BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Electric Rate Design Effective on January 1, 2015	Application 14-01-____ (Filed January 31, 2014)

Application 14-01-___
Exhibit No.: (SDG&E-___)

PREPARED DIRECT TESTIMONY OF

DAVID T. BARKER

CHAPTER 3

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION

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January 31, 2014

SDGE

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I. PURPOSE AND OVERVIEW

The purpose of my testimony is to support a proposed change in the time-of-use ("TOU") periods of San Diego Gas & Electric Company ("SDG&E"). This proposal reflects SDG&E's need to respond from an operational perspective to changes in peak demand caused by the large increase in solar generation expected to occur over the next few years in California as a whole and the expected increase in solar generation serving the SDG&E service territory in particular. In other words, the proposed changes to the TOU periods will help manage the shift to a low carbon future by recognizing that the period of high electricity prices will shift to later in the day.

The new TOU periods are designed to send more accurate price signals that will encourage less electricity use when electricity demand and prices are high, and encourage more electricity use when electricity demand and prices are low. For example, residential customers with TOU rates will be incented to shift discretionary activities such as laundry, dishwashing, and electric vehicle charging from early evening when electricity prices are expected to be the highest to other times of the day. It should be noted that SDG&E is not proposing a change in marginal costs from the level proposed in the 2012 General Rate Case ("GRC") Phase 2 proceeding. Rather, as explained in more detail below, SDG&E is proposing to only change the TOU periods, resulting in a new allocation of marginal energy costs ("MEC")[1] and marginal generation capacity costs ("MGCC").[2] In addition, SDG&E is proposing to align all current

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[1] MEC are the added energy costs incurred to meet the projected growth in electricity consumption
[2] MGCC are the added generation costs incurred to meet the projected growth in peak electric demand. MGCC are also referred to as "capacity costs" throughout this testimony.

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TOU rate schedules, so as to give all TOU customers a consistent price signal that reflects expected future electric grid needs in SDG&E's service area.

My testimony is organized as follows:

Section II. Current TOU Periods. SDG&E has a number of different TOU periods in different rate schedules that would be harmonized in this RDW. This section describes the affected rate schedules.

Section III. Expected Changes in the Near Future. The California Independent System Operator ("CAISO"), the California Energy Commission ("CEC"), and independent energy analysts suggest there will be large changes in the hourly profile of energy costs and capacity needs as a significant amount of distributed and central station solar photovoltaics are added to the electric system. These changes necessitate a redefinition of TOU periods (and load-modifying demand response availability periods) to provide appropriate demand side price signals that are necessary to move toward a low carbon future as efficiently as possible. The need for a change in TOU periods was discussed in SDG&E's last General Rate Case ("GRC") Phase 2, and has also been recognized by Southern California Edison Company ("SCE") and by the Energy Division ("ED") of the California Public Utilities Commission ("Commission").

Section IV. Allocation of Marginal Energy Costs to Hours. As significant distributed solar generation lowers demand for electricity in daylight hours and as central station solar produces increased low variable cost energy during daylight hours, the cost of electricity in various hours throughout the year are expected to change accordingly. This section describes the modeling to forecast the changed hourly profile of expected energy prices based on a production simulation model of the western United States and the resulting new hourly price profile.

Section V. Allocation of Marginal Generation Capacity Costs to Hours. As new distributed solar generation lowers the demand for local capacity in daylight hours and as new central station solar produces increased resource adequacy in daylight hours, the local San Diego needs for capacity in various hours throughout the day are expected to change. To a lesser extent, new solar will also impact the time at which there is likely a statewide need for capacity. This section describes the modeling to forecast the changed hourly expectations of the needs for capacity.

Section VI. Determination of New TOU Periods: Accurate price signals provide utility customers, or demand response providers who aggregate customer loads, with the proper incentives to make consumption/demand response decisions and result in improved economic efficiency. Hourly prices would provide 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 costs. Based on the data on hourly energy price profiles and periods of local and system capacity needs, a recommendation is made to shift the SDG&E on-peak TOU period for Summer to 2 p.m. - 9 p.m. on non-holiday weekdays and for Winter to 5 p.m. - 9 p.m. on non-holiday weekdays for all TOU rate schedules. In addition, a super off-peak TOU period is proposed for all rate schedules as 12 a.m. – 6 a.m. daily, with all other periods being semi-peak.

Section VII. Statement of Qualifications: This section presents my qualifications.

II. CURRENT TIME OF USE PERIODS

SDG&E has a number of rate schedules with different TOU periods as shown in Table DTB-1 below. These TOU periods vary because they were adopted at different times and for different customer groups, some which have not been changed for 30 years.

Table DTB-1. Current SDG&E TOU Rate Schedules

Standard TOU Period	SCHEDULES EV-TOU, EPEV-X, EPEV-Y, EPEV-Z
Summer (May 1 - October 31) On-Peak: 11 a.m. to 6 p.m. Weekdays Semi-Peak: 6 a.m. to 11 a.m. and 6 p.m. to 10 p.m. Weekdays Off-Peak: All Other Hours including Weekends & Holidays **Winter (November 1 - April 30)** On-Peak: 5 p.m. to 8 p.m. Weekdays Semi-Peak: 6 a.m. to 5 p.m. and 8 p.m. to 10 p.m. Weekdays Off-Peak: All Other Hours including Weekends & Holidays	**Summer (May 1 - October 31)** On-Peak: 12 p.m. to 8 p.m. Every Day Super Off-Peak: 12 a.m. to 5 a.m. Every Day Off-Peak: All Other Hours **Winter (November 1 - April 30)** On-Peak: 12 p.m. to 8 p.m. Every Day Super Off-Peak: 12 a.m. to 5 a.m. Every Day Off-Peak: All Other Hours
SCHEDULE DR-TOU	**SCHEDULE AS-TOD**
Summer (May 1 - October 31) On-Peak: 12 p.m. to 6 p.m. Weekdays Off-Peak: All Other Hours including Weekends & Holidays **Winter (November 1 - April 30)** On-Peak: 12 p.m. to 6 p.m. Weekdays Off-Peak: All Other Hours including Weekends & Holidays	**Summer (May 1 - October 31)** On-Peak: 11 a.m. to 6 p.m. Weekdays Off-Peak: All Other Hours including Weekends & Holidays **Winter (November 1 - April 30)** On-Peak: 5 p.m. to 8 p.m. Weekdays Off-Peak: All Other Hours including Weekends & Holidays
SCHEDULE DR-SES	**SCHEDULE EV-TOU-2**
Summer (May 1 - October 31) On-Peak: 11 a.m. to 6 p.m. Weekdays Semi-Peak: 6 a.m. to 11 a.m. and 6 p.m. to 10 p.m. Weekdays Off-Peak: All Other Hours including Weekends & Holidays **Winter (November 1 - April 30)** Semi-Peak: 6 a.m. to 6 p.m. Weekdays Off-Peak: All Other Hours including Weekends & Holidays	**Summer (May 1 - October 31)** On-Peak: 12 p.m. to 6 p.m. Every Day Super Off-Peak: 12 a.m. to 5 a.m. Every Day Off-Peak: All Other Hours **Winter (November 1 - April 30)** On-Peak: 12 p.m. to 6 p.m. Every Day Super Off-Peak: 12 a.m. to 5 a.m. Every Day Off-Peak: All Other Hours

SDG&E proposes to harmonize these rate schedules in this RDW proceeding by providing consistent on-peak, semi-peak and super off-peak time periods for all rate schedules with TOU periods for both summer and winter seasons.[3] All customers should have the same price signals as to when electricity is expensive and when it is less expensive to guide consumption and demand response decisions.

III. EXPECTED CHANGES IN NEAR FUTURE

Because of California's drive to a low carbon economy and an in-state preference for renewables, as shown below, renewable technologies including solar and wind energy will have much higher penetration in the near future and will have significant impacts on the California and San Diego electricity markets. 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. As a result of the 33 percent Renewable Portfolio Standard ("RPS"), when these renewables produce energy it is accepted by the grid regardless of need or price; hence, they are labeled "must-take" resources.

As variable renewable energy displaces fossil energy, the hours grouped today as the most expensive for which to provide electricity are no longer be the right set of hours for purposes of consumer decision-making about electricity use. I provided a preliminary

[3] These rate schedules reflect the seasons adopted in the SDG&E 2012 GRC Phase 2 Application, D. 14-01-002.

assessment of the coming required changes to TOU periods in my 2012 GRC Phase 2 testimony, originally filed in 2012.[4]

SDG&E is not alone in recognizing the significant changes on the horizon. In the 2013 Integrated Energy Policy Report ("IEPR") proceeding at the CEC, a workshop was held to begin to think about the long-term implications of expanded renewables on the electricity market in California. Table DTB-2, taken from a presentation at the CEC workshop, shows the large increase expected in renewables by the CAISO over the next 10 years, with over 70 percent being in-state variable renewable generation (wind and solar).[5]

Table DTB-2. Significant Increase in In-state Wind and Solar

Projected RPS Additions
2013 - 2022

Technology	Projected Annual Energy (GWh)			Nameplate Capacity (MW)
	In-State	Out-of-State	Total	
Solar	18,843	1,633	20,476	9,115
Wind	4,481	1,496	5,977	2,149
Geothermal	3,766	1,200	4,965	688
Biofuels	1,377	0	1,377	193
Small Hydro	0	0	0	0
Total	28,468	4,328	32,796	12,144

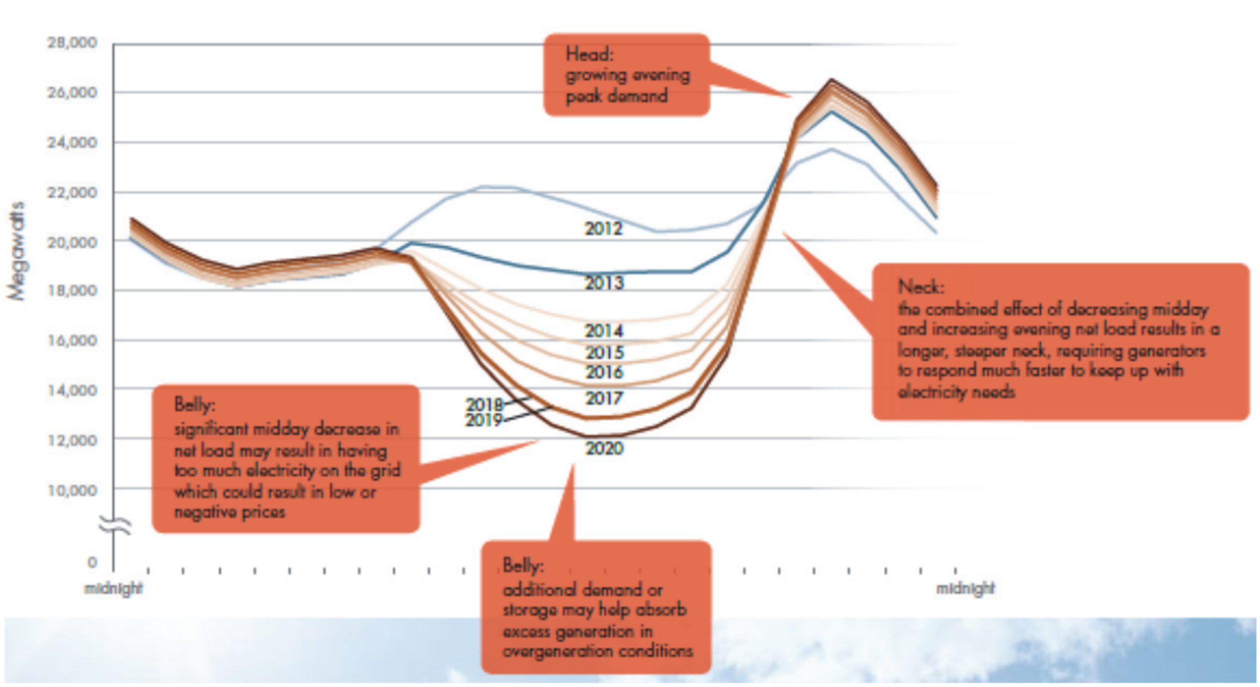
Source: California ISO

[4] See Attachment A of the Revised Prepared Direct Testimony of David T. Barker in the GRC Phase 2 Application, A.11-10-002, filed February 2012.

[5] Dave Vidaver, Electricity Analysis Office, Electricity Supply Assessment Division, "Evaluating Electricity System Needs in 2030," IEPR Lead Commissioner Workshop on Evaluation of Electricity System Needs in 2030, Sacramento, CA, August 19, 2013, based on data provided by the CAISO.

Charts DTB-1 and DTB-2 below show expected impact on typical electricity loads net of solar and wind energy in the winter and summer seasons. Chart DTB-1 below is the CAISO's "duck graph" from the CAISO document, "Building a Sustainable Future, 2014-2016 Strategic Plan."[6] As shown in the graph, net demand will become lower mid-day. Price signals to increase usage midday and reduce evening demand will reduce the required flexible generation resources to keep up with the ramp-up in electricity needs.

Chart DTB-1. Spring Loads Net of Wind and Solar



By 2017, the impact of solar on the net load shape will be substantial, requiring significant ramping resources in the afternoon to meet peak net demands in the early evening in winter and spring. TOU periods to encourage reduction in customer demand in the evening hours and increase customer energy use midday can reduce the severity of the need for ramping resources.

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[6] CAISO, "Building a Sustainable Future, 2014-2016 Strategic Plan," page 9.

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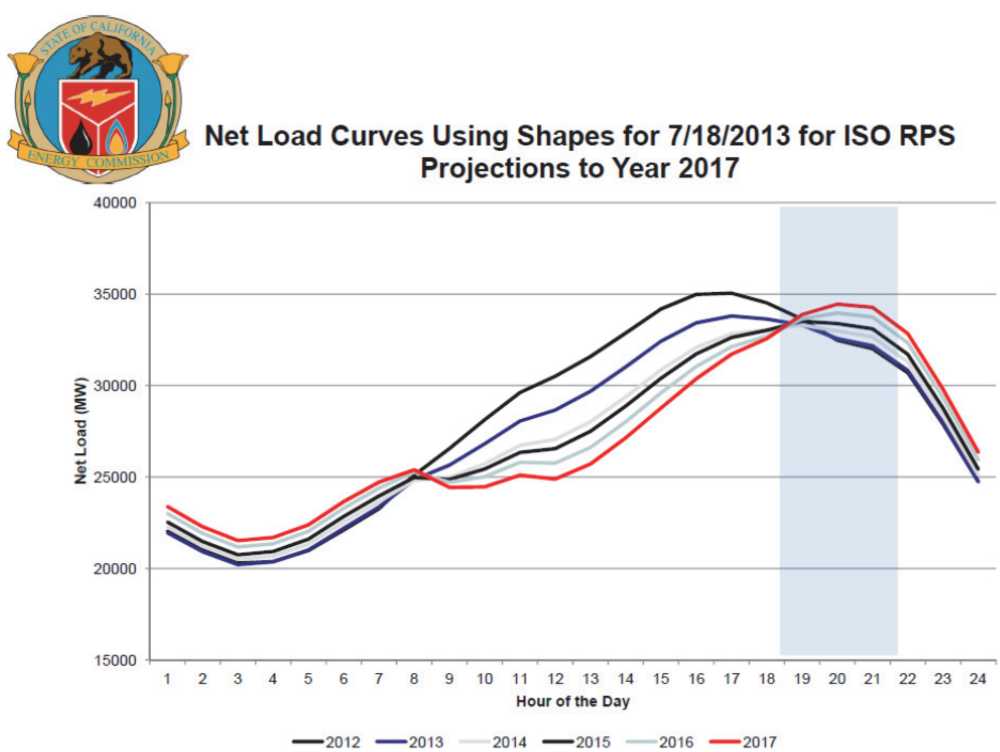
Chart DTB-2 below shows that by 2017, current TOU periods, with incentives to shift loads from summer afternoons (11 am- 6 pm) to early evening hours (6 pm – 9 pm), will no longer provide the right price signal statewide, but will exacerbate the peak load net of renewables. Adjustment of the TOU periods to encourage more customer electricity use in the midday hours (11 am – 2 pm) when solar is producing at its maximum and to encourage less customer use in evening hours (6 pm – 9 pm), highlighted in Chart DTB-2) will provide the right signal.[7]

Chart DTB-2. Summer Loads Net of Wind and Solar



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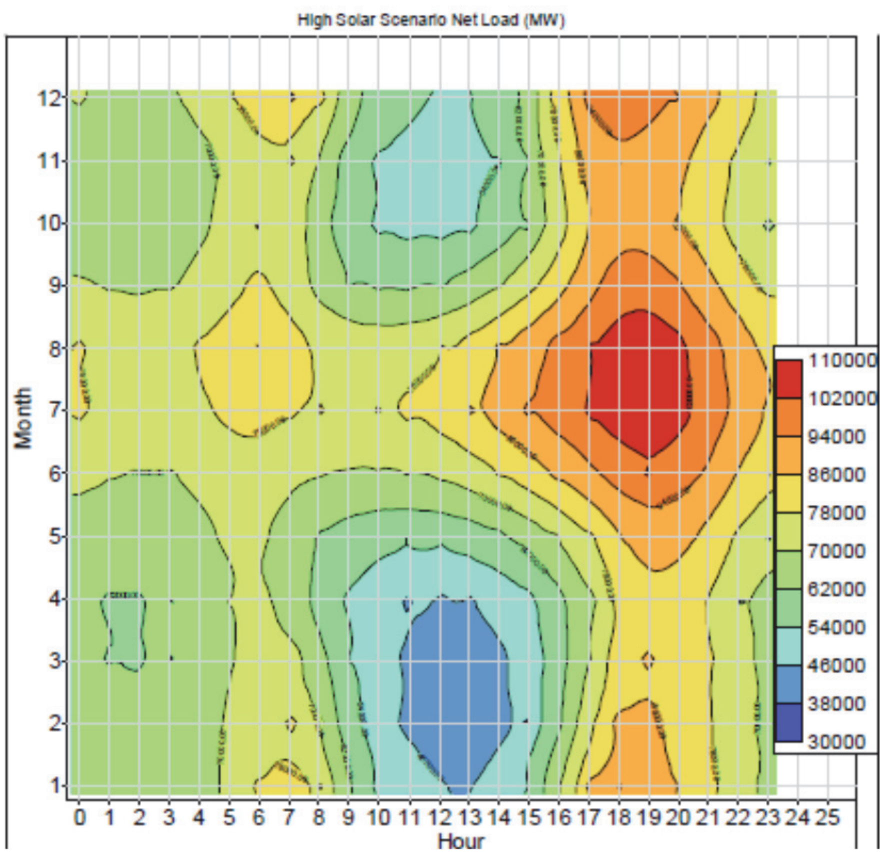
[7] Dave Vidaver, Electricity Analysis Office, Electricity Supply Assessment Division, "Evaluating Electricity System Needs in 2030," IEPR Lead Commissioner Workshop on Evaluation of Electricity System Needs in 2030, Sacramento, CA, August 19, 2013. This need to shift demand from early evening hours was also highlighted in the presentation by Craig Lewis, Executive Director of Clean Coalition, "Distributed Generation + Intelligent Grid Optimizing Value for Ratepayers," August 22, 2013 IEPR workshop, slide 16.

Data developed by the National Renewable Energy Lab ("NREL") similarly points to a changing shape of electricity load net of renewable resources.[8] The Western Wind and Solar Integration Study Phase 2 shows graphically that significant solar generation in the West can lead to significant changes in expected load net of renewable resources. In particular, the study provides a "contour map" that color codes net demand by month and hour that is reproduced in Chart DTB-3 below. The highest load net of renewable resources in the high solar penetration case is in the early evening hours between 5 pm and 9 pm in the Summer as represented by the red area. The contour map also shows ramping needs would be the largest in Winter and Spring– where contour lines are narrowest – and occur between midday and the early evening hours.

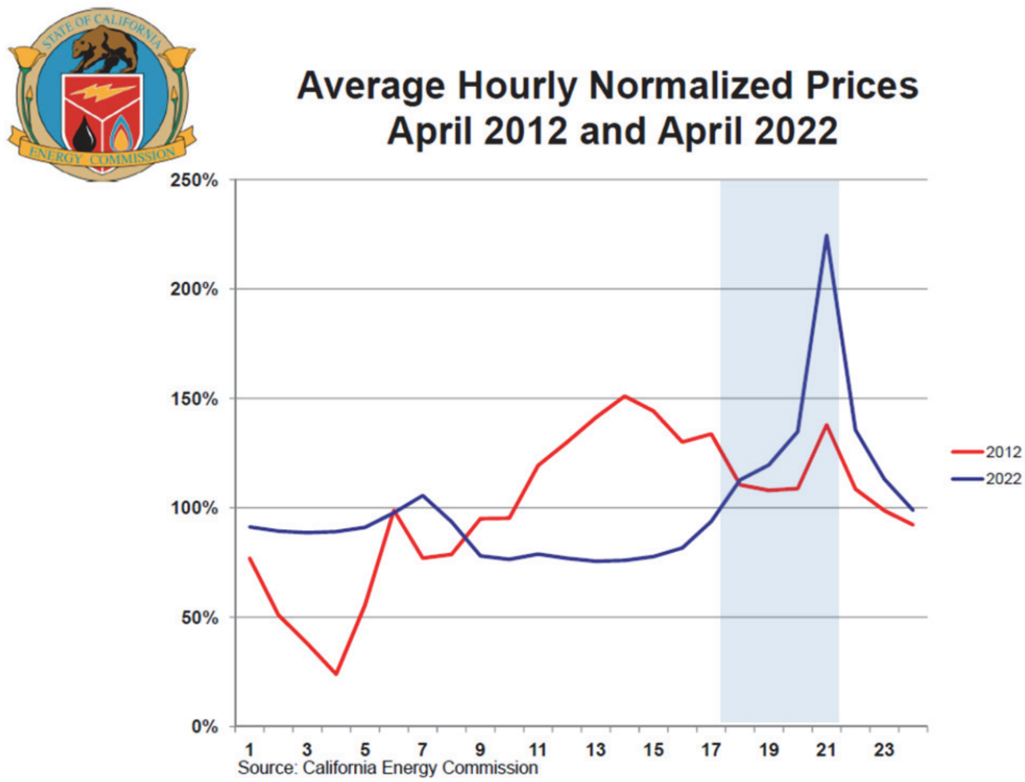
Chart DTB-3. Hourly Net Load by Month with High Solar Penetration



[8] D. Lew, G. Brinkman, E. Ibanez, A. Florita, M. Heaney, B.-M. Hodge, M. Hummon, and G. Stark, *The Western Wind and Solar Integration Study Phase 2*, Technical Report NREL/TP-5500-55588, September 2013.

The addition of must-take solar energy is also expected to impact electricity prices as shown in Chart DTB-4 below. Marginal electricity costs will become lower midday and will become consistently higher in the early evening hours as shown in the snapshot of Chart DTB-4.[9]

Chart DTB-4. Change in Electricity Price Shape



Numerous studies have documented the impact of solar on the changing the needs for capacity, though most do not indicate how the peak net of variable renewable generation changes.[10] But as Andrew Mills and Ryan Wiser explain in their recent study, "At high

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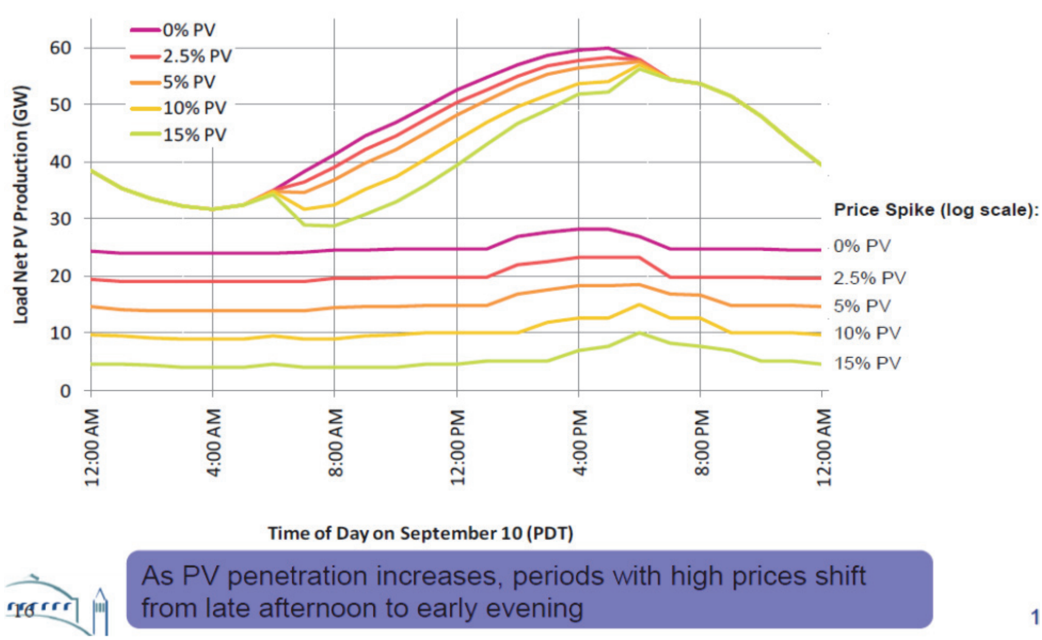
[9] Dave Vidaver, Electricity Analysis Office, Electricity Supply Assessment Division, "Evaluating Electricity System Needs in 2030," IEPR Lead Commissioner Workshop on Evaluation of Electricity System Needs in 2030, Sacramento, CA, August 19, 2013.

[10] Most document the declining capacity value of solar as solar penetration increases without explicitly saying this occurs because the peak net of solar shifts to evening hours. See Andrew Mills and Ryan Wiser, "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes," Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley CA, December 2012, page 24, figure 8.

penetration, the capacity credit of PV [photovoltaics] and CSP0 [concentrating solar power without storage] drop by a considerable amount …. because with high PV and CSP0 penetration **the net load peaks during early evening hours, and no increase in PV or CSP0 capacity can help meet demand during that time**."[11][Emphasis added] Mills shows this graphically in Chart DTB-5 below, a graph similar to Chart DTB-2, except here the adjusting factor is explicitly the amount of solar production.[12] As the net load peak shifts to after 6 p.m., added amounts of solar have a relatively small impact on net load peak reduction. Thus, the hours with expected highest electricity prices and the largest need for new capacity are expected to occur later in the day and new TOU periods (and associated load-modifying demand response periods) are needed to address this new high net load period that cannot be met with added solar generation.

Chart DTB-5. Peak Load Net of Solar in Summer

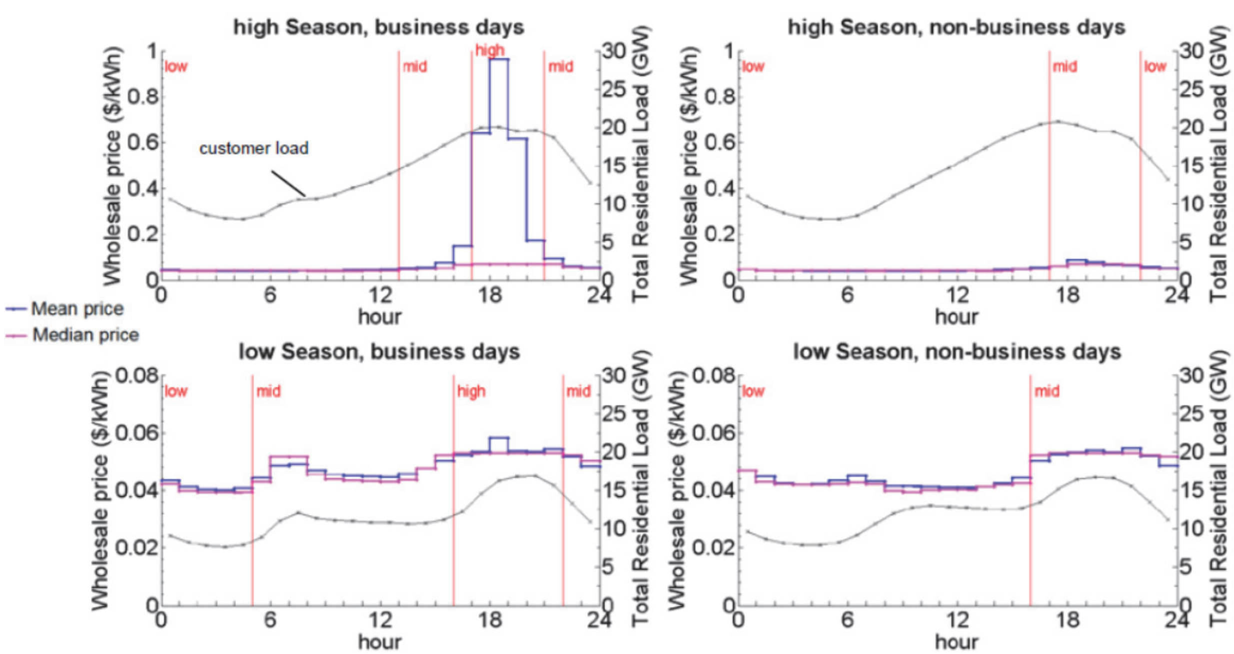


[11] Andrew Mills and Ryan Wiser, "Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California," Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley CA, May 2012, page 43.

[12] Andrew Mills, "Assessment of the Economic Value of Photovoltaic Power at High Penetration Levels," Lawrence Berkeley National Laboratory, UWIG Solar Integration Workshop, October 11, 2011, slide 16.

In another study by the Ernest Orlando Lawrence Berkeley National Laboratory, researchers developed a forecast of electricity prices in California with 33 percent renewables. High electricity prices no longer occur in the afternoon hours, but, instead, occur in the early evening hours during the Summer.[13] The data summarized in Chart DTB-6 shows the increased coincidence of residential customer load and the new hours of high energy prices during summer days. Thus it is important to provide price signals and load-modifying demand response to engage this customer class, in particular, in providing load reductions to impact the new period of high electricity prices.

DTB-6. Electricity Prices with 33% Renewables



The purpose of presenting these studies is to show that California is expecting a change in circumstances in the not too distant future as a high penetration of variable renewable generation, both distributed and central station, occurs. Both the energy price profiles and

[13] Naïm Darghouth, Galen Barbose, and Ryan Wiser, "Electricity Bill Savings from Residential Photovoltaic Systems: Sensitivities to Changes in Future Electricity Market Conditions," Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley CA, January 2013, figure 12, page 42.

periods of need for capacity change and shift to later in the day as the penetration of solar energy increases.

Recently, the Energy Division of the CPUC released a report, "Staff Proposal for Residential Rate Reform in Compliance with R.12-06-013 and Assembly Bill 327," that acknowledges TOU periods need to change.[14] The report states,

> Most parties recognize that TOU time periods and seasons will likely need to change in the future to reflect changes in customer load shapes, shifts in system peak and utility marginal costs, the value of generation on the grid at different hours of the day as well as '…the changing nature of how customers will demand power from, and increasingly will supply power to the grid.'"[15]

The Energy Division Staff then makes the following recommendation for TOU time periods:

> …staff believes that TOU time periods and rate design need to be carefully developed in the context of GRCs, or comparable rate setting proceedings. Between now and the time of default to TOU rates in 2018, the Commission should assess the appropriate TOU time periods and seasons that best reflect marginal costs and advance the OIR rate design principles. AB 327 directs the Commission to strive to adopt time periods for TOU rates that are appropriate for five years.[16]

SCE, in recognizing the directives of the legislature and the Commission, recently filed a new set of TOU hours for proposed residential rate schedule TOU-D. SCE establishes an on-peak period to 2 pm - 8 pm weekdays throughout the year. SCE's on-peak period includes hours later in the day "because the latter part of the newly proposed on-peak window better aligns with SCE's future system-wide generation peak (because of the 33 percent RPS requirement), and also aligns with SCE's current residential peak usage."[17] SCE states "it is prudent to begin now

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[14] Energy Division, "Staff Proposal for Residential Rate Reform in Compliance with R.12-06-013 and Assembly Bill 327," January 3, 2014.
[15] Id., at 60-61.
[16] Id. At 62-63.
[17] SCE, "Prepared Testimony in Support of SCE's 2013 Rate Design Window Application," filed December 24, 2013, at 20.

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(with several years of lead time) on TOU rates that designate the appropriate on-peak window to which customers can begin becoming accustomed."

The SDG&E proposed TOU period hours move toward a TOU period structure consistent with the ED's proposed criteria that it consider marginal costs, encourage conservation and energy efficiency, consider coincident and non-coincident peak, and be stable and understandable.

IV. ALLOCATION OF MARGINAL ENERGY COSTS TO HOURS

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, prices are determined by supply and demand conditions. Demand is based on customer electricity usage and offset in part by customer generation, primarily from rooftop solar. Supply is also partly outside the control of the CAISO. Variable renewable generation such as solar and wind are must-take since they produce as nature supplies. Hydro facilities can be dispatchable, but may have requirements to run for the environmental health of the natural water (lake or river) system. Some fossil resources are contractually must-take, such as combined heat-and-power facilities that operate primarily to provide heat for the facilities' thermal needs. Other fossil resources are "must-run," operating in order to provide grid stability, providing regulation down, inertia, and spinning reserves to accommodate load variations and the intermittency of renewable generation. Finally, there are dispatchable fossil resources that bid into the CAISO's markets to meet the variable consumer demands for electricity in excess of the must-run and must-take supply resources.

With added wind energy production at night, supply increases relative to demand and the electricity price is forecast to fall relative to the average price. With added distributed solar, customer demands for electricity are reduced in the middle of the day when solar production is at a maximum. With added central station solar generation, supply increases at midday relative to demand. This combination moderates electricity market prices in those hours, all other things being equal.[18] The allocation of marginal energy costs to hours will thus be affected by these expected changes in the level of intermittent renewable generation.

To assess the impact on the allocation of marginal energy costs to hours, SDG&E used a production cost model of the entire Western Electric Coordinating Council ("WECC") area. The energy market is for the most part determined by loads and generation throughout the WECC, though there can be locational differences based on local loads and transmission constraints. The analysis of the electricity price is based on the operation of power plants using Ventyx's Market Analytics production cost model. The model evaluates in detail the least cost dispatch of the electricity supply to meet system demand on an hourly basis taking into account must-take generation. It considers a complex set of operating constraints on power plants and on the transmission system to mimic "real world" power system hourly operation. The model minimizes system production cost, enforcing constraints on generation and transmission operations. 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 primary data inputs to the production cost model for outside California are from Ventyx data on electric demand forecasts and generation resources. Ventyx develops these forecasts by collecting data from various sources, including demand forecasts filed by utilities before the FERC. For California, the modeling is based on the Mid-Case scenario from CEC's

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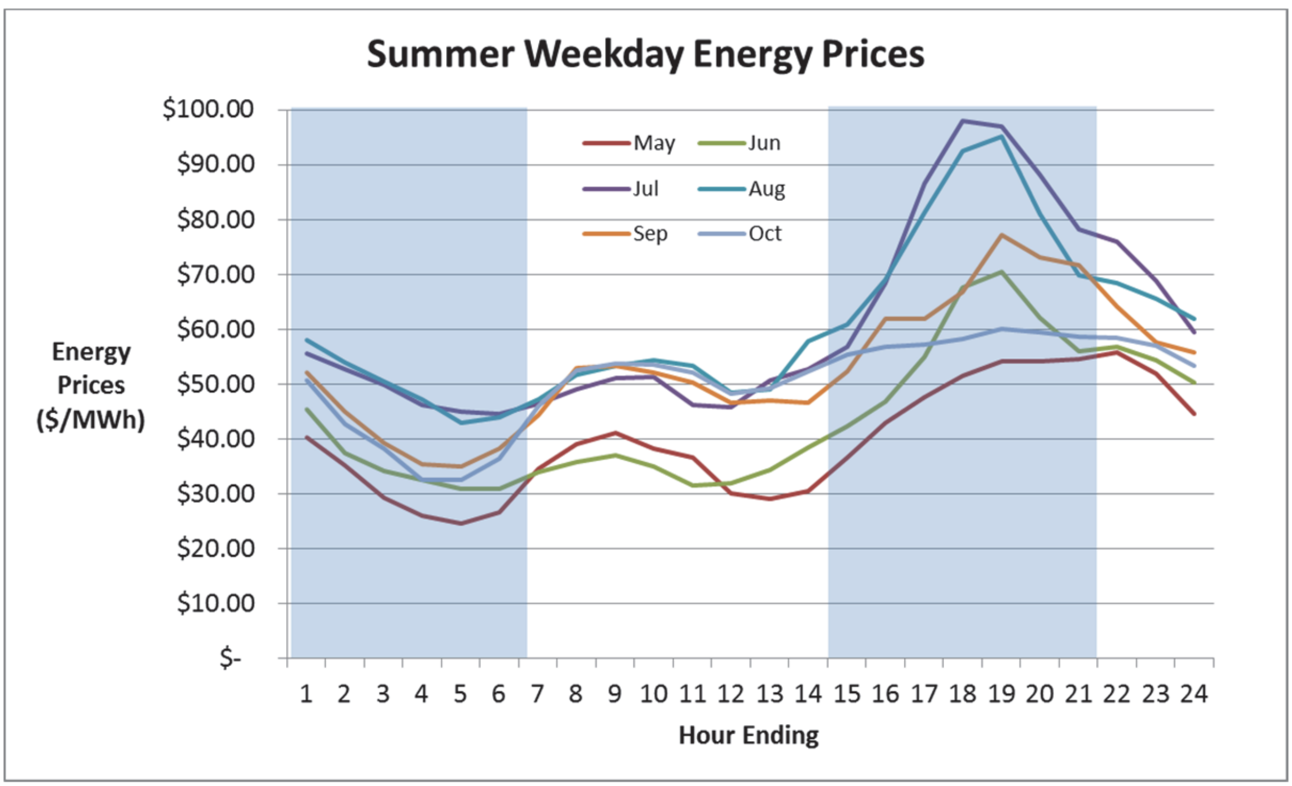
[18] The effect is called the "merit-order effect" and has been documented in Germany. See for example Tveten, Asa Grytli, et al. "Solar feed-in tariffs and the merit order effect: A study of the German electricity market," *Energy Policy,* Volume 61, October 2013, 761–770.

Revised California Energy Demand Forecast 2012-2022, dated February 2012. Since the CEC forecast did not include any uncommitted energy efficiency starting in the year 2013, the forecast was reduced for the projected incremental uncommitted electric savings from the Mid Savings Scenario included in the CEC Preliminary Demand Forecast.

The production cost model results for 2017 were used to assess the grouping of hours to provide a price signal appropriate to California's long-term low carbon future. The production cost model output prices were adjusted to match the average annual price and the spread of prices as used in the 2012 GRC Phase 2 so as to not change marginal energy costs, but reallocate those costs to new hours. The resulting SDG&E DLAP hourly prices for on-peak days in Summer are shown in Chart DTB-7 and for Winter in Chart DTB-8.[19]

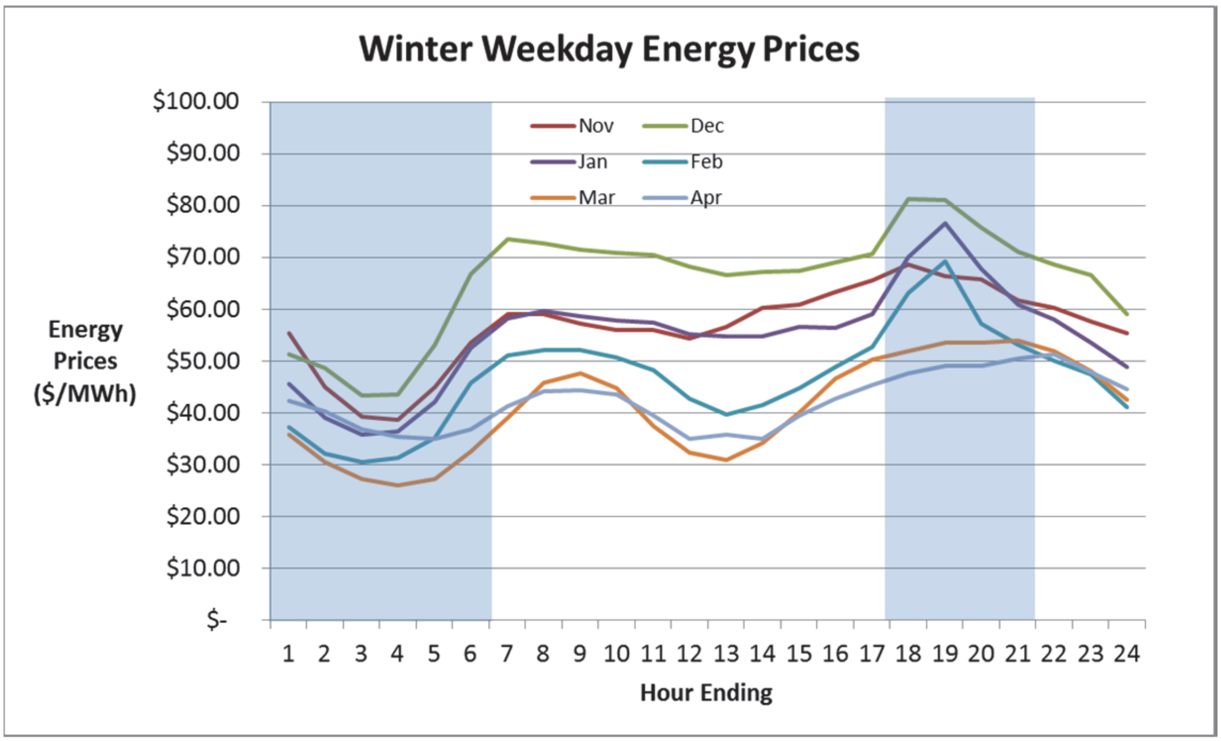
Chart DTB-7. Summer Electricity Prices with 2017 Hourly Allocators



[19] All hours shown are for "clock time." Pacific Standard time is used for months where applicable and Pacific Daylight time is used where applicable (3/12/2017- 11/5/2017).

The shaded areas represent the proposed new TOU periods. As can be clearly seen in the graph, elimination of the hours 11 am – 2 pm (hours ending 12-14) from on-peak and adding 6 pm – 9 pm (hours ending 19-21) in the Summer are both consistent with marginal electricity prices. It is further noted that including May and to a lesser extent June in the Summer period dampens the TOU energy price signal for the Summer period.

Chart DTB-8. Winter Electricity Prices with 2017 Hourly Allocators



There is significant diversity across months, but the proposed TOU periods capture the difference in prices throughout the day with the exception of midday in February, March and April, where the "duck belly" effect of the load net of solar declining, significantly impacting expected electricity prices.

The proposed TOU periods would capture the hours with the highest electricity prices even before the significant shift due to added solar energy in 2014-2017. The charts below show the SDG&E average DLAP prices by month for 2013 summer and winter. Even before the added renewables, the proposed periods capture the highest electricity prices.

Chart DTB-9. 2013 Summer SDG&E DLAP Electricity Prices

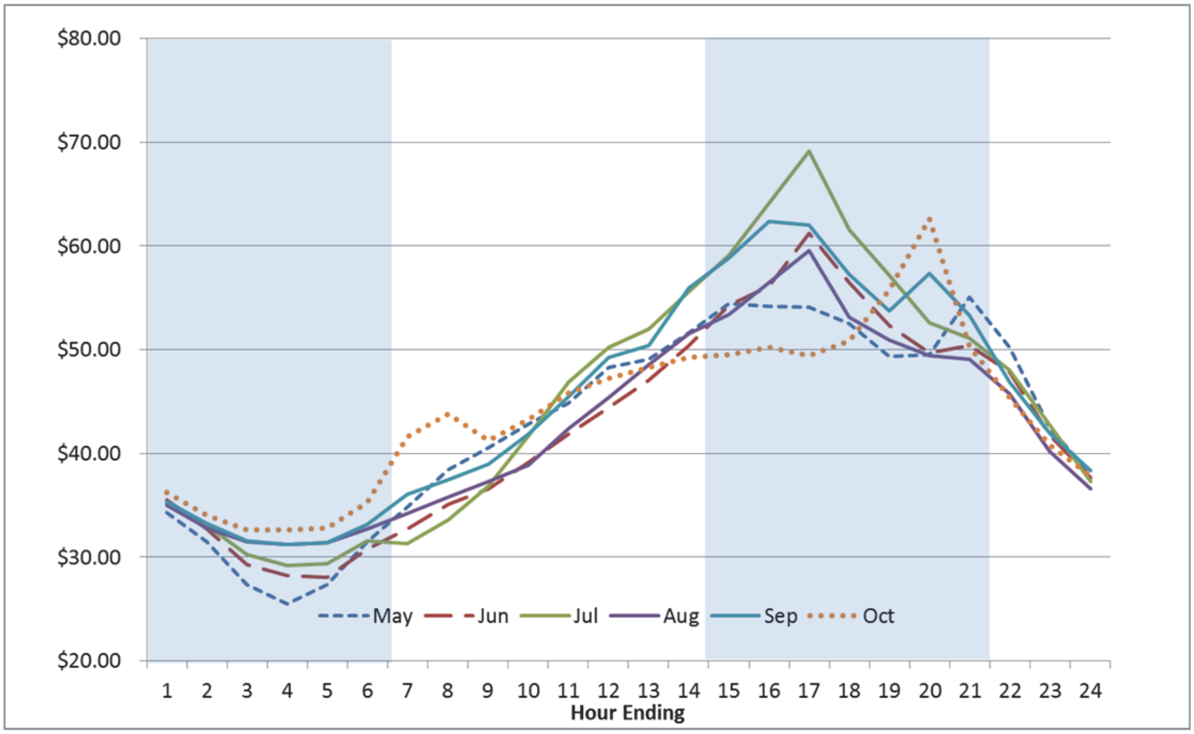
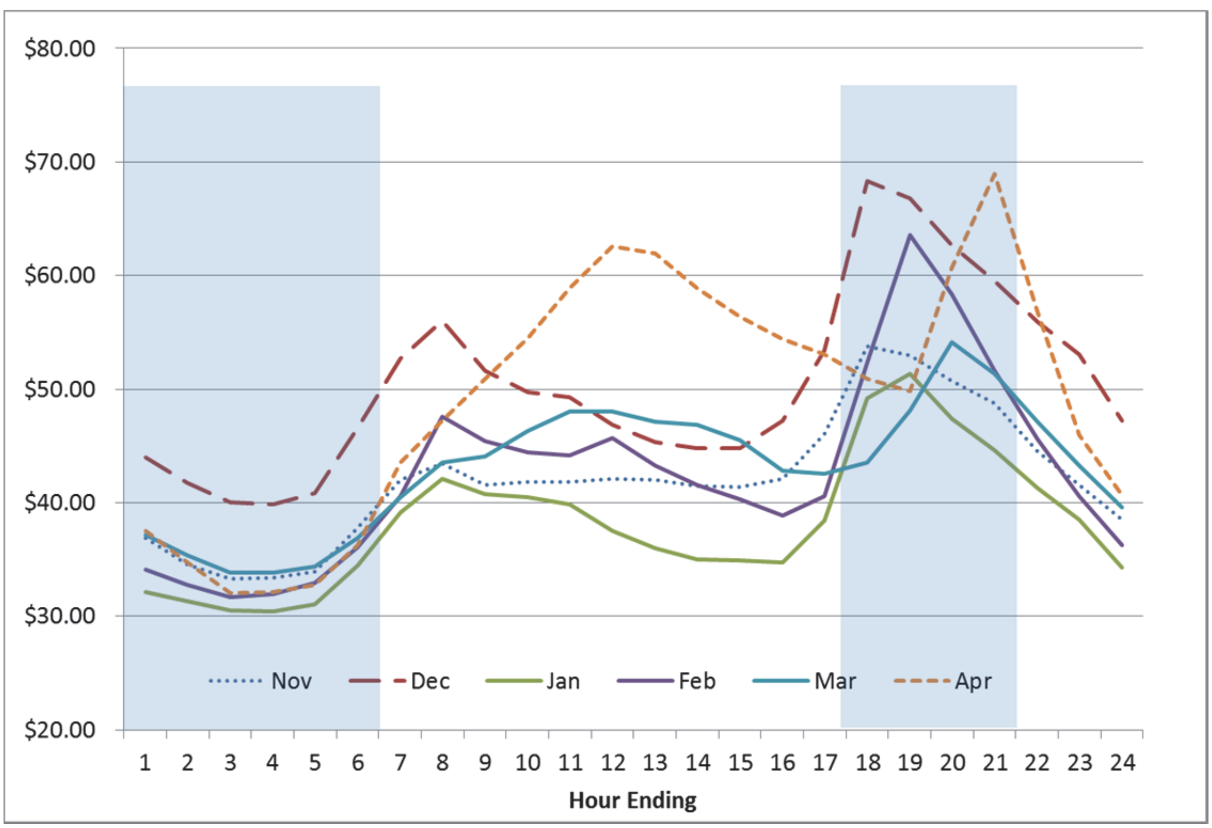


Chart DTB-10. 2013 Winter SDG&E DLAP Electricity Prices



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V. ALLOCATION OF MARGINAL GENERATION CAPACITY COSTS TO HOURS

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. The capacity component reflects the incremental cost of acquiring sufficient generating resource capacity to have on hand to meet customer demands during high net load conditions (customer load net of distributed and central station variable renewables), taking into consideration the uncertainty associated with customer demands and variable renewable generation. The TOU periods (and load modifying demand response periods) should be established to provide the right price signals; to reduce demand in periods of high net load (whether by price response, demand response programs or energy efficiency), and increase demand in periods of low net load.

To identify the periods of high net load and the likelihood of needing additional resources, SDG&E undertook two distinct methods. The first method is the same as presented in the 2012 GRC Phase 2, an investigation of net loads to see which hours are expected to experience the highest net loads. A second approach is Loss of Load Expectation ("LOLE") analysis; this type of analysis provides the expectation of the hours with the highest need for new resources given the variable nature of customer demands due to weather and the variable nature of solar and wind energy production. The net load analysis is deterministic and simple, while the LOLE analysis is stochastic and complicated.

A. NET LOAD ANALYSIS

The use of customer load net of distributed generation and central station renewables provides an indirect measure of when local capacity is likely to be needed. The basis of the analysis is SDG&E forecasted 2017 load data net of distributed solar. SDG&E forecasted system usage takes into account economic growth, energy efficiency, and expected expansion of distributed solar generation. The average usage on Summer weekdays is shown in Chart DTB-11, while Winter is shown in Chart DTB-12.

Chart DTB-11. 2017 Summer Load Net of Distributed Solar

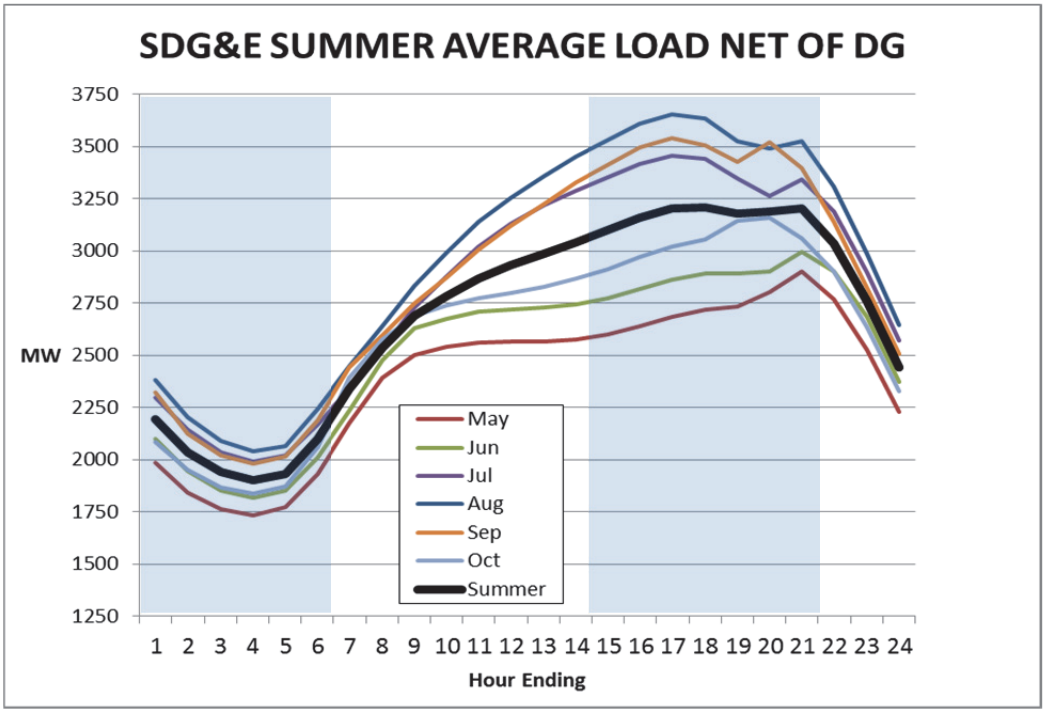
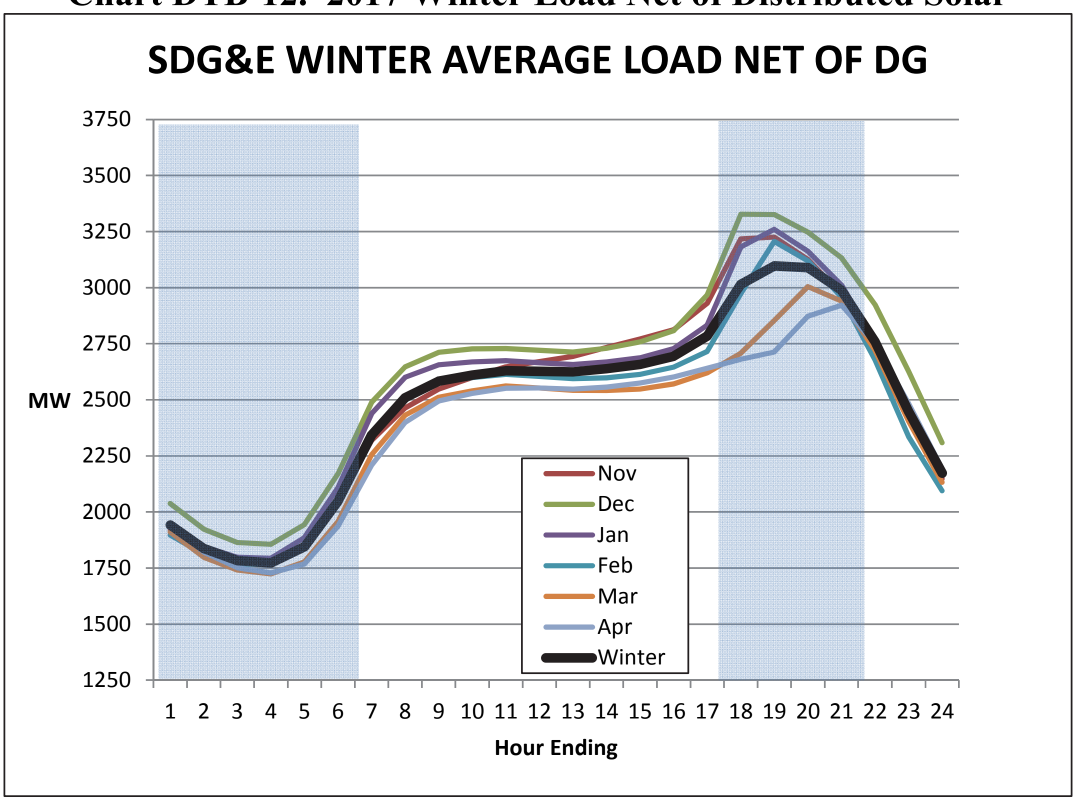
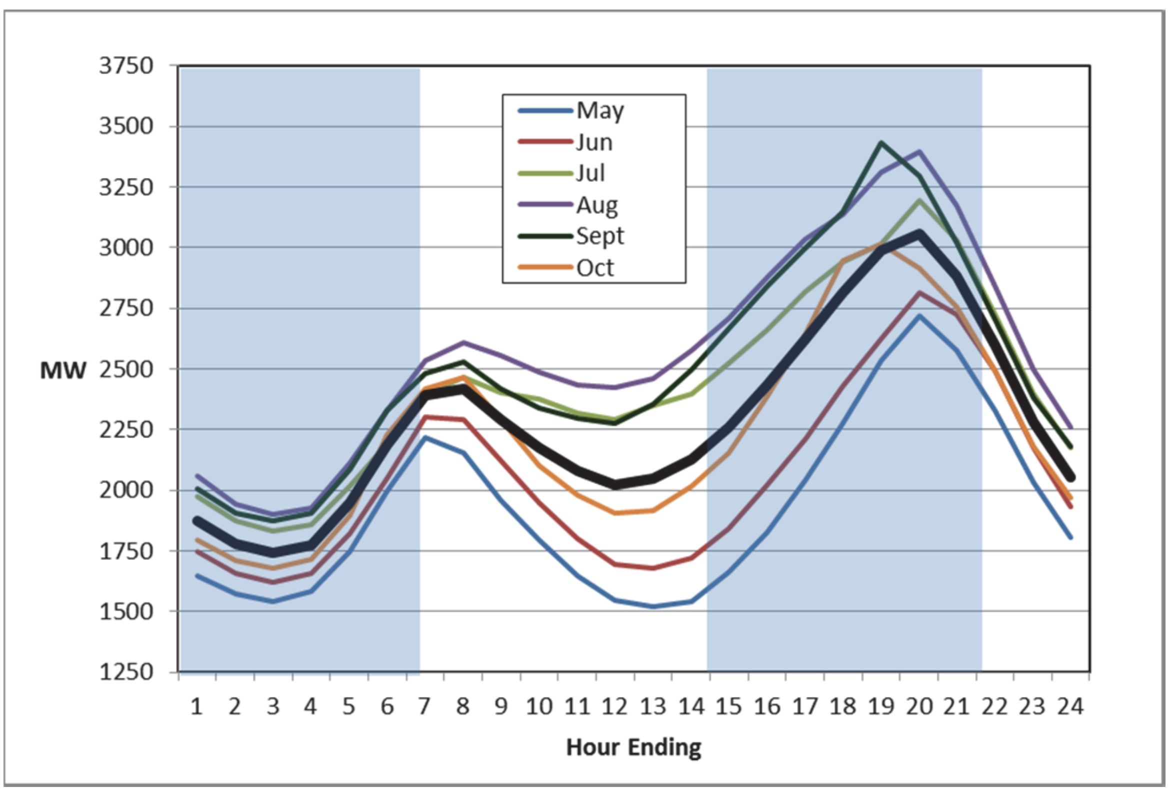


Chart DTB-12. 2017 Winter Load Net of Distributed Solar



The next level of detail is to model the impact of central station solar and wind serving SDG&E load from within San Diego and Imperial Valley. The CAISO treats San Diego and Imperial Valley as a local capacity area.[20] The solar and wind generation are estimated based on averaged actual past production if the resource already exists, or a generic profile if the resource has been contracted for by SDG&E, but is not yet operational. This average production is deducted from load net of distributed solar to develop the likely hours of need for local capacity. The SDG&E system-wide hourly load forecast net of distributed solar as modified for expected average hourly production profiles of central station wind and solar is then averaged for each hour of weekdays for each month by season and presented in Charts DTB-13 and DTB-14 below.

Chart DTB-13. 2017 Summer Load Net of All Wind and Solar



[20] CAISO's "2014 Local Capacity Technical Analysis, Final Report and Study Results," April 30, 2013, pages 94-104. See also D.13-06-024, pages 6-7 and Ordering Paragraph 1.

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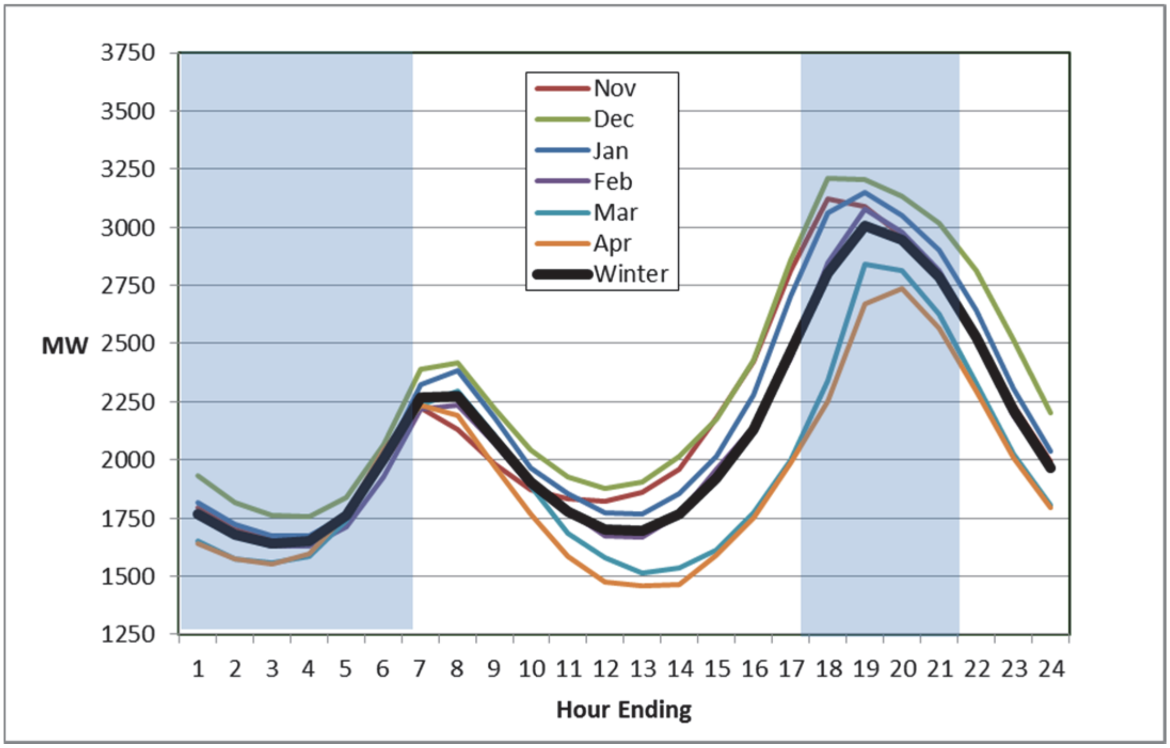
Chart DTB-14. 2017 Winter Load Net of All Wind and Solar



Both charts show the proposed on-peak TOU periods would capture periods with the highest loads net of variable renewable generation, though the summer on-peak period includes a significant number of relatively low net load hours in the afternoon.

While average patterns are important for choice of TOU periods to provide the right price signals to encourage load modifying behavior, assignment of marginal generation capacity costs ("MGCC") has historically used a top 100 hours approach or the LOLE approach. The top 100 hours allocated capacity value to the top hours based on historical experience. In the GRC Phase 2, historical load data over the three year period 2006-2008 was used. A top 100 hours approach on an historical basis will not work where the future is much different than the past, but a top 100 hours on a forecast basis is also not as meaningful since the historical data provided a stochastic element. But for informational purposes, Chart DTB-15 provides a look at the variability across high net load days. Chart DTB-16 provides an allocation of the top 100 hours to weekday summer periods on a forecast basis.

Chart DTB-15. 2017 Top 100 Hour Days

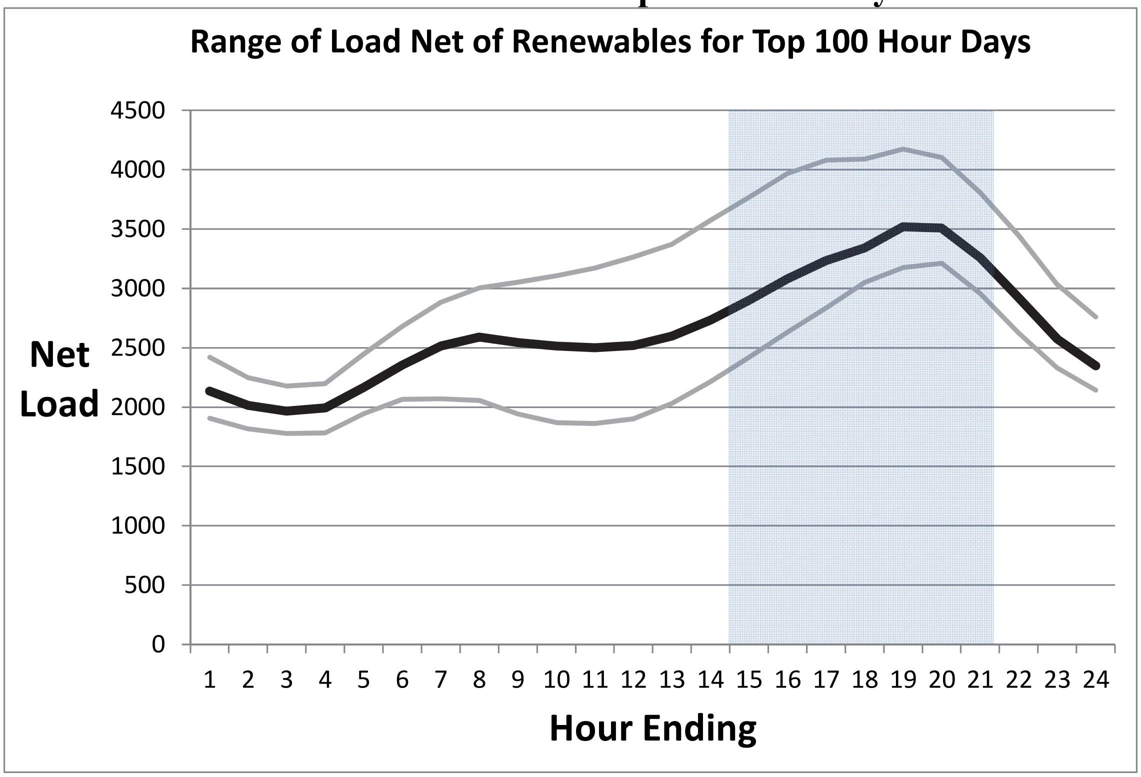
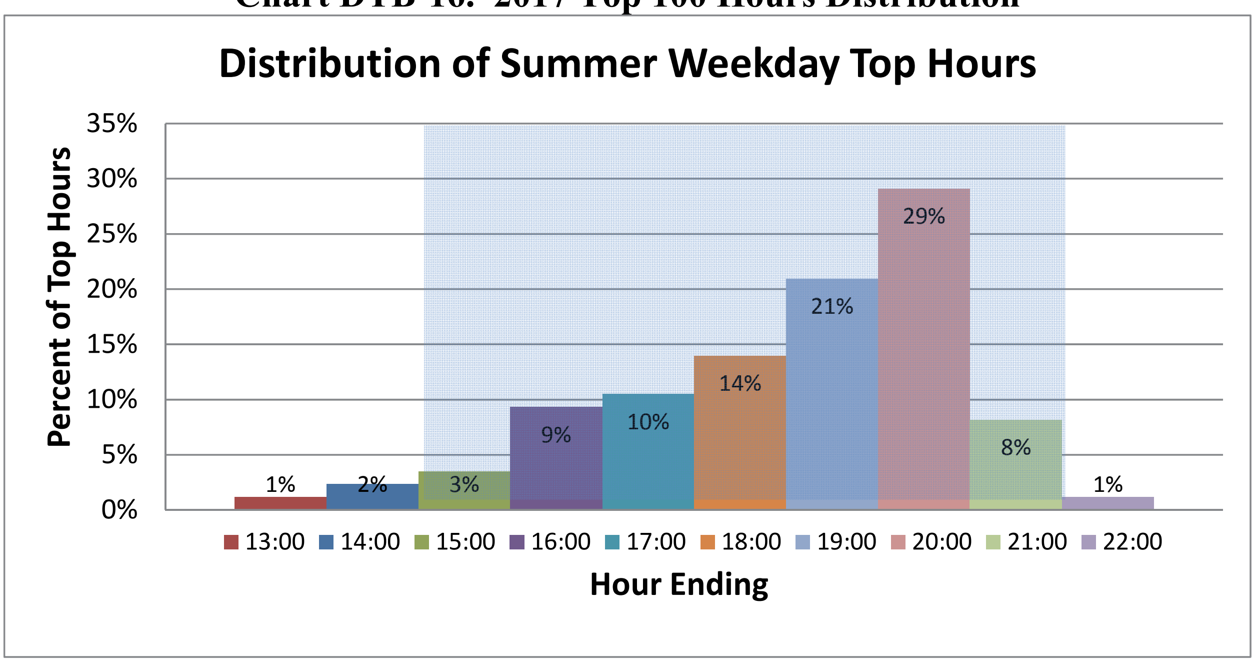


Chart DTB-16. 2017 Top 100 Hours Distribution



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Approximately 82 percent of the top 100 hours are in the proposed on-peak TOU period.

B. RELATIVE LOLE ANALYSIS

LOLE, loss of load expectation, is the probability of not meeting load in an hour when key system variables are analyzed stochastically. SDG&E determined the LOLE for the SDG&E system using the Ventyx Planning and Risk model,[21] a system dispatch model tailored to the SDG&E system. It is the same production cost model as used by SDG&E to forecast procurement costs in the ERRA and GHG proceedings. It is primarily focused on the SDG&E area, unlike the Ventyx Market Analytics model which models the entire West. The focus in this analysis is on local capacity and the needs for local capacity that can be reduced through the use of appropriate consumer price signals in TOU periods (and demand response availability periods) to provide incentives for load modification.

The Planning and Risk model accommodates detailed hour-by-hour simulation of the operations of electric systems. It considers a complex set of generation operating constraints to simulate the least-cost operation of the system. The model'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, generation stations, associated transmission, fuel, and so on. The Planning and Risk model determines power flow to equalize the incremental costs of all transmission areas in the system and enforce the power flow constraints. In order to model real world uncertainties, different load and variable renewable production levels are generated by a stochastic process based on historical data. The Planning and Risk model then performs an hourly economic dispatch of generation resources against loads

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

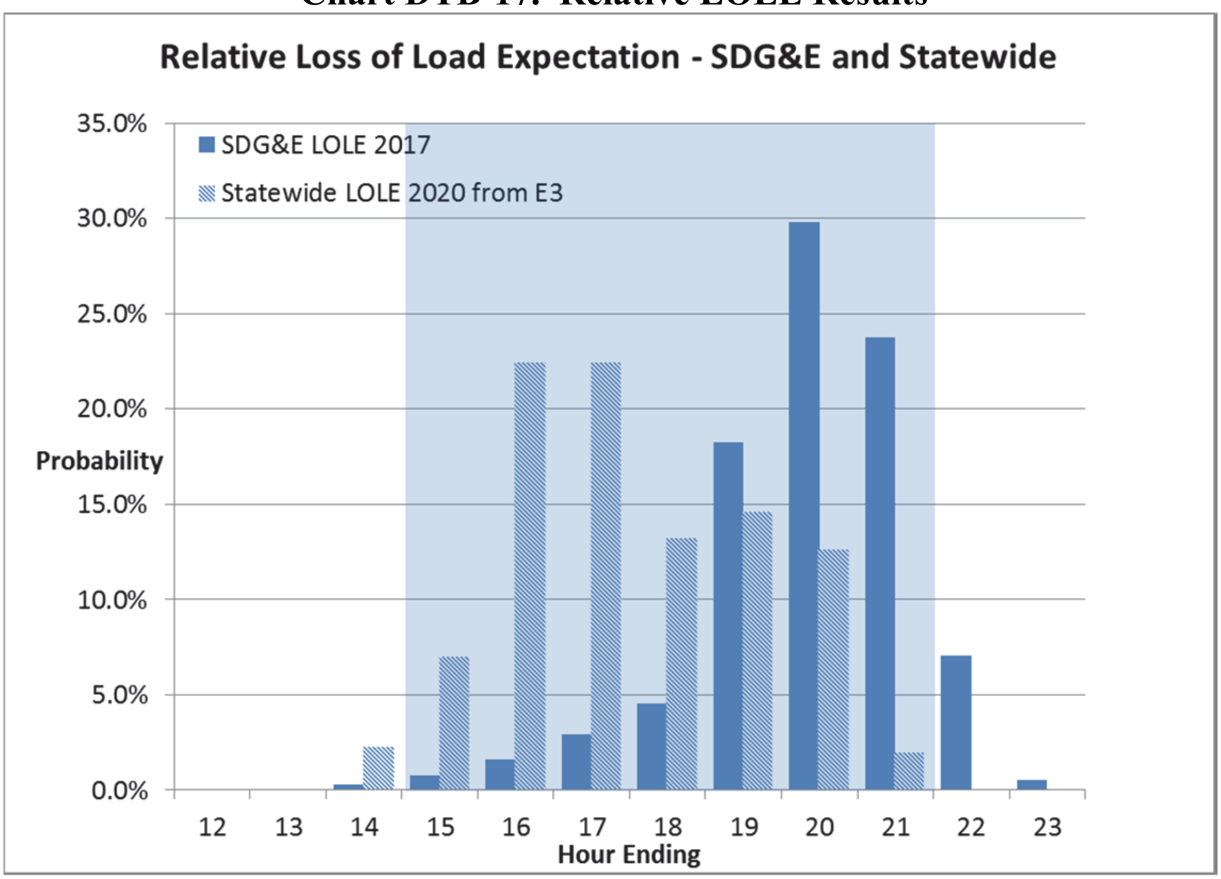
for each hour of the year. By running the model multiple times, a probability distribution of hours with relative expected loss of load can be developed.

Available generation in the analysis includes the units that exist in SDG&E's service area and Imperial Valley or are expected to be constructed by 2017 including both new renewable and conventional generation additions, but not SONGs. SDG&E made several additional model adjustments 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 included since its availability can be tailored to the hours with the highest relative LOLE. And third, no scheduled generation maintenance was included since this also can be tailored to be in hours without LOLE. The resulting analysis is not a measure of need for new capacity, but if there were a need, what hours of the year would likely experience the highest likelihood of a loss of load.

Each of the 250 model runs uses a Monte Carlo random draw to reflect 1) load for each hour due to weather volatility, 2) solar and wind production, and 3) fossil generation-forced outages. The random draw is from a distribution of outcomes based on historical data. In a majority of hours there will be sufficient generation to meet the load, and thus there will not be any unserved energy. But in some hours there will be energy not served ("ENS") 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. Undertaking several hundred model runs provides a forecast of ENS for each hour of the day per iteration which can be used to assign a greater probability of loss of load to hours with higher levels of ENS. The LOLE analysis produced probabilities of outage for each hour in each month by dividing the hourly ENS by the total ENS over the year. The probabilities were aggregated by season and weekday/weekend.

The allocation of MGCC to TOU periods has traditionally focused on local capacity value, but it should be recognized that TOU periods (and load-modifying demand response periods) also provide benefits on a statewide basis. The statewide capacity value is called "system capacity." From a system capacity standpoint, it is the State as a whole rather than the local area which is important. And the need for system capacity, while not currently an issue given the amount of new renewable capacity, should also be considered in developing TOU periods. In Chart DTB-17 below I compare relative LOLE statewide based on the capacity planning model of Commission consultant, E3, to the SDG&E local capacity results.[22]

Chart DTB-17. Relative LOLE Results



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[22] The E3 capacity planning model is available on the E3 website, www.ethree.com. In the past year, it has been used on projects for the CPUC including the RPS Calculator Update, Net Energy Metering, the CSI Impact Evaluation, and the 2012 LTPP. The data in Chart DTB-15 was taken from page C-36 of the Draft California Net Energy Metering Evaluation. Similar results were derived from directly running the model.

The statewide system capacity allocation is less shifted to the early evening hours compared to the San Diego-specific analysis. This result is not unexpected given the much larger industrial base through the rest of the state compared to San Diego and the lower relative amount of solar throughout the rest of the State compared to the San Diego local capacity area. But even though the shift is not as dramatic, there is significant probability of loss of load statewide in the early evening hours by 2020.[23] Based on the E3 capacity planning model results, the SDG&E-proposed summer on-peak period would contain 94 percent of expected statewide loss of load in 2020.

The third element of capacity is "flexible capacity," capacity that can be ramped up or down to meet the net load changes that occur in the morning and evening related to net loads. Increasing loads by lowering market prices before the ramp period will reduce ramping needs. The super off-peak period provides that benefit as does the move of 11 am – 2 pm from on-peak to semi-peak. And lowering loads at the end of a ramp period by increasing prices in the 5 pm - 9 pm period reduces ramping needs. The winter on-peak period provides that. The summer ramps are less dramatic in general so that the summer on-peak period is less critical for purposes of providing flexible capacity.

VI. TIME OF USE PERIODS

As stated previously, one general 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

[23] The E3 capacity planning model is available on the E3 website, www.ethree.com. In the past year, it has been used on projects for the CPUC including the RPS Calculator Update, Net Energy Metering, the CSI Impact Evaluation, and the 2012 LTPP. The data in Chart DTB-15 was taken from page C-36 of the Draft California Net Energy Metering Evaluation. Similar results were derived from directly running the model.

it is relatively inexpensive. The number of TOU periods is limited in order to make them understandable and actionable by customers, directly through pricing or indirectly through energy efficiency and demand response programs.

SDG&E has restricted the number of TOU periods to three periods - on-peak, semi-peak, and super off-peak - and two seasons – summer and winter – to maximize simplicity. The on-peak TOU period price informs customers that electricity is expensive and a super off-peak TOU period price informs customers that the cost of producing the electricity in this time period is much lower than average.

The results of the analysis presented above support shifting SDG&E's on-peak period to later in the day in the future as solar energy moves the net load peak, the hours most likely to experience a loss of load, and changes the profile of energy prices. SDG&E proposes the TOU periods in Table DTB-3.[24]

Table DTB – 3.

Summer on-peak	2 p.m. – 9 p.m. non-holiday weekdays
Winter on-peak	5 p.m. - 9 p.m. non-holiday weekdays
Super off-peak	12 a.m. – 6 a.m. daily
Semi-peak	All other times

The proposed Summer on-peak period is seven hours in length, the same as the current standard on-peak period, just shifted by three hours – from 11 am – 6 pm to 2 pm to 9 pm. While it is relatively long and as a result lowers the on-peak to super -peak rate ratios, it assures that both state and local capacity need periods are included. Demand response can be tailored to

[24] Similar Time of Delivery periods were adopted for use in future Renewable RFOs in D.13-11-024 as part of the 2013 SDG&E RPS Plan.

shorter periods within the TOU period targeted toward specific types of critical events that may be in the afternoon or the evening depending on state or local conditions. The Winter on-peak period expands the current standard TOU period by one hour from 5 pm – 8 pm to 5 pm – 9 pm to provide a consistent ending time for the on-peak period throughout the year. The super off-peak period of 12 am – 6 am is consistent with low net loads during this time period and lower rates during this period will encourage additional consumption during this period for customer energy storage including electric vehicle charging, other battery charging, and thermal energy storage applications.

Based on the 2012 GRC Phase 2 price variation, but with a 2017 allocation of prices to hours, the marginal energy cost factors for the proposed TOU periods is presented in Table DTB-4 below. These factors would be multiplied by the GRC Phase 2 adopted electricity price to calculate MEC for each TOU period. Energy prices do vary by TOU period, but there is less variation than prior TOU factors due to the flattening of electricity prices during daylight hours.

Table DTB-4. MEC Factors by Proposed TOU Period

	Summer	Winter
On-peak	1.327	1.272
Semi-peak	0.955	1.043
Super Off-peak	0.810	0.800

An analysis of the MGCC allocation to TOU periods is based on grouping high probability hours together in a TOU period. The resulting distribution of the likely hours of loss of load is then aggregated for each season. Table DTB-5 summarizes the results of the LOLE analysis based on the San Diego area.

Table DTB-5 Allocation of MGCC to Proposed TOU Periods

	Summer	Winter
On-peak	81.7%	2.1%
Semi-peak	16.2%	0.0%
Super Off-peak	0.0%	0.0%

The proposed allocation of MGCC reflects a small amount of capacity value in the winter on-peak period when compared to the GRC Phase 2 top 100 hours analysis of historical data.

This concludes my prepared direct testimony.

VII. WITNESS 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 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.