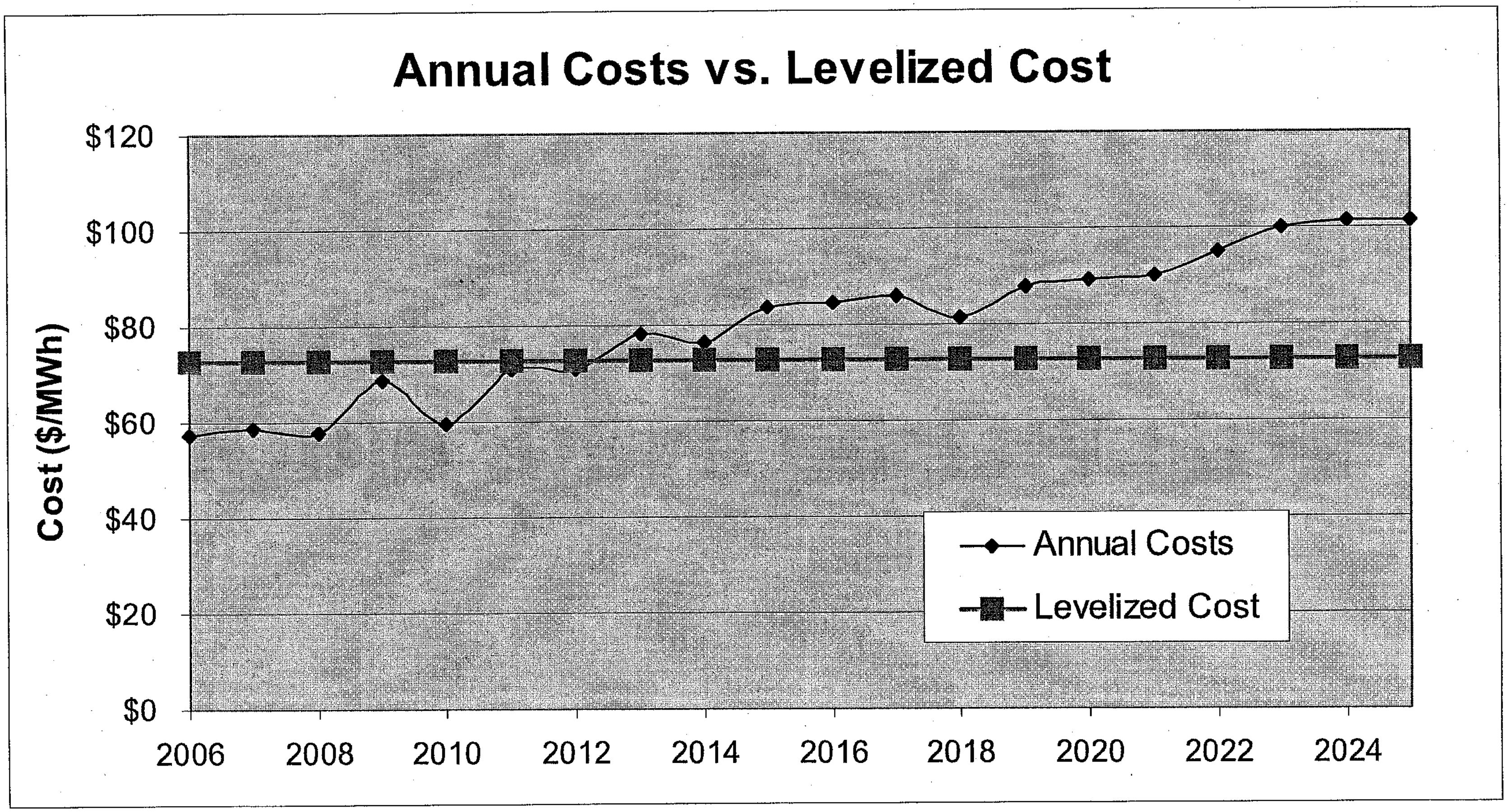
INPUT SELECTION

Plant Type Assumptions (Select)	Combustion Turbine - 50 MW
Financial (Ownership) Assumptions (Select)	Merchant Gas-Fired
Ownership Type For Scenarios	Merchant
General Assumptions (Select)	Default
Base Year (All Costs In 2005 Dollars)	2005
Fuel Type	Natural Gas
Data Source	*CEC 2007 IEPR Survey (Will Walters, Aspen)*
Start (Inservice) Year (Enter)	2007
Fuel Price Forecast (Select)	CA - Avg.
Plant Site Region (Air & Water) (Select)	CA - Avg.
Study Perspective (Select)	At Load Center
Reported Construction Cost Basis (Select)	Installed
Turbine Configuration (Select)	2

OUTPUT RESULTS
Merchant Plant

SUMMARY OF LEVELIZED COSTS Combustion Turbine - 50 MW		
Start Year = 2007 (2007 Dollars)	**$/kW-Yr**	**$/MWh**
Capital & Financing - Construction	$145.30	$347.88
Insurance	$9.25	$22.15
Ad Valorem Costs	$7.25	$17.35
Fixed O&M Costs	$20.36	$48.75
Corporate Taxes (w/Credits)	$41.85	$100.20
Fixed Costs	**$224.01**	**$536.33**
Fuel Costs	$33.27	$79.66
Variable O&M	$13.07	$31.29
Variable Costs	**$46.34**	**$110.96**
Total Levelized Costs	**$270.36**	**$647.28**

WHAT IS LEVELIZED COST?



MODEL DEMONSTRATION

NEXT ITEM

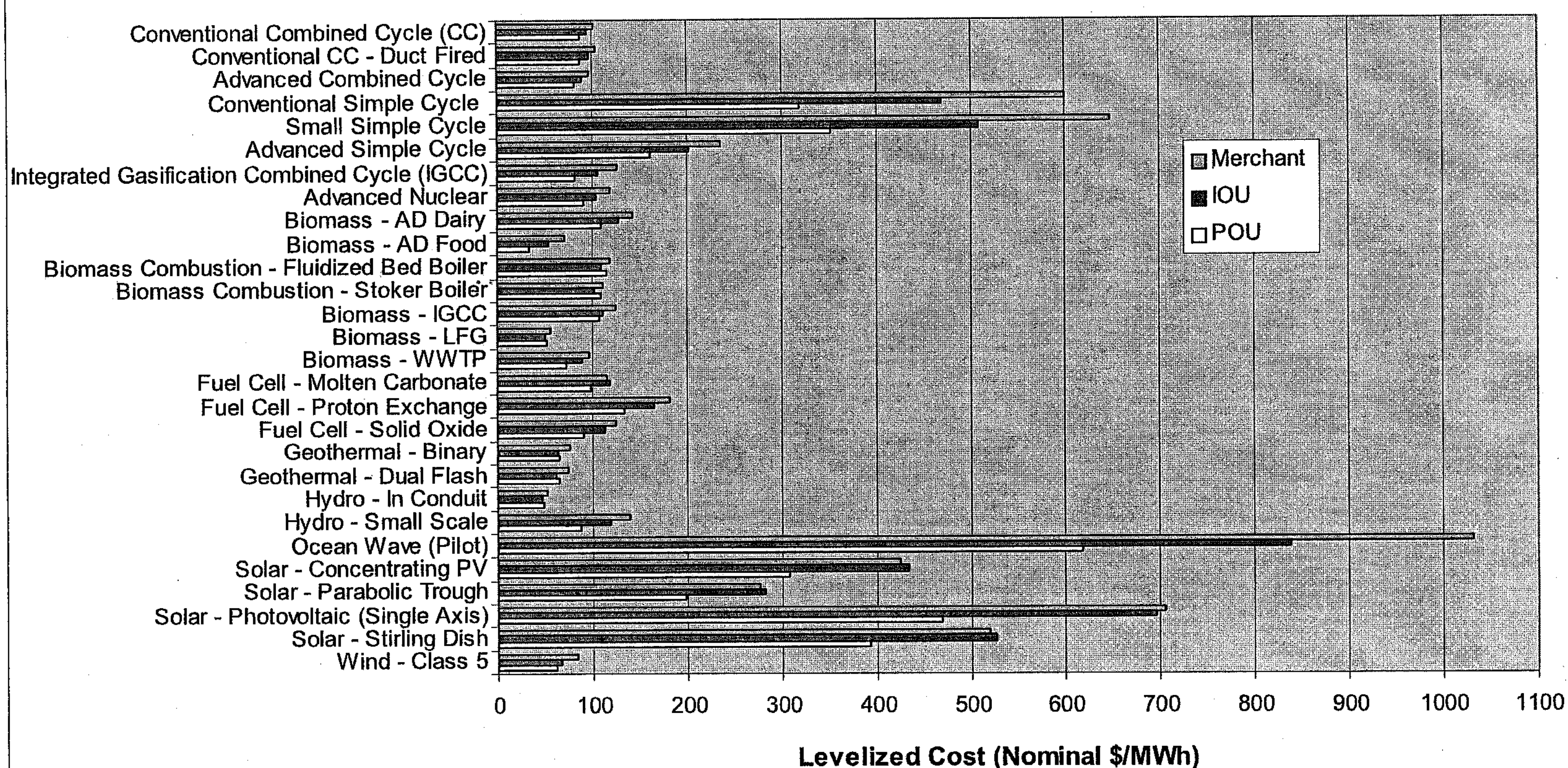
- Overview of the Cost of Generation Model.
- Summary of Levelized Costs – Output (Not Yet Approved).
  - Overview Including Fixed and Variable Costs
  - Focus on CT Fixed Costs in $/kW-Yr
  - Comparison to 2003 IEPR
- Review the Assumptions – Input.
- Data Collection ,Processing & Results.

LEVELIZED COST ESTIMATES
Fixed and Variable Cost

In-Service Year =2007 (Nominal 2007$)	Size	Merchant		IOU		POU	
	MW	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh	$/kW-Yr	$/MWh
Conventional Combined Cycle (CC)	500	505.82	102.19	466.86	94.47	428.32	86.84
Conventional CC - Duct Fired	550	512.39	103.52	472.40	95.59	432.97	87.78
Advanced Combined Cycle	800	476.97	96.36	438.22	88.68	399.62	81.02
Conventional Simple Cycle	100	250.43	599.57	195.59	468.46	132.84	318.33
Small Simple Cycle	50	270.36	647.28	212.08	507.98	146.70	351.55
Advanced Simple Cycle	200	295.96	236.12	253.22	202.10	201.13	160.60
Integrated Gasification Combined Cycle (IGCC)	575	566.58	126.51	476.15	106.32	361.52	80.72
Advanced Nuclear	1000	862.70	118.25	757.78	103.87	664.78	91.12
Biomass - AD Dairy	0.25	924.52	143.61	826.57	128.39	800.93	109.77
Biomass - AD Food	2	450.97	70.05	350.30	54.41	218.82	33.99
Biomass Combustion - Fluidized Bed Boiler	25	866.25	118.72	793.99	108.82	839.92	115.12
Biomass Combustion - Stoker Boiler	25	810.99	111.15	745.45	102.17	799.74	109.61
Biomass - IGCC	21.25	849.18	123.66	768.58	111.92	744.82	108.46
Biomass - LFG	2	382.50	56.11	345.95	50.86	352.73	52.36
Biomass - WWTP	0.5	514.65	97.34	466.63	88.84	366.54	71.78
Fuel Cell - Molten Carbonate	2	886.11	114.66	910.60	117.83	754.94	97.69
Fuel Cell - Proton Exchange	0.03	1409.63	182.41	1281.28	165.80	1025.67	132.72
Fuel Cell - Solid Oxide	0.25	955.64	123.66	868.61	112.40	695.29	89.97
Geothermal - Binary	50	477.23	75.85	396.31	63.53	394.23	65.55
Geothermal - Dual Flash	50	453.91	73.66	379.23	62.07	384.36	65.26
Hydro - In Conduit	1	213.72	52.84	183.96	45.68	188.71	47.78
Hydro - Small Scale	10	567.71	138.74	481.05	118.08	347.96	87.09
Ocean Wave (Pilot)	0.75	1239.92	1030.50	1005.64	837.65	733.96	617.12
Solar - Concentrating PV	15	620.48	424.84	631.79	434.00	442.11	308.09
Solar - Parabolic Trough	63.5	497.33	277.30	504.17	281.37	355.71	199.31
Solar - Photovoltaic (Single Axis)	1	1035.07	704.98	1019.48	695.59	681.74	468.87
Solar - Stirling Dish	15	855.55	518.89	868.93	527.00	648.77	393.47
Wind - Class 5	50	245.94	84.24	196.08	67.16	179.19	61.38

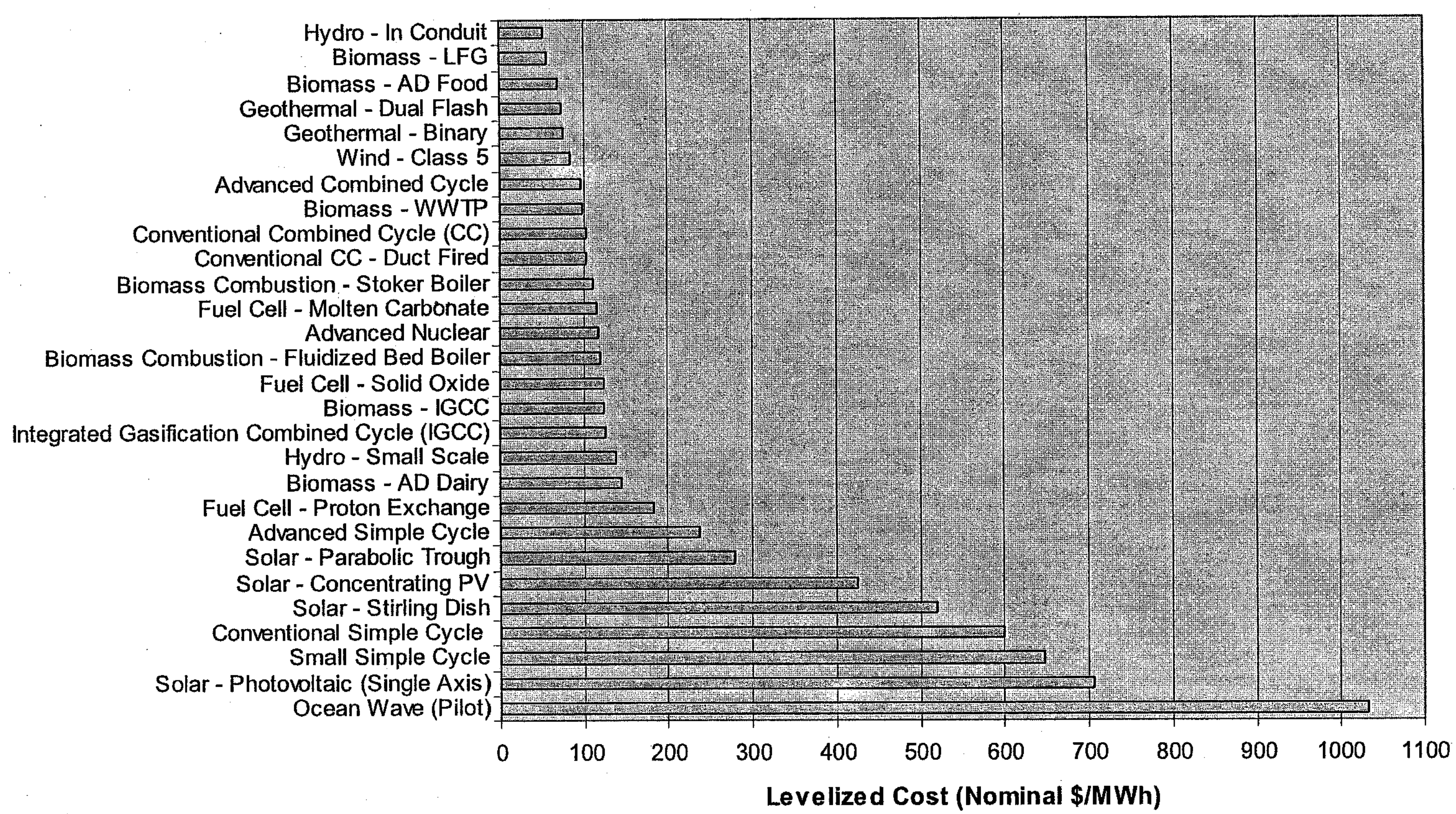
GRAPHICALLY

Start Year = 2007 (2007 Nominal$)



MERCHANT DESCENDING ORDER

Start Year = 2007 (2007 Nominal$)



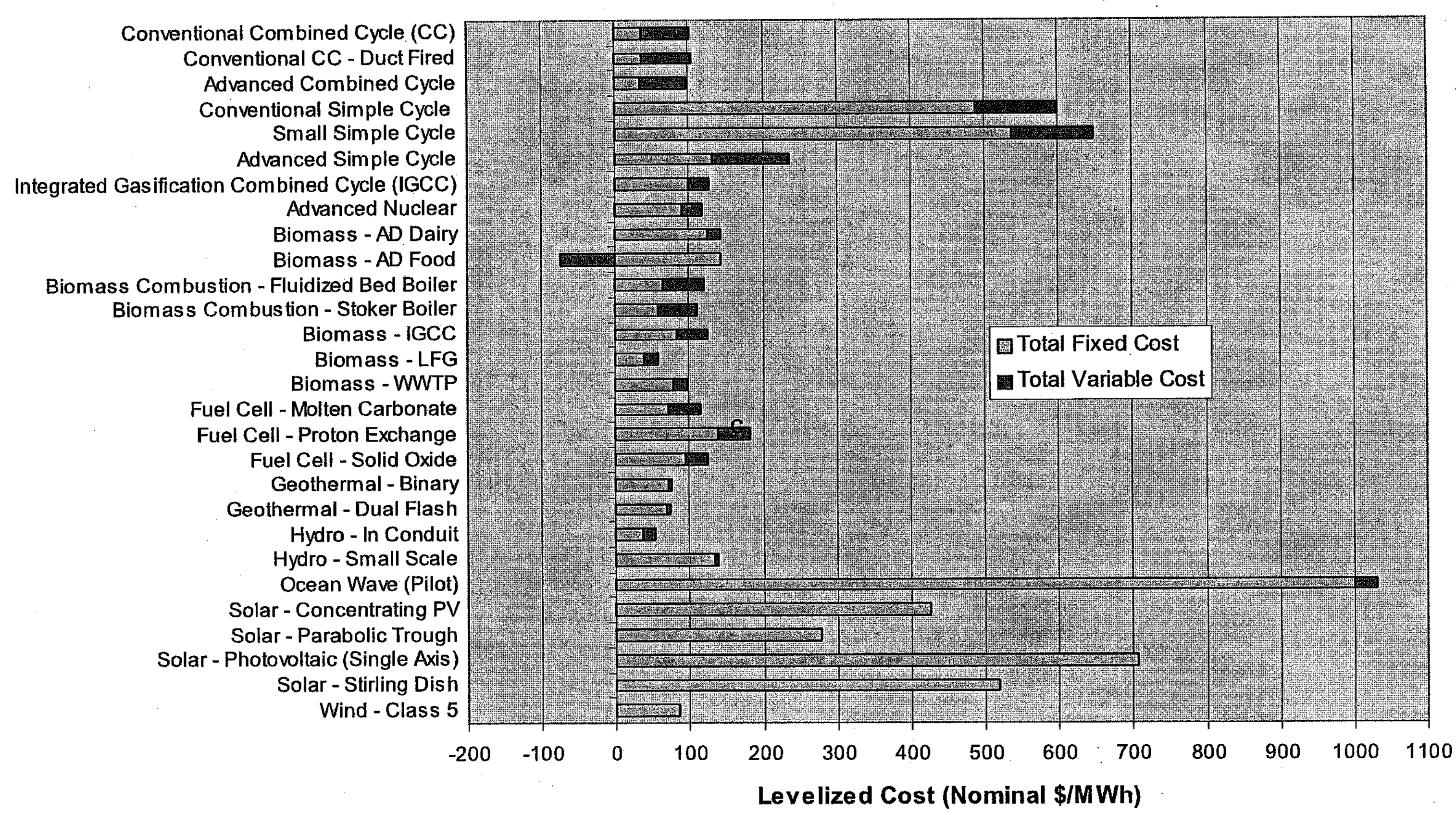
MERCHANT

BY COMPONENT ($/MWh)

In-Service Year =2007	Size MW	$/MWh (Nominal 2007$) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	Total Fixed Cost	Fuel	Variable O&M	Total Variable Cost	Total Levelized Cost
Conventional Combined Cycle (CC)	500	$23.28	$1.48	$1.16	$2.30	$7.85	**$36.07**	$60.86	$5.27	**$66.12**	**$102.19**
Conventional CC - Duct Fired	550	23.81	1.52	1.19	2.22	8.03	**36.77**	61.64	5.11	**66.75**	**103.52**
Advanced Combined Cycle	800	22.85	1.46	1.14	1.96	7.71	**35.13**	56.68	4.56	**61.24**	**96.36**
Conventional Simple Cycle	100	327.02	20.82	16.31	30.49	94.43	**489.08**	79.66	30.83	**110.49**	**599.57**
Small Simple Cycle	50	347.88	22.15	17.35	48.75	100.20	**536.33**	79.66	31.29	**110.96**	**647.28**
Advanced Simple Cycle	200	89.52	5.70	4.46	6.59	25.88	**132.15**	73.51	30.46	**103.97**	**236.12**
Integrated Gasification Combined Cycle (IGCC)	575	64.47	6.79	4.44	10.58	12.15	**98.44**	24.00	4.06	**28.07**	**126.51**
Advanced Nuclear	1000	56.79	5.14	3.70	24.18	0.64	**90.45**	21.50	6.30	**27.80**	**118.25**
Biomass - AD Dairy	0.25	110.17	7.82	6.33	9.58	-9.05	**124.84**	0.00	18.77	**18.77**	**143.61**
Biomass - AD Food	2	110.21	7.82	6.33	28.74	-9.05	**144.05**	0.00	-74.00	**-74.00**	**70.05**
Biomass Combustion - Fluidized Bed Boiler	25	48.67	4.40	3.17	25.91	-18.44	**63.72**	51.09	3.91	**55.00**	**118.72**
Biomass Combustion - Stoker Boiler	25	44.70	4.04	2.91	23.23	-18.74	**56.15**	51.09	3.91	**55.00**	**111.15**
Biomass - IGCC	21.25	53.27	4.82	3.47	28.48	-7.62	**82.42**	37.32	3.91	**41.23**	**123.66**
Biomass - LFG	2	$40.49	$2.87	$2.33	$3.62	($11.70)	**$37.61**	$0.00	$18.50	**$18.50**	**$56.11**
Biomass - WWTP	0.5	63.60	4.51	3.65	4.67	2.41	**78.84**	0.00	18.50	**18.50**	**97.34**
Fuel Cell - Molten Carbonate	2	72.48	5.14	4.16	0.34	-10.63	**71.50**	0.00	43.17	**43.17**	**114.66**
Fuel Cell - Proton Exchange	0.03	116.92	8.30	6.71	2.87	4.44	**139.24**	0.00	43.17	**43.17**	**182.41**
Fuel Cell - Solid Oxide	0.25	79.28	5.63	4.55	1.60	3.01	**94.06**	0.00	29.60	**29.60**	**123.66**
Geothermal - Binary	50	67.75	4.78	3.87	13.73	-19.84	**70.30**	0.00	5.55	**5.55**	**75.85**
Geothermal - Dual Flash	50	64.12	4.53	3.67	16.02	-20.12	**68.21**	0.00	5.45	**5.45**	**73.66**
Hydro - In Conduit	1	43.02	3.97	2.86	0.00	-13.97	**35.88**	0.00	16.96	**16.96**	**52.84**
Hydro - Small Scale	10	113.39	10.47	7.54	4.14	-0.71	**134.83**	0.00	3.91	**3.91**	**138.74**
Ocean Wave (Pilot)	0.75	777.27	54.07	43.81	30.77	93.75	**999.65**	0.00	30.85	**30.85**	**1030.50**
Solar - Concentrating PV	15	414.12	0.00	25.88	39.14	-54.30	**424.84**	0.00	0.00	**0.00**	**424.84**
Solar - Parabolic Trough	63.5	252.23	0.00	16.77	43.65	-35.34	**277.30**	0.00	0.00	**0.00**	**277.30**
Solar - Photovoltaic (Single Axis)	1	726.35	0.00	47.29	21.31	-89.97	**704.98**	0.00	0.00	**0.00**	**704.98**
Solar - Stirling Dish	15	422.09	0.00	28.06	128.97	-60.23	**518.89**	0.00	0.00	**0.00**	**518.89**
Wind - Class 5	50	75.51	6.83	4.92	13.40	-16.41	**84.24**	0.00	0.00	**0.00**	**84.24**

MERCHANT GRAPHICALLY

Start Year = 2007 (2007 Nominal$)



FIXED PORTION OF COSTS ($/kW-Yr)

Merchant		$/kW-Yr (Nominal 2007$)					
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Conventional Simple Cycle	100	136.59	8.70	6.81	12.74	39.44	**204.28**
Small Simple Cycle	50	145.30	9.25	7.25	20.36	41.85	**224.01**
Advanced Simple Cycle	200	112.21	7.14	5.60	8.25	32.44	**165.64**

IOU		$/kW-Yr (Nominal 2007$)					
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Conventional Simple Cycle	100	106.14	6.87	3.85	13.00	18.40	**148.26**
Small Simple Cycle	50	112.91	7.30	4.10	20.78	19.47	**164.55**
Advanced Simple Cycle	200	87.19	5.64	3.17	8.42	15.16	**119.58**

POU		$/kW-Yr (Nominal 2007$)					
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Conventional Simple Cycle	100	60.14	5.04	5.59	13.30	0.00	**84.08**
Small Simple Cycle	50	64.98	5.45	6.04	21.27	0.00	**97.74**
Advanced Simple Cycle	200	46.60	3.91	4.33	8.62	0.00	**63.46**

50 MW CTs ONLY (Updated But Not Yet Approved)

		$/kW-Yr (Nominal 2007$)					
In-Service Year =2007	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Merchant	50	145.30	9.25	7.25	20.36	41.85	**224.01**
IOU	50	112.91	7.30	4.10	20.78	19.47	**164.55**
POU	50	64.98	5.45	6.04	21.27	0.00	**97.74**
Average	50	107.73	7.33	5.79	20.80	20.44	**162.10**

CONVERSION $/MWh TO $/kW-Yr

- $/kW-Yr = $/MWh * Energy (GWh) / Gross Capacity (MW)
- $/kW-Yr = $/MWh * Total $/kW-Yr / Total $/MWh

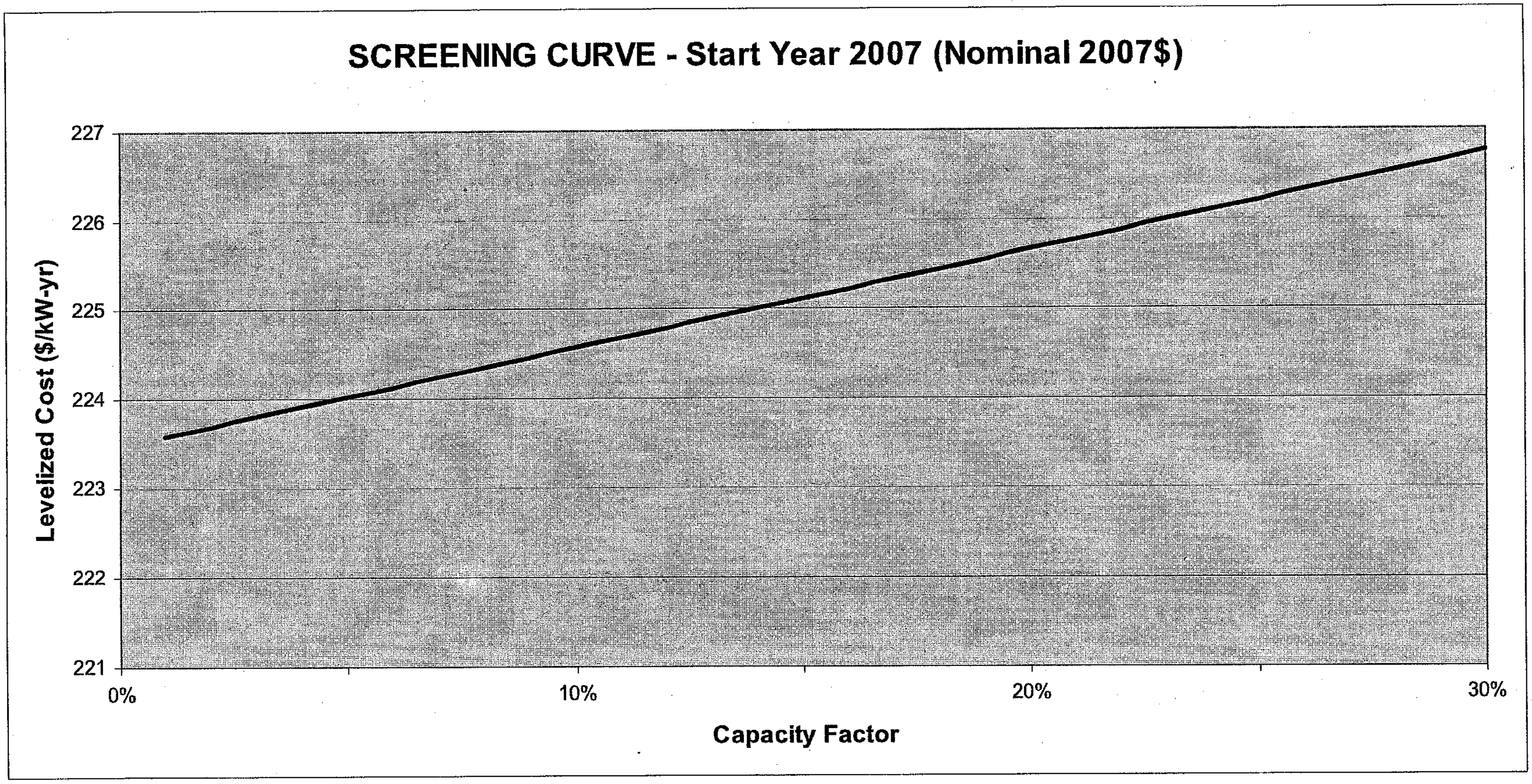
EFFECT OF LOCATION
50 MW MERCHANT CT

Plant Site Region	Fixed Cost $/KW-Yr	Explanation for High Value
CA Average	$224.01	
Bay Area	$427.64	Urban Adder
Imperial County	$227.98	Chiller Adder
San Joaquin	$223.91	
Kern	$223.91	
Mohave	$227.98	Chiller Adder
Central Coast	$223.91	
Sacramento	$223.91	
San Diego	$223.91	
San Luis	$223.91	
Santa Barbara	$223.91	
South Coast	$225.15	High ERC Cost
Ventura	$223.90	

CHANGING START YEAR
Cannot Use Nominal Inflation

START YEAR	FIXED LEVELIZED COST ($/kW-Yr)	CEC DEFLATOR	USING CEC DEFLATORS ($/kW-Yr)	NECESSARY DEFLATOR
2007	$224.01	1.000	$224.01	1.000
2008	$231.08	1.023	$236.44	1.032
2009	$238.38	1.044	$248.96	1.064
2010	$245.90	1.066	$262.02	1.098
2011	$253.67	1.087	$275.84	1.132
2012	$261.69	1.109	$290.16	1.168

SCREENING CURVE
50 MW Merchant Plant
Fixed Costs Only ($/kW-Year)



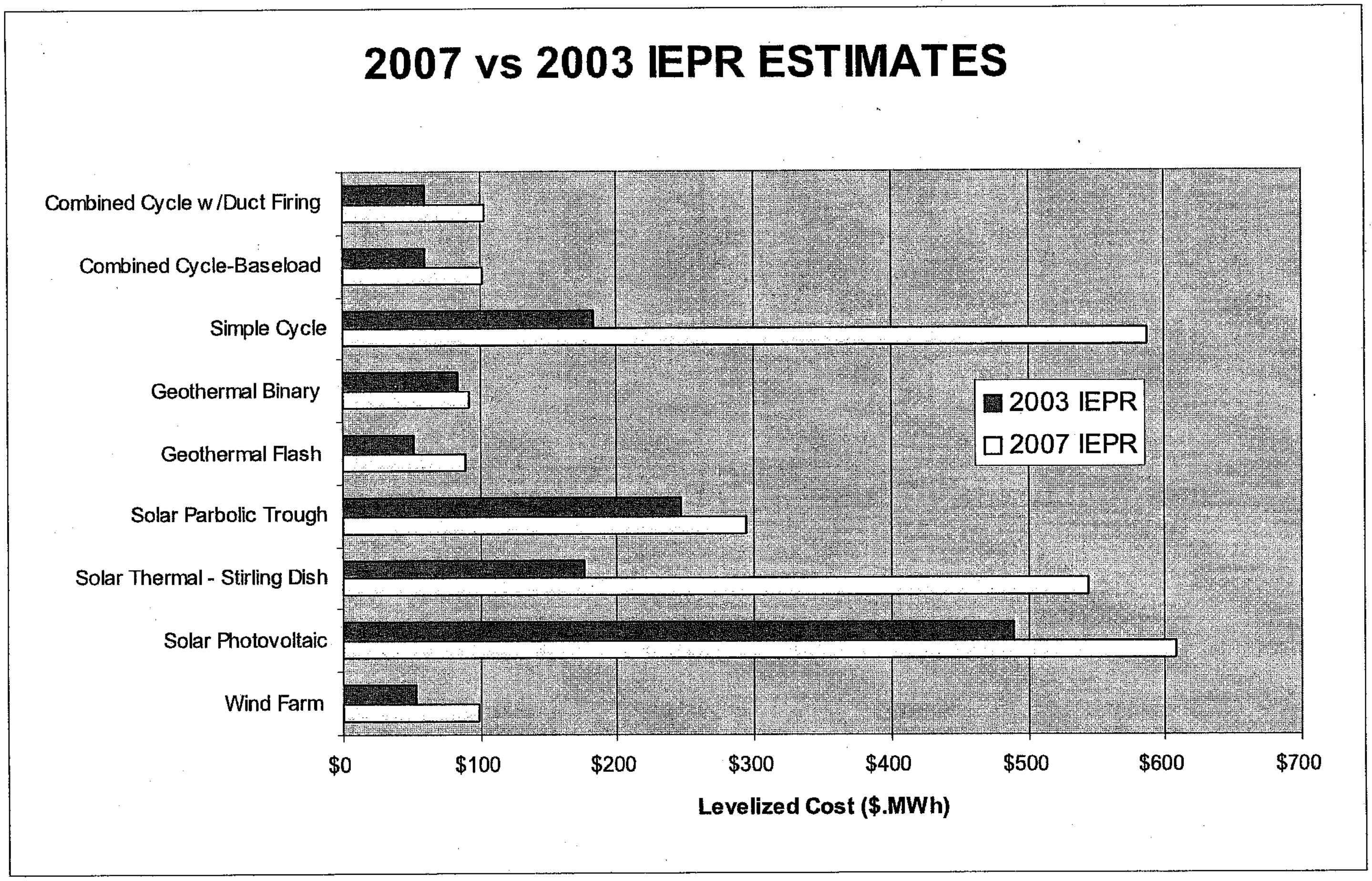
COMPARISON TO 2003 IEPR

(No 50 MW Unit for Comparison)

Technology (Costs in Nominal 2007$)	2003 IEPR			2007 IEPR			2003 IEPR		2007 IEPR	
	Gross Capacity (MW)	Levelized Cost ($/MWh)	Capacity Factor (%)	Gross Capacity (MW)	Levelized Cost ($/MWh)	Capacity Factor (%)	Instant Cost ($/kW)	Installed Cost ($/kW)	Instant Cost ($/kW)	Installed Cost ($/kW)
Conventional CC - Duct Fired	550	$59.73	91.6	550	$103.52	60.0	608	664	798	863
Conventional Combined Cycle (CC)	500	$59.50	91.6	500	$102.19	60.0	620	677	781	844
Conventional Simple Cycle	100	$182.62	9.4	100	$599.57	5.0	477	522	925	1000
Geothermal - Binary	35	$83.40	98.5	50	$75.85	95.0	3673	4140	3089	3562
Geothermal - Dual Flash	50	$51.85	96.0	50	$73.66	93.0	2435	2758	3093	3548
Solar - Parabolic Trough	110	$246.40	22.0	63.5	$277.30	27.0	2975	3203	4021	4190
Solar - Stirling Dish	15	$175.86	36.3	15	$518.89	24.0	3742	4028	6187	6446
Solar - Photovoltaic (Single Axis)	50	$488.84	23.8	1	$704.98	22.2	7614	8197	9611	9678
Wind - Class 5	100	$52.93	36.3	50	$84.24	34.0	1015	1093	1959	2000

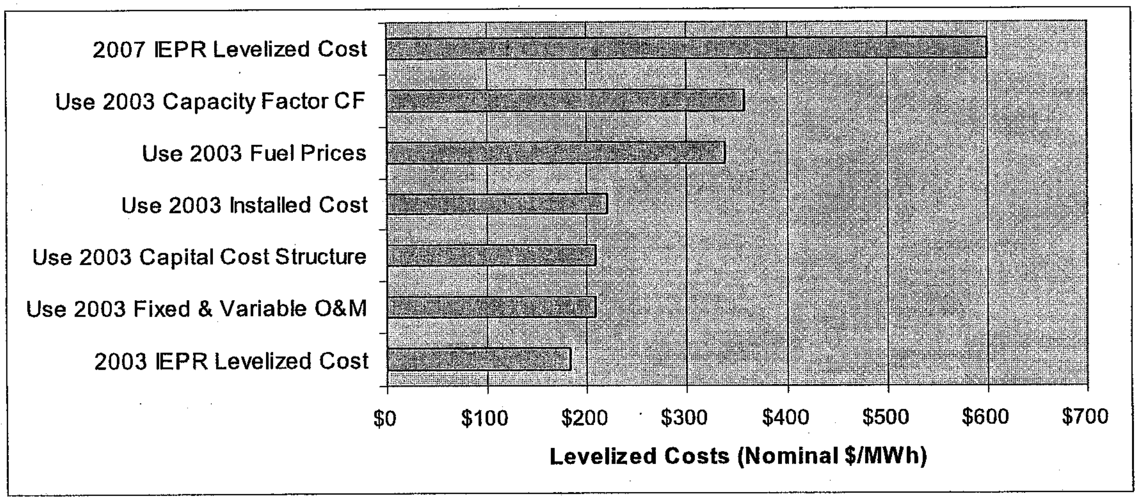
- 2007 Levelized cost is much higher.
- 2007 Capacity Factor is much lower.
- 2007 Installed cost is much higher.

TOTAL (FIXED + VARIABLE) LEVELIZED COST COMPARISON



2007 IEPR vs. 2003 IEPR
100 MW SIMPLE CYCLE UNIT

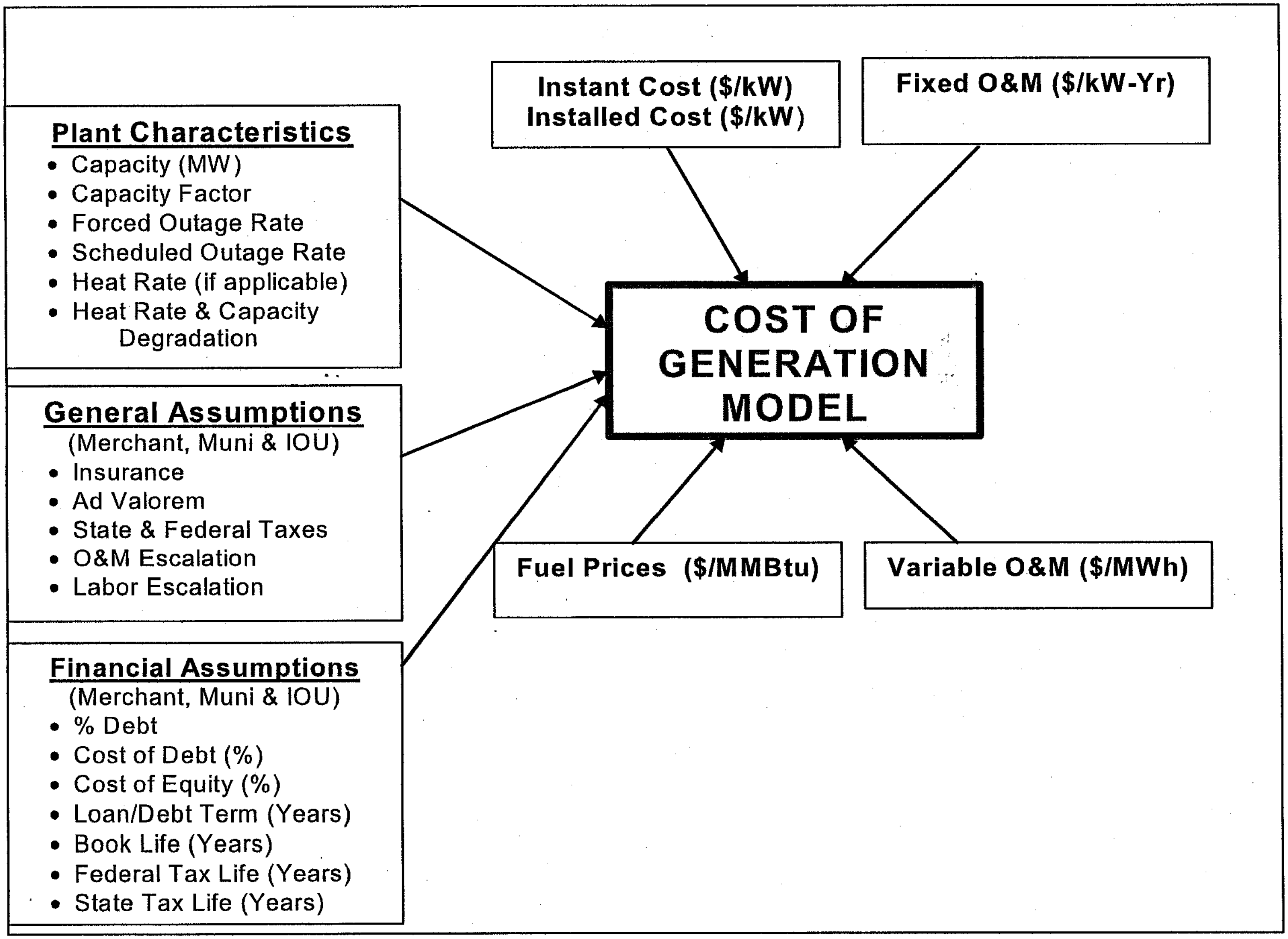
Effect of Change (2007$)	$/MWh
2007 IEPR Levelized Cost	599.57
Use 2003 Capacity Factor CF	357.01
Use 2003 Fuel Prices	337.94
Use 2003 Installed Cost	220.67
Use 2003 Capital Cost Structure	208.67
Use 2003 Fixed & Variable O&M	207.92
2003 IEPR Levelized Cost	182.62



THIRD ITEM

- Overview of the Cost of Generation Model.
- Summary of Levelized Costs - Output.
- Review the Assumptions – Input.
  - Comparison to EIA Assumptions
- Data Collection, Processing & Results.

COG ASSUMPTIONS



ASSUMPTIONS

Technology (All costs in Nominal 2007$)	Gross Capacity (MW)	Capacity Factor (%)	HHV Heat Rate (Btu/kWh)	Instant Cost ($/kW)	Installed Cost ($/kW)			Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
					Merchant	IOU	Muni		
Conventional Combined Cycle (CC)	500	60.00%	6,990	781	844	849	779	9.86	4.42
Conventional CC - Duct Fired	550	60.00%	7,080	798	863	868	798	9.53	4.28
Advanced Combined Cycle	800	60.00%	6,510	766	828	834	763	8.42	3.83
Conventional Simple Cycle	100	5.00%	9,266	925	1000	1000	793	11.00	25.72
Small Simple Cycle	50	5.00%	9,266	974	1053	1053	846	17.65	26.10
Advanced Simple Cycle	200	5.00%	8,550	756	817	817	610	7.13	25.57
Integrated Gasification Combined Cycle (IGCC)	575	60.00%	8,979	2,198	3,007	2,941	2,569	36.27	3.11
Advanced Nuclear	1000	85.00%	10,400	2,950	3,754	3,662	3,177	140.00	5.00
Biomass - AD Dairy	0.25	75.00%	12,407	5,800	5,923	5,911	5,837	51.81	15.77
Biomass - AD Food	2	75.00%	17,060	5,803	5,925	5,913	5,840	155.44	-62.18
Biomass Combustion - Fluidized Bed Boiler	25	85.00%	15,509	3,156	3,223	3,217	3,177	150.26	3.11
Biomass Combustion - Stoker Boiler	25	85.00%	15,509	2,899	2,960	2,954	2,917	134.72	3.11
Biomass - IGCC	21.25	85.00%	10,663	3,121	3,320	3,301	3,181	155.44	3.11
Biomass - LFG	2	85.00%	11,566	2,254	2,302	2,296	2,263	20.73	15.54
Biomass - WWTP	0.5	75.00%	12,407	2,743	2,801	2,794	2,748	20.73	15.54
Fuel Cell - Molten Carbonate	2	90.00%	8,322	4,488	4,678	4,659	4,546	2.18	36.27
Fuel Cell - Proton Exchange	0.03	90.00%	13,127	7,239	7,545	7,515	7,332	18.65	36.27
Fuel Cell - Solid Oxide	0.25	90.00%	8,530	4,908	5,116	5,096	4,972	10.36	24.87
Geothermal - Binary	50	95.00%	N/A	3,093	3,548	3,501	3,227	72.54	4.66
Geothermal - Dual Flash	50	93.00%	N/A	2,866	3,287	3,244	2,988	82.90	4.58
Hydro - In Conduit	1	51.40%	N/A	1,547	1,612	1,606	1,567	0.00	13.47
Hydro - Small Scale	10	52.00%	N/A	4,125	4,299	4,282	4,178	13.47	3.11
Ocean Wave (Pilot)	0.75	15.00%	N/A	7,203	7,662	7,617	7,342	31.09	25.91
Solar - Concentrating PV	15	23.00%	N/A	5,156	5,372	5,352	5,222	46.63	0.00
Solar - Parabolic Trough	63.5	27.00%	N/A	4,021	4,190	4,175	4,073	62.18	0.00
Solar - Photovoltaic (Single Axis)	1	22.14%	N/A	9,611	9,678	9,672	9,632	24.87	0.00
Solar - Stirling Dish	15	24.00%	N/A	6,187	6,446	6,423	6,266	168.92	0.00
Wind - Class 5	50	34.00%	N/A	1,959	2,000	1,997	1,972	31.09	0.00

EMISSION FACTORS

Technology	Emission Factors (Lbs/MWh)					
	NOx	VOC	CO	CO2	SOx	PM10
Conventional Combined Cycle	0.056	0.017	0.049	817.62	0.007	0.035
Conventional Combined Cycle - Duct Fired	0.064	0.018	0.050	828.14	0.007	0.028
Advanced Combined Cycle	0.046	0.016	0.046	761.47	0.007	0.026
Conventional Simple Cycle	0.093	0.023	0.093	1083.84	0.009	0.065
Small Simple Cycle	0.093	0.023	0.093	1083.84	0.009	0.065
Advanced Simple Cycle	0.076	0.019	0.053	886.63	0.008	0.053
Integrated Gasification Combined Cycle (IGCC)	0.530	0.000	0.000	1928.00	0.300	0.000
Nuclear	0.000	0.000	0.000	0.000	0.000	0.000
Biomass - AD Dairy	1.700	0.000	0.000	0.000	0.390	0.000
Biomass - AD Food	1.700	0.000	0.000	0.000	0.420	0.000
Biomass Combustion - Fluidized Bed Boiler	1.240	0.000	0.000	0.000	0.700	0.000
Biomass Combustion - Stoker Boiler	1.240	0.000	0.000	0.000	0.700	0.000
Biomass - IGCC	0.850	0.000	0.000	0.000	0.700	0.000
Biomass - LFG	1.700	0.000	0.000	0.000	0.340	0.000
Biomass - WWTP	1.700	0.000	0.000	0.000	0.390	0.000
Fuel Cell - Molten Carbonate	0.010	0.000	0.000	0.000	0.003	0.000
Fuel Cell - Proton Exchange	0.100	0.000	0.000	0.000	0.000	0.000
Fuel Cell - Solid Oxide	0.050	0.000	0.000	0.000	0.000	0.000
Geothermal - Binary	0.000	0.000	0.000	0.000	0.000	0.000
Geothermal - Dual Flash	0.000	0.000	0.000	60.000	0.350	0.000
Hydro - In Conduit	0.000	0.000	0.000	0.000	0.000	0.000
Hydro - Small Scale	0.000	0.000	0.000	0.000	0.000	0.000
Ocean - Wave	0.000	0.000	0.000	0.000	0.000	0.000
Solar - PV	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Parabolic Trough	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Stirling Dish	0.000	0.000	0.000	0.000	0.000	0.000
Solar - Concentrating PV	0.000	0.000	0.000	0.000	0.000	0.000
Wind - Class 5	0.000	0.000	0.000	0.000	0.000	0.000

FINANCIAL ASSUMPTIONS

	Merchant Gas-Fired	Merchant Non Gas-Fired	IOU	POU
Percent Debt	40.0%	60.0%	50.0%	100.0%
Percent Equity	60.0%	40.0%	50.0%	0.0%
Cost of Debt	6.5%	6.5%	5.73%	4.35%
Cost of Equity	15.9%	15.9%	11.74%	0.0%
Discount Rate (LARR)	10.65%	8.39%	7.57%	4.35%

Term/Life Assumptions	CCs	CTs
Loan/Debt Term	12	12
Equipment Life	20	20
Economic Book Life	20	20
Federal Tax Life	20	15
State Tax Life	20	15

TAX ASSUMPTIONS

Tax	Rate
Federal Tax	35.0%
CA State Tax	8.84%
Total Tax Rate	40.7%

ASSUMED LOSSES (CPUC MPR PROCEEDINGS)

Location	Losses
On Site	2.40%
Transformer	0.5%
Transmission	1.49%

Deflator Series 2007=1	Year	Naural Gas Prices (Nominal $/MMBtu)							Misc (Nominal $/MMBtu)		
		PG&E	SCE	SDG&E	SMUD	LADWP	IID	CA - Avg.	Uranium	Coal	Biomass
1.00	2007	8.30	8.23	8.74	8.50	8.50	8.50	8.34	0.63	1.47	2.57
1.02	2008	6.72	6.76	7.32	6.81	7.07	7.07	6.82	0.75	1.68	2.63
1.04	2009	6.80	6.80	7.11	6.92	7.06	7.06	6.87	0.89	1.70	2.69
1.07	2010	5.46	5.71	6.20	5.42	6.09	6.09	5.69	1.05	1.72	2.74
1.09	2011	7.04	7.25	7.74	7.05	7.66	7.66	7.26	1.26	1.71	2.80
1.11	2012	6.69	6.84	7.25	6.72	7.22	7.22	6.87	1.50	1.83	2.85
1.13	2013	8.08	8.28	8.59	8.04	8.57	8.57	8.26	1.77	1.90	2.91
1.15	2014	7.39	7.57	7.88	7.36	7.86	7.86	7.56	2.11	1.97	2.97
1.17	2015	8.52	8.61	8.65	8.57	8.90	8.90	8.63	2.58	2.04	3.02
1.20	2016	8.58	8.72	8.82	8.59	9.01	9.01	8.72	2.63	2.12	3.08
1.22	2017	8.63	8.82	8.99	8.60	9.12	9.12	8.80	2.68	2.19	3.14
1.24	2018	9.16	9.42	9.62	9.12	9.77	9.77	9.38	2.73	2.27	3.20
1.26	2019	9.71	10.04	10.28	9.65	10.45	10.45	9.98	2.78	2.35	3.25
1.29	2020	9.91	10.21	10.41	9.87	10.60	10.60	10.16	2.83	2.43	3.32
1.31	2021	10.12	10.38	10.54	10.09	10.75	10.75	10.34	2.89	2.52	3.38
1.34	2022	10.58	10.91	11.10	10.54	11.33	11.33	10.86	2.94	2.59	3.44
1.36	2023	11.06	11.47	11.69	11.00	11.94	11.94	11.39	3.00	2.70	3.51
1.39	2024	11.53	11.87	12.01	11.47	12.28	12.28	11.81	3.05	2.73	3.57
1.41	2025	12.01	12.28	12.35	11.95	12.63	12.63	12.23	3.11	2.83	3.64
1.44	2026	12.44	12.72	12.80	12.37	13.09	13.09	12.67	3.17	2.94	3.71
1.47	2027	12.91	13.21	13.28	12.83	13.58	13.58	13.15	3.23	3.02	3.78
1.49	2028	13.44	13.75	13.79	13.35	14.12	14.12	13.68	3.29	3.12	3.85
1.52	2029	13.96	14.28	14.30	13.87	14.65	14.65	14.21	3.35	3.23	3.92
1.55	2030	14.48	14.80	14.78	14.38	15.16	15.16	14.73	3.41	3.33	3.99
1.58	2031	15.05	15.36	15.31	14.94	15.71	15.71	15.28	3.48	3.44	4.07
1.61	2032	15.65	15.97	15.89	15.53	16.31	16.31	15.89	3.54	3.56	4.14
1.64	2033	16.27	16.59	16.47	16.15	16.92	16.92	16.50	3.61	3.67	4.22
1.67	2034	16.91	17.21	17.05	16.78	17.52	17.52	17.13	3.67	3.77	4.30
1.70	2035	17.57	17.87	17.66	17.43	18.16	18.16	17.78	3.74	3.90	4.38
1.73	2036	18.26	18.55	18.30	18.10	18.83	18.83	18.46	3.81	3.97	4.46
1.77	2037	18.97	19.26	18.96	18.80	19.52	19.52	19.16	3.88	4.04	4.54
1.80	2038	19.72	20.00	19.65	19.53	20.25	20.25	19.90	3.96	4.12	4.63
1.83	2039	20.49	20.77	20.36	20.29	20.99	20.99	20.66	4.03	4.20	4.72
1.87	2040	21.29	21.56	21.09	21.08	21.76	21.76	21.44	4.11	4.27	4.80
1.90	2041	22.12	22.38	21.86	21.90	22.56	22.56	22.26	4.18	4.35	4.89
1.94	2042	22.99	23.24	22.65	22.75	23.39	23.39	23.12	4.26	4.44	4.99
1.97	2043	23.90	24.13	23.47	23.64	24.25	24.25	24.00	4.34	4.52	5.08
2.01	2044	24.83	25.05	24.31	24.56	25.13	25.13	24.92	4.42	4.60	5.17
2.05	2045	25.80	26.01	25.19	25.51	26.06	26.06	25.87	4.51	4.69	5.27

COMPARISON TO EIA ASSUMPTIONS

Technology	Size (Gross MW)		Instant Cost ($/kW)			Fixed O&M ($/kW-Yr)			Variable O&M ($/MWh)			Capacity Factor (%)		Heat Rate (Btu/kWh)	
(Nominal 2007$)	CEC	EIA	CEC	EIA	Ratio	CEC	EIA	Ratio	CEC	EIA	Ratio	CEC	EIA	CEC	EIA
Combined Cycle (CC)	500	250	784	641	1.22	9.91	12.49	0.79	4.42	2.07	2.91	60%	87%	6,990	6,800
Advanced CC	800	400	771	632	1.22	8.47	11.70	0.72	3.83	2.00	2.70	60%	87%	6,510	6,333
Simple Cycle (SC)	100	160	925	447	2.07	11.06	12.12	0.9	25.76	3.57	13.5	5%	30%	9,266	10,450
Advanced SC	200	230	756	423	1.79	7.13	10.53	0.7	25.57	3.17	13.8	15%	30%	8,550	8,550
IGCC	575	550	2192	1585	1.38	36.22	38.68	0.2	3.10	2.92	14.5	60%	85%	8,979	6,800
Adv Nuclear	1000	1350	2505	2213	1.13	56.91	67.92	0.8	1.24	0.49	2.5	85%		10,400	10,400
Fuel Cell (Molten Carbonate)	2	10	4481	5085	0.88	2.17	5.65	0.4	36.22	47.95	0.8	90%		8,322	8,832
Geothermal - Binary	50	50	3089	1999	1.55	72.43	164.72	0.4	4.66	0.00	-	95%	90%		
Conventional Hydropower	10	10	4118	1595	2.58	13.45	13.97	1.0	3.10	3.51	0.9	52%			
Wind	50	50	1956	1282	1.53	31.04	30.31	1.0	0.00	0.00	-	34%	34.1%		
Photovoltaic	1	5	8237	5051	1.63	12.42	11.68	1.1	0.00	0.00	-	17.3%			

- CEC Instant cost much higher
- Fixed O&Ms are comparable.
- CEC Variable O&M much higher
- CEC Capacity Factor much lower.
- CEC Heat Rate significantly lower.

SIMPLE CYCLE UNITS

Power Plant	QFER 2002	QFER 2003	QFER 2004	QFER 2005
Calpeak Border	7.77%	2.71%	2.28%	1.86%
Calpeak Enterprise	7.53%	2.18%	2.35%	1.55%
Century Alliance	4.76%	1.80%	1.34%	0.39%
Drews Alliance	4.80%	1.83%	1.46%	0.34%
King City	4.10%	4.24%	5.24%	3.95%
Wildflower Indigo	0.33%	5.86%	6.39%	4.71%
Wildflower Larkspur	1.18%	4.01%	4.74%	3.85%
Gilroy	5.15%	5.69%	5.94%	4.34%
Henrietta	3.57%	2.34%	1.31%	1.55%
Los Esteros	nd	9.62%	16.42%	16.26%
Hanford	4.74%	2.17%	1.16%	3.83%
Tracy Peaker	nd	0.71%	0.77%	0.66%
Average	4.39%	3.60%	4.12%	3.61%

LAST ITEM

- Overview of the Cost of Generation Model.
- Summary of Levelized Costs - Output.
- Review the Assumptions – Input
- Data Collection, Processing & Results

DATA COLLECTION

- Combined and Simple Cycle Units – Aspen.
  - Survey of CC and CT units constructed 2001 - 2006.
- Nuclear, IGCC and Alternative Technologies – NCI.
  - Survey of actual costs and experts in the field.

POWER PLANTS SURVEYED

Combined Cycle Plants (19)			Simple Cycle Plants (15)		
Plant Name	County	Operating	Plant Name	County	Operating
Los Medanos	Contra Costa	2001	Wildflower Larkspur	San Diego	2001
Sutter	Sutter	2001	Wildflower Indigo	Riverside	2001
Delta	Contra Costa	2002	Drews Alliance	San Bernardino	2001
Moss Landing	Monterey	2002	Century Alliance	San Bernardino	2001
La Paloma	Kern	2003	Hanford	Kings	2001
High Desert	San Bernardino	2003	Calpeak Escondido	San Diego	2001
MID Woodland	Stanislaus	2003	Calpeak Border	San Diego	2001
Sunrise	Kern	2003	Gilroy	Santa Clara	2002
Blythe	Riverside	2003	King City	Monterey	2002
Elk Hills	Kern	2003	Henrietta	Kings	2002
Von Raesfeld	Santa Clara	2005	Los Esteros	Santa Clara	2003
Metcalf	Santa Clara	2005	Tracy Peaker	San Joaquin	2003
Magnolia	Los Angeles	2005	Kings River Peaker	Fresno	2005
Malburg	Los Angeles	2005	Ripon	San Joaquin	2006
Pastoria	Kern	2005	Riverside	Riverside	2006
Mountainview	San Bernardino	2006			
Palomar	Kern	2006			
Cosumnes	Sacramento	2006			
Walnut	Stanislaus	2006			

Comparative Costs of California Central Station Electricity Generation Technologies

Attachment 1

SURVEY PARAMETERS

Capital Cost Parameters	Operating & Maintenance Cost Parameters
Gas Turbine and Combustor Make/Models	Total Annual Operating Costs
Steam Turbine Make/Model	Operating Hours
Total Capital Cost of Facility	Startup/Shutdown Hours
Gas Turbine Cost	Natural Gas Sources
Steam Turbine Cost	Duct Burner Natural Gas Use
Air Inlet Treatment Cost	Water Supply Source/Cost/Consumption
Cooling Tower/Air Cooled Condenser Cost	Labor (Staffing and Cost)
Water Treatment Facilities	Non-Fuel Annual Operating Costs (Consumables, etc.)
Site Footprint and Land Cost	Annual Regulatory Costs (Filings, Consumables, etc.)
Total Construction Costs (Labor/Equipment/etc.)	Major Scheduled Overhaul Frequency/Cost
Cost of Site Grading	Normal Annual Maintenance Costs
Cost of Pipeline Linear Construction	Reconciliation of QFER data (MW generation and total fuel use)
Cost of Transmission Linear Construction	
Cost of Licensing/Permitting Project	
Air Pollution Control Costs	
Cost of Air Quality Offsets	

COMBINED CYCLE BASE CASE CONFIGURATION

1) 500 MW Plant W/O Duct Firing
2) 2 Turbines W/ 1 Steam Generator
3) GE 7F Gas Turbines
4) Wet Cooling
5) Greenfield Site
6) Non-Urban Land Cost
7) Reclaimed Water Source
8) Evaporative Coolers/Foggers
9) Selective Catalytic Reduction (SCR) & Oxidation Catalyst
10) Zero Liquid Discharge (ZLD)
11) Not Co-Located W/ Other Power Facilities
12) 12-Month Licensing Process

COMBINED CYCLE INSTALLED COSTS

500 MW Combined Cycle Unit (Nominal 2007$)	**Merchant ($/kW)**	**IOU ($/kW)**	**Muni ($/kW)**
Base Installed Cost	**747**	**753**	**716**
Linears	66	66	33
Permits	11	11	11
ERCs (California Average)	23	23	23
Total Installed Cost	**847**	**852**	**782**

Various Combined Cycle Units (Nominal 2007$)	**Merchant ($/kW)**	**IOU ($/kW)**	**Muni ($/kW)**
Conventional 500 MW CC without Duct Firing	**847**	**852**	**782**
Conventional 550 MW CC with Duct Firing	868	873	803
Advanced 800 MW CC without Duct Firing	833	838	768

COMBINED CYCLE ADDERS
To Be Used Exogenously

Combined Cycle Units (Nominal 2007$)	**$/kW**
Dry Cooling	48
Chillers	11
Plume Abated Cooling Tower	6
No Oxidation Catalyst	-4
Urban Site	11
Co-located facility (Muni only)	-43
Alternative Gas Turbine Type	
SW 501	-32
Alstom GT-24	21
GE 7E	48
Alstom GTX100	53
GE LM6000	16

SIMPLE CYCLE
BASE CASE CONFIGURATION

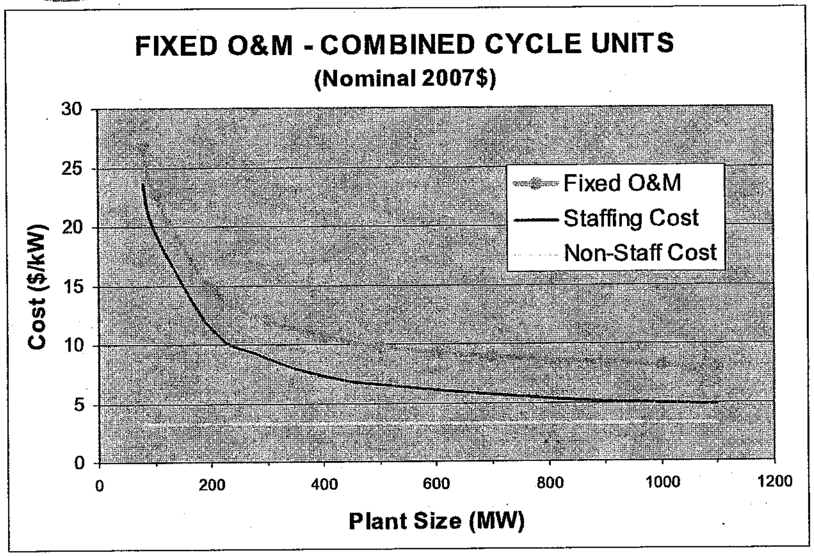
1) 100 MW Merchant Plant
2) 2 LM6000 Turbines
3) Wet Cooling Or Dry Cooling
4) Brownfield Site
5) Non-Urban Land Cost
6) Potable Water Source
7) Evaporative Coolers/Foggers
8) SCR and Oxidation Catalyst Used
9) ZLD
10) Not Co-Located W/ Other Power Facilities

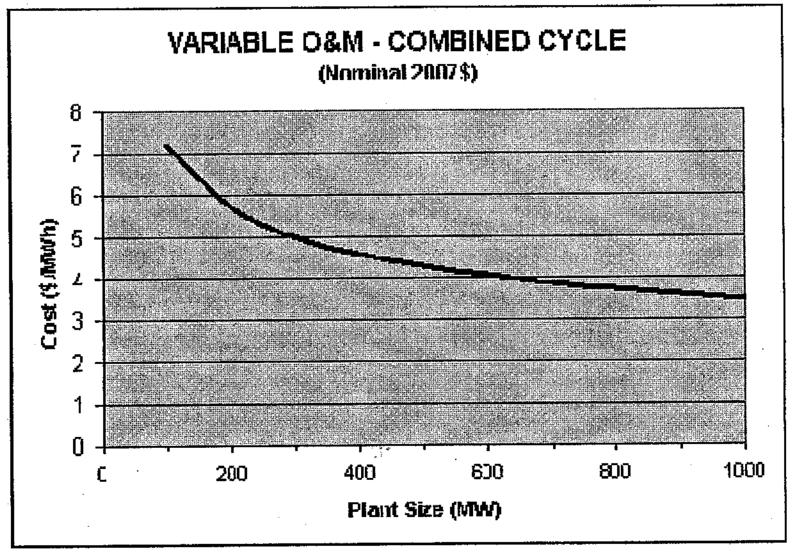
SIMPLE CYCLE INSTALLED COSTS

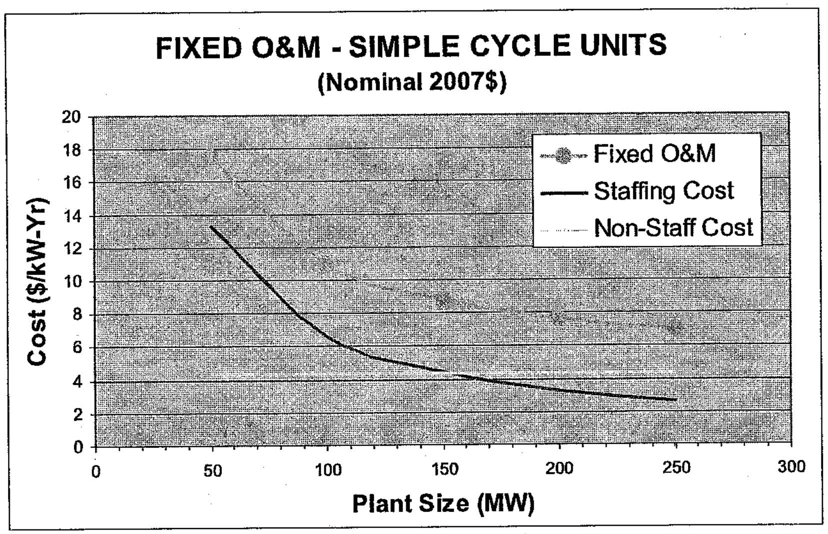
100 MW Simple Cycle Unit (Nominal 2007$)	Merchant ($/kW)	IOU ($/kW)	Muni ($/kW)
Base Installed Cost	**942**	**942**	**735**
Linears	34	34	34
Permits	21	21	21
ERCs (California Average)	3	3	3
Total Installed Cost	**1000**	**1000**	**793**

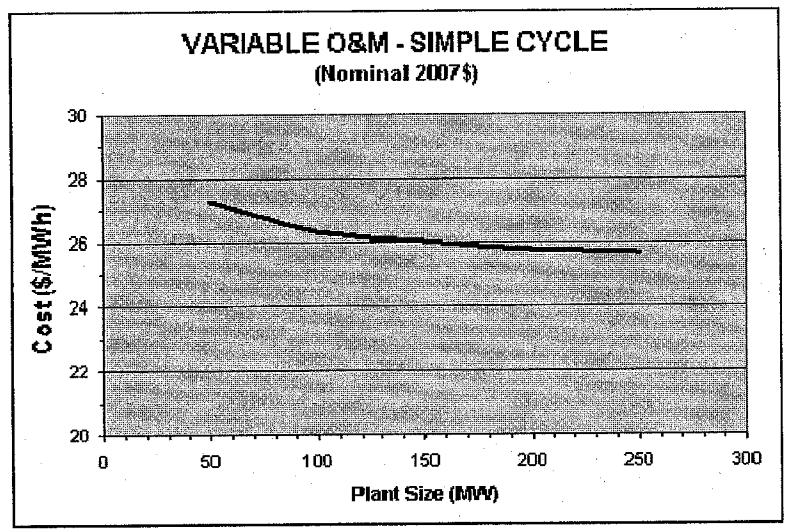
Various Simple Cycle Units (Nominal 2007$)	Merchant ($/kW)	IOU ($/kW)	Muni ($/kW)
Conventional 50 MW SC	1064	1064	857
Conventional 100 MW SC	**1000**	**1000**	**793**
Advanced 200 MW SC	817	817	610

FIXED & VARIABLE O&M

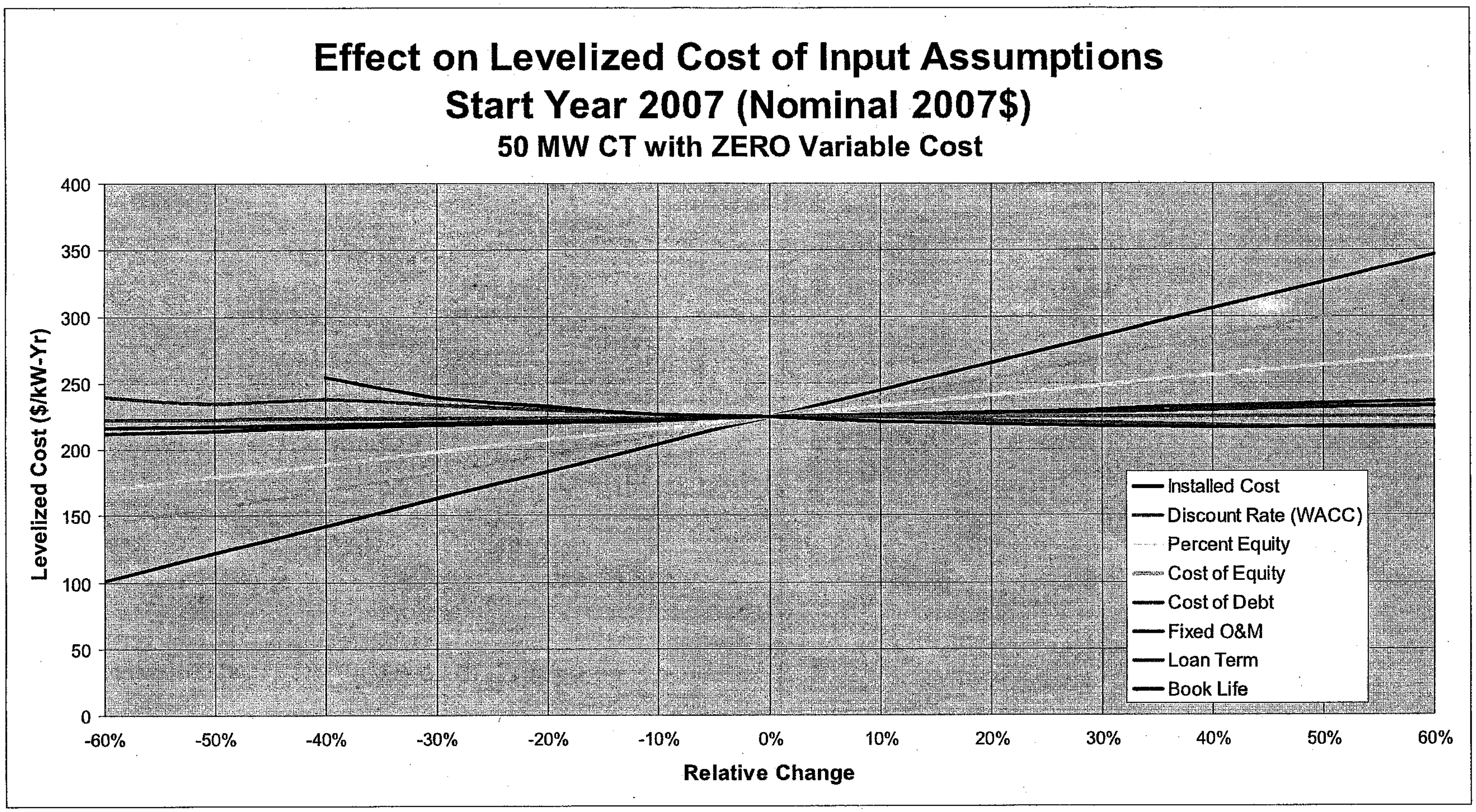








EFFECT OF ASSUMPTIONS



SUMMARY OF VULNERABILITIES

- Model Logic – Reviewed by four inside CEC and 30 outside CEC.
- Installed Cost – Survey of As-Built Costs.
- Fixed O&M – Survey of As-Built Costs.
- Financial Assumptions – Provided by consultant.
  - Cost of Equity
  - Percent Equity

STATUS

- Had workshop on June 12, 2007.
- Have incorporated comments and redrafted Report.
- Awaiting approval by Director and Commission.
- Hope to post Final Report for second review by end of October and issue Final Report by first part of November.
- Post Cost of Generation Model and User's Guide for public use in November.

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Report, Model and User's Guide available at:
http://www.energy.ca.gov/2007_energypolicy/documents/index.html#061207

END

Attachment H

STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

VIA ELECTRONIC POSTING

January 9, 2008

Office of the Secretary
Kimberly D. Bose
Docket Room
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A, East
Washington, D.C. 20002

Re: *California Independent System Operator Corporation*, **Docket No. EL08-20, Notice Of Intervention And Comments Of The California Public Utilities Commission On FERC's Order Instituting A Section 206 Investigation**

Dear Ms. Bose:

Attached for filing in the above-docketed case, please find an electronic version of the above-referenced document.

Thank you for your cooperation in this matter and please do not hesitate to contact me at the phone number or e-mail address below if you have any questions or concerns regarding the foregoing.

Sincerely,

/s/ Elizabeth Dorman

Staff Counsel
Phone: (415) 703-1415
E-Mail: edd@cpuc.ca.gov

Enclosure

311505

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)))	Docket No. EL08-20

NOTICE OF INTERVENTION AND COMMENTS OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION ON FERC's ORDER INSTITUTING A SECTION 206 INVESTIGATION

RANDOLPH L. WU
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Phone: (415) 703-1415

Attorneys for the California Public Utilities Commission

January 9, 2008

311505

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)))	Docket No. EL08-20

NOTICE OF INTERVENTION AND COMMENTS OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION ON FERC's ORDER INSTITUTING A SECTION 206 INVESTIGATION

Pursuant to Rules 211 and 214(a)(2) of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC") the California Public Utilities Commission ("CPUC") submits this Notice of Intervention and Comments in response to the FERC's Order Instituting A Section 206 Investigation filed on December 20, 2007 in the above entitled docket.

I. NOTICE OF INTERVENTION

The California Public Utilities Commission hereby intervenes and offers its comments in the above-captioned proceeding. The CPUC is a constitutionally established agency charged with the responsibility for regulating electric corporations within the State of California. In addition, the CPUC has a statutory mandate to represent the interests of electric consumers throughout California in proceedings before the FERC.

The names and addresses of persons to whom communications should be addressed are:

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This Notice of Intervention serves to make the CPUC a party to this proceeding.

II. COMMENTS

A. The Extension Of The RCST Would Prevent Frustration Of Load Serving Entity Centered Procurement.

The CPUC believes that it would be just and reasonable to extend all or parts of the California Independent System Operator's ("CAISO") Reliability Capacity Services Tariff ("RCST")[1] until either the implementation of the CAISO's Market Redesign and Technology Upgrade ("MRTU") tariff or the implementation of an alternative interim backstop capacity procurement mechanism.

The CPUC bears the statutory duty to provide for California's long-term energy supply needs.[2] A key principle underlying the development of the CPUC's Resource Adequacy ("RA") program is that CPUC's procurement programs should be designed and allowed to fulfill California's energy needs, because short term, out of market procurement by the CAISO will not incent investment in generation when and where it is

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[1] The CPUC understands that CAISO staff is concerned about integrating all features of the RCST during the year of transition to MRTU. The CPUC may not oppose extension of limited parts of the RCST as long as certain portions remain. Of primary interest to the CPUC is the continuation of CAISO reporting regarding scope and reasons for RCST designations. Such reporting is necessary for the determination of whether and how the CPUC's RA program may be modified to better fulfill the CAISO's operational needs.

[2] Section 824o, subdivision (i), of the Federal Power Act, which facilitates creation of electricity reliability organizations to promote reliability of bulk power systems, expressly retains state authority to assure reliability (e.g. adequacy) of energy supply within the state. (16 U.S.C. § 824o, subd. (i).)

needed.[3] CPUC staff understands, however, that the state's current energy market design would benefit from the CAISO's having a mechanism by which to procure backstop capacity in the event that Load Serving Entities ("LSEs") operating within the CAISO fail to procure adequate resources in a timely fashion; or extreme, unanticipated circumstances change fundamental assumptions about the grid's operation upon which LSEs' resource adequacy requirements were based.

In order to fulfill the CAISO's energy supplies needed to assure short-term grid reliability, the CPUC has expanded its initial system RA requirements to include a local reliability requirement that arises from CAISO's analysis. The CPUC has also adopted for 2008 a counting convention to address "zonal" issues arising from transmission constraints over Path 26, the major transmission corridor between northern and southern California. The CPUC is also in the process of considering whether to add ancillary services and multi-year RA capacity procurement requirements to its program.[4] The CPUC's system and local capacity procurement requirements have resulted in a dramatic reduction in CAISO out of market procurement.[5] The CPUC continues to move swiftly to fulfill the CAISO's legitimate short-term operational needs, as well as Californias' long-term power supply needs.

[3] See CAISO News Release: *California ISO Reduces RMR Contracts by 60 Percent[;] Utility Resource Adequacy Contracts Replacing RMR*, issued October 19, 2006, available at http://www.caiso.com/1894/1894848a3e390.pdf stating, "RMR contracts are enacted for one-year terms, whereas bilateral contracts can be enacted for longer terms if the parties choose to do so. By nature, longer-term contracts provide more cost certainty for the buyer, and more guarantee of cost recovery and cash flow for the seller. While the ISO is not a party to the terms of the bilateral contracts, the potential for long-term local reliability contracts bodes well for stability and reliability in California's energy industry."

[4] *Assigned Commissioner's Ruling and Scoping Memo for Phase Two*, Issued December 22, 2006 in Rulemaking 05-12-013 at p. 17.

[5] CAISO News Release, *California ISO Reduces RMR Contracts by 60 Percent[;] Utility Resource Adequacy Contracts Replacing RMR*, issued October 19, 2007. Additionally, CPUC staff understands from

The RCST settlement was designed in part to function collaboratively with the CPUC's RA program.[6] Accordingly, the FERC determined that a critical element of any backstop procurement mechanism for California is to find a carefully balanced price to promote "longer-term contracting" and avoid undue reliance on the backstop procurement mechanism,[7] i.e., to prevent the backstop mechanism from driving or becoming the primary procurement mechanism. The CPUC agrees with this observation. CPUC staff negotiated the RCST settlement based on the idea that the chosen capacity price was a fair proxy for going-forward costs for the existing fleet of generation that fulfills California's energy needs, including both older, depreciated units and some new generation. CPUC staff continues to believe that this is a reasonably fair basis for compensation for existing generation called out of market for short term reliability needs.

The CPUC is currently considering whether and how to implement a centralized capacity market within its RA program. The CPUC's early 2008 RA decision should provide some guidance on how to design a backstop procurement tool that will complement California's long-term energy supply planning process and will not inadvertently become a primary procurement mechanism. The CPUC would object to any backstop methodology that would drive RA capacity prices. Many market participants observed during the stakeholder process regarding the CAISO's Interim Capacity Procurement Mechanism, consistent with FERC observations, that a steep rise in backstop capacity payments would likely drive the price of RA capacity up to meet

CAISO MOWD report required by the RCST settlement that there was a substantial decrease in MOWDs in 2007 over 2006 MOWD rates.

[6] For example, the RCST MOWD reporting requirements help inform both oversight of the CAISO's out of market procurement activities as well as the development of the CPUC's RA program.

that backstop capacity price. Absent a CPUC decision on the next phase of California capacity market development, FERC imposition of a new, different backstop mechanism, including a rise in backstop capacity payments may thus inadvertently distort or frustrate California's existing and future positive market developments. The CPUC therefore strongly supports extension of the RCST until MRTU startup or implementation of a replacement backstop mechanism that reflects California energy and capacity market developments.

B. The RCST Pricing Mechanism Is Just And Reasonable Because It Reasonably Reflects Capacity Payments To Generators That Are Participating In The CPUC's RA Program.

The CPUC anticipates that some parties may argue that the RCST does not provide adequate compensation for capacity services. The CPUC believes, however, that any increase in backstop capacity payments must be justified in view of many factors, including policy considerations. The FERC found that a primary consideration in whether a backstop procurement system is just and reasonable was that the capacity price should not be too high, as the price "should encourage generators to instead negotiate contracts"[8] rather than luring them to seek backstop payments in hopes of a windfall.

In approving the original RCST settlement, the FERC held that it was "unduly discriminatory that units under the [must offer obligation] would be required to operate for reliability purposes in a manner similar to units contracted for capacity under the resource adequacy program and not receive similar capacity payment."[9] CPUC staff

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[7] *Indep. Energy Producers Ass'n v. California Indep. Sys. Operator Corp.*, 118 FERC ¶ 61,096 (2007) ("Feb. 2007 Order"), reh'g pending, at p. 71.

[8] Feb. 2007 Order at p. 75.

[9] *Independent Energy Producers Association v. California Independent System Operator Corporation*, 116 FERC ¶ 61,069 (2006) ("Settlement Order") at p. 36.

observations of CPUC jurisdictional LSE capacity procurement indicate that Local RA capacity is generally transacting in a $20 to $45 per kw year price range, depending on the economics of the specific local area; while capacity used to fulfill system-wide RA requirements is generally transacting in the $15 to $25 per kw year price range.[10] It is important to note that this capacity compensation does not include a Peak Energy Rent ("PER") deduction such as that used in some eastern system operators' capacity markets, which would have the effect of reducing the overall capacity payment when energy prices are high.

CPUC jurisdictional load serving entities' general ability to comply with the CPUC's Resource Adequacy ("RA") requirements indicate that such prices accurately reflect capacity market conditions in California.[11] Further, the CPUC's RA program includes a provision that an LSE that has been unable to procure capacity contracts for less than $40 per kw year may seek from the CPUC a waiver of its local RA contracting requirements.[12] No LSE has successfully applied for such a waiver during the period spanning from the 2006 commencement of the CPUC's RA program through the recently submitted 2008 year-ahead showings.[13]

[10] The CPUC has not systematically collected data regarding all RA capacity transactions used to satisfy CPUC RA requirements, and the prices described above were derived from interactions with LSEs and not through a statistically valid research methodology. CPUC staff are, however, considering developments in market monitoring methodologies.

[11] There were minor incidents of non-compliance with the 2008 year-ahead RA procurement requirements, but none was large enough to warrant backstop procurement, pursuant to CAISO evaluation.

[12] See Decision 06-06-064, *Opinion On Local Resource Adequacy Requirements*, filed on June 29, 2006 in section 3.3.12 at p. 71-74.

[13] There were no requests for waivers for the 2006 or 2008 RA requirements. One LSE applied for a waiver for 2007, but it did not qualify for a waiver and was fined for non-compliance.

The capacity price offered by the RCST settlement thus appears more than adequate to fulfill FERC's desire to assure a capacity payment that is similar to that received by generators that are parties to RA contracts.

Respectfully submitted,

RANDOLPH L. WU
MARY F. MCKENZIE
ELIZABETH DORMAN

By: /s/ ELIZABETH DORMAN

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San Francisco, CA 94102
Phone: (415) 703-1415

Attorneys for the California Public Utilities Commission

January 9, 2008

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served a copy of the foregoing document upon each person designated on the official service list in this proceeding in accordance with the requirements of Rule 2010 of this Commission's Rules of Practice and Procedure.

Dated at San Francisco, California, this 9th day of January, 2008.

/s/ HALINA MARCINKOWSKI

Halina Marcinkowski

Submission Contents