PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

I.D. # 6199

ENERGY DIVISION **RESOLUTION E - 4049**

December 14, 2006

R E S O L U T I O N

This Resolution formally adopts the 2006 Market Price Referent (MPR) values for a baseload proxy plant for the use in the 2006 Renewable Portfolio Standard (RPS) solicitations. This Resolution is made on the Commission's own motion.

SUMMARY

2006 MPR values have been calculated for use in the 2006 Renewables Portfolio Standard (RPS) solicitations.

This Resolution formally adopts the 2006 MPR values for a baseload proxy plant for the use in the 2006 RPS solicitations. This Resolution is made on the Commission's own motion.

Adopted 2006 Market Price Referents
(Nominal - cents/kWh)

Resource Type	10-Year	15-Year	20-Year
2007 Baseload MPR	0.08046	0.08176	0.08424
2008 Baseload MPR	0.07979	0.08195	0.08482
2009 Baseload MPR	0.07925	0.08223	0.08548
2010 Baseload MPR	0.07929	0.08295	0.08652
2011 Baseload MPR	0.07890	0.08307	0.08688
2012 Baseload MPR	0.07961	0.08420	0.08820
2013 Baseload MPR	0.08072	0.08566	0.08981
2014 Baseload MPR	0.08229	0.08746	0.09167
2015 Baseload MPR	0.08435	0.08964	0.09468

Note: Using 2007 as the base year, Staff calculates MPRs for 2008 – 2015 that reflect different project on-line date

BACKGROUND

Release of 2006 MPRs is consistent with prior Commission decisions

In D.04-06-015[1], we adopted a methodology to calculate MPRs for use in the 2004 renewable power solicitations, as generally set forth in Pub. Util. Code §§ 399.11-399.16.[2] In addition, D.04-06-015 directed staff to prepare the MPR calculation and release it through a joint Assigned Commissioner and Administrative Law Judge (ALJ) ruling. Parties filed comments and reply comments on the staff report releasing the MPR calculation. Staff then prepared a resolution for the adoption of the final MPR for 2004.[3]

D.05-12-042[4] adopted a more robust and transparent methodology to calculate 2005 MPR, and determined that a simpler process may be used to calculate and adopt annual MPRs going forward. Specifically, D.05-12-042[5] directed staff 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 been closed. Parties will have the usual opportunity to file comments and reply comments on the draft resolution prior to its formal consideration by the Commission. [6]

The three IOUs submitted their letters to the Executive Director notifying the Commission that their solicitations were closed and the preliminary short-lists were complete:

- Pacific Gas & Electric (PG&E) – September 11, 2005[7]
- Southern California Electric (SCE) – September 22, 2006[8]
- San Diego Gas & Electric (SDG&E) – September 1, 2006 [9]

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[1] http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/37383.DOC

[2] An act to add Sections 387, 390.1, and 399.25 to, and to add Article 16 (Sections 399.11 - 399.16) to Chapter 2.3 of Part 1 of Division 1 of, the Public Utilities Code, relating to renewable energy.

[3] http://www.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/48242.doc

[4] http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/52178.DOC

[5] Modified by D.06-01-029 (OP #5, pg. 3)

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

[7] On 9/19/06, PG&E notified the CPUC Executive Director by letter that its 2006 RPS solicitation had closed

[8] On 11/13/06, SCE notified the CPUC Executive Director by letter that its 2006 RPS solicitation had closed

[9]On 9/18/06, SDG&E notified the CPUC Executive Director by letter that its 2006 RPS solicitation had closed.

DISCUSSION

MPRs Were Calculated Using a Cash-Flow Simulation Methodology

The MPRs shown above were calculated using the Southern California Edison MPR model, a cash-flow simulation methodology approved by the Commission in D.04-05-015 and modified by Resolution E – 3942[10], D.05-12-042, and Resolution E-3980.[11] The MPR model calculates what it would cost to own and operate a power plant over a 10, 15, and 20-year period. The cost of electricity generated by such a power plant, at an assumed capacity factor and set of costs, is the proxy for the long-term market price of electricity.

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 the baseload MPRs.

MPR Based on Combined Cycle Gas Turbine (CCGT) Proxy

In 2004 Staff calculated an MPR for a CCGT (baseload) and CT (peaker) proxy plant. In their 2005 MPR comments, PG&E and several other parties recommend that an MPR based on a peaking proxy unit not be adopted for use in 2005. Rather, the MPR for peak period energy should be established by applying factors derived through the Time of Delivery (TOD) methodology to the baseload MPR. The application of TOD factors to the baseload MPR would eliminate the combustion turbine (CT) - based peaking MPR and the "blended" off-peak MPR (adopted in D.04-07-029).

PG&E noted that its proposal did not conflict with the statutory direction to establish a methodology to determine the MPR in consideration of "the value of different products including baseload, peaking, and as-available output."[12] TOD factors are based on the forward value of electricity during different TOD periods. Output from baseload, peaking, and as-available units may be time-differentiated by these periods, so the application of TOD factors to the MPR will result in a market price for each product and electric generating unit. Thus, it was not necessary to separately adopt an MPR based on the cost of an electric generating unit operated only during periods of peak demand.

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[10] http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/48242.DOC
[11] http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/55465.DOC
[12] Section 399.15(c)(3).

D.05-12-042 agreed with PG&E that the application of TOD factors to the baseload MPR did take into account "the value of different products including baseload, peaking, and as-available output." Nothing in the statute requires the Commission to use multiple plant proxies in order to do so. Thus, D.05-12-042 ordered Staff to no longer calculate a CT-specific MPR based on the cost of an electric generating unit operated only during periods of peak demand.

MPRs 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. Consequently, renewable projects bid into an RPS solicitation could have a commercial online date as late as 2015. D.05-12-042[13] orders Staff to calculate nominal MPRs that reflect different project online dates by escalating the non-gas inputs using an inflation index.[14] The Decision also orders Staff to assume that capital costs for the proxy plant should be escalated until 2010 and then held constant to reflect the fact that increased efficiencies will offset incremental capital costs.[15] To ensure that there is an appropriate MPR for all of the 2006 RPS projects; Staff has calculated the 2006 MPRs assuming a range of project online dates (2007 – 2015). See CF_Data Set Tab in the 2006 MPR model for the specific calculation.

MPR Gas Forecast Methodology and Inputs

D.04-06-015 noted that there is no transparent, liquid market for natural gas forward products for 10, 15 or 20-year terms, which is necessary in order to fuel a proxy power plant producing fixed-priced electricity over these time periods. Consequently, D.04-06-015 outlined a California gas forecasting methodology for years 1 through 6, and another methodology for years 7 through 20, both of which are based on the forward Henry Hub (HHub) gas price that is basis adjusted to California.[16]

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[13] D.05-12-042, pg. 44

[14] Installed capital costs were escalated using the US Army Corp of Engineers Escalation Index (CWBS Feature Code 07 - Updated Sept 30, 2006). Insurance, FOM, and VOM were escalated using the EIA 2006 GDP Chain-Type Price Index.

[15] D.05-12-042, pg. 55 (FoF #30)

[16] "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/).

D.05-12-042, modified by D.06-01-029, refined the methodology for years 1- 5 by changing the 60-day-averaging period for the NYMEX forward prices to a 22-trading day averaging period, ending with the close of the utilities' solicitations.[17] For years 6 – 20, D.05-12-042 noted that parties criticized the methodology used in 2004 as not yielding consistent and explainable results using data from a variety of time periods and market conditions. Most notably, the gas prices for Years 7-20 were heavily (possibly too heavily) influenced by the forward gas price in the last year of NYMEX data used in the 2004 MPR forecast.

Consequently, D.05-12-042 adjusted the relationship between the end of NYMEX data (no later than Year 6, and possibly Year 5, see D.04-06-015) and the beginning of reliance on the fundamentals forecasts in Year 6 to address the problems with the forecast in 2004. D.05-12-042 determined that, instead of using the escalation forecasting methodology of the 2004 MPR for Years 6-20, Staff should use a three-year straight line blending between the near-term (Years 1-5) and the long-term (Years 6-20), and then use the average of the fundamental forecasts for the remaining years. This method retains the absolute value of the fundamentals-based gas price forecasts and eliminates the escalation process for Years 6-20 that we used in 2004, which was the subject of criticism from the parties.

The fundamental forecast for years 6 – 20 was developed using two private and one public 20-year Henry Hub fundamental forecasts[18]. Specifically, the public forecast was based on the HHub wellhead prices provide in the U.S. Energy Information Administration (EIA) 2006 Annual Outlook[19]. With regard to the two private forecasts, they are a private sector natural gas forecasts from Cambridge Energy Research Associates (CERA), PIRA Energy Group, or Global Insight. Due to contractual obligations requiring the CPUC to keep the forecast confidential, staff can not reveal which of the three firms the forecasts were purchased from.

It should be noted that the EIA HHub forecast is derived by manipulating the EIA's forecasted wellhead prices. Specifically, EIA examined the relationship between Henry Hub spot prices for natural gas and the U.S. wellhead price for

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[17] SCE's 2006 RPS solicitation closed on 9/22/06, - after the SCE and PG&E 2005 RPS solicitations. Consequently, Staff used 9/22/06 as the last day in the 22-trading day averaging period.

[18] In 2004, 3 public forecasts and 1 private forecast were used, e.g., timely forecasts produced by CERA, PIRA, Global Insight, EIA, and the CEC.

[19] http://www.eia.doe.gov/oiaf/aeo/excel/aeotab_19.xls

the period spanning August 1996 through December 2000[20]. Their analysis determined the extent to which the two price series are linearly correlated and also evaluated the statistical properties of two simple price relationships—the actual difference and the percent difference. The results of the analysis indicated that there was a strong linear relationship between the two price series, to the effect that, on average the Henry Hub spot prices were 32 cents per thousand cubic feet (10.8 percent) higher than wellhead prices. The median value of the actual difference is 24 cents per thousand cubic feet, and the median value of the percent difference is 10.4 percent. Consequently, staff escalated the EIA wellhead prices by 10.8% to derive a proxy HHub forecast.

Please refer to:

- Appendix B for the 2006 California and Henry Hub gas forecasts (2007 – 2034)
- Appendix D for specific inputs used in the 2006 gas forecast

MPR Non-Gas Methodology and Inputs

<u>Cost of Capital</u>

1. Debt/Equity Ratio

D.05-12-042 noted that the proxy plant should be financed not as a stand-alone project, but on a total balance sheet basis. Most developers either are large corporate entities, or have more than one generation project; few if any have only one CCGT with one long-term PPA (the one being used as the proxy plant) in their portfolios. Therefore, D.05-12-042 adopted the debt/equity profile of a proxy plant with a more conservative financing structure of 50%/50%.[21]

2. Cost of Capital

D.05-12-042 stated that a long-term PPA with a credit-worthy utility allows the generator to transfer almost all market and regulatory risk to the utility purchasing the power. The generator's risk would therefore closely approximate that of the utility. Therefore, the risk profile of the proxy plant should fall somewhere between that of a merchant generator (selling into the

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[20] U.S. Natural Gas Markets: Relationship Between Henry Hub Spot Prices - EIA Analysis (http://www.eia.doe.gov/oiaf/analysispaper/henryhub/index.html)

[21] While a developer could use the 20-year PPA and the strength of its balance sheet to increase the leverage in financing a particular project, the consensus of the parties is that the developer would use those characteristics to reduce the proportion of debt in project financing.

market without a long-term contract) and a utility. So, having concluded that a capital structure similar to that of a utility is appropriate, but a risk profile the same as that of a utility is not, D.05-12-042 adopted a methodology that uses the cost of capital of industrial companies in the Standard and Poor's 500 index (S&P 500) with risk profiles that are comparable to that of the independent power generation industry as a whole.

See Cost_Cap Tab in the 2006 MPR model for a detailed calculation of the 2006 WACC.

Heat Rate Adjustments

D.05-12-042 instructed staff to gather information from the manufacturer about the General Electric (GE) "F" series turbine, as well as information about the operation of California power plants, to determine how to adjust the MPR heat rate to reflect heat rate degradation, dry cooling, and start/stops. Staff selected the S207FA F-Series Turbine[22] from GE as the starting point for determining the operating heat rate. Lastly, 2005 MPR model used an incorrect new and clean heat rate for the combined cycle. The 2005 MPR model used a 6,375 Btu/kWh (LHV) for the new and clean heat of a S207FA CC, the designated CC unit according to MPR Resolution E-3980. However, this value is in the wrong units (kJ/kWhr). The correct value should be 6,040 Btu/kWhr. See Heat_Rate Tab (cell F4) in the 2006 MPR model.

For the 2004 MPR, the Commission adopted a 3.5% heat rate degradation factor recommended by the parties. In its 2005 MPR comments, SCE recommended that Staff contact the manufacturer for a specific heat rate degradation factor. Using a heat rate degradation equation provided by GE, [23] Staff calculated the average heat rate degradation per hour of plant operation and adjusted the heat rate appropriately. Note – the average heat rate degradation factor, over the life of the plant, is 1.7%. This value assumes normal maintenance and off-line compressor water wash of the CC turbine and a major overhaul is conducted every 6 years (45-48,000 hrs), which brings the CC back to almost "new & clean".

Dry cooling is the second heat rate adjustment that D.05-12-042 required Staff to research and calculate. In its 2005 MPR comments (pg.6), CalWEA stated:

> The assumed heat rate must reflect the efficiency of dry-cooled plants. D. 04-06-015 found that the baseload MPR should be calculated using the costs of a dry-cooled CCGT.[4] For example, Calpine's dry-cooled Sutter and

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[22]http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger3574g.pdf
[23] See GE Tech. Notice - 101HA1567

Otay Mesa plants are expected to have heat rates that are about 200 Btu/kWh higher than comparable wet-cooled plants.

Given that the majority of CA's plants are being built inland, i.e., not desert or coastal locations, Staff made a simplifying assumption that the 1.5%[24] increase in heat rate for Sutter is an appropriate value use for the 2005 MPR. The adoption of this value is supported by the rule-of-thumb adjustment (1.5%) recommended by GE for F-series turbines with dry cooling.[25] Staff has used the same dry cooling adjustment for the 2006 MPR.

Lastly, with regards to the Start/Stop impact on heat rate, parties noted that using a capacity factor lower than 92% will have an impact on the achieved heat rate, because the proxy plant will have less efficient operation when starting and stopping more frequently. Other parties agreed that the lower capacity factor could affect heat rate. Because we did not have quantitative information about the effect of lower capacity factor on heat rate, D.05-12-042 instructed Staff to collect information about the impact of a lower capacity factor on heat rate, and include such information, if relevant, in the staff calculation and supporting materials for the 2005 MPR draft resolution.

Staff contacted GE for a recommendation and was informed that without doing production cost modeling, 100 – 150 starts/year was an appropriate proxy value to use. This value assumes a must-run plant with a capacity factor between 85% - 92% capacity factor. Consequently, Staff selected 125 as a mid-point. For start-up fuel cost (MMBtu/MW), Staff used a value of 2.8 MMBtu/MW, which is based on CEC production cost modeling data (8/31/05). Staff has used the methodology and values for the 2006 MPR. See Heat_Rate Tab in the 2006 MPR model for the specific calculation.

<u>Capacity Factor</u>

D.05-12-042 agreed with the IOUs that a developer with a fixed-price must-run contract, *paid a levelized price*, would find it economic to run in all hours, operate at full load in all hours, and can recover its fixed costs at a price that assumes the maximum feasible amount of generation, i.e., capacity factor of 92%. However, D.05-12-042 points out that the introduction of Time of Delivery (TOD) profiles provide the generators with a market pricing signal. The generator is now paid a different $/kWh/TOD period depending on when it generates. The end result is

[24] See the CEC's Final Certification Decision for the Sutter Power Project, Docket No.97-AFC-2, at 269

[25] http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger4200.pdf

that the generator will not operate in hours where its marginal costs are greater than its marginal profits, which will be something below 92% of the time.

Consequently, D.05-12-042 ordered Staff to calculate the capacity factor for the MPR CCGT by computing a capacity factor based on each utility's TOD profile and then averaging the three MPR capacity factors to arrive at a statewide average capacity factor to be used in the final MPR calculation. This approach embraces the "market behavior" approach because we would be modeling what the owner of a new CCGT would do if it contracted with a California IOU.

The TOD capacity factor calculation developed by Staff determines the periods in which the TOD factor results in an MPR that is below the plant's variable operating costs. When operating revenues for a TOD period are below both the variable operating costs and start up costs, it is assumed that the plant will shut down for all the hours in that period. The variable operating costs are assumed to be the levelized MPR variable component calculated by the MPR model. Start-up costs are based on a fuel use of 2.8 MMBtu/MW or roughly $10,000 depending on the levelized price of natural gas over the MPR contract period.

The calculation starts with an assumed technical capacity factor of approximately 92%: in this case the fixed costs for the referent plant are allocated over 92% of the year, or 8,087 hours. The calculation then estimates the number of hours the plant will shut down for economic reasons and calculates the resulting capacity factor, which may be lower, but not higher, than the technical capacity factor. If the capacity factor is lower, the fixed costs will be allocated over fewer hours (i.e. 88% or 7,735 hours). Thus, the lower capacity factor results in a higher MPR. The higher MPR in turn may reduce the number of hours that the plant shuts down, resulting in a higher capacity factor. Therefore, it is necessary to run the calculation iteratively until the result becomes stable or alternates between a higher and lower capacity factor. In the later case, the final result is the average of the high and low capacity factor. The MPR Cash Flow Model is designed to iterate the calculation five times.

Calculating an economic capacity factor using TOD's is, by definition, a non-continuous or 'step' function. A plant is assumed to be on or off for all hours in a given TOD period (The off-peak periods with the lowest TOD factors total between 736-2,032 hours, or 8-23% of the year). In addition, the TOD's for off-peak periods may result in MPR's that are very close to the variable operating costs. Both these factors result in a capacity factor calculation that may be very sensitive to a change in the fixed cost, start up cost and TOD factor inputs. Staff has used the same methodology for the 2006 MPR. See the Cap_Fac Tab in the 2006 MPR model for the specific calculation

<u>Baseload Capital Costs</u>

D.05-12-042 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. [26] D.05-12-042 also adopted additional criteria for conducting a market survey of plant costs. 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

Staff identified the installed capital costs for the 2006 MPR CCGT proxy using the reported capital costs ($ per kW) of comparable CCGT plants. To find comparable plants, Staff started with the list of existing and planned CCGT plants within the Western Electricity Coordinating Council (WECC) found on the CEC's "Energy Facility Status" website.[27] Using the survey criteria outlined above, Staff identified the following plants that had publicly available cost data:

- Palomar (SDG&E)
- Cosumnes (SMUD)

Based on the plants listed above the average installed capital cost, reflecting interconnection costs, environmental permitting costs (aside from emissions), additional capital costs for dry cooling, and contingency costs is $964/kW (2007$). Please refer to Appendix C for a detailed discussion regarding how the installed capital cost for the 2006 MPR was derived.

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[26] The Energy Commission's cost of generation report is produced roughly biannually. The August 2003 Comparative Cost of California Central Station Electricity Generation Technologies report, www.energy.ca.gov/reports/2003-08-08_100-03-001.PDF, is the most recent. This report was prepared in support of the Energy Commission's 2003 Integrated Energy Policy Report (IEPR) Subsidiary Volume: Electricity and Natural Gas Assessment Report (www.energy.ca.gov/2003_energypolicy/index.html).

The Energy Commission does not plan to adopt its new cost of generation report in time for the 2006 MPR calculation. Analysis relevant to the 2006 MPR may, however, be available at a staff level. D.05-12-042 directs staff to confer with Energy Commission staff to determine what information and analysis related to the cost of generation may be available for use in the 2006 MPR.

[27] http://www.energy.ca.gov/sitingcases/all_projects.html

Fixed and Variable O&M Costs

For the 2005 MPR, Staff used the SCE Benchmark Study of Operation and Maintenance (O&M) values, sponsored by SCE witness Joe Wharton before the FERC on behalf of Edison in the Mountainview case, with some modifications:

- Removed EOB and Mountainview from the Wharton O&M data set
- Added Contra Costa 8 and Palomar
- Updated the EIA value using EIA's 2006 Annual Energy Outlook Report[28]

Staff has used the same values for the 2006 MPR by escalating the 2005 MPR O&M costs to 2007$.

Data Source	**Fixed O&M (2007$)**	**Variable O&M (2007$)**
Palomar	14.08	3.24
CC8	15.20	1.87
2006 EIA	11.20	3.29
Henwood	10.59	2.12
CERA	16.29	1.09
CEC	16.29	2.58
Stone & Webster	N/A	3.06
Average	$13.94	$2.46

Additional Modifications to 2006 MPR Calculation

Correction of Tax Expense Factors

The tax depreciation approach proposed by the parties and adopted by the Commission for the 2004 and 2005 MPR incorrectly calculates state income tax depreciation expenses. Prior MPR calculations assumed that the tax life of a new CCGT under California law was 30 years. The MPR cash flow model incorrectly placed all the depreciation for years 20-30 in the 20th year of the MPR calculation. This resulted in depreciation factor of 24% in the 20th year.

Under California tax law, a CCGT owned by a partnership (as opposed to a corporation), may be depreciated over 20 years for both federal and California income tax purposes by using federal MACRS depreciation expense factors.[29]

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[28] http://www.eia.doe.gov/oiaf/archive/aeo05/assumption/pdf/0554(2005).pdf

[29] R&T Code Section 17250 provides the authority for partnerships being allowed to utilize the IRC Section 168 MACRS method of depreciation. Corporate partners receiving its distributive share of partnership income from partnerships utilizing the MACRS method, are not required

Prior Commission decisions did not specify the ownership structure of the proxy plant to be used for purposes of calculating the MPR. A 20 year state tax life includes nearly all the depreciation of the CCGT within the term of analysis and is consistent with the federal depreciation schedule. Therefore, the 2006 MPR, assumes ownership by a partnership and a 20 state tax life.

The 20 year MACRS schedule used for both federal and state depreciation assumes that an asset is placed in service in the middle of the first year; depreciation expenses are deducted over 21 years including the last half of the first year, and the first half of the 21st year. The 2005 MPR incorrectly combines the depreciation expense for both the 20th and the first half of the 21st year in the 20th year of the MPR analysis. This error is corrected in the 2006 MPR - see Fixed_Comp tab cell V33 in MPR model.

Tax Calculation Updated to Reflect Tax Law Changes

SCE and PG&E noted in their comments on the 2005 MPR draft resolution that the MPR tax calculation needed to be updated to take into account recent changes to current tax law. Specifically, the 2005 MPR model calculates federal net taxable income and then applies a federal tax rate of 35%. SCE and PG&E recommended that the MPR model be modified to account for Section 102 of the American Jobs Creation Act of 2004, which contains a tax deduction for manufacturing activities ("TDMA").[30] The TDMA provides a deduction for income from the sale of electricity produced by a generator. The deduction amounts to 3% for 2005-2006, 6% for 2007-2009, and 9% from 2010 forward.[31] In response to their comments, Staff stated in the final 2005 MPR resolution that the suggested tax changes were outside the scope of the 2005 MPR calculation and would be addressed in future MPR calculations.

Staff has adopted the proposed tax changes for the 2006 MPR. Pursuant to TDMA, the 2006 MPR model now takes into account the fact that the resulting deduction may not exceed the lesser of:

(1) the taxable income derived in that year from generating and selling electricity, or

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to recompute their distributive share of partnership income to account for the depreciation difference between MACRS and those methods allowed for corporations. *California Franchise Tax Board Notice 89-528, 10/18/1989*.

[31] IRC §199 and Federal Regulation §1.199-1.

(2) 50% of the W-2 wages in that year of the employees that were engaged in those activities.

The CEC's "Comparative Cost of California Central Station Electricity Generation Technologies"[32] report, presents the payroll for the 25 employees of a new 500 MW CCGT in Table C-8. For the 2006 MPR the wages were updated using 2004 Bureau of Labor Statistics (BLS) data.[33] The number of hours worked were increased to include vacation and holidays in order to match the wage data provided by the BLS. Inflating the wages to 2006 dollars results in total first year wages of $1.9 million. These wages are inflated each year at the same rate as O&M expenses in the MPR model. Per the tax rules cited above, the TDMA deduction is limited to 50% of the wages calculated using the CEC and BLS data. See "CF_Inputs" tab starting at cell B30 and "Fixed_Comp" tab row 53 in MPR model.

Use Economic Carrying Charge for the Fixed MPR

The 2005 MPR model assumed that the levelized fixed costs associated with a 20-year PPA with a CCGT was also the fixed cost for both a 10 and 15- year PPA. This methodology likely overstated the fixed cost component of the MPR for contracts with 10 and 15 year terms. For a cost stream that increases over time a levelized price tends to be higher than the actual costs in the early years and lower in later years. Thus, using the MPR levelized over a 20 year term for 10 and 15 year contracts overstated the fixed cost component. Instead the calculation to levelize the fixed costs for the 10, 15 and 20 year contract terms should have been performed individually.

The 2006 MPR uses an "economic carrying charge" method to properly calculate levelized fixed costs for each contract term.[34] Economic carrying charges are the inflation-adjusted annual costs that result in same present value as the fixed costs of the hypothetical CCGT plant over the period of analysis.[35] The economic carrying charges may then be accurately levelized over the 10, 15 and 20 year

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32 http://www.energy.ca.gov/reports/2003-08-08_100-03-001.PDF

33 BLS, November 2004 National Industry-Specific Occupational Employment and Wage Estimates NAICS 221100 - Electric Power Generation, Transmission and Distribution, http://www.bls.gov/oes/current/naics4_221100.htm,

34 The economic carrying charge method is used in the Energy and Environmental Economics (E3) Avoided Cost Methodology adopted in D.05-04-024 of the Avoided Cost Proceeding. http://www.ethree.com/cpuc_avoidedcosts.html

35 The nominal dollar-denominated economic carrying charges for the fixed costs of the hypothetical CCGT is equivalent to a stream of payments from an inflation-indexed annuity that has the same present value as that CCGT's fixed costs.

contract terms respectively. The net effect is a lower levelized fixed cost component for the 10 and 15 year MPR calculations as compared to the 2005 methodology. See "Fixed_Comp" tab rows 63-65 in MPR model.

<u>Including Gross Margins in Computation of Taxable Income</u>

The 2005 MPR model computed the revenues that the MPR proxy plant would need to cover its variable costs. However, it did so by ensuring that the present value of the stream of annual revenues would be equal to the present value of the stream of its annual variable costs. As a result, in certain years those revenues exceeded variable costs, while in others the variable costs exceeded annual revenues. The 2005 MPR model did not include these annual gross profits or losses (i.e., revenues minus variable costs) in computing annual taxable income. Furthermore, the 2005 MPR model derived the revenues that the MPR plant would need to cover its fixed costs based on the plant's levelized fixed cost/kWh, which was the same in every year.

The model then calculates annual taxable income by subtracting annual tax depreciation expenses[36] and interest expenses from the operating income resulting from the difference between those annual revenues and the plant's annual fixed costs. It then derived income tax expenses by multiplying the applicable federal and state income rates to taxable income for federal and state tax purposes.

Although the 2005 MPR methodology did not account for annual variations in taxable income, this did not have a significant impact on the net present value of tax expenses over the term of analysis. However, this is no longer the case due to the changes described above to incorporate the TDMA tax deduction and economic carrying charge methodology.

Specifically, the annual revenues computed by the 2006 MPR model are now derived by escalating the economic carrying charge for those costs at the rate of inflation, rather being based on a levelized fixed cost. As a result, the annual taxable income for a specific year is different than the annual taxable income the 2005 MPR model would have computed for that year. In addition, because a different TDMA percentage is used to compute the tax deduction for different

[36] The model deducted state tax depreciation and interest expenses to compute taxable income for state income tax purposes. The model deducted federal income tax depreciation expenses, state income tax expense, and interest expenses in computing taxable income for federal income tax purposes.

years, the present value of the resulting deductions will be different than the tax deduction calculated by the 2005 MPR model.

The 2006 MPR model addresses the issue of fluxuating net income by including the annual gross profit or loss from the variable cost calculations in the calculation of annual taxable income on the fixed cost worksheet. See Fixed_Comp tab(Row 11) in MPR model.

COMMENTS

Public Utilities Code section 311(g) (1) requires that draft resolutions 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) (3) provides that this 30-day period may be reduced or waived pursuant to Commission adopted rule.

The 30-day comment period for this resolution has been reduced in accordance with the provisions of Rule 77.7(f) (9). Rule 77.7(f) (9) provides that the Commission may waive or reduce the comment period for a decision when the Commission determines that public necessity requires reduction or waiver of the 30-day period for public review and comment. For purposes of Rule 77.7(f) (9), "public necessity" refers to circumstances in which the public interest in the Commission's adopting a decision before expiration of the 30-day review and comment period clearly outweighs the public interest in having the full 30-day period for review and comment, and includes circumstances where failure to adopt a decision before expiration of the 30-day review and comment period would cause significant harm to public health or welfare.

The public necessity in this case is that the Commission needs to evaluate the 2006 RPS solicitation results at the earliest possible opportunity to ensure that RPS program moves successfully towards the 20% by 2010 goal. However, pursuant to SB 1078, Commission staff is not allowed to see the results of the 2006 RPS solicitation until the Commission has formally adopted the 2006 MPR. Shortening the comment period for the 2006 MPR resolution clearly serves the public interest because a delay in the approval of the resolution delays staff evaluation of the 2006 RPS solicitation results.

This matter will be placed on the first Commission's agenda 27 days following the mailing of this draft resolution. Comments shall be filed no later than 14 days following the mailing of this draft resolution, reply comments shall be filed no later than 20 days following the mailing, of this draft resolution.

FINDINGS

1. The 2006 MPRs were calculated and released consistent with prior Commission decisions.
2. Party comments on the 2006 MPR will guide future MPR calculations.
3. The 2006 MPR values for baseload proxy plants have been finalized for use in the 2006 Renewables Portfolio Standard (RPS) solicitations.

THEREFORE IT IS ORDERED THAT:

1. The 2006 MPRs in Appendix A are approved for use in the 2006 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 14, 2006; the following Commissioners voting favorably thereon:

____

STEVE LARSON
Executive Director

APPENDIX A

Adopted 2006 Market Price Referents

(Nominal - cents/kWh)

Operation Date	Baseload MPR	10 year	15 year	20 year
2007	MPR All-in	**0.0805**	**0.08176**	**0.08424**
	MPR fixed component	0.02236	0.02304	0.02366
	MPR variable component	0.05810	0.05872	0.06059
2008	MPR All-in	**0.07979**	**0.08195**	**0.08482**
	MPR fixed component	0.02278	0.02353	0.02418
	MPR variable component	0.05702	0.05842	0.06064
2009	MPR All-in	**0.07925**	**0.08223**	**0.08548**
	MPR fixed component	0.02322	0.02404	0.02472
	MPR variable component	0.05603	0.05819	0.06076
2010	MPR All-in	**0.07929**	**0.08295**	**0.08652**
	MPR fixed component	0.02368	0.02456	0.02527
	MPR variable component	0.05561	0.05839	0.06125
2011	MPR All-in	**0.07890**	**0.08307**	**0.08688**
	MPR fixed component	0.02316	0.02406	0.02476
	MPR variable component	0.05574	0.05902	0.06212
2012	MPR All-in	**0.07961**	**0.08420**	**0.08820**
	MPR fixed component	0.02322	0.02413	0.02484
	MPR variable component	0.05639	0.06007	0.06336
2013	MPR All-in	**0.08072**	**0.08566**	**0.08981**
	MPR fixed component	0.02328	0.02421	0.02492
	MPR variable component	0.05745	0.06145	0.06489
2014	MPR All-in	**0.08229**	**0.08746**	**0.09167**
	MPR fixed component	0.02335	0.02429	0.02499
	MPR variable component	0.05894	0.06317	0.06668
2015	MPR All-in	**0.08435**	**0.08964**	**0.09468**
	MPR fixed component	0.02344	0.02437	0.02582
	MPR variable component	0.06091	0.06527	0.06886

APPENDIX B

2006 MPR California and Henry Hub Gas Forecast (2007 – 2034)

Year	MPR Hhub Forecast (nominal$)	MPR CA Gas Forecast (nominal$)
2007	$8.80	$8.70
2008	$8.67	$8.67
2009	$8.21	$8.27
2010	$7.82	$7.88
2011	$7.48	$7.54
2012	$7.29	$7.36
2013	$7.11	$7.19
2014	$6.93	$7.01
2015	$6.74	$6.83
2016	$6.97	$7.07
2017	$7.31	$7.43
2018	$7.64	$7.77
2019	$8.05	$8.19
2020	$8.40	$8.57
2021	$8.70	$8.87
2022	$9.02	$9.21
2023	$9.33	$9.54
2024	$9.68	$9.90
2025	$10.04	$10.28
2026	$10.35	$10.61
2027	$10.69	$10.96
2028	$11.00	$11.29
2029	$11.33	$11.64
2030	$11.71	$12.04
2031	$12.03	$12.37
2032	$12.37	$12.73
2033	$12.37	$12.75
2034	$13.06	$13.47

APPENDIX C

Calculation of 2007 Installed Capital Costs

Cosumnes (SMUD)

Background:
The Cosumnes Combined-Cycle Gas Turbine (CCGT) Project has two phases. SMUD is currently building the first 500 MW plant (Phase 1) and then it will determine by 2006 if it will build the second 500 MW plant (Phase 2) or defer construction. The plant is being built at a rural site in Sacramento County about 25 miles southeast of Sacramento.

The plant is located on a 30-acre site about a half-mile south of the now closed Rancho Seco Plant. This location allows the reuse of existing water systems, switchyards, and transmission lines that are already in place. The location of the plant site, within 2,480-acres of SMUD property, will help to reduce costs and make the best use of existing SMUD customer resources.[37]

Calculation:
The Cosumnes Project Revenue Bonds Series 2006 document[38] shows a Total Construction Cost of $435 million at pages 4, 19, A-23, and A-24. However, on page 4, it is noted that the Total Construction Cost does not include interconnection facilities (water, gas, electric). Consequently, Staff added interconnection costs[39], which were estimated at 5% of $435 million, and a $20 million adjustment for dry cooling.

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[37] http://www.smud.org/cpp/project.htm

[38] SMUD Bond Series document available online at http://www.munios.com/re.asp?ID=%9D%9Dw%81br%8Bi%85%95%87%81%BE%B7%99%93%A5%8F%C3%9A%97%97%87ik%8B%82 or type "Cosumnes" or "Sacramento" in the search box located in the upper left corner of the www.munios.com homepage. Users may have to register with the website, but documents can be downloaded at no cost.

[39] In its 2003 Testimony, CEERT described these costs as "interconnection to the electric grid, interconnection to the local distribution company's gas system or an interstate pipeline, water interconnections, sewage interconnections, and other so-called "linears" (CEERT, R.01-10-024, RPS Phase, April 1, 2003, p.II-10).

Install Capital Cost Inputs (2007$)	Cosumnes (SMUD) Combined-Cycle 500 MW	
	(Million $)	$/kW
Capital Cost Investment - Overnight Costs	$447	$894
Interconnection (natural gas, water, electric)	$22.35	$45
Environmental Review & Permitting	Included in Instant Capital Costs Shown Above	Included in Instant Capital Costs Shown Above
Emissions offsets		
Dry Cooling Adjustment	$21	$55
Contingency	-	-
AFUDC	-	-
EITC	-	-
Other or Subtotal	-	-
Total "Turn-Key" Capital Costs (2007$)	$490	$994

Palomar

On June 9, 2004, the Commission issued D.04-06-011, which approved a Turnkey Acquisition Agreement (TAA) between SDG&E and Palomar Energy, LLC (Palomar Energy) (a subsidiary of Sempra Generation), dated January 29, 2004. Palomar is a 500 MW (base load)/555 MW (peaking load) combined cycle natural gas-fired generation plant located in Escondido, California. SDG&E will assume care, custody and control and risk of loss under the TAA upon closing, which SDG&E presently expects will occur on or about

In their 2005 MPR comments, several parties recommended that that the Commission use Palomar costs to derive the 2005 MPR installed capital costs. CalWEA proposed the most detailed proposal but it incorrectly calculated its proposed total cost per kW ($1,017/kW)[40].

Staff contacted Crossborder Energy and learned that the $1,017/kW estimate was derived from values shown on Attachment A to the CalWEA Brief, “Palomar Plant Information.” On Attachment A in the Annual Average column, Lines 3

[40] CalWEA Brief, Table 1, pp.5-6, and p.11

and 11 were added together, and the resulting sum was divided by 500 MW[41]: [$467.3251 million + $41.0398 million = $508.36 million] ÷ 500 MW = $1,017/kW.

There are two errors in this calculation. The $467 million figure should be $484.343 million, and the $41 million figure should not be included. First, CalWEA states that both figures on Lines 3 and 11 (CCC Brief, Attachment A) were taken from the Direct Testimony of Mike Calabrese, SDG&E, November 1, 2004, in the Palomar Application, A.04-11-003, specifically, Attachment A & B of the Calabrese Testimony. Upon reviewing the actual Direct Testimony of Mike Calabrese, it is clear that the $467 million figure used by CalWEA is an average of a mid-2006 figure and an end-of-year 2007 figure. This is problematic because nominal dollar amounts from different years are combined. In addition, the $467 million figure is reduced by accumulated depreciation and accumulated deferred taxes, both reductions from the initial balance figure. Instead, it is the initial balance figure of $484.343 million that should be used to represent the total cost of the Palomar project, given that it is the amount that would be put into rate base. [42]

Second, CalWEA's addition of $41 million to the $467 million figure is in error because an annual Rate of Return (ROR) on rate base figure cannot be added to a total rate base amount to represent a total cost or purchase price. The $41 million figure is a year-specific cost paid by ratepayers as a payment for the Palomar asset that is in rate base.

Thus, the total cost for Palomar can be fairly represented by (1) the Initial Balance figure of $484.343 million as shown in the Calabrese Testimony, Attachment B; and (2) the addition of $20 million for a dry cooling system. This results in a total cost of $504 million or $1,009/kW. The $74 million shown on Line 9 of the Energy Division spreadsheet for Palomar is merely the difference between the $504 million and the overnight base purchase price of $410 (Calabrese Testimony, Attachment B). The $74 million includes base purchase price adjustments, other adjustments, general plant, materials and supplies, and working cash (Id.)

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[41] CalWEA incorrectly used the baseload nameplate capacity – peaking nameplate (555 MW) should have been used

[42] Source for the $410 and $484 million figures: Direct Testimony of Michael Calabrese with Attachments A-C, SDG&E, November 1, 2004, Attachment B, Sheet 1 of 1.

Install Capital Cost Inputs (2007$)	**Palomar (San Diego) Combined-Cycle 555 MW**	
	(Million $)	**$/kW**
Capital Cost Investment - Overnight Costs	$421	$759
Interconnection (natural gas, water, electric)	Included in Instant Capital Costs Shown Above	Included in Instant Capital Costs Shown Above
Environmental Review & Permitting		
Emissions offsets		
Dry Cooling Adjustment	$21	$37
Contingency	-	-
AFUDC	-	-
EITC	-	-
Other or Subtotal	$76	$138
Total "Turn-Key" Capital Costs (2007$)	$518	$934

STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Gover*

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE

SAN FRANCISCO, CA 94102-3298

November 17, 2006 RESOLUTION E-
4049 Commission Meeting
December 14, 2006

TO: R.06-02-012 and R.06-05-027

Enclosed is the draft 2006 Market Price Referent Resolution E-4049. This Resolution is made on the Commission's own motion. It will be on the agenda at the next Commission meeting, which will be held 27 days after the date of this letter. The Commission may then vote on this Resolution or it may postpone a vote until later.

When the Commission votes on a draft Resolution, it may adopt all or part of it as written, amend, modify or set it aside and prepare a different Resolution. Only when the Commission acts does the Resolution become binding on the parties.

Parties may submit comments on the draft Resolution.

An original and two copies of the comments, with a certificate of service, should be submitted to:

Honesto Gatchalian
Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

A copy of the comments should be submitted to:

Paul Douglas
Energy Division
California Public Utilities Commission
505 Van Ness Avenue

San Francisco, CA 94102
Fax: 415-703-2200

Any comments on the draft Resolution must be received by the Energy Division by December 1, 2006. Those submitting comments must serve a copy of their comments on 1) the entire service list attached to the draft Resolution, 2) all Commissioners, and 3) the Director of the Energy Division, on the same date that the comments are submitted to the Energy Division.

Comments shall be limited to five pages in length plus a subject index listing the recommended changes to the draft Resolution, a table of authorities and an appendix setting forth the proposed findings and ordering paragraphs.

Comments shall focus on factual, legal or technical errors in the proposed draft Resolution. Comments that merely reargue positions taken in the advice letter or protests will be accorded no weight and are not to be submitted.

Replies to comments on the draft resolution may be filed (i.e., received by the Energy Division) on December 7, 2006, six days after comments are filed, and shall be limited to identifying misrepresentations of law or fact contained in the comments of other parties. Replies shall not exceed five pages in length, and shall be filed and served as set forth above for comments.

Late submitted comments or replies will not be considered.

Valerie Beck

Program and Project Supervisor

Energy Division

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1.7 Enclosure: Service Lists R.06-05-027, R.06-02-012

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I certify that I have by mail this day served a true copy of Draft Resolution E-4049 on all parties in these filings or their attorneys as shown on the attached list.

Dated November 17, 2006 at San Francisco, California.

____

Paul Douglas

NOTICE

Parties should notify the Energy Division, Public Utilities Commission, 505 Van Ness Avenue, Room 4002 San Francisco, CA 94102, of any change of address to insure that they continue to receive documents. You must indicate the Resolution number on the service list on which your name appears.

Appendix D
2006 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		Energy Information Administration (EIA)	$/MMBtu	N/A	EIA (Feb. 2006) - 20 yr.wellhead prices adjusted 10.8% to reflect Henry Hub forecast (public)
3	General Inputs	Transaction Cost	$/MMBtu	$0.082	D.04-06-015, pg. 26, reafirmed in D.05-12-042 (pg. A-7)
4		Transportation Escalation Rate	Percent-%	2.46%	Average of EIA 2006 GDP Chain-Type Price Index. See 2006 MPR model - Delivery_Tar Tab (Cell E9)
5		20-year WACC	Percent-%	8.50%	2006 MPR model - Cost Cap Tab (Cell D9)
6	Municipal Surcharge	SoCal Muni Surcharge	Percent-%	1.553%	Schedule G-MSUR - http://www.socalgas.com/regulatory/tariffs/tm2/pdf/G-MSUR.pdf
7		PG&E Muni Surcharge	Percent-%	1.130%	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
8	PG&E Gas Distrib. Rate	Customer Access Charge	$/day	$179	http://www.pge.com/tariffs/pdf/G-EG.pdf
9		Proxy Plant Capacity	MW	500	2005 MP6 model - Delivery_Tar Tab (Cell E15)
10		Heat Rate	MMBtu/MWh	6.93	2006 MPR model - Delivery_Tar Tab (Cell E16)
11		Capacity Factor	%	77%	2006 MPR model - Delivery_Tar Tab (Cell E17)
12		Monthly Gas Consumption	MMBtu	63,733	(Row 8 * Row 9* Row 10) * 24 hours
13		Unit Cost of Customer Access Charge	$/MMBtu	$0.0028	Row 7 / Row 11
14		Transportation Charge	$/MMBtu	$0.2528	http://www.pge.com/tariffs/pdf/G-EG.pdf
15	SoCal Gas Distrib. Rate	Customer Charge	$/month	$0.00000	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
16		Transmission Charge	$/MMBtu	$0.3954	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
17		Interstate Transportation Cost Surcharge	$/MMBtu	$0.0000	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
2006 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	$964	2.07%	Per D.05-12-042, Staff conducted a survey of actual plant costs in CA. Four plants were selected and an average was calculated
2		Fixed O&M	($/kW-yr) 1st operational yr.	$13.94	2.46%	See Attachement F, Mountainview Application (FERC Docket ER04-316). Highest and lowest values were deleted from Wharton data set, Palomar and CC8 were added, and an average value was calculated
3		Variable O&M	(mills/kWh) 1st operational yr.	$2.46	2.46%	See Attachement F, Mountainview Application (FERC Docket ER04-316). Highest and lowest values were deleted from Wharton data set, Palomar and CC8 were added, and an average value was calculated
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-%	1.65%	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	6969	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-%	8.50%	n.a.	Weight-Average Cost of Capital = (Cost of Equity x Equity %) + (Cost of Debt x (1-tax rate) x Debt %)
8	b	Cost of LT Debt	Percent-%	7.13%	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+)
9	Finance Inputs	Cost of Equity	Percent-%	12.78%	2.00%	Per D.05-12-042, Cost of Equity = risk free rate (20-yr Tbill) + risk premium (equity) + mid-cap risk premium (equity)
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%	2.46%	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 - Parties did not propose changes for 2005
14		Generation Meter Multiplier (GMM) to load center	Percent-%	98.5%	n.a.	Per CCC recommendation (comments, pg. 13) , Staff calculated the 2005 system annual average for GMMs used data provided by CAISO
15		Capacity Factor	Percent-%	79%	n.a.	Per D.05-12-042, Staff developed a methodology, using the average of IOU TODs, to calculate a range of capacity factors. See Cap_Fac Tab in 2006 MPR model
16	Tax Rate Inputs	Federal Tax Rate	Percent-%	35%	n.a.	Tax rate proposed by the parties and used in the 2004 MPR calculation - Parties did not propose changes for 2006
17		State Tax Rate	Percent-%	8.84%	n.a.	Tax rate proposed by the parties and used in the 2004 MPR calculation - Parties did not propose changes for 2006
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 - 2007 levelized	$/MMBtu	$8.11	n.a.	Output from CA_Gas_Forecast Tab (Cell L39) in 2006 MPR model