Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Electric Rate Design Effective January 1, 2015

Application 14-01-027
Exhibit No.: (SDG&E-____)

PREPARED REBUTTAL TESTIMONY OF

DAVID T. BARKER

CHAPTER 3

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

December 12, 2014

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TABLE OF CONTENTS

PREPARED REBUTTAL TESTIMONY OF
DAVID T. BARKER
(CHAPTER 3)

I. PURPOSE AND OVERVIEW

The purpose of my testimony is to reply to the opening testimony of Robert M. Fagan and Patrick Luckow of Synapse Energy Economics ("Synapse") on behalf of the Office of Ratepayer Advocates ("ORA") ; Lee-Whei Tan on behalf of ORA ("ORA-Tan"); David Croyle on behalf of the Utility Consumer Action Network ("UCAN"); Jose Luis Contreras on behalf of the California Solar Energy Industries Association ("CALSEIA"); William Monson on behalf of the City of San Diego; and Laura Norin on behalf of the California Farm Bureau Federation ("Farm Bureau") regarding San Diego Gas & Electric Company's ("SDG&E's") proposed time-of-use ("TOU") periods.

The TOU proposal put forward in my direct testimony 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 increase in solar generation serving the SDG&E service territory, which is expected in greater amounts in the next few years in particular. For all of the reasons discussed below, the Commission should adopt the TOU periods as proposed in my prepared direct testimony.

My testimony reaches the following conclusions regarding ORA's position on SDG&E's proposed change in the TOU periods:

- ORA's analysis supports the shift in summer on-peak hours as proposed by SDG&E.
- ORA does not support a super off-peak period, but provides no analysis to support its position. Moreover, ORA's proposal would not provide a price signal to encourage customer-owned storage and electric vehicles.

My testimony reaches the following conclusions regarding UCAN's and CALSEIA's positions on the proposed change in the TOU periods:

- UCAN's analysis fails to support its contention that the new TOU period definitions will lead to a new peak.
- The data does not support a provision of different TOU periods for solar customers.

My testimony reaches the following conclusions regarding the City of San Diego's position on the proposed change in the TOU periods:

- The data does not support postponement of the change in TOU periods proposed by SDG&E. The data request responses provided by SDG&E were misinterpreted by the City of San Diego.
- Energy prices developed should reflect market conditions. SDG&E's adjustment of energy prices from the production simulation is appropriate and does not change any conclusions regarding the summer on-peak period.

My testimony reaches the following conclusions regarding the Farm Bureau's position on the proposed change in the TOU periods:

- Data supports inclusion of the 8 pm - 9 pm hour in the winter on-peak period. Energy prices are variable and often peak in the 8 - 9 pm hour, especially in April and May.
- The data does not support including all weekend hours in the super off-peak period. Maintaining the 12 am – 6 am super off-peak period provides for significant price differentials. These price differentials will support new technologies such as customer-owned storage to deal with ramping and avoidance of new infrastructure potentially caused by electric vehicle charging.

II. RESPONSE TO ORA

First, let me provide a clarification regarding the methodology I employed to develop SDG&E's proposed TOU periods. ORA suggests the analysis is flawed by excluding uncommitted energy efficiency (ORA, page 5). However, ORA misinterpreted statements in my direct testimony. Uncommitted energy efficiency was deducted from the load forecast as indicated in my direct testimony and in the clarifying SDG&E data request response provided to ORA.[1]

[1] SDG&E Response to ORA Data Request 4, Question 6.

Second, as stated in my direct testimony, in choosing TOU period definitions, SDG&E considered a large number of factors including marginal energy costs, relative statewide capacity needs, relative local capacity needs, customer loads, customer loads net of intermittent renewable energy, and simplicity. SDG&E proposed the TOU periods in Table DTB-3 of my direct testimony, as shown below, based on these considerations.

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 ORA analysis supports the SDG&E proposal for the summer and winter on-peak periods as shown in Table 1 of the opening testimony of Synapse consultants, Mr. Fagan and Mr. Luckow, on behalf of ORA. Their analysis confirms the shift in the periods of relative capacity need for the broad local area (including Imperial Valley) (ORA, pages 6-12) and for the State (ORA, pages 13 - 15). Mr. Fagan and Mr. Luckow also provide data from the Long-term Procurement Plan ("LTPP"), indicating another data point that shows a similar long-term shift for the State in the California Independent System Operator ("CAISO") modeling (ORA, pages 19-20). The CAISO study finds a need for expected capacity in the "high load" scenario over the period of 3 pm to 9 pm, and over the period 5 pm to 8 pm in the "trajectory" case. (ORA, page 20, lines 21-26)

ORA does not support SDG&E's super off-peak period. However, there is no analytic analysis explaining ORA's conclusion in the testimony of Mr. Fagan and Mr. Luckow. The only statement explaining ORA's position is one sentence in the testimony of ORA witness Lee-Whei Tan that "elimination of the super off-peak period makes the default schedule simpler and more understandable to customers." (ORA-Tan, page 13, lines 15-16).

The super off-peak period of 12 am – 6 am was proposed by SDG&E because it is a time period with low net loads as shown in charts DTB-11 and DTB-12 in my direct testimony. These charts, reproduced below, show that the period 12 am – 6 am (Hours ending 1 through 6) are the periods with very low loads and so are ideal for encouraging additional consumption without requiring additional utility-built generation or transmission infrastructure.

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

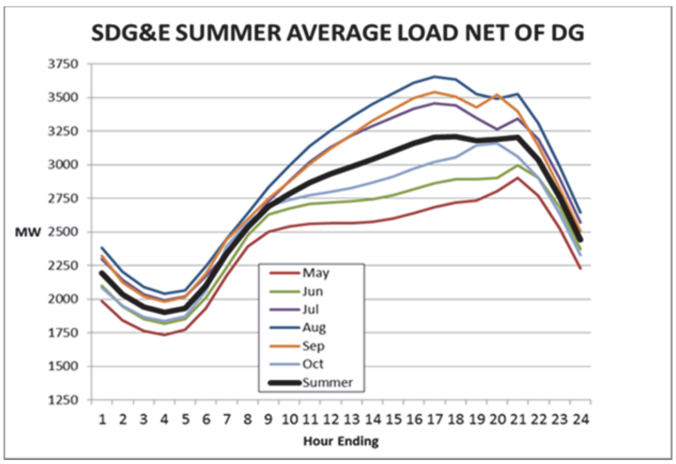
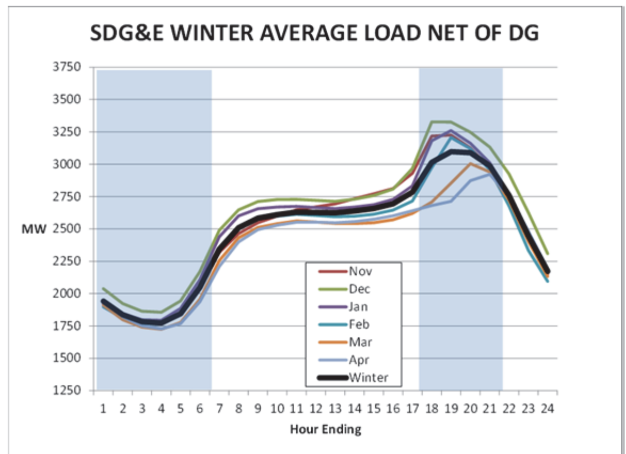


Chart DTB-12. 2017 Winter Load Net of Distributed Solar



Encouraging additional consumption in that period from customers with variable loads (such as agricultural customers' pumping loads) and for customer energy storage applications (such as electric vehicle charging, battery charging, and thermal energy storage applications) will flatten load profiles. Storage applications consume during the low use periods and discharge in the on-peak periods, reducing the amount of ramping capacity needed. Large price differentials between high load on-peak periods and low load super off-peak periods will make adoption of customer-owned storage more economically attractive. In addition, since loads in San Diego are low during this period, additional consumption from electric vehicle ("EV") charging will also flatten the load profile in San Diego. However, a low price period is needed to encourage EV owners to charge at a time that would minimize infrastructure investments. The super off-peak period provides such a period already as shown by the 2013 SDG&E DLAP prices from my direct testimony.[2]

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

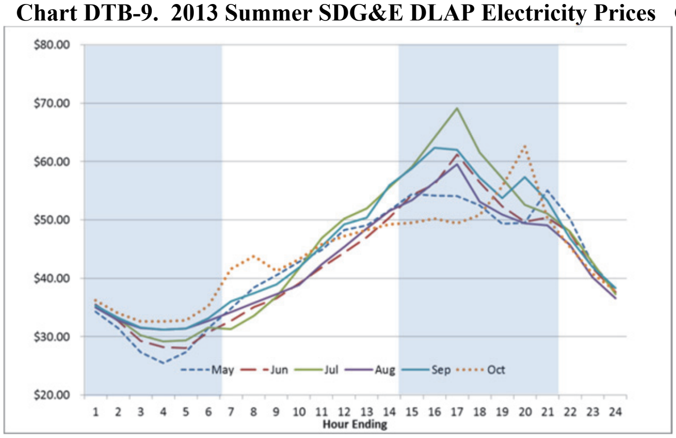
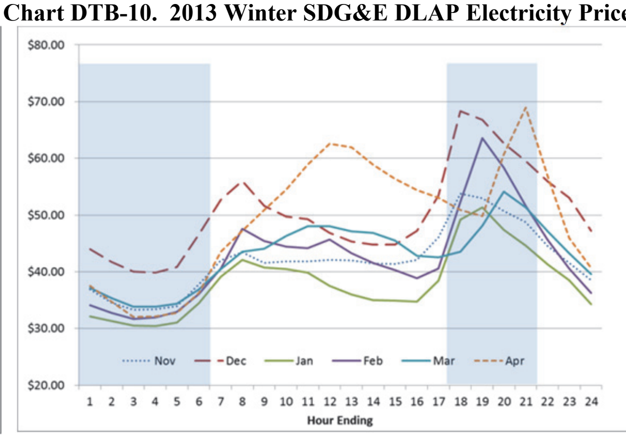
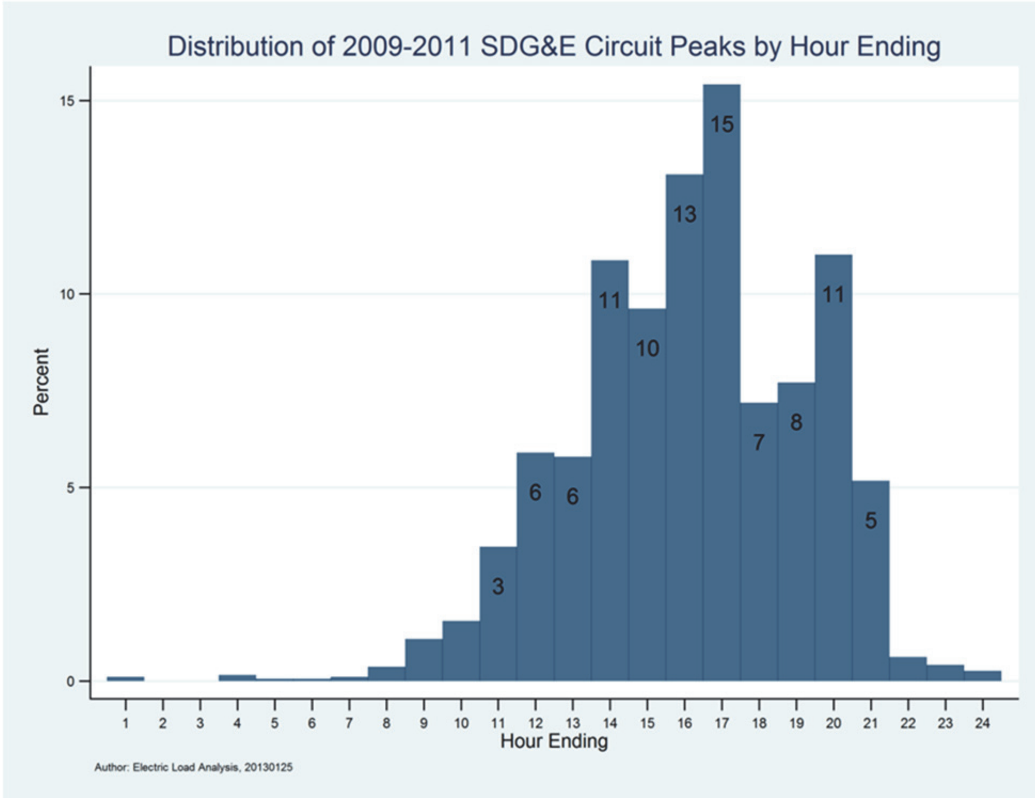


Chart DTB-10. 2013 Winter SDG&E DLAP Electricity Prices



A super off-peak period would also reduce the burden on the distribution system that might occur at other times of the day. As shown in the chart below, SDG&E's circuits peak at nearly every hour of the day, but the percentage peaking in the super off-peak period of 12 am to 6 am (Hours ending 1 to 6) is by far the lowest throughout the day. Circuits are unaffected by central station renewables. Distributed solar, with appropriate physical assurance, may only lower the percentage of circuits peaking at midday, assuming no cloud cover during circuit peaks. Providing price signals to increase consumption in the proposed super off-peak period has the added benefit of minimizing the impact on the distribution infrastructure.

[2] It should be noted that gas prices can vary from month to month, especially in winter, causing monthly prices to vary for reasons other than relative need and shifting the levels of the price profiles.



III. RESPONSE TO UCAN AND CALSEIA

Mr. Croyle (UCAN), and Mr. Contreras (CALSEIA), both propose multiple TOU periods rather than consolidating them to a single schedule by leaving TOU tariffs of solar customers unchanged. Both raise the same two issues that I respond to below. First, Mr. Croyle states, "UCAN believes that SDG&E's proposal will contribute to increased concentration or coincidence of demand as demand ramps up at the end of the proposed on-peak periods." (UCAN, page 7) Similarly, Mr. Contreras states, "With the expected introduction of residential time of use rates and adoption of smart appliances, other devices will join thermostats and electric vehicles in postponing usage until those peak periods, exacerbating the problem. The goal is to flatten the demand curve to improve utilization of the system, not to move peaks from one time of day to another." (CALSEIA, page 6, line 13-17)

Contrary to the UCAN statement, demand generally peaks in the middle of the on-peak period, not at the end, based on average net load graphs presented in my direct testimony (Charts DTB-11, DTB-12, DTB-13, and DTB-14). But more importantly, average net loads drop significantly from 3,056 Megawatts ("MW") in the peak hour in the on-peak period to 2,596 MW in the 9-10 pm hour, the first semi-peak hour in the summer, and 1,871 MW in the 12 am – 1 pm hour, the first hour of the super off-peak period. Similarly, average net loads drop from 3,005 MW in the peak hour to 2,526 MW in the 9-10 pm hour, the first semi-peak hour in the winter, and 1,767 MW in the 12 am – 1 pm hour, the first hour of the super off-peak period.[3] While there are variations day-to-day and month-to-month, the peak will not shift to the super off-peak period given more than a 1,200 MW drop in net load on average from the peak to the beginning of the super off-peak period. Increased load in the super off-peak period from energy storage and EVs would only flatten the load profile, moderating the ramping down of resources and the ramp up the next day, a goal that CALSEIA supports. It will not create a new peak as suggested in the testimony of UCAN and CALSEIA given the large differences in average net loads between the on-peak and super off-peak periods.

Second, Mr. Croyle states "solar can still be an effective renewable technology to manage peak demand and the need for peaking generation in the midday hours…" (UCAN, page 9), a sentiment echoed by CALSEIA.[4] But nothing in Mr. Croyle's analysis supports that there will be peak in net loads at midday or that there is any need for future peaking generation at midday. Both the analysis presented in my direct testimony on net load and the analysis conducted by the CAISO suggest that additional solar will increase the need to use peaking generation as flexible capacity to handle the ramp down of solar production in the afternoon, but not for use at midday.

[3] The average net loads are based on the Greater San Diego reliability area including Imperial Valley.
[4] CALSEIA, page 5, line 29 – page 6, line 7.

From a system perspective, keeping the TOU periods for solar customers fixed at current levels will encourage consumption in the 6 pm – 9 pm hours, after the end of the historically-defined, increasingly inaccurate "on-peak period", currently defined as the 11 am – 6 pm hours. With the period ending at 6 pm, customers have incentive to shift consumption from the 11 am – 6 pm period to outside that time period. For example, they may shift load to the 6 - 9 pm hours when the new net load peaks are expected to occur. Long-term, it makes no sense to exclude providing the right price signals for consumption to a growing segment of the SDG&E customer base with an unknown ability to shift consumption to alternate time periods directly or through the use of storage technologies. Providing the right price signals would encourage solar customers to shift consumption away from the 6 pm – 9 pm weekday hours to other hours including 11 am - 2 pm weekdays, when their solar energy production is at a maximum, or to anytime on weekends. Depending on their ability to shift load, solar customers may be no worse off from a bill perspective and the system would benefit.

It should also be pointed out that the SDG&E TOU proposal does not uniformly reduce compensation to solar customers since weekend daylight hours are compensated at the higher semi-peak rate rather than the historically-defined off-peak rate. In fact, almost three times as many daylight hours per year will have an increase in compensation for solar (1,120 hours per year) than a decrease (381 hours per year) under the SDG&E TOU proposal.[5]

[5] 1,120 hours is based on 7 am – 5 pm two days a week (weekends) for 52 weeks plus 8 holiday days, while 381 hours is based on 11 am – 2 pm 5 days per week for 6 months less 3 holidays.

IV. RESPONSE TO THE CITY OF SAN DIEGO

The City of San Diego "has proposed a very aggressive Climate Action Plan,"[6] but proposes to postpone adoption of SDG&E's TOU period proposal as premature. The crux of the incongruity between the City of San Diego's own aggressive plans and rejection of SDG&E's TOU proposal to address the consequences of climate mitigation efforts is based on a misunderstanding by Mr. Monson, the City of San Diego's consultant, of several SDG&E data request responses.

Mr. Monson states that "it appears that projects that were online before May 1, 2013, delivered less than 60% of the expected value of generation that was assumed by SDG&E to be generated from these same projects in 2017." (City of San Diego, page 25, lines 7-10) This conclusion, however, is based on an error in Mr. Monsen's interpretation of the SDG&E data request responses. First, the list of projects that SDG&E provided that were online before May 1, 2013 included a number of projects which are outside of the Greater San Diego Reliability area and were, therefore, not included in the Planning and Risk model analysis (see Attachment 1). SDG&E's analysis only included resources located in the Greater San Diego local reliability area (which includes San Diego County and the part of Imperial Valley). While the Market Analytics modeling considered the entire WECC in the determination of local price formation, the Planning and Risk modeling was focused on local capacity needs and so considered only local generation that could meet local electricity demand.[7] This fact negates the underperformance compared to the contract amount of out-of-state projects. The reduced performance of out-of-local-area renewable projects should have no impact on the expected performance of renewables located in the local area.

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[6] City of San Diego, page 3, line 23 – page 4, line 3.
[7] Consideration of broader statewide capacity needs relied on analysis conducted by E3 on behalf of the CPUC.

In addition, SDG&E uses historical data to forecast future renewables production where a project has been up and running for several years, not the expected amounts in the contract. For example, project 7 had a contractual expected output of 178,704 MWh and an actual 2013 production of 148,466 MWh, 17 percent less than expected per the contract. However, in the SDG&E Planning and Risk modeling, the forecasted amount was 146,470 based on historical experience.[8] Against this level of expected production, the actual 2013 production was 1.4 percent higher than expected, not 17 percent less.

Mr. Monson also cited the lack of performance of several recent projects which are in the local area, stating "SDG&E assumed that Projects 31 and 33 would deliver 345 GWh and 323 GWh per year, respectively, when the projects' PPAs were signed. However, after these contracts came online, the actual generation was only 168 GWh and 273 GWh per year, respectively." (City of San Diego, page 26, lines 10-12) This conclusion, however, is based on a misunderstanding of "annual" production. The SDG&E data request response was based on an interpretation of "annual" as calendar year since all renewable production for reporting purposes is based on the calendar year. These projects both had online dates that were later in 2013 resulting in actual generation amounts based on partial year 2013 production.[9] Data for 2014 shows these projects are on track to deliver 100 percent of their estimated annual generation. Project # 23 actual production is also misleading. While a portion of the project came online at the end of 2012, electricity production was ramped up in phases over 2013. The 2013 production was not representative of full production of the complete project.

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[8] SDG&E Response to City of San Diego Data Request 2, question 4f

[9] Mr. Monson also had concerns about projects 37-40, stating, "In addition, SDG&E assumed that Projects 37-40 collectively would deliver approximately 50 GWh per year but when the projects came online, they only generated about 24 GWh per year." (City of San Diego, page 26, lines 14-16) Here there are two problems – one is that the 50 GWh was for 6 projects and two of the projects have not come online. And for the contracts that did come online, they also had partial year deliveries in 2013. The projects online are expected to deliver close to 100 percent of their estimated contractual annual generation in 2014.

Excluding project #23, excluding projects outside of the Greater San Diego reliability area, and using the SDG&E forecast for project #7, actual 2013 generation for the projects that came online by May 1, 2013 was 96 percent of the estimated annual generation. With a proper interpretation of the data, it becomes clear that Mr. Monson's conclusion that "SDG&E clearly assumed higher levels of generation for its modeling of existing resources than has been seen in actual operation" is not correct. Accordingly, Mr. Monson's argument that SDG&E has significantly overestimated the expected level of renewable generation from existing renewable resources in its net load analysis should be ignored.

On pages 27 and 28 of his testimony, Mr. Monson also states that SDG&E did not account for project failures, thus overestimating the amount of renewables coming online by 2017. While project failure is a possibility, Mr. Monson's testimony ignores the important section of the San Diego Gas & Electric Company 2013 Renewables Portfolio Standard Procurement Plan Compliance Filing, "SDG&E's current assessment is that projects in its portfolio are at a low risk of non-performance" (City of San Diego, page 28, lines 38-39). The types of technologies being employed are not experimental, unlike some of the early renewable projects, but are standard solar photovoltaic and wind energy projects. Also, the projects do not depend on new transmission lines being built. Thus, absent another financial meltdown like that experienced in 2008, the prospects for non-performance are low.

Mr. Monson also expresses concern about project delays. He states "[f]our projects that sell to SDG&E have been delayed by more than one year, with three projects being delayed by 3 to 5 years." (City of San Diego, page 31, lines 19-21) However, Mr. Monson did not consider timing, location, or technology type in his analysis. The 2008 financial crisis definitely delayed projects, as financing was difficult to obtain for several years. New, untested renewable technologies are also more challenging for developers. However, SDG&E has seen a dramatic improvement in contract success since the early years of RPS implementation as the renewable technologies have matured, reducing development risk. As stated in its 2014 Draft Renewable Procurement Plan, "SDG&E currently expects that a majority of the projects in its portfolio will meet their commercial operation dates either on schedule or within the prescribed cure period." (City of San Diego, page 33, lines 5-8)

Mr. Monson suggests the Commission wait to see if "SDG&E's forecasts are correct." (City of San Diego, page 21, lines 9-16) However, even if the electricity delivered from utility-scale renewable generation projects coming online were delayed, the conclusions of the net load analysis would be relatively unchanged due to the amount of renewables already online. The net load graphs for summer and winter would look more like charts DTB-11 and DTB-12 than DTB-13 and DTB-14, respectively. The afternoon ramping requirements would be less, but the proposed summer and winter on-peak periods would be those of highest net load and proposed super-off-peak periods would be those of lowest net load. Likewise, energy prices in the SDG&E service area in 2013, as shown in charts DTB-9 and DTB-10, already reflect that the proposed summer and winter on-peak periods would coincide with those hours of highest electricity prices in the San Diego area and proposed super off-peak period already coincides with the hours with the lowest electricity prices in the San Diego area.

Further, the State has engaged in extensive planning for the changes due to the increase in renewables, before seeing if load-serving entities comply with the 33 percent RPS. In the Resource Adequacy proceeding, the Commission has addressed ramping needs through the development of a new category of capacity, "flexible capacity," even though the need for flexible capacity is based on the addition of significant solar resources in the State that has yet to materialize.[10] Waiting until 2017 before addressing the issue is not in SDG&E customers' interest, as described in the testimony of Mr. Yunker.

Mr. Monson also takes issue with the SDG&E approach to calculating electricity prices, suggesting that "'stretching' unreasonably exaggerates the differences in prices between hours." (City of San Diego, page 38, lines 3-4) Mr. Monson's conclusion regarding the electricity price forecast does not change the conclusion as to the correct hours to include in the on-peak period - it would only affect the price differentials between periods. Thus, it is not a reason to delay the adoption of SDG&E's proposed TOU periods.

The production cost model used by SDG&E in the estimation of electricity price patterns assumes all generators have perfect foresight, that renewable energy output follows a known fixed pattern, that transmission systems are optimally used, and generators bid only at marginal cost. Therefore, because of these assumptions, production cost model results will likely underestimate the variations in actual market prices. In order to better approximate actual market variations, I have applied a "stretching" factor to the production simulation output to match actual spread in market prices observed historically. The highest prices from the production simulation are increased and the lowest prices reduced so that the resulting variability matches historically observed variations. Mr. Monson takes the most extreme adjustment to make the process seem unreasonable, whereas most adjustments are relatively small over the entire year. And on a peak day, as illustrated in Figure 1 of Mr. Monson's testimony, the stretched prices exceed $100/MWh while the production simulation prices are in the range of $70/MWh. In 2013, San Diego market electricity prices were over $100/MWh more than 30

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[10] CPUC Rulemaking 11-10-023.

times and were as high as $180/MWh.[11] In 2014, San Diego market electricity prices were over $100/MWh over 40 times and were as high as $169/MWh.[12]

The stretching process takes the highest (lowest) energy prices from the production simulation and increases (decreases) them to match past observed variations in market prices, excluding the effects of natural gas prices. The process is based on the assumption that the production simulation can identify the hours of highest relative need for generation, but cannot fully capture market variations because the model is deterministic with perfect foresight. Thus, I did not ignore the prices from the production simulation as suggested by Mr. Monson.[13] I simply amplify them in a reasonable way to match expectations that market prices are more variable than suggested by deterministic production simulations.

Even without considering prices (as ORA does), the LOLE analysis of SDG&E and of the CAISO would still indicate a need to adjust the summer on-peak TOU period to reduce load and avoid the need for added infrastructure to meet peak net loads.

V. RESPONSE TO THE FARM BUREAU

The testimony of Ms. Laura Norin on behalf of the Farm Bureau concentrates on two other changes to the TOU structure besides the change in the summer on-peak period. The Farm Bureau opposes the addition of the 8 pm - 9 pm hour to the winter on-peak period and the adjustment of the super off-peak period (currently called off-peak) to exclude 10 pm – 12 pm on weekdays and 6 am – 12 am on weekends and holidays.

With respect to adding the 8 pm -9 pm hour to the winter on-peak period, Ms. Norin suggests there is no analysis supporting its inclusion in the on-peak period. At pages 10 and 11

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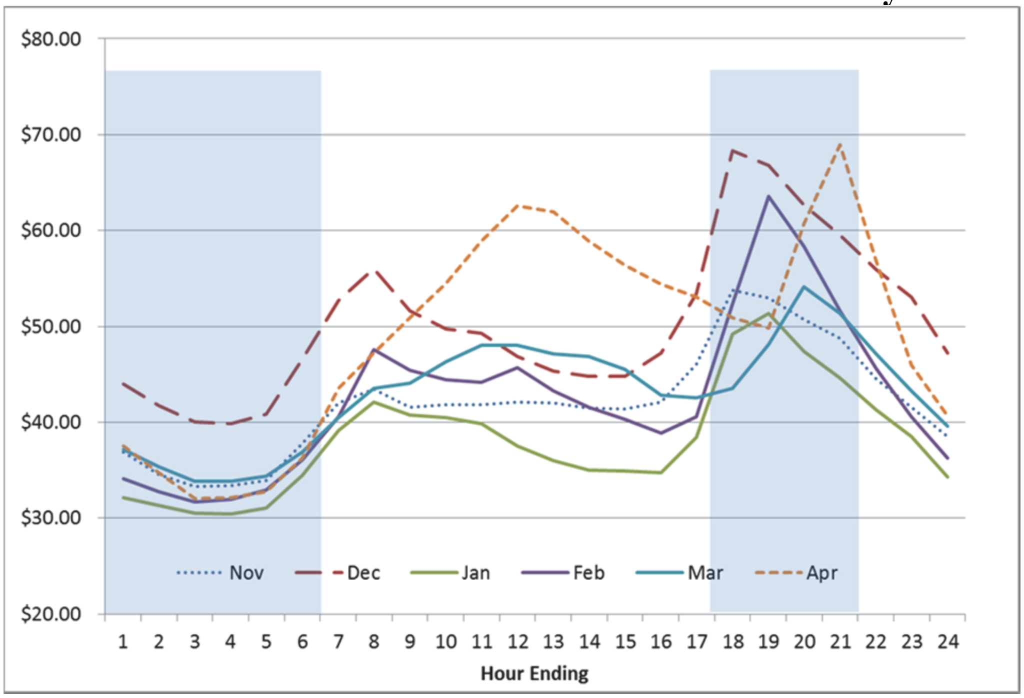
[11] Rate Design Window Workpapers of David T. Barker, workbook RDW-workpapers-2013pricedata.xls.
[12] SDG&E Response to Farm Bureau Data Request 3, question 10.
[13] Section 5A is entitled, "SDG&E Ignores Its Own Modeling Results in Developing TOU Periods," City of San Diego, page 38, lines 6-7.

of her testimony, Ms. Norin shows charts from the CAISO showing a typical January day and typical March day (Figures 4 and 5). The January peak is in the 5 pm- 6 pm hour, while the March peak is in the 7 pm – 8 pm hour. She suggests this data indicates no need for including the 8 pm – 9 pm hour in the on-peak period since the peak occurs earlier. (Farm Bureau, page 10, line 18 and page 11, lines 3-7). However, what Figures 4 and 5 do show is that the peak is variable by day and month and that the 8 – 9 pm hour is still a relative high load hour. In figure 5, the load in the 8 pm - 9 pm hour is nearly the same as the 7 pm - 8 pm period. If the on-peak period encouraged shifting of load through storage technologies, the 8 pm - 9 pm hour could be a peak hour if not included in the on-peak period.

In the months of March and April, the level of net load in the 8 pm – 9 pm period in San Diego could be high on days when the wind does not blow as summarized in Chart DTB-12 (Chart DTB-14 shows the net effect if average wind production occurs). Given the daily variability in net peak loads due to the variability in wind production, the 8 pm – 9 pm hour should be in the winter on-peak period.

Ms. Norin also indicates that winter weekday prices do not justify inclusion of the 8 pm – 9 pm period, stating "SDG&E's Chart DTB-8 (reproduced in Figure 7) shows winter weekday energy prices peaking between 5 pm and 7 pm and falling significantly by 8 PM from November through February." (Farm Bureau, page 13, lines 6-8) But the winter period also includes March and April. In those months the peak energy prices are in the 7 pm-9 pm range. Ms. Norin's figure 13 shows April prices peaking in the 8 pm – 9 pm hour. Similarly, the 2013 electricity prices presented in Chart DTB-10 support the 8 pm – 9 pm hour as a high priced hour already. For example, April 2013 prices peaked in the 8 pm – 9 pm hour. With the winter including March and April, the 8 pm-9 pm hour is justified for inclusion in the on-peak period.

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



In addition to the above analysis of net loads and energy prices, another compelling reason to include 8 pm - 9 pm hour in the winter on-peak period is that the hour is included in the CAISO's availability hours for Resource Adequacy in the winter period.[14] To qualify for Resource Adequacy credit, a supply resource must be available in the 8 pm – 9 pm hour. This fact indicates that in the CAISO's view, the hour has the potential to be a high demand hour period necessitating making adequate capacity available in that hour in the winter.

The second issue raised by the Farm Bureau is the proposed super off-peak period of 12 am to 6 am every day. Ms. Norin states,

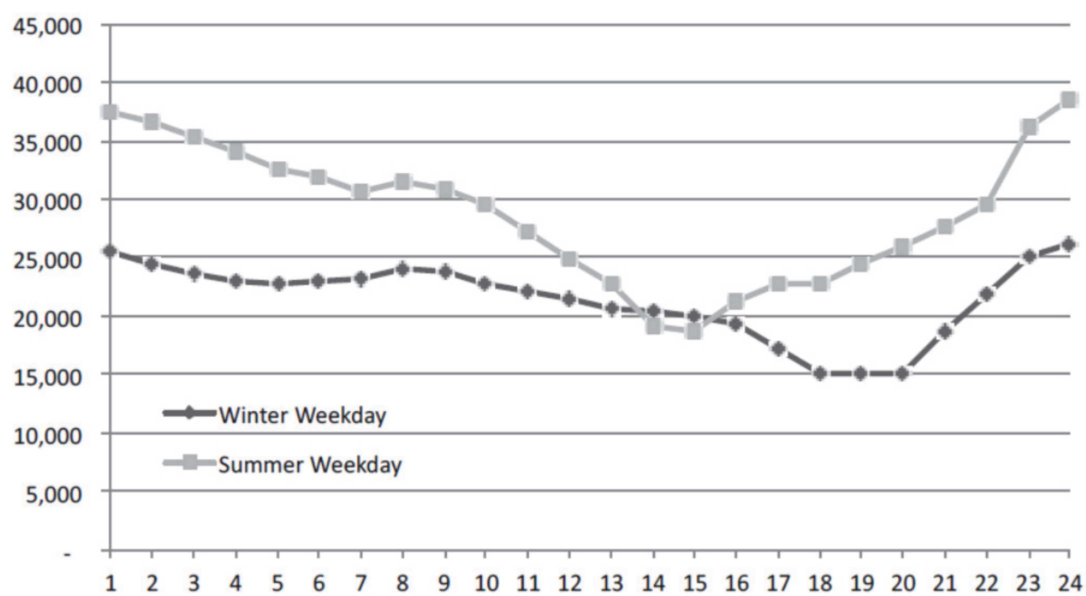
> Under SDG&E's proposal, there would be fewer than half as many off-peak hours as there are under SDG&E's current standard TOU period definitions. SDG&E justifies this proposal on the basis of the need for flexible capacity, stating that the super off-peak period will reduce ramping needs by increasing loads before the ramp period. In other words, SDG&E proposes to have higher prices all day long on weekends and holidays and at the end of the day on each weekday in order to

[14]http://bpmcm.caiso.com/BPM%20Document%20Library/Reliability%20Requirements/BPM_for_Reliability_Requirements_V20_clean.docx

> reduce prices from midnight to 6 AM below current off-peak prices and thereby increase loads in these hours in order to moderate the morning upward ramp. However, SDG&E does not provide any data or further explanation to support this proposal. (Farm Bureau, page 17, lines 7-15)

To clarify my testimony, ramping needs are reduced when peak usage is reduced and consumption in low usage periods is increased. One way this happens is that customers shift their usage patterns. Ms. Norin's Figure 16 (reproduced below) shows an example of that effect where customers' lowest usage is in current on-peak periods (hours ending 12 – 18 in the summer and 17-20 in the winter) and the highest usage is in off-peak periods (hours ending 1-6 and 23-24). If the TOU periods are changed, we would expect the usage pattern to shift accordingly.

Figure 16: Average Hourly PA-T-1 Energy Usage, kWh[36]



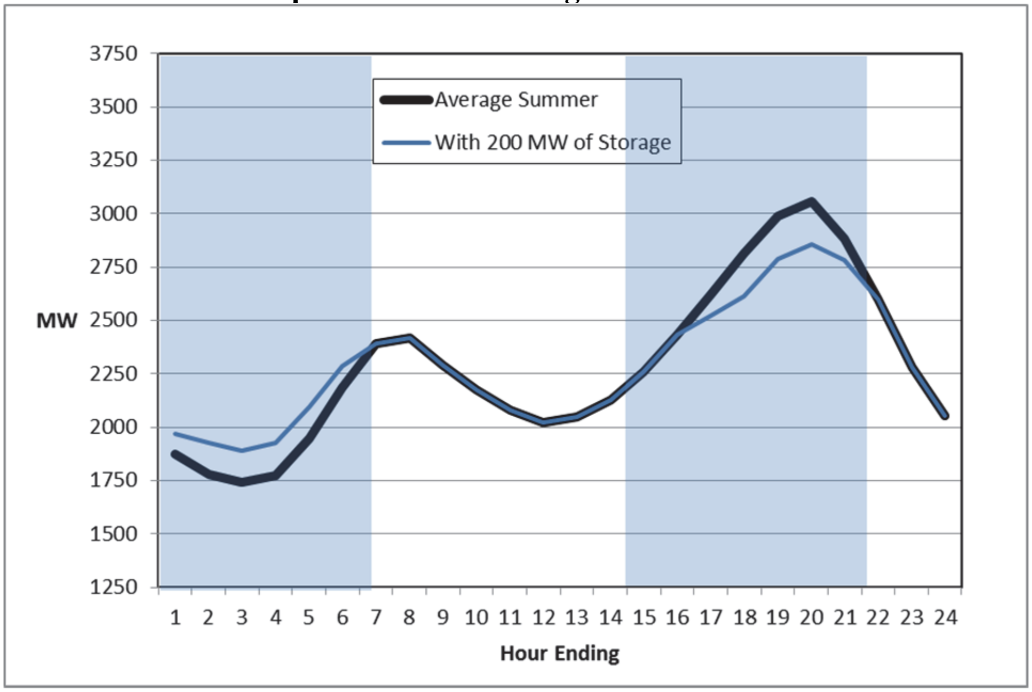
Similarly, charging the battery of an electric vehicle ("EV") is a discretionary choice of the EV owner that can have significant impacts on the utility infrastructure needs depending on when charging takes place. Creating the proposed super off-peak period provides a significant price signal to charge when load is low and avoid creating new utility generation costs related to peak usage and avoid new distribution costs by charging when net loads are lowest in the service area as shown in Charts DTB-11 and DTB-12. Increases in load in the 12 am – 6 am period, especially load shifted from the on-peak period, would flatten the load profile and reduce ramping needs.

A second important way to reduce ramping needs is through energy storage. Ms. Norin acknowledges that fact stating,

> "[a]nother important emerging technology that can target ramping periods is energy storage. Particularly when combined with distributed solar, energy storage can be a powerful tool for counteracting the mid-day increase in generation by storing that power for later use and could moderate the steep ramping needs anticipated by the CAISO with the fall-off in solar generation in the evenings. While still a niche technology today, the CPUC included customer-sited storage in its storage targets for the utilities, and growth in this sector appears to be underway.

The economics of customer-owned storage is directly related to the price differentials between TOU periods when charging occurs (super off-peak) and when discharge occurs (on-peak). By creating a concentrated period of low demand and low price via a super off-peak period, the economics of customer-owned storage are improved, improving adoption of the technology. Customer-owned storage can increasingly be used to reduce ramping needs in the afternoon and early evening by discharging during the period as well as reducing the downward ramp later at night and upward morning ramp by increasing load in the super off-peak period. The chart below, DTB-R-1, shows the impact of increasing consumption in the super off-peak and decreasing consumption proportionally in the on-peak period. As can be seen graphically, the impact would be to flatten the net load profile and reduce the amount of ramping capability needed. A similar chart would show much the same for winter – customer response to TOU periods via storage or load shifting would flatten the SDG&E load profile, reducing the need for added generation and/or transmission infrastructure to meet ramping and net peak needs.

Chart DTB-R-1. Impact of Load Shifting Is to Flatten the Load Profile



The second issue with the SDG&E super off-peak period proposal for the Farm Bureau is the shift of weekend hours from the super off-peak period (currently labeled off-peak) to semi-peak. With the relative growth of residential loads in San Diego to industrial loads since the 1980s, weekends and holidays have higher loads relative to weekdays compared to the 1980s when the current TOU periods were set. The peak day in 2007 was in fact during the Labor Day holiday weekend. The LOLE analysis shows weekend hours have a significant relative probability of loss of load, primarily in the late afternoon hours. This fact alone would suggest that weekend hours should not be considered for the super off-peak period. The idea of a super off-peak period is not to water down the period of low demand and low prices with additional higher load, higher priced hours; adding weekend hours would have that effect.

In addition, Ms. Norin's Figure 14 shows that the semi-peak prices on weekends and holidays are higher than the super off-peak period on weekends in most months, though the differential is less than on weekdays. The potential magnitude of the difference, however, is substantially masked by using unstretched prices. The fact that weekend average prices are higher than in the super off-peak would muddy the price signal needed to encourage electric storage and electric vehicle charging. Ms. Norin's recommendation for rejecting the super off-peak period as proposed by SDG&E so as to include all weekend hours is not supported by the data.

While I disagree with Ms. Norin that the current off-peak period be retained, I have to agree with Ms. Norin that the data could support adding a weekend period of 6 am – 2 pm to the super off-peak period. The higher energy prices and the relative loss of load that occur on the weekend occur after 2 pm. The net load expected in the midday hours, as shown in Ms. Norin's Figure 15, is likely to be similar to the super off-peak period because as Ms. Norin indicates, "[d]uring weekends, the situation is more extreme because the sun does not take weekends off, while many businesses do. This results in expected net loads on weekends and holidays falling to their lowest points in the middle of the day in both summer and winter (Figure 15)." (Farm Bureau, page 22, lines 8-11) Of course, there is more variability in the midday period because of cloudy days, but on average net loads and electricity prices in this period are likely to be low because of the amount of solar generation.

Attachment 1

Attachment 1

(white)	SDG&E Local Area (included in analysis)
(dark blue)	Outside of SDG&E's local area
(grey)	SDG&E Local Area (not included in analysis)

	Question #	4a	4b	4c	4d	4e	4g	
Project No.	Status	Original Anticipated COD	Actual COD (Projects Online)	Assumed COD (Projects Not Yet Online)	Expected Annual Generation (MWh)	Actual Annual Generation (MWh)	Production Profile Available?	Bilateral?
1	Delivering	12/15/1985	12/15/1985		899	443	N/A	
2	Delivering	7/1/1987	7/1/1987		2,121	1,064	N/A	
3	Delivering	4/13/1994	4/13/1994		1,971	81	N/A	
4	Delivering	1/1/2004	12/15/2003		89,431	77,007	Y	
5	Delivering	6/28/2004	6/28/2004		23,954	28,915	N/A	
6	Delivering	12/25/2004	12/31/2004		178,704	148,466	N/A	
7	Delivering	12/31/2005	3/21/2006		167,900	149,633	Y	Y
8	Delivering	12/31/2006	1/23/2007		20,000	17,560	N/A	
9	Delivering	12/31/2006	3/8/2007		24,000	21,604	Y	
10	Delivering	10/1/2007	10/1/2007		46,894	41,959	Y	
11	Delivering	1/1/2008	1/1/2008		364,854	362,099	Y	
12	Delivering	1/1/2008	1/1/2008		22,000	18,269	N/A	
13	Delivering	12/31/2008	12/29/2008		325,000	287,638	N/A	Y
14	Delivering	5/1/2009	5/1/2009		13,140	11,251	N/A	
15	Delivering	12/31/2009	10/16/2009		310,000	278,977	N/A	Y
16	Delivering	3/1/2010	3/1/2010		219,000	219,000	Y	Y
17	Delivering	4/1/2009	4/30/2010		89,760	74,449	Y	
18	Delivering	11/1/2010	2/1/2011		26,940	26,587	Y	
19	Delivering	12/31/2010	5/16/2011		11,784	6,712	N/A	
20	Delivering	5/1/2011	5/18/2011		11,784	11,132	N/A	
21	Delivering	7/1/2011	7/1/2011		13,140	11,843	N/A	
22	Delivering	12/31/2007	8/16/2012		844,284	326,191	N/A	
23	Delivering	12/15/2013	12/27/2012		789,276	334,750	Y	
24	Delivering	12/31/2012	12/31/2012		259,296	283,768	Y	
25	Delivering	7/31/2012	2/12/2013		60,000	66,998	Y	Y
26	Delivering	5/20/2013	5/20/2013		17,282	27,740	Y	
27	Delivering	6/21/2013	6/21/2013		12,483	6,561	N/A	
28	Delivering	6/21/2013	6/21/2013		12,483	6,244	N/A	
29	Delivering	12/31/2013	10/10/2013		496,867	49,429	Y	
30	Delivering	12/31/2010	10/15/2013		1,053,828	349,232	Y	Y
31	Delivering	12/31/2009	10/22/2013		168,086	109,471	N/A	
32	Delivering	10/31/2013	10/31/2013		1,150	1,145	N/A	
33	Delivering	1/1/2014	11/1/2013		273,312	155,596	Y	Y
34	Delivering	12/20/2013	11/5/2013		286,029	195,505	Y	
35	Delivering	6/30/2013	11/27/2013		223,900	204,242	Y	
36	Delivering	11/30/2014	12/24/2013		55,265	1,394	Y	
37	Delivering	12/31/2013	12/31/2013		3,288	74	Y	Y
38	Delivering	12/31/2013	12/31/2013		8,220	106	Y	Y
39	Delivering	12/31/2013	12/31/2013		4,054	136	Y	Y
40	Delivering	12/31/2013	12/31/2013		8,108	198	Y	Y
41	Delivering	1/26/2014	1/26/2014		6,800	-	Y	
42	Delivering	3/30/2014	3/30/2014		13,403	8,200	N/A	

	SDG&E Local Area (included in analysis)
	Outside of SDG&E's local area
	SDG&E Local Area (not included in analysis)

	Question #	4a	4b	4c	4d	4e	4g	
Project No.	Status	Original Anticipated COD	Actual COD (Projects Online)	Assumed COD (Projects Not Yet Online)	Expected Annual Generation (MWh)	Actual Annual Generation (MWh)	Production Profile Available?	Bilateral?
43	Developing			8/9/2014	272,142	49,792	Y	
44	Developing			8/9/2014	65,253	N/A	Y	
45	Developing			12/31/2016	356,140	N/A	Y	Y
46	Developing			10/30/2014	15,730	N/A	Y	Y
47	Developing			12/31/2015	48,400	N/A	Y	Y
48	Developing			12/31/2015	12,100	N/A	Y	Y
49	Developing			5/31/2015	381,270	N/A	y	
50	Developing			12/31/2015	203,000	N/A	Y	Y
51	Developing			12/31/2015	113,000	N/A	Y	Y
52	Developing			8/1/2014	360,600	N/A	Y	Y
53	Developing			3/15/2015	4,442	N/A	N/A	
54	Developing			4/1/2015	45,031	N/A	Y	Y
55	Developing			4/1/2015	54,874	N/A	Y	Y
57	Developing			2/1/2015	32,377	N/A	Y	
58	Developing			2/27/2015	57,550	N/A	Y	
59	Developing			11/22/2014	3,348	N/A	N/A	
60	Developing			11/22/2014	3,348	N/A	N/A	
61	Developing			11/22/2014	3,348	N/A	N/A	
62	Developing			12/7/2014	2,329	N/A	N/A	
63	Developing			1/23/2015	3,348	N/A	N/A	
64	Developing			12/23/2015	13,316	N/A	Y	
65	Developing			12/23/2015	29,043	N/A	Y	
66	Developing			12/23/2015	14,075	N/A	Y	
67	Developing			12/23/2015	21,778	N/A	Y	
68	Developing			11/30/2015	6,684	N/A	N/A	
69	Developing			3/28/2016	5,178	N/A	N/A	
70	Developing			2/1/2016	8,066	N/A	N/A	
71	Developing			5/16/2015	8,847	N/A	N/A	