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PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION

I.D. #8090
RESOLUTION E-4214
December 18, 2008

R E S O L U T I O N

This Resolution formally adopts the 2008 Market Price Referent values for the use in the 2008 Renewable Portfolio Standard solicitations. This Resolution is made on the Commission's own motion.

SUMMARY

2008 Market Price Referent (MPR) values have been calculated for use in the 2008 Renewable Portfolio Standard (RPS) solicitations.

This Resolution formally adopts the 2008 MPR values for use in the 2008 RPS solicitations. This Resolution is made on the Commission's own motion.

Adopted 2008 Market Price Referents[1]
(Nominal - dollars/kWh)

Resource Type	10-Year	15-Year	20-Year	25-Year
2009 Baseload MPR	0.09980	0.10509	0.11119	0.11624
2010 Baseload MPR	0.10103	0.10716	0.11380	0.11905
2011 Baseload MPR	0.10318	0.11008	0.11716	0.12253
2012 Baseload MPR	0.10607	0.11362	0.12107	0.12652
2013 Baseload MPR	0.10949	0.11767	0.12539	0.13088
2014 Baseload MPR	0.11287	0.12159	0.12950	0.13502
2015 Baseload MPR	0.11663	0.12580	0.13378	0.13934
2016 Baseload MPR	0.12061	0.13018	0.13817	0.14377
2017 Baseload MPR	0.12463	0.13460	0.14259	0.14819
2018 Baseload MPR	0.12904	0.13927	0.14723	0.15276
2019 Baseload MPR	0.13381	0.14417	0.15207	0.15744
2020 Baseload MPR	0.13894	0.14923	0.15710	0.16223

[1] Note: using 2009 as the base year, Staff calculates MPRs for 2009-2020 that reflect different project online dates. The 2008 MPR model is available at: http://www.ethree.com/MPR.html

BACKGROUND

The RPS Program requires each utility to increase the amount of renewable energy in its portfolio

The California Renewables Portfolio Standard (RPS) Program was established by Senate Bill 1078 (Chapter 516, statutes of 2002, effective January 1, 2003) and codified at California Public Utilities Code Section 399.11, et seq. The statute requires that RPS-obligated investor-owned utilities (IOU), energy service providers (ESP) and community choice aggregators (CCA) meet annual targets by increasing procurement of Eligible Renewable Energy Resources (ERR) by at least 1 percent of annual retail sales per year until 20 percent is reached, subject to the Commission's rules on flexible compliance, no later than 2017.

The State's Energy Action Plan (EAP) called for acceleration of this RPS goal to reach 20 percent by 2010[2]. This was reiterated again in the Order Instituting Rulemaking (R.04-04-026)[3] issued on April 28, 2004, which encouraged the utilities to procure cost-effective renewable generation in excess of their RPS annual procurement targets[4] (APTs), in order to make progress towards the goal expressed in the EAP. On September 26, 2006, Governor Schwarzenegger signed Senate Bill (SB) 107[5], which officially accelerated the State's RPS targets to 20 percent by 2010, subject to the Commission's rules on flexible compliance.[6]

MPR is an important element in the RPS procurement process

The MPR is a key component of the RPS program. Pursuant to Legislation, the MPR has three functions.[7] The first, expressed in § 399.14(g), is to deem reasonable per se and allow to be recovered in rates those "[p]rocurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable energy resources pursuant to this

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[2] The Energy Action Plan was jointly adopted by the Commission, the California Energy Resources Conservation and Development Commission (CEC) and the California Power Authority (CPA). The Commission adopted the EAP on May 8, 2003.

[3] http://www.cpuc.ca.gov/Published/Final_decision/36206.htm

[4] APT - An LSE's APT for a given year is the amount of renewable generation an LSE must procure in order to meet the statutory requirement that it increase its total eligible renewable procurement by at least 1% of retail sales per year.

[5] SB 107, Chapter 464, Statutes of 2006

[6] Sec. 399.14(a)(2)(C)

[7] The RPS legislation is codified at Pub. Util. Code §§ 399.11-399.20.

article, at or below the market price determined by the commission pursuant to subdivision (c) of Section 399.15. . ." The second function of the MPR is to establish the basis for the use of Above-Market Funds (AMFs) which are awarded by the Commission pursuant to SB 1036, Statutes 2007, ch. 685.[8, 9] The third function of the MPR is to set limits on the procurement obligations of retail sellers under the RPS program.[10] That is, if the amount of AMFs available to an electrical corporation is insufficient to support the total costs expended above the market price, then the Commission shall allow an electrical corporation to limit its annual procurement obligation to the quantity of eligible renewable energy resources that can be procured with available AMFs.

To establish the market price necessary for implementation of the RPS program, the Legislature directed the CPUC, in consultation with the Energy Commission, to:[11]

> Establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with renewable generators, in consideration of the following:
>
> > (1) The long-term market price of electricity for fixed price contracts, determined pursuant to the electrical corporation's general procurement activities as authorized by the Commission.
> >
> > (2) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities.

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[8] The original method for funding above-market costs was the use of Supplemental Energy Payments (SEPs), administered by the CEC. See §§ 399.13(c), 399.15(b)(5). The SEP program was eliminated by SB 1036 (Perata), Stats. 2007, ch. 685. The existing funds were refunded to the three large IOUs (PG&E, SDG&E, and SCE) and, along with the portion of funds which would have been collected through January 1, 2012, will be used to fund above-market costs of their long-term RPS contracts. See Res. E-4160 (April 10, 2008).

[9] In order to carry out this function, D.04-06-015 concluded that the contract price should be compared to the MPR on a net present value basis as calculated over the entire contract term.

[10] §399.15(d)(3)

[11] §399.15(c)

(3) The value of different products, including baseload, peaking, and as-available output.

In D.03-06-071, the CPUC determined that it was not feasible to employ the first consideration set out in § 399.15(c), "the long-term market price of electricity for fixed price contracts, determined pursuant to the electrical corporation's general procurement activities." Because the existing long-term contracts for electricity were almost exclusively those signed by the Department of Water Resources (DWR) pursuant to Water Code § 80100 et seq., the CPUC concluded that there were not a sufficient number of existing, reasonably-priced, long-term power contracts of recent vintage currently in the utilities' resource portfolios to establish an MPR based on the first consideration. The CPUC, in D.03-06-071, therefore relied on the second and third considerations, developing a proxy plant to model the long-term costs "associated with fixed-price electricity from new generating facilities," taking into account "the value of different products, including baseload, peaking, and as-available output."

MPR procedural history

The Commission set the initial parameters for the MPR in D.03-06-071. The method for calculating the MPR was first developed in D.04 06-015. In D.04-06-015, the CPUC clarified "what the MPR is not: it does not represent the cost, capacity or output profile of a specific type of renewable generation technology. . . [T]he MPR is to represent the presumptive cost of electricity from a non-renewable energy source, which this Commission, in D.03-06-071, held to be a natural gas-fired baseload or peaker plant." (D.04-06-015, mimeo., p. 6, n.10.)

In D.05-12-042, the methodology for calculating the MPR was expanded and stabilized. This methodology has been used for the resolutions implementing the MPR for 2005 and 2006. The 2007 MPR was calculated pursuant to D.07-09-024, wherein the Commission adopted an interim method to account for the costs of the emission of greenhouse gases (GHG adder).

D.07-09-024 authorized the use of the GHG adder for the 2007 MPR only. That decision also authorized an examination of the MPR for 2008 and later years, to determine whether any changes should be made to the MPR methodology, including how the costs of regulation of GHG emissions should be reflected in the MPR.

MPR methodology was reevaluated in 2008

The 2008 review process[12] began with comments filed on March 6, 2008 in response to the Administrative Law Judge's (ALJ's) February 8, 2008, Ruling requesting pre-workshop comments on the 2008 MPR. On March 27, 2008, Energy Division staff (Staff) held a workshop where parties discussed potential modifications to the MPR methodology, inputs, and assumptions for 2008 and later years. Parties identified several key issues for review:

- Capacity Factor
- MPR Gas Methodology
- GHG Adder
- Installed Capital Costs and Cost Escalation
- Generation Meter Multiplier (Transmission Line Losses)
- MPR Contract Length

A May 20, 2008 Ruling requested post-workshop comments, which were filed on June 6, 2008; reply comments were filed on June 18, 2008. Parties' comments and reply comments, including pre-workshop comments and presentations made at the March 27, 2008 workshop, informed D.08-10-026, the Commission's 2008 Decision on the Market Price Referent for the California Renewables Portfolio Standard. D.08-10-026 refined the MPR in matters related to the methodology; additionally, several issues were determined to be within the discretion of Staff. Accordingly, we discuss those changes in this resolution.

[12] The following parties participated in the 2008 MPR proceeding: California Wind Energy Association (CalWEA), California Cogeneration Council, Concentrated Solar Power Companies, Large-scale Solar Association, and Solar Alliance, jointly (collectively, CalWEA); Center for Energy Efficiency and Renewable Technologies (CEERT); Central California Power (CCP); Energy Producers and Users Coalition (EPUC) and Cogeneration Association of California, jointly (collectively, EPUC); Green Power Institute (GPI); GreenVolts, Cleantech America, and Community Environmental Council, jointly; Shell Energy North America (US), L.P (Shell); Division of Ratepayer Advocates (DRA); Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); Southern California Edison Company (SCE); The Utility Reform Network (TURN); and Union of Concerned Scientists (UCS).

MPRs were calculated using a cash-flow simulation methodology

The 2008 MPRs were calculated using the "MPR model", which is based on a cash-flow simulation methodology approved by the Commission.[13] The MPR model requires several types of input data, including natural gas prices, capital costs, operating costs, finance costs, taxes, and power delivery assumptions. The primary input drivers for the MPR calculation are the California (CA) gas price forecast, power plant capital costs, and the capacity factor for a proxy baseload plant. (Refer to 2008 MPR model, tabs; CA_Gas_Forecast, Install_Cap, and CF_Inputs.)

The MPR model calculates what it would cost to own and operate a baseload combined cycle gas turbine (CCGT) power plant over a 10, 15, 20 and 25-year period. The cost of electricity generated by such a power plant, at an assumed technical capacity factor and set of costs, is the proxy for the long-term market price of electricity. To ensure that the MPR represents "the value of different products including baseload, peaking, and as-available output,"[14] the IOUs apply their IOU-specific Time of Delivery (TOD)[15] profiles to the baseload MPR when evaluating RPS renewable facilities. The application of TOD factors to the MPR result in a market price for each product and electric generating unit. (Refer to 2008 MPR model "CF_Data Set" and "Control" tabs.)

Release of 2008 MPR is consistent with prior Commission decisions

Pursuant to D.05-12-042, Staff is required to prepare a draft resolution for the annual MPR, including any relevant supporting materials as attachments to the draft resolution. The draft resolution will be released after all utility solicitations have closed.[16] For 2008, the draft resolution incorporates the methodological changes adopted in the Commission's recent decision D.08-10-026 and refines several MPR inputs at the recommendation of Staff, as discussed herein. Parties

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[13] A list of all relevant MPR documents, with links, is provided at the beginning of this resolution's Discussion section.

[14] Sec. 399.15(c)(3).

[15] TOD factors are based on the forward value of electricity during different TOD periods.

[16] The three large California utilities submitted their letters to the Executive Director notifying the Commission that their solicitations were closed on: Pacific Gas & Electric– May 13, 2008, Southern California Electric– May 5, 2008 and San Diego Gas & Electric– April 30, 2008.

will have the usual opportunity to file comments and reply comments on the draft resolution prior to its formal consideration by the Commission.[17]

DISCUSSION

Please refer to the following documents in the following chronological order for a detailed discussion of the MPR methodology:

- **D.04-06-015**: Opinion Adopting Market Price Referent Methodology http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/37383.doc
- **Resolution E-3942**: Adopts 2004 MPR Values for 2004 RPS Solicitation http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/48242.DOC
- **D.05-12-042**: Interim Opinion Adopting Methodology for 2005 Market Price Referent http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/52178.DOC
- **Resolution E-3980**: Adopts 2005 MPR Values for 2005 RPS Solicitation http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/55465.DOC
- **Resolution E-4049**: Adopts 2006 MPR Values for 2006 RPS Solicitation http://www.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/63132.doc
- **D.07-09-024**: Opinion on Petition for Modification of Decision 05-12-042 http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/73031.DOC
- **Resolution E-4118**: Adopts 2007 MPR Values for 2007 RPS Solicitation http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/73594.doc
- **D.08-10-026**: Decision on Market Price Referent for the California Renewables Portfolio Standard http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/92445.htm

The 2008 MPRs are calculated pursuant to D.08-10-026 and Staff recommendations

In D.08-10-026, the Commission modified the MPR methodology and broadly examined the MPR model inputs. In this section we discuss modifications to the MPR model by Commission decision and Staff discretion.

To facilitate party review of 2008 MPR modifications, the 2008 MPR model includes toggle switches or lists on the "Control" tab that allows parties to evaluate MPR values while applying 2007 and/or 2008 inputs.

[17] D.04-06-015 (Footnote 21, p.30)

2008 MPR Gas Methodology and Inputs

The most significant cost during the life a new CCGT is the cost of its natural gas fuel. The MPR models the cost of gas over the entire life of the proxy plant's long-term contract. As the Commission pointed out in D.05-12-042, no new gas-fired plant in California actually enters into a 20-year fixed price contract for physical gas delivery. Therefore, in order to capture the "fixed-price fuel costs associated with fixed-price electricity from new generating facilities," the MPR model creates a forecast of long-term gas prices for purposes of the MPR. As explained in D.05-12-042, the MPR model is based on the fact that California market participants , when considering a power purchase agreement (PPA), "use some mixture of market data (NYMEX prices) and fundamentals forecasts for estimating long-term gas prices in a variety of settings, not only new PPAs for electricity produced from CCGTs".[18]

New York Mercantile Exchange (NYMEX) data

In D.05-12-042, the Commission authorized Staff to use all available NYMEX forward contract data, under this guidance, the 2005, 2006 and 2007 MPRs were calculated using the full six years of NYMEX. In 2008, NYMEX extended its forward gas contract term offering from six to 12 years.

The Commission weighed the pros and cons of extending the MPR methodology to incorporate the additional years of NYMEX data that parties identified in their comments. Specifically, CAlWEA, UCS and PG&E supported the MPRs' continued preference for market data, i.e., full 12 years,[19] while TURN, SCE and SDG&E opposed the use of 12 years NYMEX based on concern about relying on the outer years of NYMEX data where minimal or no actual trades had occurred. SCE supported its position stating that for its own operations, they do not enter into NYMEX transactions so far into the future.[20] From a procurement

[18] D.05-12-042, p. 17.

[19] D.05-12-042 adopted five Guiding Principles for the MPR Gas Methodology: 1) The natural gas prices used to calculate the MPR should reflect the behavior of market participants, 2) Market data should be used to the extent possible, 3) For shorter-term contracts, forecast data should be verified against forward market data; for longer-term contracts that extend beyond available market data, forecasts should be benchmarked against fundamental costs and/or historical market data, 4) The methodology should be consistent with the evaluation of other products and 5) The methodology should be consistent with previous regulatory decision.

[20] SCE, post-workshop reply comments, p. 13.

perspective, the opposing parties concerns have merit. In D.08-10-026, however, the Commission highlighted an important distinction about the MPR. That is, "…that gas forecast information for the MPR is part of a modeling exercise, not a procurement transaction".

Thus, D.08-10-026 authorized Staff to use between nine and 12 years (the current maximum) of NYMEX forward price data. In reviewing the applicable NYMEX data set,[21] Staff determined that there was no evidence of a single outlier that would argue for using less than all available NYMEX forward prices. (Refer to 2008 model, "NYMEX_Futures" and "CA_Gas_Forecast" tabs.)

Transition to Fundamental Forecast

The MPR model's long-term gas contract requires the use of fundamental gas forecasts to project gas prices when NYMEX forward prices are not available. The MPR fundamental forecast for years 12 – 25 was developed using three out of four private sector natural gas forecasts (Henry Hub) from Cambridge Energy Research Associates, PIRA Energy Group, Global Insight or Wood Mackenzie. Due to contractual obligations requiring the Commission to keep the forecast confidential, Staff can not reveal which of the four firms the forecasts were purchased from.

The use of fundamental forecasts requires a two-step implementation process. First, a methodology must determine how to utilize the fundamental forecast data, and secondly, a methodology is required to transition from NYMEX data to fundamentals data.

For 2007, the transition between NYMEX forward prices and the MPR fundamental forecast was accomplished by making a straight line interpolation between the last year of NYMEX data (year 2012) and the MPR fundamental forecast's year 2016 value to create prices for years 2013, 2014 and 2015. (Refer to 2007 MPR model, "CA_Gas_Forecast" tab.)

D.08-10-026 ordered Staff to continue the use of private fundamental forecasts; however, the methodology now utilizes the annual percentage rate change, rather than the actual values, *per se,* to produce the MPR fundamental forecast.

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[21] The MPR Gas Methodology uses a 22-trading day average of NYMEX forward prices ending with the close of the utilities' solicitations. Accordingly, the 2008 MPR Gas Methodology is derived based on the 22-trading day average of NYMEX forward prices leading up to May 13, 2008.

D.08-10-026 also directed Staff to make the transition from NYMEX forward prices to the first year of the MPR fundamental forecast by using a linear trend of the last three to five years of NYMEX forward prices, which mitigates the impact of any one price in the outer years of NYMEX. The first year of the MPR fundamental forecast is then extended using the annual escalation rate for the remainder of the MPR fundamental forecast. (Refer to Appendix C for the 2008 California and Henry Hub gas forecasts (2009 – 2050) and Appendix D for specific inputs used in the 2008 gas forecast.)

California Basis Adjustment

The 2007 MPR used NYMEX Clearport futures data to account for the cost of delivery from Henry Hub to California.[22] Staff averaged PG&E Citygate and SoCal Border Clearport prices for the three years of available data and then fixed the average price in year three for all years throughout the proxy CCGT's contract term.

D.08-10-026 ordered Staff to retain the use of NYMEX Clearport prices for years when NYMEX data is used, but now requires that California Basis data from private fundamental forecasts be used when the MPR Gas Methodology relies on fundamental forecast data. (Refer to 2008 MPR model "CA_Basis_Adj" tab.)

Pursuant to D.08-10-026, Staff continued its use of PG&E Citygate and SoCal Border Clearport prices for the first three years and then fixed the average price in year three through 2020, the last year when the MPR Gas Forecast relies on NYMEX forward prices.[23] The California Basis Adjustment for the remainder of the proxy CCGT's contract term is based on the average of basis prices from the private fundamental forecasts used to develop the long-term California MPR Gas Forecast. (Refer to 2008 MPR model "CA_Basis_Adj" tab.)

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[22] "The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The New York Mercantile Exchange (NYMEX) uses the Henry Hub as the point of delivery for its natural gas futures contract." http://www.eia.doe.gov/oiaf/analysispaper/henryhub/

[23] NYMEX Clearport provides SoCal prices for up to six years; however, PG&E Citygate is only available for three; therefore, Staff determined it most reasonable to use the same methodology that was used in prior years.

2008 MPR Non-Gas Methodology and Inputs

Installed Capital Cost Data Set

D.05-12-042 adopted criteria for conducting a market survey of plant costs and ordered Staff to use installed capital costs that reflect the actual cost of a range of CCGT projects that have been built in the last few years or are currently under construction in California. Specifically, Staff was ordered to use the following as suggested criteria in selecting plants to survey:

- 500 MW CCGT (approximate)
- Utilizes GE "F-Series" turbine
- Located in California

Using the survey criteria outlined above, Staff identified the following plants that had publicly available cost data; Palomar (SDG&E), and Cosumnes (SMUD).[24] The 2007 MPR model's data set for installed capital cost consists of the Palomar and Cosumnes power plants.

D.08-10-026 examined whether the Colusa power plant, which is currently under construction, would meet the criteria for use in the MPR calculation.[25] CalWEA and Shell argued that Colusa represented a distressed sale, and therefore, did not meet the criteria established in D.05-12-042.[26] Ultimately, D.08-10-026 determined that Colusa does meet the MPR criteria, because the reasonableness for Colusa was approved through formal contested Commission proceedings and moreover, the certificate of public convenience and necessity (CPCN) retained the initial cost cap.[27]

While D.08-10-026 does not order Staff to incorporate Colusa into the MPR model, based on the decision's findings, Staff determined that the MPR

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[24] Refer to Resolution E-4049, Appendix C, for a detailed discussion on how the installed capacity cost for the 2006 MPR was developed.

[25] D08-10-026, pp 21-23.

[26] CalWEA, post-workshop comments, pp 3-4; Shell, post-workshop comments, pp 4-5.

[27] D.06-11-048 approved several contracts, including the Colusa plant, which resulted from PG&E's 2004 long-term request for offers; D.08-02-019 granted PG&E's request for a certificate of public convenience and necessity to build the plant itself and reaffirmed Colusa's $684 cost cap imposed in D.06-11-048.

calculation would benefit from adding Colusa to the limited data set for installed capital costs. According to D.08-02-019, the cost to build Colusa is set at $684.4 million, which results in $1,042/kw based on a 2010 operating online date. To incorporate Colusa into the MPR model, Staff de-escalated Colusa's cost cap using USACOE. The adjustment results in overnight installed capital costs of $670.57 million or $1,021/kw. (Refer to 2008 MPR model, "Install_Cap" and "Control" tabs.)

<u>Escalation of Historic Capital Cost</u>

The 2007 MPR model calculated its installed capital cost estimate by applying the annual United States Army Corps of Engineers (USACOE) Construction Cost Index to capital cost data from the Palomar and Consumnes plants.[28]

D.08-10-026 agreed with the majority of parties, that given the MPR model's limited and relatively older data set, combined with a significant increase in power project development costs, that the use of a private index may be warranted, "…to bring the older cost values more into line with 2008 values".[29] D.08-10-026 authorized Staff to determine the most reasonable data source for escalating the MPR model's historic capital costs.

For the 2008 MPR calculation, Staff used Handy-Whitman's Index of Public Utility Construction Costs (Handy-Whitman)[30] to escalate the historic installed capital costs for Palomar and Consumes. Applying the Handy-Whitman Index results in approximately a 7% increase in the MPR model's installed capital costs.[31, 32] (Refer to 2008 MPR model "Install_Cap" and "Control" tabs.)

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[28] CWBS Feature Code 07 (Power Plants). Updated March 30, 2007. http://www.usace.army.mil/inet/usace-docs/eng-manuals/em1110-2-1304/toc.htm

[29] D.08-10-026, pp 23-24.

[30] Whitman, Requardt & Associates, LLP publishes the Handy-Whitman Index of Public Utility Construction Costs. http://www.wrallp.com/

[31] Assumes Palomar, Consumnes and Colusa.

[32] The model used Handy-Whitman's Bulletin 167, January 2008. As of November 4, 2008 the date this draft resolution was mailed, Handy-Whitman had not yet released its updated Index, Bulletin 168. In conversation with Handy-Whitman's publisher, Energy Division understands that the updated Index will be released during the time the draft resolution is out for public comment. Therefore, Energy Division will update the final model using the updated Index for the final 2008 MPR calculation.

Escalation of Current Capital Cost

The 2007 MPR model escalated capital costs through 2010 according to the methodology adopted in D.05-12-042, which assumed that in 2010, increased technical efficiencies would offset incremental capital costs (e.g., inflation).

In D.08-10-026, the Commission determined that, "… the record in this proceeding reveals no reason to believe that the dynamic relationship between cost increases and efficiency improvements will suddenly end in 2010".[33] Accordingly, the MPR methodology was revised to provide for the escalation of installed capital costs on a rolling five-year basis. The 2008 MPR values are calculated assuming that capital costs increase through 2013 and then remain fixed throughout the proxy CCGT contract term. (Refer to 2008 MPR model "CF_Data_Set" tab; cells J13:O13) Installed capital cost will continue to be escalated, prospectively, using the USACOE Index.

Capacity Factor

The 2007 MPRs were calculated using an "economic" capacity factor based on the weighted average of the utility's time of delivery (TOD) factors to determine when it was economic for the proxy CCGT to operate. The 2007 MPR methodology produced an economic capacity factor of approximately 71%.[34]

D.08-10-026 determined that the Commission's statutory obligation was best achieved by calculating MPR values based on a technical capacity factor rather than an economic capacity factor. Specifically, D.08-10-026 found that, "The use of the technical capacity factor eliminates the distortions of the weighted average of TOD factors in the current method [and] …results, when properly time-differentiated, in an MPR that better reflects the values of baseload, peaking, and intermittent products".[35]

Accordingly, Staff revised the 2008 MPR model so that the proxy CCGT's capacity factor is now based on the proxy plant's technical capacity factor, which is assumed to be 92%. The MPR's capacity factor is now an input on the "CF_Inputs" tab and Staff deleted the "Cap_Fac" tab, which was used expressly for calculating the economic capacity factor.

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[33] D.08-10-26, p. 25.

[34] See 2007 MPR model "Cap_Fac" tab.

[35] D.08-10-26, p. 20

D.08-10-026 highlighted the necessity that an MPR calculation using a technical capacity factor must be applied to the utility's TODs to ensure that the calculation fully reflects the costs and revenue of the proxy CCGT. That is, the technical capacity derived MPR, when multiplied by the utility's TOD factors, results in the market price. Moreover, applying the utility's TODs is necessary to evaluate RPS bids received in the annual solicitations in order to produce a time-differentiated bid evaluation process. (Refer to Appendix B for review of the utilities TOD periods and factors)

GHG compliance cost

In D.07-09-024, the Commission determined that it was reasonable to include a GHG adder to account for the costs of compliance with recent California climate laws, Assembly Bill (AB) 32 (Statutes 2006, ch. 488 and SB 1368 (Statutes 2006, ch. 598), because the MPR applies to long-term contracts.[36] Pursuant to D.07-09-024,[37] Staff calculated the 2007 MPRs using the $/$CO_2$ ton values and methodology of the Energy and Environmental Economics (E3) Avoided Cost model for calculating a GHG adder.[38] The 2007 MPR model assumed a CO_2 adder of $8/ton for 2004, escalated at 5 percent per year through 2023 and then escalated using a straight line trend of $0.90/ton per year from 2024-2040.

D.08-10-026 revised further the MPR methodology to reflect California's GHG environmental laws. D.08-10-026 made the cost of compliance with GHG regulation a permanent component of the MPR calculation and because at this time there is no GHG compliance market in California, the decision adopted criteria for Staff to employ in modeling the GHG compliance costs incurred for the MPR proxy CCGT. Specifically, D.08-10-026 identified criteria that Staff must

[36] The Global Warming Solutions Act and Emissions Performance Standard, respectively.

[37] D.07-09-024, Ordering Paragraph 1 states, "The calculation of the 2007 market price referent (MPR) used in the renewables portfolio standard program shall use the model for calculating greenhouse gas emissions costs (GHG adder) developed by Energy and Environmental Economics and adopted in Decision 04-12-048, applied to the MPR's combined cycle combustion turbine proxy plant for GHG emissions costs beginning January 1, 2012. "

[38] The Avoided Cost model developed by E3's avoided cost model was adopted by the Commission in D.04-12-048 (R.04-04-003) and D.05-04-024 (R.04-04-025). The model is available here: http://www.ethree.com/cpuc_avoidedcosts.html

use for selecting a resource for modeling GHG compliance costs for the MPR. The model should be:

- publicly available;
- based on multiple scenarios and sources of information;
- based on realistic and public assessments of policy proposals and scenarios;
- based on the most current reliable information that conforms to the other three criteria.

As discussed in D.08-10-026, E3's Avoided Cost model or the model developed by Synapse Energy Economics, Inc. (Synapse) would meet the criteria identified above. At the March workshop, Synapse discussed its methodology and explained how it was based on the analysis of multiple state and federal GHG policies, economic models used to determine price impacts, as well as, ranges of CO_2 prices used by utility regulatory commissions and utilities in resource planning.[39] Staff has determined that at this time, the Synapse model best meets the criteria established in D.08-10-026.

The 2008 MPR model uses $/$CO_2$ ton values based on Synapse's most recent report, "Synapse 2008 CO_2 Price Forecasts".[40] Specifically, Staff used the Synapse "mid-case" cost data, which was recommended by CalWEA and UCS.[41] The Synapse report assumes CO_2 prices of $15 in 2013, increasing to $30.80 in 2020 and $53.40 in 2030, which results in a levelized price of $30/ CO_2 ton in 2007$. Staff converted the reports $/$CO_2$ ton values, which are provided in 2007$, to nominal$ using a 2.5% inflation rate.[42] (Refer to 2008 MPR model "CF_Data_Set" tab; row 9.)

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[39] Synapse presentation materials are available at: http://www.cpuc.ca.gov/NR/rdonlyres/022569BE-516A-4E13-87D8-733C989D8411/0/MPRGHGadder_2008MPR_workshop_Synapse_UCS.ppt#256,1, Greenhouse Gas Adder for Use in Determining the 2008 MPR

[40] http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf

[41] CalWEA post-workshop reply comments, p. 10; UCS post-workshop reply comments, p. 5.

[42] Staff implemented the Synapse values in consultation with David White, one of the principal authors of the report, "Synapse 2008 CO_2 Price Forecasts Report".

Staff incorporated MPR GHG compliance costs consistent with the phase in approach recommended in D.08-10-037, the Commission's decision on Greenhouse Gas Regulatory Strategies. Specifically, the Commission stated, "We conclude that in 2012 there should be 20% auctioning and 80% free allocation of allowances to deliverers, with a transition to 100% auctioning by 2016".[43] The table below illustrates the impact on the GHG compliance costs for the 2008 MPR, notice that in 2016 the MPR GHG compliance costs equal Synapse's nominal values. (Refer to 2008 MPR model, "CF_Data_Set" tab; cells M6:Q6 and MP:Q9)

Year	2012	2013	2014	2015	2016
Synapse (nominal$/ CO_2 ton))	10.18	17.40	20.56	23.76	27.23
MPR GHG compliance costs ($/$CO_2$ ton)	**2.04**	**6.96**	**12.34**	**19.01**	**27.23**

General Meter Multiplier (Transmission Line Losses)

The 2007 MPR model used a General Meter Multiplier (GMM) of 98.5%, which is equivalent to a 1.5% line loss factor, based on a simple average of CAISO's transmission losses.[44]

D.08-10-026 determined that the MPR methodology should be revised to accommodate the likelihood that a PPA between a California LSE and a CCGT would require delivery at the busbar.[45] Accordingly, the 2008 MPR model calculates MPRs based on delivery at the delivery at the busbar. (Refer to "CF_Inputs" tab; cell E34:E35.)

Capital Cost Inputs

The MPR model requires fixed and variable operational and maintenance (O&M) costs to calculate total installed capital costs for the MPR proxy CCGT. The 2007 MPR calculated average fixed and variable O&M costs based on data from

[43] D.08-10-037, p. 206.
http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/92591.doc

[44] http://oasis.caiso.com/

[45] D.08-10-026, pp 25-26.

Palomar, Gateway (formerly, Contra Costa), and Mountain View facilities, as well as data from the CEC and Energy Information Agency (EIA).

During the evaluation of the 2008 MPR methodology and inputs, parties were asked to comment on the extent to which the MPR model may benefit from either inputs or assumptions from the CEC's Comparative Cost of Generation Model (COG).[46] CalWEA supported the use of the COG's fixed and variable O&M and heat rate values and PG&E stated that the COG's fixed O&M and heat rate assumptions seemed reasonable.[47]

Staff determined that the MPR model should update its fixed and variable O&M costs using the CEC's COG report, which is based on a survey of 19 CCGTs built in California, nine of which began operating as recently as 2005 or 2006.[48] See table below for comparison of 2007 and 2008 MPR fixed and variable O&M data sets. The MPR model's heat rate is based on the turbine employed in the proxy CCGT. Because the 2008 MPR model assumes the same turbine used in calculating the 2007 MPR, the 2008 MPR model's heat rate is unchanged. (Refer to 2008 MPR model "CF_Data_Set" and ""Control" tabs.)

MPR Model Data Set	Fixed O&M	Variable O&M
2007 MPR inputs[49]	$13.28/kw-yr	$2.58/Mwh
2008 MPR inputs	$9.70/kw-yr	$4.36/MWh

[46] Comparative Cost of California Central Station Electricity Generation Technologies, December 2007. The report is available at: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF

[47] Respectively, CalWEA, pre-workshop comments, p. 4; PG&E pre-workshop comments, p. 4

[48] Comparative Cost of California Central Station Electricity Generation Technologies, December 2007, Table 11.

[49] These 2007 MPR input values represent the inputs used for calculating the 2007 MPR, escalated to 2008$ for an equivalent comparison to the COG values in 2008$. The 2007 MPR values also reflect a corrected minor error in the 2007 MPR fixed cost data set.

MPR Contract Length

The 2007 MPR model calculated MPR values based on 10, 15 and 20-year contracts. In D.08-10-026, the Commission found that, "because parties have negotiated and presented for approval RPS contracts with extended terms, it is reasonable to allow staff to calculate the MPR so that such contracts can be evaluated consistently with contracts with more standard lengths".[50]

Pursuant to D.08-10-026, Staff revised the MPR model to allow for MPR calculations for a 25-year contract. (Refer to 2008 MPR model, "Control" tab.)

Miscellaneous 2008 MPR Model Updates

- Dry Cooling Cost Inputs
  - Staff updated the 2008 MPR model's dry cooling cost data based on the CEC's most recent COG report. (Refer to 2008 MPR model, "Install_Cap" tab)
- PG&E Gas Delivery Tariff
  - The 2008 MPR model includes PG&E's Backbone transmission tariff rates for delivery from Malin (redwood) and Topock (Baja) as inputs to the MPR model's average gas distribution rate. Including the average of these tariffs increases the 2008 MPR model's average distribution rate by approximately \$0.16/MMBtu. (Refer to 2008 MPR model, "Delivery_Tar" tab, cells D21:D22.)

MPRs are calculated to reflect multiple CCGT online dates

Many renewable projects in California typically take 2 – 5 years to construct and are potentially dependent on major transmission upgrades that will not be completed until 2010 or later. Additionally, recent renewable solicitations have included bids with multiple phase build-outs and options for subsequent projects. Consequently, renewable projects that bid into an RPS solicitation could have commercial online dates as late as 2020. To ensure that there is an appropriate MPR for all of the 2008 RPS projects; Staff has calculated the 2008 MPRs assuming a range of project online dates (2009 – 2020).

[50] D.08-10-026, p. 27.

COMMENTS

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this draft resolution was mailed to parties for comments, and will be placed on the Commission's agenda no earlier than 30 days from today.

FINDINGS

1. The 2008 MPRs were calculated and released consistent with D.08-10-026 and prior Commission decisions.
2. The 2008 MPR values for baseload proxy plants have been finalized for use in the 2008 Renewables Portfolio Standard (RPS) solicitations.

THEREFORE IT IS ORDERED THAT:

1. The 2008 MPRs in Appendix A are approved for use in the 2008 RPS solicitations.
2. This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on December 18, 2008; the following Commissioners voting favorably thereon:

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Paul Clanon
Executive Director

APPENDIX A

Adopted 2007 Market Price Referents (Nominal - dollars/kWh)

Operation Date	Baseload MPR	10 year	15 year	20 year	25 year
2009	MPR All-in	**0.09980**	**0.10509**	**0.11119**	**0.11624**
	MPR fixed component	0.02251	0.02330	0.02401	0.02401
	MPR variable component	0.07729	0.08179	0.08718	0.09223
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.00432	0.00742	0.01006	0.01227
2010	MPR All-in	**0.10103**	**0.10716**	**0.11380**	**0.11905**
	MPR fixed component	0.02297	0.02379	0.02452	0.02452
	MPR variable component	0.07806	0.08337	0.08927	0.09453
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.00575	0.00893	0.01167	0.01386
2011	MPR All-in	**0.10318**	**0.11008**	**0.11716**	**0.12253**
	MPR fixed component	0.02342	0.02426	0.02502	0.02502
	MPR variable component	0.07976	0.08582	0.09214	0.09751
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.00742	0.01065	0.01346	0.01560
2012	MPR All-in	**0.10607**	**0.11362**	**0.12107**	**0.12652**
	MPR fixed component	0.02388	0.02475	0.02553	0.02553
	MPR variable component	0.08220	0.08887	0.09554	0.10099
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.00935	0.01259	0.01543	0.01750
2013	MPR All-in	**0.10949**	**0.11767**	**0.12539**	**0.13088**
	MPR fixed component	0.02435	0.02525	0.02605	0.02605
	MPR variable component	0.08514	0.09242	0.09934	0.10484
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.01144	0.01467	0.01750	0.01949
2014	MPR All-in	**0.11287**	**0.12159**	**0.12950**	**0.13502**
	MPR fixed component	0.02437	0.02528	0.02608	0.02608
	MPR variable component	0.08850	0.09631	0.10341	0.10893
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.01352	0.01677	0.01954	0.02146
2015	MPR All-in	**0.11663**	**0.12580**	**0.13378**	**0.13934**
	MPR fixed component	0.02440	0.02531	0.02612	0.02612
	MPR variable component	0.09223	0.10048	0.10766	0.11323
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.01558	0.01887	0.02155	0.02341
2016	MPR All-in	**0.12061**	**0.13018**	**0.13817**	**0.14377**
	MPR fixed component	0.02443	0.02535	0.02615	0.02615
	MPR variable component	0.09619	0.10483	0.11201	0.11762
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.01753	0.02090	0.02346	0.02526
2017	MPR All-in	**0.12463**	**0.13460**	**0.14259**	**0.14819**
	MPR fixed component	0.02446	0.02538	0.02618	0.02618
	MPR variable component	0.10017	0.10922	0.11641	0.12201
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.01928	0.02274	0.02520	0.02696
2018	MPR All-in	**0.12904**	**0.13927**	**0.14723**	**0.15276**
	MPR fixed component	0.02449	0.02541	0.02621	0.02621
	MPR variable component	0.10455	0.11386	0.12102	0.12655
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.02111	0.02459	0.02696	0.02867
2019	MPR All-in	**0.13381**	**0.14417**	**0.15207**	**0.15744**
	MPR fixed component	0.02453	0.02545	0.02624	0.02624
	MPR variable component	0.10928	0.11872	0.12582	0.13120
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.02301	0.02645	0.02873	0.03038
2020	MPR All-in	**0.13894**	**0.14923**	**0.15710**	**0.16223**
	MPR fixed component	0.02457	0.02549	0.02627	0.02627
	MPR variable component	0.11437	0.12374	0.13083	0.13596
	Capacity Factor	92%	92%	92%	92%
	GHG Adder	0.02500	0.02831	0.03050	0.03208

APPENDIX B
Utility's 2008 Time-of-Delivery (TOD) periods and factors

PG&E[51]

Month	Period	Definition	Factor
June - September	Super-Peak	Hours Ending (HE) 13-20 Monday-Friday (except NERC holidays)	**2.01**
	Shoulder	HE 7-12, 21 and 22 Monday-Friday (except NERC holidays); HE 7-22 Saturday, Sunday and all NERC holidays	**1.14**
	Night	HE 1-6, 23 and 24 all days (including NERC holidays)	**0.72**
October - February	Super-Peak	Defined above	**1.09**
	Shoulder	Defined above	**0.96**
	Night	Defined above	**0.78**
March - May	Super-Peak	Defined above	**1.13**
	Shoulder	Defined above	**0.86**
	Night	Defined above	**0.63**

[51] PG&E 2008 RPS Solicitation, pro forma contract, pp. 30-31. http://www.pge.com/includes/docs/word_xls/b2b/wholesaleelectricsuppliersolicitation/AttachmentGAsAvailableFormPPARev022908.DOC

SCE[52]

Season	Period	Definition	Factor
Summer June - September	On-Peak	WDxH[1], noon-6 pm	**3.13**
	Mid-Peak	WDxH, 8-noon, 6-11 pm	**1.35**
	Off-Peak	All other times	**0.75**
Winter October - May	Mid-Peak	WDxH, 8 am-9 pm	**1.00**
	Off-Peak	WDxH, 6-8 am, 9 pm-midnight; WE/H[2] 6 am-midnight	**0.83**
	Super-Off-Peak	Midnight-6 am	**0.61**

1/ WDxH is defined as weekdays except holidays
2/ WE/H is defined as weekends and holidays

SDG&E[53]

Season	Period	Definition[1]	Factor
Summer July - October	On-Peak	Weekdays 11am-7pm	**1.6411**
	Semi-Peak	Weekdays 6am-11am; Weekdays 7pm-10pm	**1.0400**
	Off-Peak	All other hours	**0.8833**
Winter November - June	On -Peak	Weekdays 1pm-9pm	**1.1916**
	Semi -Peak	Weekdays 6am-1pm; Weekdays 9pm-10pm	**1.0790**
	Off-Peak	All other hours	**0.7928**

1/ All hours during National Electric Reliability Council (NERC) holidays are Off-Peak.

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52 SCE 2008 RPS Solicitation, pro forma contract, Exhibit K, p. 2.
http://www.sce.com/nrc/rfp/2008_RPS_Appendix_B_ProForma_Agreement.doc

53 SDG&E 2008 RPS Solicitation, pro forma contract, p. 39.
http://www.sdge.com/documents/rfo/renewablerfo2008/ModelPPA.doc

APPENDIX C
2008 MPR California and Henry Hub Gas Forecast (2009 – 2045)

Year	2008 MPR Henry Hub Forecast (nominal$)	MPR CA Gas Forecast (nominal$)
2009	$10.47	$10.60
2010	$9.69	$9.97
2011	$9.40	$9.68
2012	$9.25	$9.54
2013	$9.14	$9.44
2014	$9.12	$9.43
2015	$9.19	$9.50
2016	$9.27	$9.60
2017	$9.39	$9.73
2018	$9.55	$9.90
2019	$9.72	$10.08
2020	$9.88	$10.25
2021	$10.10	$10.63
2022	$10.46	$10.97
2023	$10.98	$11.49
2024	$11.60	$12.10
2025	$12.13	$12.64
2026	$12.49	$13.00
2027	$13.05	$13.57
2028	$13.57	$14.09
2029	$14.05	$14.57
2030	$14.56	$15.09
2031	$15.05	$15.60
2032	$15.55	$16.11
2033	$16.05	$16.63
2034	$16.29	$16.88
2035	$16.78	$17.40
2036	$17.28	$17.92
2037	$17.78	$18.43
2038	$18.27	$18.95
2039	$18.77	$19.47
2040	$19.27	$19.98
2041	$19.76	$20.50
2042	$20.26	$21.02
2043	$20.76	$21.54
2044	$21.25	$22.06
2045	$21.75	$22.58

APPENDIX D
2008 MPR Gas Forecast Inputs

Row No.	Input Category	Input	Units	Baseload Inputs	Notes
1	Henry Hub Forecasts /1	CERA, PIRA, or Global Insight /2	$/MMBtu	N/A	20 yr. Henry Hub forecast (private - purchased)
2	General Inputs	Transaction Cost	$/MMBtu	$0.082	D.04-06-015, pg. 26, reafirmed in D.05-12-042 (pg. A-7)
3		Transportation Escalation Rate	Percent-%	1.99%	Average of EIA 2008 GDP Chain-Type Price Index. See 2008 MPR model - Delivery_Tar Tab (Cell E9)
4		20-year WACC	Percent-%	8.51%	2008 MPR model - Cost Cap Tab (Cell D9)
5	Municipal Surcharge	SoCal Muni Surcharge	Percent-%	1.462%	Schedule G-MSUR - http://www.socalgas.com/regulatory/tariffs/tm2/pdf/G-MSUR.pdf
6		PG&E Muni Surcharge	Percent-%	0.950%	PG&E Rate Schedule GC-P: (1) http://www.pge.com/rates/tariffs/GCP_Current.xls and (2) http://www.pge.com/rates/tariffs/GSUR_Current.xls
7	PG&E Gas Distrib. Rate	Customer Access Charge	$/day	$182	http://www.pge.com/tariffs/pdf/G-EG.pdf
8		Proxy Plant Capacity	MW	500	2008 MPR model - Delivery_Tar Tab (Cell E15)
9		Heat Rate	MMBtu/MWh	6.88	2008 MPR model - Delivery_Tar Tab (Cell E16)
10		Capacity Factor	percent-%	92%	2008 MPR model - Delivery_Tar Tab (Cell E17)
11		Monthly Gas Consumption	MMBtu	75,750	(Row 8 * Row 9* Row 10) * 24 hours
12		Unit Cost of Customer Access Charge	$/MMBtu	$0.0024	Row 7 / Row 11
13		Transportation Charge	$/MMBtu	$0.1827	http://www.pge.com/tariffs/pdf/G-EG.pdf
14	SoCal Gas Distrib. Rate	Customer Charge	$/month	$0.00000	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
15		Transmission Charge	$/MMBtu	$0.2936	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
16		Interstate Transportation Cost Surcharge	$/MMBtu	$0.0005	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf

1/ The Henry Hub forecasts are inputs for the MPR - Henry Hub forecast - there are no specific baseload values.
2/ Due to contractual obligations requiring the CPUC to keep the forecast confidential, staff can not reveal which of the three firms the forecast was purchased from.

APPENDIX E
2007 MPR Non-Gas Inputs

Row No.	Input Category	Input	Units	Baseload Inputs	Escal. Rates/yr.	Notes
1	Capital Inputs	Total capital cost January 1 - 1st operational yr.	$/kw	$1,182	2.15%	Per D.05-12-042, Staff conducted a survey of actual plant costs in CA. Four plants were selected and an average was calculated
2		Fixed O&M	($/kW-yr) 1st operational yr.	$9.70	1.99%	CEC Cost of Generation Report CEC-200-2007-001-SF Table 6, p. 18. Escalated from $2007 to $2009 using EIA GDP Chain-type Price Index.
3		Variable O&M	(mills/kWh) 1st operational yr.	$4.35	1.99%	CEC Cost of Generation Report CEC-200-2007-001-SF Table 6, p. 18. Escalated from $2007 to $2009 using EIA GDP Chain-type Price Index.
4		New & Clean heat rate	Btu/kWh HHV	6704	n.a.	Per D.05-12-042, Staff used the the "new & clean" heat rate for an F-Series (GE S207FA) CC Turbine, adjusted for Higher Heating Value
5		Heat rate degradation factor	Percent-%	1.74%	n.a.	Per D.05-12-042, Staff contacted GE for an appropriate heat rate degradation factor for an F-series CC turbine. GE provide a degradtion curve that calculated the average degradation over the life of the project.
6		Average heat rate	Btu/kWh HHV	6924	n.a.	Average heat rate over life of plant, taking into account the impact of Higher Heating Value, degradation, dry cooling, and starts/stops
7	Finance Inputs	20-year WACC	Percent-%	8.51%	n.a.	Weight-Average Cost of Capital = (Cost of Equity x Equity %) + (Cost of Debt x (1-tax rate) x Debt %)
8		Cost of LT Debt	Percent-%	7.84%	n.a.	Per D.05-12-042, Cost of Debt (industrial firms) = risk free rate (20 year T-Bill) + risk premium (mid point between BBB & B+). http://www.bondsonline.com, May 13, 2008
9		Cost of Equity	Percent-%	12.38%	2.00%	Per D.05-12-042, Cost of Equity = risk free rate (20-yr Tbill) + risk premium (equity) + mid-cap risk premium (equity). http://www.bondsonline.com, May 13, 2008
10		Debt as % of total cost	Percent-%	50%	n.a.	Per D.05-12-042, LT debt ratio for BBB rated company
11		Debt Term	Years	20	n.a.	Adopted in D.04-06-015 and reaffirmed in D.05-12-042
12		Insurance as % of plant cost	Percent-%	0.60%	1.99%	Same value used for 2004 MPR. Energy Division contacted insurance brokers for quotes and calculated an average value.
13	Power Delivery Inputs	Transformer Loss Factor	Percent-%	0.50%	n.a.	Loss factor recommended by parties and used in 2004 MPR calculation
14		Generation Meter Multiplier (GMM) to load center	Percent-%	98.5%	n.a.	Not Used. Pursuant to D. 08-10-026, the MPR Model assumes delivery at the busbar
15		Capacity Factor	Percent-%	92%	n.a.	Per D.08-10-026
16	Tax Rate Inputs	Federal Tax Rate	Percent-%	35%	n.a.	Tax rate proposed by the parties and used in the 2004 MPR calculation
17		State Tax Rate	Percent-%	8.84%	n.a.	Tax rate proposed by the parties and used in the 2004 MPR calculation
18		Total Effective Tax Rate	Percent-%	40.75%	n.a.	Effective Tax = Federal Tax * (1 - State Tax) + State Tax
19		Property taxes as % of plant cost	Percent-%	1.20%	n.a.	Same value used for 2004 MPR. Energy Division averaged the property tax rates for 14 counties in which power plants were constructed (or under construction) in the last 5 years.
20	Gas Forecast	20yr gas forecast - 2009 levelized	$/MMBtu	$10.42	n.a.	Output from CA_Gas_Forecast Tab (Cell N42) in 2008 MPR model
21	GHG	GHG Compliance Cost	$/Ton	$15.00	n.a.	($15 in 2013). Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning. Synapse Energy Economics. March 2, 2007. Updated July 2008, Synapse 2008 CO2 Price Forecast (in $2007). (Table 2, p. 16) http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf