Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application 11-10-002
Exhibit No.: (SDG&E-105)

REVISED PREPARED DIRECT TESTIMONY OF

DAVID T. BARKER

CHAPTER 5

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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PREPARED DIRECT TESTIMONY OF

DAVID T. BARKER

(CHAPTER 5)

I. PURPOSE AND OVERVIEW

The purpose of marginal cost based ratemaking is to send customers a price signal that will encourage them to consume electricity efficiently. Marginal commodity costs are the incremental electric commodity costs incurred on behalf of utility customers, and are composed of marginal energy costs and marginal generation capacity costs. Marginal energy costs (MEC) are the added energy costs incurred to meet the projected growth in electricity consumption. Marginal generation capacity costs (MGCC) relate to the added costs incurred to meet the projected growth in peak electric demand. San Diego Gas & Electric Company (SDG&E) is proposing in this General Rate Case (GRC) Phase 2 proceeding to allocate costs to reflect the marginal commodity costs developed herein.

My testimony is organized as follows:

Section II – Calculation of Marginal Energy Costs: As stated previously, MEC are the projected energy costs incurred to meet electricity consumption. Since SDG&E transacts in the California Independent System Operator (CAISO) markets, the marginal energy costs are based on average annual electric forward market prices specific to SP-15 and the annual hourly profile of electricity prices based on the CAISO day-ahead energy market prices for the SDG&E area, the SDG&E Daily Load Average Price (DLAP).

Section III – Calculation of Marginal Generation Capacity Costs: MGCC relate to the added costs incurred to meet the projected growth in peak electric demand. MGCC are calculated based on long-term considerations and so are based on the net cost of new entry of a combustion turbine (CT), the long-term cost of adding new capacity. This amount is equal to the fixed costs of a CT less expected profits from energy and ancillary service markets.

Section IV – Time-of-Use Periods: Time-of-use (TOU) rates improve the price signals that utility customers face as a result of their consumption decisions and so result in improved economic efficiency. Hourly prices would be the most accurate price signals, but are impractical to implement. TOU periods are a workable compromise between hourly differentiated prices and flat rates. The objective in choosing TOU period definitions is to group together hours with similar marginal commodity costs, including both energy and capacity, but to have TOU period prices that are different so as to provide price signals. SDG&E is proposing to adjust TOU periods in this GRC Phase 2 so that all TOU periods have the common summer season, May – October, and to maintain a winter on-peak period. These changes are a first step toward consolidating and aligning the TOU periods for different customer classes in the future. Combining information on current variations in hourly prices from Attachment B with a study of the impact of solar and wind on hourly prices in Attachment A, recommendations are made on potential future TOU period changes.

Section V - Statement of Qualifications: presentation of my qualifications.

My testimony also contains the following attachments detailing the additional studies regarding marginal commodity costs in this GRC Phase 2 proceeding. The studies in Attachments B, C, and D were required by the Settlement Agreement adopted by the California Public Utilities Commission (Commission or CPUC) in D.08-02-034.

Attachment A – An Analysis of TOU Periods: This study is a review of SDG&E TOU periods in light of added solar and wind energy in the future. The renewable resources are very low variable cost resources that will cause reduction in marginal prices in periods when they operate. Their operation affects marginal energy and capacity costs in such a way that SDG&E TOU periods should be adjusted in the future if there is a substantial penetration of these variable generation resources in areas that impact the SDG&E service area.

Attachment B – An 8760-hour Analysis of Marginal Energy Costs: This study includes derivation of the new 8760-hour shape of SDG&E's MEC. Four different comparisons are provided to investigate how the proposed hourly price shape compares to potential alternatives. The comparisons provided include hourly price profiles developed from the following: gas-price adjusted SDG&E DLAP for 2009-2011; the hourly price profile used in the previous GRC Phase 2; the hourly price profile from SDG&E's production cost model; and the hourly price profile developed by E3, a CPUC consultant that has been used in CPUC cost effectiveness proceedings. The results are compiled by TOU periods for both current and potential future TOU periods.[1]

Attachment C – Capacity Factors of SDG&E Owned Combustion Turbines Operating in CAISO Markets in 2009 and 2010: This study is an analysis of capacity factors of the Miramar I and II combustion turbines operating in CAISO markets in 2009 and 2010.

[1] The 8760 hourly price profiles are available upon request. The hourly price profile from the production cost modeling is available to parties under appropriate confidentiality agreements, consistent with D.06-12-030.

Attachment D – Comparison of LOLE and Top 100 Hours: This study is an analysis of the top 100 hours of load data for SDG&E for 2006-2008 and comparison of the data with Loss of Load Expectation ("LOLE") data from SDG&E's production cost model.

II. CALCULATION OF MARGINAL ENERGY COSTS

MEC reflect expected future energy market conditions considering the mix of existing and new resources, weather conditions, hydro conditions, greenhouse gas costs, and natural gas prices.[2] SDG&E's proposed approach to forecasting MEC is outlined below:

1. The approach starts with the 8760 hourly price profile over the year based on the SDG&E analysis contained in Attachment B. The hourly price profile is based on the CAISO day-ahead energy market data for the San Diego DLAP price for July 2009 – June 2010, publicly available data on a market that was actively traded. The hourly electricity price profile is analyzed by month to determine the range of prices.
2. Then these hourly prices are matched with load based on the assumption that market energy prices are highly correlated with actual loads for 2009-2010. The load forecast under average year conditions then yields an 8760 hourly price profile that accounts for the weather conditions specific to 2009-2010. This approach is taken for its simplicity, transparency, and consistency.
3. Next, the hourly price profile is multiplied by the ratio of forecasted monthly natural gas prices to annual average gas price to account for seasonal variations in gas prices which impact electricity prices.
4. Finally, since the goal is to forecast future hourly prices, the average annual 2013-2014 electric market forward market prices are used to establish the average price over the period. The average price is calculated to be $49.42 per MWh, or 4.942 cents per kWh, based on an average of forward prices for SP-15 for calendar years 2013-2014.[3] The prices in SP-15 are used since SDG&E's load is in the SP-15 market area. Futures prices reflect the best estimate of market participants as to what

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[2] 2013-2014 is chosen since forward prices include expected greenhouse gas compliance costs, whereas 2012 forward prices do not. The compliance obligation under the proposed California Cap-and-Trade regulation begins in 2013.

[3] The average is a simple of average of trading day data for each year. The annual average is a weighted average of the on-peak and off-peak prices based on the number of hours in each period.

electricity prices will be in the future at this point in time.[4] Such forward prices are frequently used for forecasting by the Commission.

The resulting 8760 prices are then aggregated into weekdays and weekends for each month for use in cost allocation and for use in calculating time-of-use factors that are part of rate design. These marginal energy costs are input values for the cost allocation to customer classes in the direct testimony of William G. Saxe (Chapter 4).

The 8760 hours of prices aggregated into weekdays and weekends for each month also form the basis for various TOU periods as shown in Table DTB-1. The hourly prices are aggregated by the appropriate time periods to develop the TOU marginal energy rates.

Table DTB-1 Time-of-use Marginal Energy Prices

Standard TOU Period (A-TOU, AL-TOU, AY-TOU, A6-TOU, DGR, PA-T-1, OL-TOU and DR-TOD)	
Summer (May 1 - October 31)	**Cents/kWh**
On-Peak: 11 a.m. to 6 p.m. Weekdays	6.975
Semi-Peak: 6 a.m. to 11 a.m. and 6 p.m. to 10 p.m.	5.457
Off-Peak: All Other Hours including Weekends & Holidays	3.845
Winter (November 1 - April 30)	**Cents/kWh**
On-Peak: 5 p.m. to 8 p.m. Weekdays	6.534
Semi-Peak: 6 a.m. to 5 p.m. and 8 p.m. to 10 p.m.	5.592
Off-Peak: All Other Hours including Weekends & Holidays	4.286

[4] Forward prices increase substantially between 2012 and 2013 to reflect the beginning of the Greenhouse Gas Cap-and-Trade compliance in 2013.

Table DTB-1 Time-of-use Marginal Energy Prices (cont.)

SCHEDULE DR-TOU	
Summer (May 1 - October 31)	**Cents/kWh**
On-Peak: 12 p.m. to 6 p.m. Weekdays	7.015
Off-Peak: All Other Hours including Weekends & Holidays	4.438
Winter (November 1 - April 30)	**Cents/kWh**
On-Peak: 12 p.m. to 6 p.m. Weekdays	5.797
Off-Peak: All Other Hours including Weekends & Holidays	4.786

SCHEDULE DR-SES	
Summer (May 1 - October 31)	**Cents/kWh**
On-Peak: 11 a.m. to 6 p.m. Weekdays	6.975
Semi-Peak: 6 a.m. to 11 a.m. and 6 p.m. to 10 p.m.	5.457
Off-Peak: All Other Hours including Weekends & Holidays	3.845
Winter (November 1 - April 30)	**Cents/kWh**
Semi-Peak: 6 a.m. to 6 p.m. Weekdays	5.604
Off-Peak: All Other Hours including Weekends & Holidays	4.625

SCHEDULE EV-TOU	
Summer (May 1 - October 31)	**Cents/kWh**
On-Peak: 12 p.m. to 8 p.m. Every Day	6.480
Super Off-Peak: 12 a.m. to 5 a.m. Every Day	2.711
Off-Peak: All Other Hours	4.728
Winter (November 1 - April 30)	**Cents/kWh**
On-Peak: 12 p.m. to 8 p.m. Every Day	5.771
Super Off-Peak: 12 a.m. to 5 a.m. Every Day	3.542
Off-Peak: All Other Hours	5.031

Table DTB-1 Time-of-use Marginal Energy Prices (cont.)

SCHEDULE EV-TOU-2	
Summer (May 1 - October 31)	**Cents/kWh**
On-Peak: 12 p.m. to 6 p.m. Every Day Except Holidays	6.540
Super Off-Peak: 12 a.m. to 5 a.m. Every Day	2.709
Off-Peak: All Other Hours	4.941
Winter (November 1 - April 30)	**Cents/kWh**
On-Peak: 12 p.m. to 6 p.m. Every Day Except Holidays	5.524
Super Off-Peak: 12 a.m. to 5 a.m. Every Day	3.541
Off-Peak: All Other Hours	5.241

SCHEDULES AS-TOD, PA-TOD	
Summer (May 1 - October 31)	**Cents/kWh**
On-Peak: 11 a.m. to 6 p.m. Weekdays	6.975
Off-Peak: All Other Hours including Weekends & Holidays	4.357
Winter (November 1 - April 30)	**Cents/kWh**
On-Peak: 5 p.m. to 8 p.m. Weekdays	6.534
Off-Peak: All Other Hours including Weekends & Holidays	4.811

SEASONAL RATES	
	Cents/kWh
Summer (May 1 - October 31)	4.876
Winter (November 1 - April 30)	4.957

III. CALCULATION OF MARGINAL GENERATION CAPACITY COSTS

The methodology employed by SDG&E in calculating MGCC can be viewed as building on the method for calculating long-term avoided capacity costs adopted by the Commission in recent cost effectiveness analyses, a net cost of new entry approach. MGCC answers the question: If a new generator were to want to enter the market and sell firm capacity, what would be the selling price? The answer would be based on the cost of building the facility less the amount the firm expected to earn operating in California's energy markets. SDG&E proposes to calculate MGCC by calculating the cost of building a new combustion turbine in the San Diego area including all permitting, financing, and development costs and deducting expected earnings in California energy and ancillary service markets.

Adding combustion turbines reflects a least cost way for SDG&E to avoid shortages and the way that utilities in the past have invested to avoid shortages.[5] The Commission's cost effectiveness calculations over the past three years have also used a CT as the basis for determining marginal capacity costs. For example, the recent demand response cost effectiveness decision, D.10-12-024, relied on a CT as the marginal long-term resource for providing peaking power to assure reliability.

To estimate a CT's fixed cost, SDG&E uses data from its recent Miramar II CT addition and fixed and variable Operations & Maintenance (O&M) costs from the California Energy Commission's (CEC) Comparative Costs of California Central Station Electricity Generation, CEC-200-2009-07SD. SDG&E's cost for most recent CT addition, the second unit at Miramar, was \$1,180/kW, is less than the average installed cost of a generic CT from the CEC report, \$1,322/kW.[6] The installed cost is converted to a short-term annual cost using a real economic carrying charge approach (RECC), and then fixed O&M and various loaders are added.[7] Finally, the cost is adjusted for inflation to 2012 dollars using the same escalators as used in GRC Phase 1.

To calculate the net cost of capacity, projected market earnings from California's energy, and ancillary service markets are deducted from the annualized cost of a CT. A stochastic analysis was completed to reflect the variability in electric prices in the CAISO's real-time market, which can vary from the day-ahead market, and projected market revenues were calculated. The variable costs of operating a CT were based on variable O&M plus fuel costs of

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[5] SDG&E provided a study in its last GRC Phase 2 proceeding demonstrating that duct firing on a combined cycle plant could not be the marginal cost and that a CT was the appropriate avoided resource for meeting peak capacity.

[6] The \$1,180 was calculated based on an installed cost of \$56.5 million and a net qualifying capacity of 47.9 MW. Miramar II is representative of the future costs of new capacity in the San Diego area, compared to the CEC estimate that is an average over all of California. Also, it is a utility-owned plant and so is consistent with the use of utility ratemaking factors used to annualize the cost of the CT. Since Miramar II is an LM 6000 generating unit, the same type unit on which the CEC based their analysis, the fixed and variable costs from the CEC Report are used in the analysis since it is publicly available data. Miramar II is different in two ways from the assumed CT addition – it uses wet cooling and has black start capability. An assumption was made that dry cooling costs would be similar to the costs of providing black start capability, so that Miramar II's costs would be representative of a CT with dry cooling and without black start capability. CEC cost estimate from Table C-25 on page C-30 of CEC-200-2009-07SD

[7] SDG&E RECC factors include property tax in the RECC factor.

the CT; these costs were deducted from market revenues to generate projected earnings.[8] The resulting energy market earnings were calculated on an expected basis to be $23/kW-year, with an associated CT capacity factor of 12.2 percent on a whole hour basis.[9] Ancillary service values are estimated to be 11% of CAISO energy market revenues, consistent with the Commission-adopted approach in D.10-12-024, and representative of the CAISO market experience over 2006-2009. The MGCC calculation is shown in Table DTB-2.

Table DTB-2 Marginal Generation Capacity Cost

Short-term Marginal Cost of a Combustion Turbine	$	152.03
Less Energy Market Earnings	$	23.00
Less Ancillary Service Market Earnings	$	8.97
Marginal Generation Capacity Costs	$	120.06

The MGCC is rounded to $120/kW-year. While this cost is significantly higher than the cost used by SDG&E in its last GRC Phase 2 proceeding, it reflects the run-up in the costs of new generation during this period, consistent with the significant increases shown in the CEC reports on the costs of new generation between 2005 and 2009.[10] It is also comparable to the long-term avoided cost of capacity calculated in the demand response cost effectiveness based on the guidelines in D.10-12-024.

[8] SDG&E used a heat rate of 9930 in contrast to the lower heat rate reflected in the CEC report to account for the increased heat rate that occurs with increased temperatures. Since peaking conditions occur during higher temperature days, the heat rate is expected to be higher when the plant is likely to be in use.
[9] Generally capacity factors are calculated using partial hours; however, to be consistent with the hourly approach used in the modeling, a "whole hour" capacity factor is shown in Attachment C. The average of 12.2 percent is consistent with operations of SDG&E peaking units in 2009 and 2010 as shown in Attachment C.
[10] CEC, *Comparative Costs of California Central Station Electricity Generation*, CEC-200-2009-07SF, table 10, page 42.

The MGCC is an input for the cost allocation to customer classes in Mr. Saxe's direct testimony (Chapter 4).

IV. TIME OF USE PERIODS

TOU rates improve the price signals utility customers face as a result of their consumption decisions and so result in improved economic efficiency. Well-designed TOU periods discourage customers from using electricity for low-valued activities during times when the cost of producing the electricity is high, and encourage customers to shift their use of electricity to when the cost of producing the electricity is lower. The objective in choosing TOU-period definitions is to group together hours with similar marginal commodity costs, including both energy and capacity. As part of the GRC Phase 2, SDG&E has undertaken a study to evaluate the implications of the expanded use of solar and wind technologies in the SDG&E procurement portfolio for the design of the SDG&E TOU periods in this GRC Phase 2 proceeding and future proceedings.

In analyzing TOU periods, it is important to consider the economic environment. For example, in the capacity market, the CAISO and CPUC have already defined high potential electricity usage periods in the measurement of qualifying capacity for resource adequacy purposes. The high usage periods are expected to be 1 pm – 6 pm in April-October, and 4 pm – 9 pm in November through March. Likewise, in the energy markets in California, the general structure of forward contracts defines on-peak as 6 am – 10 pm Monday – Saturday, and off-peak all other times.

A second aspect is future changes to the economic environment. Because of California's drive to a low-carbon economy, renewable technologies including solar energy and wind will have much higher penetrations in the future and will drive marginal costs down during periods when they are producing. While these are expensive technologies to build, once in place their marginal cost is very low and so displace fossil resources with higher variable costs. As a result, the hours grouped today as the most expensive to provide energy and capacity may no longer be the right set of hours in the future for purposes of consumer decision-making.

The results of the TOU study presented in Attachment A support two decisions made in the present filing: 1) retaining a winter on-peak period, and 2) adding October to Summer for all schedules. Retaining a winter on-peak makes sense because customers are paying resource adequacy costs for this period and significant penetration of solar energy will drive the peak net of solar toward evening hours and the summer peak net of solar toward the winter peak. Second, October is already a summer month for the residential sector and for time-of-delivery of renewable energy. The study shows forecasted afternoon usage levels in October to be more comparable to other summer months than to winter months. Similarly, afternoon weekday hourly prices in October demonstrate a pattern closer to summer than winter.

The study results also show SDG&E's existing on-peak period appears likely to capture the high-cost hours in summer. However, SDG&E's on-peak period could be shifted to later in the day in the future as solar energy moves the peak net of solar. High-cost hours could move toward later in the day as more solar energy comes online. The study also shows that the period 12 am – 6 am are very low-usage hours, causing the relatively low hourly prices shown in Table DTB-1 for the period. The effect of adding wind energy will push load net of wind even lower during the 12 am – 6 am period, but does not shift the occurrence of minimum load. As more wind energy comes online, the price differential between the 12 am and 6 am TOU period and other TOU periods will increase even further.

This concludes my prepared direct testimony.

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V. STATEMENT OF QUALIFICATIONS

My name is David T. Barker. My business address is 8330 Century Park Court, CP32F, San Diego, California 92123.

I have been employed as an economist in the Resource Planning group of San Diego Gas & Electric Company since 2007. Prior to that, I was employed as an economist in the Regulatory Affairs Department of Sempra Energy Utilities for five years from 2002 to 2007. Before 2002, I was employed at Southern California Gas Company in various staff positions including Economist (1991-1995 and 1998-2002), Market Consultant (1988-1989 and 1995-1998), Electric Energy Analyst (1990-1991), and Demand Forecasting Supervisor (1989-1990).

I received a B.S. in Mathematics from New York State University, a Masters of Economics degree from North Carolina State University, and a joint Ph.D. in Economics and Statistics from North Carolina State University. I taught undergraduate economics and statistics courses for four years on a full-time basis in Oregon, and then worked in the private sector for five years as an economist at Merrill Lynch prior to joining Southern California Gas Company.

I have previously testified before the Commission on economic analysis issues.

ATTACHMENT A

Time-of Use Rate Structure Study

Time-of-use (TOU) rates improve the price signals which utility customers face as a result of their consumption decisions and so result in improved economic efficiency. The objective in choosing TOU period definitions is to group together hours with similar marginal commodity costs, including both energy and capacity, in such a way that customers know when electricity is expensive on average and when it is relatively inexpensive. Well-designed on-peak TOU periods inform customers when the cost of producing the electricity is generally high, and encourage customers to shift their use of electricity to when the cost of producing the electricity is lower. Off-peak TOU periods inform customers when the cost of producing the electricity is lower than average, and encourage customers to shift their use of electricity to the period.

Because of California's drive to a low carbon economy, renewable technologies including solar and wind energy will have much higher penetration in the future and will have significant impacts on a number of different areas of the utility operations. These technologies, once in place, produce electricity as nature provides. Solar technologies produce electricity when the sun shines (concentrated in the middle of the day), and wind technologies produce when the wind blows (mostly in the middle of the night). While these are expensive technologies to build, once in place their variable costs are very low and so displace fossil resources with higher variable costs. As a result, the hours grouped today as the most expensive for which to provide energy and capacity may no longer be the right set of hours for purposes of consumer decision-making. The purpose of this study is to evaluate the implications of the expanded use of these technologies in the SDG&E procurement portfolio for the design of the SDG&E TOU periods in this GRC Phase 2 proceeding and future rate design proceedings.

I. EXISTING TOU STRUCTURES

SDG&E has had effective TOU rates for a number of years. There are a number of rate schedules with different TOU periods that have been simplified into the TOU periods shown in Table DTB-1 above. SDG&E pays for energy and capacity in markets where the value of delivered electricity is paid a different amount depending on when it is delivered. Table 5A-1 below summarizes the trading market definitions of on-peak and off-peak energy delivery and the CAISO/CPUC definitions of on-peak capacity delivery for reliability purposes. In addition, the table includes the SDG&E time of delivery (TOD) periods. The current QF TOD periods mirror the former C&I TOU period with an added super-off-peak period, while the Renewable Portfolio Standard (RPS) periods were developed more recently and tend to have hourly definitions close to market TOD periods. The different TOD periods are summarized in Table 5A-1.

Table 5A-1 Current TOD Periods

Source	Definition of Summer	On-peak	Off-peak	Other
Energy Market				
SP-15 Forward Markets	None	6 am - 10 pm Monday - Saturday all year	10 pm - 6 am M - Sat, all day Sunday	
Capacity Market				
CA Resource Adequacy Counting Rules for Demand Response	Apr. -Oct.	Summer: 1 pm - 6 pm Winter: 4 pm - 9 pm	All other	
Contracts				
QF	May -Sept.	Summer: 11 am - 6 pm weekdays Winter: 5 pm - 8 pm weekdays	Super off-peak - 12 am - 5 am all days All other off-peak	Semi-peak : Summer - 6 am-11 am, 6 pm-10 pm weekdays Winter: 6 am - 5 pm, 8-10 pm weekdays
Renewable	Jul- Oct.	Summer: 11am-7pm weekdays Winter 1pm-9pm weekdays	All other	Semi-peak Summer 6-11am, 7-10 pm weekdays Winter 6am-1pm, 9-10pm weekdays

II. ANALYSIS APPROACH

As stated previously, the objective in choosing TOU period definitions is to group together hours with similar marginal commodity costs, including both energy and capacity. In competitive electricity markets, lower-cost generation units are operated first, and higher-cost units only operate when load is sufficiently high to cause increased prices to economically justify their operation. There is a clear link between marginal energy costs and loads; marginal energy costs are higher in periods with higher load and lower in periods with low loads. Similarly, the capacity component reflects the incremental cost of acquiring sufficient generating resource capacity to have on hand to meet customer demands during high load conditions, taking into consideration the uncertainty associated with customer demand. Thus the CAISO/CPUC specifies time periods when customer demand response must be available to provide resource adequacy. This study exploits the high correlation of marginal commodity costs, both energy and capacity costs, with loads. Rather than try to forecast locational marginal prices (LMP) by hour, the study looks directly at SDG&E loads in each hour and assumes the SDG&E DLAP price will be correlated with the load on the SDG&E system and that load on the SDG&E system is correlated with overall state load.

For the analysis of the potential impact of solar energy on TOU periods, the focus is on the impact to the Summer On-peak period. This answers the question: does the load on the SDG&E system net of solar peak differently? The lower the load net of solar production in a particular hour, the lower the marginal commodity costs in that hour. Since the production of solar energy varies by hour, the impact of solar will be greater in some hours than others and will have zero impact in nighttime hours. The key analysis is how much higher marginal cost hours will be shifted toward the evening and the extent of the shift in relation to solar penetration.

For the analysis of wind energy, the focus is on low-usage periods where marginal costs may be low because of already low usage due to advances in lighting energy efficiency and the availability of resources required to meet daytime peak usage remaining available in other hours. The addition of wind resources will exacerbate the hourly pricing differential between the late night hours and daytime or evening peak hours, especially in the presence of other must-take resources.

III. DATA

The use of load to provide an indirect measure of the impact on hourly prices, the basis of the analysis is SDG&E forecasted 2012 load data used in this GRC Phase 2. The impact of solar is measured by deducting solar energy produced from the 2012 load data. The solar and wind data for SDG&E is from the CAISO's renewable integration scenario analysis, the trajectory case.[11] The CAISO data provided an 8760 large solar profile, an 8760 small solar production

[11] The solar and wind data are from CAISO's May 9, 2011 update.

profile, an 8760 Distributed Generation (DG) solar production profile, and a wind profile, which are all specific to the SDG&E service area. For the solar profile, a simple average of the three solar profiles was calculated, because it is not precisely known what the long-term composition of developed solar will be.

IV. ANALYSIS

The focus is on hourly loads in the 2012-2020 time frame as a proxy for the change in marginal costs, so the baseline is the 2012 SDG&E system-wide hourly load forecast for non-holiday weekdays. The information on SDG&E forecasted usage takes into account economic growth, energy efficiency, expected expansion of distributed generation, planned renewable purchases, etc.

Summer On-peak TOU Period

The data is aggregated into average hourly usage on non-holiday weekdays. High-use hours are defined for purposes of this study as the peak hour and all hours with average usage within 100 MW of the peak usage in each month subject to the condition it is above 3,000 MW. It is assumed that random variations in load due to temperature are correlated with the average usage profile. The higher usage hours in each month are highlighted, with the peak seasonal hour with the darkest shading. The data in Table 5A-2 show that October has characteristics of both summer and winter, but the high use hours in the afternoon, comparable to June and more than May, support October being included in the summer period.

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Table 5A-2

Forecasted 2012 SDG&E System Load

Hour	11-12 am	12-1 pm	1-2 pm	2-3 pm	3-4 pm	4-5 pm	5-6 pm	6-7 pm	7-8 pm	8-9 pm	9-10 pm
JAN	2813	2804	2785	2747	2718	2773	3118	3199	3114	2961	2728
FEB	2796	2791	2768	2731	2696	2709	2924	3152	3083	2917	2648
MAR	2768	2787	2790	2778	2747	2711	2688	2732	3009	2993	2814
APR	2816	2869	2895	2893	2868	2834	2783	2722	2881	2976	2765
MAY	2859	2916	2945	2950	2936	2905	2845	2743	2765	2944	2764
JUN	3038	3100	3131	3150	3147	3124	3060	2933	2862	3025	2905
JUL	3348	3470	3554	3607	3627	3609	3510	3302	3134	3251	3090
AUG	3424	3566	3670	3738	3771	3750	3633	3404	3310	3382	3157
SEP	3271	3398	3499	3559	3582	3550	3430	3272	3363	3269	3016
OCT	2992	3075	3131	3148	3139	3097	3049	3171	3195	3055	2807
NOV	2886	2903	2906	2880	2847	2921	3218	3186	3084	2929	2695
DEC	2766	2751	2729	2693	2680	2856	3358	3359	3267	3107	2834
Summer	3155	3254	3322	3359	3367	3339	3254	3137	3105	3154	2957
AUG	3424	3566	3670	3738	3771	3750	3633	3404	3310	3382	3157

This baseline data is first compared to historical data from 2006-2008 for SDG&E system load, the same data used for the top 100 hours analysis. The comparison in Table 5A-3 shows some impacts of the growth of solar DG, but also the fact that historical weather can be different than the average weather assumed for the forecast. The forecast of the average usage for Summer 2012 in Table 5A-2 shows energy usage is shifted to slightly later in the day compared to the average for 2006-2008 as shown in Table 5A-3; the hours of 11 am – 1 pm have lower levels of usage relative to the hour of peak usage.

Table 5A-3

Average 2006-2008 SDG&E System Load

Hour	11-12 am	12-1 pm	1-2 pm	2-3 pm	3-4 pm	4-5 pm	5-6 pm	6-7 pm	7-8 pm	8-9 pm	9-10 pm
JAN	2703	2682	2663	2620	2588	2637	2991	3095	3027	2907	2692
FEB	2670	2654	2637	2602	2565	2569	2786	3016	2959	2839	2626
MAR	2669	2667	2664	2638	2600	2572	2607	2768	2884	2815	2616
APR	2704	2715	2718	2697	2659	2613	2563	2546	2739	2805	2615
MAY	2789	2808	2819	2807	2781	2741	2684	2632	2719	2845	2664
JUN	3043	3093	3129	3142	3140	3106	3025	2905	2852	2980	2843
JUL	3366	3446	3507	3543	3555	3530	3433	3265	3153	3252	3098
AUG	3415	3512	3585	3632	3651	3619	3502	3310	3263	3333	3116
SEP	3199	3277	3342	3374	3378	3332	3215	3097	3233	3155	2905
OCT	2921	2979	3024	3034	3011	2950	2894	2990	3049	2926	2699
NOV	2773	2790	2802	2777	2731	2779	3062	3045	2948	2816	2596
DEC	2698	2673	2654	2622	2605	2748	3163	3196	3125	3019	2810
Summer	3122	3186	3234	3255	3253	3213	3125	3033	3045	3082	2887
AUG	3415	3512	3585	3632	3651	3619	3502	3310	3263	3333	3116

The analysis then investigates the impact of added solar energy in the amounts of 250 MW, 500 MW, and 750 MW *incremental* to the amount expected in 2012. The level of 750 MW of incremental solar would bring total solar to a level comparable to a proportionate share for SDG&E of the Governor's 12,000 MW goal for distributed generation. New solar energy can be of the form of large solar exporting to the grid, small solar exporting to the grid, or distributed photovoltaics (PV) that do not export to the grid. The analysis assumes these levels are possible without any detailed analysis.[12] The impact on prices is assumed to be correlated with load net of solar as more expensive fossil generation is backed down in merit order with more solar. The shift toward a later on-peak period in the summer is clearly indicated by the data as the penetration of solar increases as demonstrated in Tables 5A-4 – 5A-6. As the penetration of solar technologies approaches 750 MW, the summer peak moves to nighttime and is comparable to the winter peak.

Table 5A-4

Forecasted 2012 SDG&E System Load net of 250 Incremental MW of Solar

Hour	11-12 am	12-1 pm	1-2 pm	2-3 pm	3-4 pm	4-5 pm	5-6 pm	6-7 pm	7-8 pm	8-9 pm	9-10 pm
JAN	2673	2660	2651	2634	2635	2728	3118	3199	3114	2961	2728
FEB	2662	2651	2635	2614	2605	2650	2910	3152	3083	2917	2648
MAR	2600	2603	2598	2593	2584	2583	2604	2699	3009	2993	2814
APR	2625	2662	2683	2691	2690	2691	2683	2676	2878	2976	2765
MAY	2670	2713	2737	2751	2759	2764	2743	2687	2753	2944	2764
JUN	2856	2902	2926	2952	2970	2978	2952	2869	2841	3025	2905
JUL	3161	3268	3348	3410	3453	3470	3409	3244	3115	3251	3090
AUG	3250	3376	3475	3551	3605	3618	3541	3358	3305	3382	3157
SEP	3088	3199	3297	3372	3421	3426	3349	3245	3363	3269	3016
OCT	2830	2898	2952	2985	2999	2994	2999	3168	3195	3055	2807
NOV	2722	2736	2752	2754	2764	2895	3218	3186	3084	2929	2695
DEC	2622	2606	2592	2579	2601	2833	3358	3359	3267	3107	2834
Summer	2976	3059	3123	3170	3201	3209	3165	3095	3095	3154	2957
AUG	3250	3376	3475	3551	3605	3618	3541	3358	3305	3382	3157

[12] In other words, the study does not make any judgments on whether these levels are possible. The assumption is for the sole purpose of investigating the impact of these technologies on prices.

Table 5A-5

Forecasted 2012 SDG&E System Load net of 500 Incremental MW of Solar

Hour	11-12 am	12-1 pm	1-2 pm	2-3 pm	3-4 pm	4-5 pm	5-6 pm	6-7 pm	7-8 pm	8-9 pm	9-10 pm
JAN	2532	2515	2517	2521	2553	2683	3117	3199	3114	2961	2728
FEB	2528	2512	2502	2498	2514	2592	2896	3152	3083	2917	2648
MAR	2433	2419	2405	2408	2420	2455	2520	2666	3009	2993	2814
APR	2434	2455	2470	2490	2513	2548	2584	2629	2875	2976	2765
MAY	2482	2510	2530	2553	2583	2623	2640	2630	2741	2944	2764
JUN	2674	2704	2721	2753	2794	2832	2843	2805	2819	3025	2905
JUL	2974	3067	3143	3213	3279	3332	3308	3185	3096	3251	3090
AUG	3076	3186	3281	3363	3439	3487	3450	3313	3299	3382	3157
SEP	2906	3000	3095	3185	3261	3302	3268	3219	3363	3269	3016
OCT	2668	2722	2772	2821	2859	2892	2948	3165	3195	3055	2807
NOV	2557	2570	2599	2629	2681	2870	3218	3186	3084	2929	2695
DEC	2478	2461	2455	2464	2523	2810	3358	3359	3267	3107	2834
Summer	2797	2865	2924	2981	3036	3078	3076	3053	3086	3154	2957
AUG	3076	3186	3281	3363	3439	3487	3450	3313	3299	3382	3157

Table 5A-6

Forecasted 2012 SDG&E System Load net of 750 Incremental MW of Solar

Hour	11-12 am	12-1 pm	1-2 pm	2-3 pm	3-4 pm	4-5 pm	5-6 pm	6-7 pm	7-8 pm	8-9 pm	9-10 pm
JAN	2391	2371	2383	2408	2470	2639	3117	3199	3114	2961	2728
FEB	2395	2372	2368	2381	2422	2533	2882	3152	3083	2917	2648
MAR	2265	2234	2212	2224	2257	2328	2436	2633	3009	2993	2814
APR	2243	2248	2258	2289	2335	2406	2485	2583	2873	2976	2765
MAY	2293	2307	2322	2355	2407	2481	2538	2574	2730	2944	2764
JUN	2492	2507	2517	2555	2617	2687	2735	2741	2798	3025	2905
JUL	2786	2866	2937	3015	3105	3193	3208	3127	3077	3251	3090
AUG	2903	2996	3086	3175	3273	3355	3358	3268	3293	3382	3157
SEP	2723	2800	2893	2998	3100	3177	3187	3192	3363	3269	3016
OCT	2507	2545	2592	2658	2719	2789	2898	3162	3195	3055	2807
NOV	2393	2404	2446	2503	2598	2845	3218	3186	3084	2929	2695
DEC	2334	2316	2319	2350	2445	2787	3358	3359	3267	3107	2834
Summer	2617	2670	2724	2793	2870	2947	2987	3011	3076	3154	2957
AUG	2903	2996	3086	3175	3273	3355	3358	3268	3293	3382	3157

Super Off-peak TOU Period

The analysis of wind impacts on market prices in off-peak periods starts with the energy market definition of off-peak power. Forward contracts for SP-15 power sold in exchanges and through brokers use a market off-peak definition of 10 pm to 6 am Monday through Saturday and all day Sunday. For the analysis of a super off-peak period, the time period is limited by the market definition of 10 pm – 6 am. Visual analysis of the load net of wind during the 10 pm – 6 am period in Tables 5A-7 and 5A-8 suggests that adding wind does not change the pattern of system load during the night, but does lower the load in most hours fairly uniformly. It appears that the period 12 am – 5 am or 6 am have similar levels of load and are in most months significantly less than the average load during the 10 pm-12 am period. In the tables below, all hours with MWs less than 2000 are highlighted as low load hours.

Table 5A-7

Forecasted 2012 SDG&E System Load

Hour	10-11 pm	11-12 pm	12-1 am	1-2 am	2-3 am	3-4 am	4-5 am	5-6 am
JAN	2423	2167	1961	1872	1822	1826	1925	2148
FEB	2334	2108	1910	1830	1790	1797	1896	2125
MAR	2544	2242	2020	1853	1779	1746	1771	1902
APR	2433	2151	1957	1835	1776	1756	1791	1912
MAY	2426	2152	1957	1837	1779	1756	1786	1894
JUN	2611	2300	2070	1917	1846	1819	1851	1965
JUL	2772	2460	2225	2065	1987	1951	1979	2084
AUG	2835	2523	2274	2117	2033	1995	2019	2140
SEP	2686	2381	2162	2018	1946	1916	1947	2081
OCT	2497	2207	2008	1884	1823	1800	1833	1965
NOV	2398	2160	1933	1844	1795	1802	1904	2137
DEC	2485	2236	2002	1909	1861	1865	1955	2158

Table 5A-8

Forecasted 2012 SDG&E System Load net of 500 MW of Delivered Wind

Hour	10-11 pm	11-12 pm	12-1 am	1-2 am	2-3 am	3-4 am	4-5 am	5-6 am
JAN	2205	1959	1753	1668	1619	1623	1727	1951
FEB	2094	1872	1655	1583	1547	1573	1682	1918
MAR	2297	2003	1771	1603	1527	1505	1527	1660
APR	2222	1935	1740	1610	1551	1540	1582	1724
MAY	2148	1870	1684	1588	1535	1524	1579	1707
JUN	2360	2043	1820	1673	1621	1612	1663	1791
JUL	2530	2221	1997	1836	1780	1767	1819	1942
AUG	2667	2347	2102	1962	1895	1871	1912	2053
SEP	2513	2200	1974	1840	1769	1751	1796	1949
OCT	2390	2103	1902	1783	1723	1700	1734	1875
NOV	2231	1983	1762	1672	1620	1649	1762	1997
DEC	2359	2107	1862	1775	1730	1736	1832	2041

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ATTACHMENT B

An 8760-hour Analysis of Marginal Energy Costs

This study provides the derivation of the 8760-hour shape of its marginal energy costs based on data from the CAISO's new day-ahead market prices for the San Diego area over 2009-2010 and hourly loads. The exact derivation is described and then a number of comparisons are made to other potential sources for an hourly price shape including the following: Gas-price-adjusted data for the SDG&E DLAP prices over July, 2009 to June, 2011; data on hourly incremental costs to serve customers from the SDG&E production cost model;[13] the modified PX data used in the last SDG&E GRC Phase 2 analysis; and the recently developed hourly price profile developed by E3 for use in demand response and distributed generation cost effectiveness analyses. For ease of comparison, the hourly data is compiled by the existing standard TOU periods and potential future standard TOU periods.

I. DERIVATION OF THE NEW HOURLY PRICE PROFILE

The market price shape is a variation of an hourly load shape modified by the observed range of day-ahead locational marginal prices (LMP). The general procedure was for each month of the year to develop an hourly load shape. Each on-peak hour is represented by the ratio of the load in that hour to the applicable average on-peak load for the month where on-peak period is the market definition - 6 am to 10 pm, Monday through Saturday. Each off-peak hour is represented by the ratio of the load in that hour to the applicable average off-peak load for the month. Next the range of load in each month was determined for both on- and off-peak periods by taking the maximum load and the minimum load for each on- and off-peak period for each month.

The same general procedure was applied to 2009-2010 CAISO day-ahead LMP prices for each month of the year. Each on-peak hourly price is calculated as the ratio of the price in that hour to the applicable average on-peak price for the month where on-peak period is the market

[13] The hourly modeling results are available to parties under appropriate confidentiality agreements, consistent with D.06-12-030.

definition - 6 am to 10 pm, Monday through Saturday. Each off-peak hour is represented by the ratio of the price in that hour to the applicable average off-peak price for the month. The range of prices in each month was determined for both on- and off-peak periods by taking the maximum price and the minimum price for each on- and off-peak period for each month.

The LMP price ranges were divided by the load ranges for both on-peak and off-peak periods for each month to create pricing factors. These pricing factors were then applied to the original load shape to produce the market price shape. On-peak pricing factors were applied to on-peak hours for each month and off-peak pricing factors were applied to off-peak loads in month to develop the hourly price profile. While the approach is somewhat simplistic, it creates a correlation between prices and loads that would be expected and provides an hourly price profile comparable to the CAISO day-ahead market price range for 2009-2010.

II. COMPARISONS

Comparisons are made easier to understand by grouping the data into TOU periods. The tables below show the comparisons based on the standard TOU period in this GRC Phase 2 as shown in Table 5-1. In addition, the hourly profile is aggregated into a potential future standard TOU period definition. For all of the comparisons, "Summer" is defined as May – October and "Winter" as November – April. The TOU periods used for comparison are shown below:

Current

On-peak – 11 am – 6 pm weekdays in Summer; 5 pm – 8 pm weekdays in Winter

Semi-peak – 6 am - 11 am and 6 pm – 10 pm weekdays in Summer;
6 am – 5 pm and 8 pm -10 pm weekdays in Winter

Off-peak – All other hours

Future

On-peak – 1 pm – 8 pm weekdays in Summer; 5 pm – 8 pm weekdays in Winter

Super Off-Peak – 12 am - 6 am every day

Off-peak – All other hours

Comparison of MEC to 2009-2011 Gas-Price-Adjusted SDG&E DLAP

The hourly price profile of marginal energy costs was developed based on data from the CAISO's Integrated Forward Market for 2009-2010 and hourly loads on the SDG&E system.

The first comparison is to two years of SDG&E DLAP data that is adjusted to the same gas price throughout the two-year period only. Unlike the developed MEC hourly price profile, this DLAP data is not adjusted to correlate with loads. The only adjustment is for gas prices to avoid problems that would occur with a trend in the gas prices over time. Table 5B-1 below shows the comparison based upon the current time of use periods, while 5B-2 is based on one potential future TOU period definition.

Table 5B-1 Current TOU Period Definition

Marginal Energy Cost Profile

On-peak Summer Price	1.419	On-peak Winter Price	1.329
Semi-peak Summer Price	1.110	Semi-peak Winter Price	1.137
Off-peak Price	0.782	Off-peak Price	0.872

Gas-Price-Adjusted 2009-2011 SDG&E DLAP Data

On-peak Summer Price	1.347	On-peak Winter Price	1.189
Semi-peak Summer Price	1.065	Semi-peak Winter Price	1.090
Off-peak Price	0.868	Off-peak Price	0.879

Table 5B-2 Future TOU Period Definition

Marginal Energy Cost Profile

On-peak Summer Price	1.398	On-peak Winter Price	1.329
Off-peak Summer Price	1.012	Off-peak Winter Price	1.049
Super Off-peak Price	0.719	Super Off-peak Price	0.719

Gas-Price-Adjusted 2009-2011 SDG&E DLAP Data

On-peak Summer Price	1.362	On-peak Winter Price	1.189
Off-peak Summer Price	1.052	Off-peak Winter Price	1.052
Super Off-peak Price	0.691	Super Off-peak Price	0.691

The average prices are comparable for all but the 3-hour on-peak period in the Winter. Since 2009-2011 SDG&E DLAP prices are based on actual weather conditions, while the MEC profile is based on average conditions, mild weather conditions may have masked the true price range for on-peak periods.

Comparison of MEC to Marginal Price Output of the Production Cost Model

A comparison requested in the last GRC Phase 2 is of the hourly price profile of marginal energy costs to the hourly price profile developed from marginal prices that are an output of the production cost model. Since the MEC hourly price shape is an input to the production cost model, the differences in Tables 5B-3 and 5B-4 reflect the impact of the simulation process.

Table 5B-3 Current TOU Periods

Marginal Energy Cost Profile

On-peak Summer Price	1.419	On-peak Winter Price	1.329
Semi-peak Summer Price	1.110	Semi-peak Winter Price	1.137
Off-peak Price	0.782	Off-peak Price	0.872

Marginal Cost Prices from Production Cost Model - Average Year Case

On-peak Summer Price	1.388	On-peak Winter Price	1.254
Semi-peak Summer Price	1.086	Semi-peak Winter Price	1.074
Off-peak Price	0.858	Off-peak Price	0.881

Table 5B-4 Future TOU Periods

Marginal Energy Cost Profile

On-peak Summer Price	1.398	On-peak Winter Price	1.329
Off-peak Summer Price	1.012	Off-peak Winter Price	1.049
Super Off-peak Price	0.719	Super Off-peak Price	0.719

Marginal Cost Prices from Production Cost Model - Average Year Case

On-peak Summer Price	1.368	On-peak Winter Price	1.254
Off-peak Summer Price	1.040	Off-peak Winter Price	1.055
Super Off-peak Price	0.693	Super Off-peak Price	0.693

The comparisons in Tables 5B-3 and 5B-4 show that the proposed hourly MEC profile is fairly close to the output of the SDG&E production cost model, described in more detail in Attachment 5-D.

Comparison of MEC to Modified PX Data

A third useful comparison is how the MEC hourly profile varies from the profile of MEC used in the last GRC Phase 2. The data in Tables 5B-5 and 5B-6 below are based on the same hourly data as used in the last GRC Phase 2. However, the hourly data was aggregated into the same TOU periods as used in this GRC Phase 2 proceeding, namely, adding the month of October to the summer period. While the same pattern exists, the old PX data provided for a higher summer on-peak price as might be expected given that California has a separate resource adequacy requirement now that did not exist in the late 1990s, so that energy markets captured more capacity value than the current CAISO energy markets do.

Table 5B-5 Current TOU Periods

Marginal Energy Cost Profile

On-peak Summer Price	1.419	On-peak Winter Price	1.329
Semi-peak Summer Price	1.110	Semi-peak Winter Price	1.137
Off-peak Price	0.782	Off-peak Price	0.872

Modified PX Data

On-peak Summer Price	1.481	On-peak Winter Price	1.339
Semi-peak Summer Price	1.015	Semi-peak Winter Price	1.148
Off-peak Price	0.793	Off-peak Price	0.859

Table 5B-6 Future TOU Periods

Marginal Energy Cost Profile

On-peak Summer Price	1.398	On-peak Winter Price	1.329
Off-peak Summer Price	1.012	Off-peak Winter Price	1.049
Super Off-peak Price	0.719	Super Off-peak Price	0.719

Modified PX Data

On-peak Summer Price	1.474	On-peak Winter Price	1.339
Off-peak Summer Price	0.981	Off-peak Winter Price	1.075
Super Off-peak Price	0.662	Super Off-peak Price	0.662

Comparison of MEC to Marginal Prices from the Avoided Cost Calculator

A fourth comparison is between the MEC hourly profile and the profile of marginal prices used in the Avoided Cost Calculator (ACC), the basis for DG and demand response cost effectiveness, as shown in Tables 5B-7 and 5B-8. The hourly price profile of the ACC were developed by CPUC consultant, E3, based on statewide electricity markets after the implementation of CAISO's Integrated Forward Market.

Table 5B-7 Current TOU Periods

Marginal Energy Cost Profile

On-peak Summer Price	1.419	On-peak Winter Price	1.329
Semi-peak Summer Price	1.110	Semi-peak Winter Price	1.137
Off-peak Price	0.782	Off-peak Price	0.872

Marginal Prices from Avoided Cost Calculator

On-peak Summer Price	1.328	On-peak Winter Price	1.265
Semi-peak Summer Price	1.080	Semi-peak Winter Price	1.060
Off-peak Price	0.865	Off-peak Price	0.890

Table 5B-8 Future TOU Periods

Marginal Energy Cost Profile

On-peak Summer Price	1.398	On-peak Winter Price	1.329
Off-peak Summer Price	1.012	Off-peak Winter Price	1.049
Super Off-peak Price	0.719	Super Off-peak Price	0.719

Marginal Prices from Avoided Cost Calculator

On-peak Summer Price	1.329	On-peak Winter Price	1.265
Off-peak Summer Price	1.066	Off-peak Winter Price	1.031
Super Off-peak Price	0.703	Super Off-peak Price	0.703

The ACC hourly price profile has slightly lower on-peak prices, but are generally of the same magnitude.

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ATTACHMENT C

Capacity Factors of SDG&E Owned Combustion Turbines Operating in CAISO Markets in 2009 and 2010

The Settlement Agreement adopted in D.08-02-034 provided for an analysis of the capacity factors of SDG&E operated combustion turbines (CTs). The analysis below is for Miramar I and Miramar II combustion turbines, new LM 6000 technology turbines, which operated in CAISO markets in 2009 and 2010. For Miramar I, the analysis includes the entire year 2009 and the period after the initial introduction of CAISO's new day-ahead market, a period starting at April 1, 2009. For Miramar II, the 2009 period begins with commercial operation, August 7, 2009. For both units, 2010 is a complete year of operation in CAISO markets.

In preparing the analysis, it became apparent that the comparison of capacity factors as calculated for general reporting to the capacity factors produced by a model that is based on hourly increments is an apples-to-oranges comparison because of the treatment of partial hours. Since the CAISO real-time energy market operates in 5-minute increments, a CT could be dispatched at 7:45 am and operate to 8:15 am, a half-hour period for purposes of calculating the capacity factor for general reporting. However, in an hourly model, this would appear as 2 hours of operation, operation in the hour ending 8 am and operation in the hour ending 9 am. The following analysis, therefore, presents the annual capacity factor information in two ways – the capacity factor calculation for general reporting based on partial hours and a "complete hours" capacity factor. The latter capacity factor counts all hours in which the CT operated, including partial hours, and divides by 8,760 hours to calculate the capacity factor.

The results in table 5C-1 below show capacity factors post-MRTU are in the range of 9.7 percent to 12.3 percent. However, the same CT operation measured <u>on a complete hours basis</u> yields capacity factors ranging from 13.0 to 17.3 percent. Because the partial 2009 can skew the capacity factor (since a CT is more likely to operate in the summer on-peak period), the range narrows if 2010 data alone is used. The capacity factor measured on a partial hour basis is 10.3 percent for Miramar II and 11.7 percent for Miramar I. But measured on a complete hours basis, the capacity factors were 15.1 percent for Miramar II and 16.9 percent for Miramar I.

The other conclusion from the data shown in Table 5C-1, as well as FERC Form 1 SDG&E 2008 data, is that CTs have had higher capacity factors since the introduction of the redesigned CAISO markets in April 2009, whether measured traditionally or on a complete hours basis.

Table 5C-1

	Miramar I			Miramar II	
	2009		2010	2009	2010
	Complete Year	Post MRTU 4/1/09+		8/7/09 +	
Total Hours of Operation	675	637	1025	450	900
Measured Capacity Factor	7.7%	9.7%	11.7%	12.3%	10.3%
Hours in which CT operated	924	861	1483	635	1324
Capacity Factor Based on Complete Hours	10.5%	13.0%	16.9%	17.3%	15.1%

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ATTACHMENT D

Comparison of Loss of Load Expectation and Top 100 Hours

I. DESCRIPTION OF LOSS OF LOAD EXPECTATION

SDG&E determined the Loss of Load Expectation (LOLE) using the Ventyx Planning and Risk (Planning and Risk) model, a stochastic system dispatch model. Planning and Risk is an electric system analysis and accounting system designed for performing planning studies.[14] It has a chronological structure, which accommodates detailed hour-by-hour simulation of the operations of electric systems. It considers a complex set of operating constraints to simulate the least-cost operation of the system. Planning and Risk's unit commitment and dispatch logic is designed to mimic "real world" power system hourly operation, minimizing system production cost, enforcing the constraints specified for the system, stations, associated transmission, fuel, and so on. The minimization of the system "production cost" is based on generating station production cost. Planning and Risk determines power flow to equalize the incremental costs of all transmission areas in the system and enforce the power flow constraints. A transmission area may import inexpensive power from neighboring transmission areas or export power to replace a neighboring transmission area's expensive power, subject to the limits imposed by available transmission capacity.

The basic inputs to the Planning and Risk model include annual hourly loads and data representing the physical and economic operating characteristics of the electric generating units. In addition, each transmission area is considered attached to the main system by a transmission link; the SDG&E system is modeled to reflect the limited transmission capacity serving its load. A transmission line with capacity equal to the utility's net transmission capability is used to limit SDG&E's ability to import resources.

LOLE in this study is calculated based on the probability of not meeting load in an hour when key system variables are stressed stochastically over multiple iterations. Energy not served (ENS) is the amount of load obligation not covered by available generation over a span of time. The use of ENS in this study provides a greater probability to hours with a higher level of ENS.

[14] More detail on the model can be found at http://www1.ventyx.com/analytics/planning-and-risk.asp.

II. GENERAL METHOD

To understand how the production cost modeling deploys the fundamental data of load demand, unit capacity, and random outage rate, consider a three-unit example. The generation system comprises three units:

	Capacity	Forced Outage Rate
Unit A	50	.05
Unit B	100	.07
Unit C	200	.10
System	350	

For this three-unit system, there are eight combinations of generating units on outage and in service. The following table enumerates all of the states and the probability of each occurrence:

On Outage	MW of outage	In Service	Probability
None	0	A,B,C 350 MW	.95*.93*.90=.79515
A	50	B,C 300 MW	.05*.93*.90=.04185
B	100	A,C 250 MW	.95*.07*.90=.05985
C	200	A,B 150 MW	.95*.93*.10=.08835
A,B	150	C 200 MW	.05*.07*.90=.00315
A,C	250	B 100 MW	.05*.93*.10=.00465
B,C	300	A 50 MW	.95*.07*.10=.00665
A,B,C	350	None 0 MW	.05*.07*.10=.00035
			1.00000

The probability of not being able to supply 220 MW of demand occurs if 220 MW or less capacity is in service. According to the data in the table above, the probability of less than 220 MW being available is:

0.08835+0.00315+0.00465+0.00665+0.00035 = 0.10315

In this simple system of three resources and a load of 220 MW, about 10 percent of the time, the model would show that there were insufficient resources to meet load. The methodology used to conduct the LOLE study is exactly the same, except that it is much more complicated due to considering variations in load and many resources, each with a probability of outage. It involves performing hourly economic dispatch of generation resources against loads for each hour of the year, under different load and resource outcomes generated by a stochastic process, in order to model real world uncertainties.

In a single iteration for each year 2012, 2013, and 2014, there will be 8,760 hours where load must be met with available generation in the system. Monte Carlo random draws reflect: 1) adjusted load for each hour due to weather volatility; and 2) generation-forced outages. In a majority of hours there will be sufficient generation to meet the load, and thus there will not be any un-served energy. But in some hours there will be energy not served if sufficient generation is not available to meet load. Each iteration results in a different number of hours with ENS given the random nature of Monte Carlo draws. The major output from the simulations is a forecast of ENS for each hour of the day per iteration. By comparing the ENS expected during any particular time of use (TOU) period (e.g., summer during 11 am - 6 pm on weekdays) to the full year, the value of incremental capacity in that time period can be calculated relative to other time periods.

III. KEY ASSUMPTIONS

Available generation in calendar years 2012, 2013, and 2014 includes the units that exist in SDG&E's service area as well as owned or contracted thermal units, contracts located outside the service area, and expected renewable and conventional generation additions so that the supply is equal to 115% of the forecasted peak load. SDG&E made two additional assumptions to the model to develop its LOLE analysis. First, it has assumed that during times SDG&E is experiencing peak load conditions, the entire CAISO system is also stressed and therefore available market supplies are limited. Second, demand response is not considered since it can be tailored to the hours with the highest LOLE, rather than being fixed and altering the periods with the highest LOLE.

The analysis uses Monte Carlo draws to reflect higher or lower than normal loads starting with an expected hourly profile of SDG&E loads under average conditions. The largest uncertainty in load in any hour of year is caused by temperature variations from normal. The stochastic model used in this analysis is a "normal mean-reversion" model. There is expected to be a normal (bell-shaped) distribution of loads around the peak daily load value caused by daily temperature variations that is reflected in the "volatility" parameter. "Mean reversion" refers to the statistical property that abnormal daily loads will revert back toward the normal weather level at some specified rate.

The Monte Carlo process used to impact load in the model is done prior to unit commitment dispatch decisions for that week. Such an approach assumes that plant operators have somewhat accurate weekly weather forecasts when they make their unit commitment decisions. In the model, forced outages are modeled as random events over the hours of the year with an assigned probability. A generation unit with a 5% forced outage rate will be out five percent of the hours. In each iteration, the particular hours will vary, but over the year the unit will be out roughly five percent of the time.

IV. OUTPUT

The LOLE analysis produced probabilities of outage for each hour in each month for each of the three years 2012, 2013, and 2014, by dividing the hourly ENS by the total ENS over the year. The probabilities for the 3 years were aggregated by sorting from the highest ENS day to the lowest each month. The days are then aggregated by averaging the hourly probabilities for the highest ENS day of the month, the second highest day, etc., for all days with a non-zero ENS. This approach indicates the relative value in different time periods, not the absolute need for capacity.

V. TOP 100 HOURS METHODOLOGY

The "Top 100 hours" methodology used in this Attachment is a variation on the Top 100 and Top 300 hours used in this and prior GRC Phase 2 proceedings and Rate Design Windows (RDWs). The main difference is that the hours are weighted so that higher load hours receive more weight. The weighting is consistent with the approach used by the Commission consultant, E3, in the allocation of capacity in the distributed generation and demand response cost effectiveness analyses. This approach provides an apples-to-apples comparison with the LOLE analysis that provides more weight to hours with more energy not served.

SDG&E used three years of load research data – 2006, 2007, and 2008. The 100 hours of highest usage for years 2006, 2007, and 2008 were sorted in descending order by system load to provide the top 100 hours for each year. The top 100 hours of each year were then weighted using the following:

$$\frac{1}{(1.15 \times \text{peak load} - \text{load of the particular hour})}$$

These weights were summed to a total and a percentage was calculated based on the weight of a particular hour divided by the total weights for the 100 hours. This procedure provides more weight to hours with load closer to the peak load hour. This particular weighting scheme and the SDG&E distribution of loads in top hours causes the peak load hour to receive roughly double the weight of the 100th hour.

The days within each month were sorted from the day with highest weight to the day with the lowest weight and then averaged. For example, if 2006 had a June with 1 day with top hours, 2007 had 2 days, and 2008 had 5 days, the result would have 5 days, with each ordered day summed and divided by three. Day 1 for all three years are added together and divided by three, day 2 for 2007 and 2008 are added together and divided by three, day 3 from 2008 is divided by three, and so forth through day 5.

VI. COMPARISON OF LOLE AND TOP 100 HOURS PROBABILITIES

In this section the probabilities of the need for capacity are compared between the Top 100 hours approach and the LOLE analysis. In Table 5D-1 below, the probability of the relative need for capacity by month shows the LOLE has a small probability of outage in the Winter (2.2%), unlike the Top 100 hours (0.0%), where Winter is defined as November through April. This result is to be expected since the LOLE considers loss of load due to plant outages as well as stresses caused by high system loads. However, surprisingly, the LOLE provides a more concentrated probability of the need for capacity in July and August (81%) compared to the Top 100 hours approach (54%). The Top 100 hours has more of a normal distribution pattern centered on the month of August.

TABLE 5D-1

Probability of Need for Capacity

Month	LOLE	Top 100 Hours
January	0.05%	0.00%
February	0.02%	0.00%
March	0.25%	0.00%
April	0.00%	0.00%
May	0.00%	0.91%
June	0.00%	10.47%
July	44.85%	24.83%
August	35.83%	28.97%
September	11.27%	27.72%
October	5.82%	7.09%
November	1.80%	0.00%
December	0.00%	0.00%

A second comparison is the need for capacity by hours during the day. In Table 5D-2 below, the comparison of the LOLE and Top 100 hours shows a similar daily pattern. The LOLE analysis has some probability in the Winter (Nov – Apr), so separate Summer and Winter values are shown; in contrast, all the probability for the need for capacity in the Top 100 hours is concentrated in the Summer. Again, the Top 100 hours methodology has more of a normal distribution centered on a peak of 3 pm than the LOLE analysis, which has a concentration within the 3 pm to 4 pm period and fairly long tails. LOLE has higher probabilities for hours at the end of the range of hours of 11 am to 8 pm than the Top 100 hours.

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TABLE 5D-2

Probability of Need for Capacity

Hour	LOLE		Top 100 Hours
	Summer	Winter	All Year/Summer
12 am -1 am	0.00%	0.00%	0.00%
1 am - 2 am	0.00%	0.00%	0.00%
2 am - 3 am	0.00%	0.00%	0.00%
3 am - 4 am	0.00%	0.00%	0.00%
4 am - 5 am	0.00%	0.00%	0.00%
5 am - 6 am	0.00%	0.00%	0.00%
6 am - 7 am	0.00%	0.00%	0.00%
7 am - 8 am	0.00%	0.00%	0.00%
8 am - 9 am	0.00%	0.00%	0.00%
9 am -10 am	0.57%	0.00%	0.00%
10 am -11 am	2.45%	0.00%	0.91%
11 am -12 pm	6.60%	0.00%	3.34%
12 pm -1 pm	12.52%	0.00%	10.05%
1 pm - 2 pm	8.78%	0.00%	14.18%
2 pm - 3 pm	9.57%	0.00%	17.79%
3 pm - 4 pm	23.95%	0.00%	18.88%
4 pm - 5 pm	9.83%	0.00%	16.61%
5 pm - 6 pm	7.35%	0.43%	10.24%
6 pm - 7 pm	7.58%	1.58%	4.30%
7 pm - 8 pm	7.41%	0.00%	2.48%
8 pm - 9 pm	1.11%	0.12%	1.23%
9 pm -10 pm	0.05%	0.00%	0.00%
10 pm -11 pm	0.00%	0.00%	0.00%
11 pm -12 am	0.00%	0.00%	0.00%

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