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Exhibit Number	:	
Commissioner	:	Michel Peter Florio
Admin. Law Judge	:	Stephen C. Roscow
ORA Witnesses	:	Robert M. Fagan Patrick Luckow

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

TESTIMONY OF OFFICE OF RATEPAYER ADVOCATES [SET 1] ROBERT M. FAGAN AND PATRICK LUCKOW, SYNAPSE ENERGY ECONOMICS

APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) FOR AUTHORITY TO UPDATE ELECTRIC RATE DESIGN EFFECTIVE ON JANUARY 1, 2015

Application 14-01-027

San Francisco, California
November 14, 2014

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I. INTRODUCTION AND SUMMARY OF FINDINGS

What is the purpose of this testimony?

The purpose of this testimony is respond to the January 31, 2014 Direct Testimony of David T. Barker of San Diego Gas and Electric ("SDG&E"). Dr. Barker supports a change in the time-of-use ("TOU") periods for SDG&E based on analysis conducted by SDG&E. Our response is limited to an examination of the proposed TOU periods and the supporting analysis behind SDG&E's proposal for TOU period changes; it does not examine the broad array of remaining issues that comprise SDG&E's application in this Rate Design Window ("RDW")[1].

What is the structure of your testimony?

We first provide a limited critique of certain aspects of SDG&E's analysis. We then provide additional analysis on potential TOU periods using the material provided in Dr. Barker's testimony and workpapers. This material includes projected 2017 energy price patterns, **and** 2017 and 2020 relative loss-of-load expectation ("LOLE") hourly patterns seen in Dr. Barker's data and in the E3 LOLE analysis[2]. Dr. Barker's hourly LOLE analysis has critical implications for specific TOU-period start and stop hours. We provide context for how San Diego area TOU period definition can consider current findings from the 2014 LTPP docket[3]. Lastly, we explain how the Office of Ratepayer Advocate's ("ORA's") suggestions for a modification to SDG&E's TOU periods are supported by Synapse's analysis.

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[1] For example, SDG&E witness Cynthia Fang testifies to the RDW's relationship to other rate proceedings and the new rates for small business and residential customer classes based on SDG&E's proposed TOU periods. We do not address these issues here.

[2] LOLE is a probabilistic measure of the potential for not having sufficient energy available to serve load, and hourly LOLE implies that the LOLE metric is computed at the hourly level. Relative hourly LOLE implies that the metric is used to compare LOLE across different hours, but that it is not meant to imply an estimate of the absolute probability of loss of load. The E3 LOLE analysis is contained in Dr. Barker's workpapers. It is summarized in Chart DTB-17 of Dr. Barker's testimony, and in short is represents a "statewide" rather than SDG&E-specific analysis of the probabilistic potential for a loss of load arising from a shortage of resources. It is for 2020, while SDG&E's own LOLE analysis is for 2017.

[3] R.13-12-010.

What are your key findings?

The analysis offered by SDG&E supports suggested TOU summer peak periods that have shifted into later hours of the day. The evidence is not as clear to retain seven hours in duration (2-9 PM) over the course of six months (May through October) for the summer TOU period. In particular, the data indicate that smaller duration summer peak TOU periods, on the order of 3 to 4 hours long, address the hourly periods when the relative LOLE[4] is highest during the summer weekday peak periods, and when energy prices are highest. ORA suggests an optional 3-hour TOU peak period for summer weekdays to complement the longer-peak-period SDG&E proposal.[5] Also, SDG&E's analysis indicates that 1) August and September are the key summer months of concern from the perspective of relative loss-of-load expectation, and 2) July and August show significantly greater average summer weekday prices during the afternoon hours, compared to May, September and October. Taken together, ORA suggests a 3-month duration for summer TOU period definition for the optional plan, July through September. Based on a review of the winter energy price patterns for 2017, ORA recommends winter TOU peak weekday periods aligned with SDG&E's proposal, but does not think that a "super off peak" period is warranted at this time.

Synapse conducted a supplemental analysis using SDG&E's relative LOLE findings, focusing on the hours of non-zero LOLE. We used a benchmark price for marginal capacity costs[6] to develop a notional capacity-based hourly "adder" to help identify which summer peak period hours may be best considered for peak TOU rate design treatment. This method was employed solely to gauge the relative impact between

[4] Relative hourly LOLE is a relative, rather than an absolute, measure of reliability as defined by the fraction of unserved energy in an hour compared to the total modeled unserved energy. See e.g., Barker workpaper on Planning and Risk Modling, at page 8.

[5] ORA provides policy and rate design principles to retain the current seasonal definition, use SDG&E's proposed seven-hour on-peak summer weekday TOU plan, as well as an optional 3-hour TOU on-peak summer weekday plan with a shorter summer season. This is seen in Mrs. Lee-Whei Tan's testimony.

[6] Our benchmark cost for a marginal MW of capacity was $100/kW-year, roughly equivalent to the carrying costs of a new combustion turbine. This figure represents an approximate mid-point of the estimates presented by parties in the General Rate Case, Phase 2, proceedings. ORA typically recommends values less than $100/kW-year.

1) marginal energy costs and 2) marginal capacity costs on identifying TOU periods. Based on this analysis, shorter-duration, rather than longer-duration summer peak TOU periods; and a shorter summer period (3 months) would better represent those times when the system would be at a *relatively* greater risk for loss-of-load. Allowing an optional shorter-duration TOU period would provide a stronger – and thus more economically efficient - price signals, and encourage greater price response, for those customers able to do so.

Lastly, SDG&E's 2017 LOLE analysis for the local San Diego area shows different results than E3's 2020 statewide analysis of relative LOLE. The critical summer peak TOU periods are several hours earlier in the day in E3's study, compared to SDG&E's study. This suggests the importance of reviewing the TOU period structure after transmission improvements planned for implementation over the next six years are complete[7], since they may have the effect of more tightly integrating the San Diego local reliability area to the rest of the Southern California electric power system. This would lead to closer alignment of critical TOU periods for SDG&E with the rest of Southern California.

What are ORA's recommendations?

ORA recommends modification of SDG&E's proposed TOU periods by offering an additional "opt-in" shorter time period TOU rate option for the summer, and Synapse's analysis supports that modification. Table 1 below summarizes ORA's recommendation. In short, ORA's default[8] TOU proposal would be similar to SDG&E's proposal but with one modification, no super off-peak period is defined. In addition, ORA proposes an optional, or "opt-in," summer TOU peak period with a summer on-peak period of three hours duration (6-9 PM) for three months (July through September).

[7] As referenced in this testimony, this includes transmission improvements included in the 2013/2014 CAISO Transmission Plan, especially those seen in Table 2.6-5, "Summary of Proposed Transmission Solutions, Cost Estimates, and Local Resource Reduction Benefits", page 108.

[8] It is our understanding that this schedule could not be offered in the residential class as a default schedule until 2018, pursuant to provisions in Assembly Bill 327. Before then, we understand it would be a voluntary, op-in, schedule. It would be the default schedule for all non-residential customers starting in 2015.

For those choosing that option, the winter period TOU structure would be similar to SDG&E's proposal except that it would be for nine months (October through June), complementing the seasonality of the opt-in summer TOU period. In the default schedule, the semi-peak period for the opt-in, shorter, summer TOU period is defined as the hours immediately around the peak period, as seen in Table 1; and all other hours are defined as offpeak.

Table 1. Suggested Modifications to SDG&E TOU Periods

	Summer			
	SDGE Current TOU Hours	**SDGE RDW Proposed TOU**	**ORA Default Proposal (2 periods)**	**ORA Opt-in Proposal (3-periods) -**
Summer on-peak	11 a.m. – 6 p.m. non-holiday weekdays, May through October	2 p.m. – 9 p.m. non-holiday weekdays, May through October	2 p.m. – 9 p.m. non-holiday weekdays, May through October	6 p.m. - 9 p.m. non-holiday weekdays, July through September
Semi-peak	All other times	All other times	All other times – offpeak - no "super offpeak"	2 p.m. - 6 p.m. & 9 p.m. - 11 p.m. non-holiday weekdays
Super off-peak	12 a.m. – 6 a.m. daily	12 a.m. – 6 a.m. daily		All other times – offpeak - no "super offpeak"
	Winter			
Winter on-peak	5 – 8 pm non-holiday weekdays, November through April	5 p.m. - 9 p.m. non-holiday weekdays, November through April	5 p.m. - 9 p.m. non-holiday weekdays, November through April	5 p.m. - 9 p.m. non-holiday weekdays, October through June
Semi-peak	All other times	All other times	All other times – offpeak - no super offpeak	All other times – offpeak - no super offpeak
Super off-peak	12 a.m. – 6 a.m. daily	12 a.m. – 6 a.m. daily		

Note: Changes to SDG&E's proposed TOU periods are highlighted in yellow.

II. LIMITED CRITIQUE OF SDG&E

Dr. Barker analyzes energy price patterns and LOLE results in his testimony. Please comment.

Dr. Barker presents both energy price data and LOLE data that result from SDG&E's analysis. In particular, Chart DTB-7 presents summer weekday energy prices for 2017, and Chart DTB-17 presents relative LOLE results. Relative LOLE results means that the information does not provide an estimate of actual loss-of-load expectation, but rather indicates which hours would be more susceptible to loss of load relative to other hours in the year.

Dr. Barker makes a recommendation for TOU periods based on these data, but he acknowledges that the proposed summer on-peak period is "relatively long"[9]. He notes that the longer period "assures that both state and local capacity need periods are included"[10] and he also indicates that "Demand response can be tailored to shorter periods within the TOU period…"[11]. However, he does not assign any particular weighting to energy prices, or LOLE values, for any given hour for the proposed TOU periods. He does not indicate if, or the extent to which, SDG&E's proposed TOU periods are weighted towards energy price patterns or LOLE period patterns. He does not explore options for more granular TOU periods, nor more granular seasonal TOU periods. Our analysis focuses on these aspects of SDG&E's testimony.

Dr. Barker does not include incremental energy efficiency in his analysis. Please comment.

Dr. Baker states that additional achievable energy efficiency (AAEE), also known as "incremental uncommitted" electric savings, is excluded from his analysis for 2017[12]. Inclusion of AAEE could change the pattern of spot energy prices seen in Chart DTB-7 and change the pattern of relative LOLE as seen in Chart DTB-17, and as such, the analysis would have been more precise if such resources were considered. AAEE should be included in all analysis of energy pricing and LOLE patterns, since it is expected that these savings will occur. In the 2014 LTPP docket, future AAEE is included in the planning models, even though it is not included in the base CEC forecast. The extent to which inclusion of AAEE would change the projected energy price patterns or the projected patterns of LOLE is unknown, but since the choice of TOU period must consider various factors and should not rely solely on such patterns, it's not likely that

[9] Barker at page DTB-28: 19.

[10] Barker at page DTB-28: 20.

[11] Barker at DTB-28: 20 – DTB-29: 1.

[12] Barker at page DTB-16, lines 2-4.

inclusion of AAEE effects would materially change either SDG&E's or ORA's TOU period proposals.

III. SYNAPSE EXAMINATION OF LOLE, ENERGY PRICE, AND OTHER RELEVANT INFORMATION TO ASSESS TOU PERIOD PROPOSAL

Please describe the framework for assessing "best" TOU peak periods, and indicate which issues are most important in this case in terms of defining TOU periods.

Theoretically efficient TOU peak periods would generally represent times of high or highest marginal energy and/or marginal capacity cost.[13] Marginal energy costs are the cost of supplying the next increment, or next MWh, of energy resource. Those costs can be represented by the spot price of energy, and on an average hourly basis for weekdays in May through October, a projection of 2017 weekday prices is seen in Dr. Barker's Chart DTB-7. Marginal capacity costs are different, since no hourly market exists for spot capacity. In many hours, surplus capacity exists on the grid, and there is little or no marginal cost associated with having the next MW of capacity available to supply energy. In other hours, there is a greater chance of shortage of available capacity, relative to those hours with surplus capacity. Dr. Barker refers to this when he presents information on relative LOLE in Chart DTB-17. The LOLE represents the relative chance that capacity may be short such that a loss of load could occur. To estimate true marginal costs of capacity associated with those relatively tighter hours, there needs to be an allocation of the total costs of an incremental MW of capacity to a certain number of hours.

There are a number of issues to be assessed when specifying TOU periods and seasons for SDG&E, including the following. Synapse's examination of energy and LOLE data from Dr. Barker's testimony and workpapers focus on these issues:

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[13] A number of factors must be considered when updating TOU periods and seasons, as indicated in the Energy Division Staff Proposal on Residential Rate Structure Reform, at page 66. Staff notes (at page 63, e.g.,) that TOU periods and seasons should "best reflect marginal costs", along with advancing OIR rate design principles.

- How to determine a value for marginal capacity costs, for the purpose for assessing TOU periods.
- How much weight to give to marginal energy costs versus marginal capacity costs, for any given hour, month, or season.
- How to treat differences in marginal energy and capacity costs across different months and how, and/or whether, to group those months together for a given TOU period definition.
- How to determine the specific start hour, and the specific stop hour, for a peak TOU period.

We first focused on the results of the LOLE analysis, because one of the reasons to implement TOU pricing is to promote efficient load shifting that can reduce the need to procure new capacity.

What are the results of the SDG&E and the E3 LOLE analysis?

Table 2 contains the relative LOLE values for the year 2017 (for the San Diego local area) from Dr. Barker's workpapers. Table 3 contains the statewide relative LOLE values for 2020 from E3's analysis, as contained in Dr. Barker's workpapers.

What does Table 2 indicate?

Table 2 illustrates the patterns of weekday, weekend, and seasonal shares of the relative loss of load expectation from Dr. Barker's analysis. It shows the periods in which capacity available to serve load is tightest, relative to other periods. As Dr. Barker points out, the values are not indicative of the probability of actual loss of load, but merely help to identify periods of greatest resource adequacy stress on the system.

Table 2. Relative Loss of Load Expectation Percentages – SDG&E Analysis, for 2017

	Hour End - Clock Time													
Summer - Weekday	**1-12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	Total All Hours
May	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Jun	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Jul	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	1.0%	0.1%	0.0%	0.0%	1.6%
Aug	0.0%	0.0%	0.2%	0.4%	0.9%	1.7%	2.1%	7.3%	14.1%	13.8%	4.7%	0.4%	0.0%	45.7%
Sep	0.0%	0.0%	0.1%	0.4%	0.7%	1.3%	2.4%	10.9%	15.2%	8.9%	2.2%	0.1%	0.0%	42.3%
Oct	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
All months	0.0%	0.0%	0.3%	0.8%	1.6%	2.9%	4.6%	18.2%	29.8%	23.8%	7.0%	0.5%	0.0%	89.6%
Summer - Weekend														
May	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Jun	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Jul	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Aug	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	1.2%	0.1%	0.0%	0.0%	2.2%
Sep	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	2.5%	1.5%	0.2%	0.0%	0.0%	6.1%
Oct	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
All months	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	3.3%	2.8%	0.4%	0.0%	0.0%	8.3%
Winter - Weekday	**1-12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	
Nov	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Dec	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Jan	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	1.4%	0.1%	0.0%	0.0%	0.0%	0.0%	2.0%
Feb	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Mar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Apr	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
All months	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	1.4%	0.1%	0.0%	0.0%	0.0%	0.0%	2.1%
Winter - Weekend														
Nov	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Dec	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Jan	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Feb	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Mar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Apr	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
All months	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Source: Synapse compilation from David Baker, Workpapers, SDG&E LOLE Analysis for 2017. Note: shaded areas are SDG&E proposed TOU peak periods.

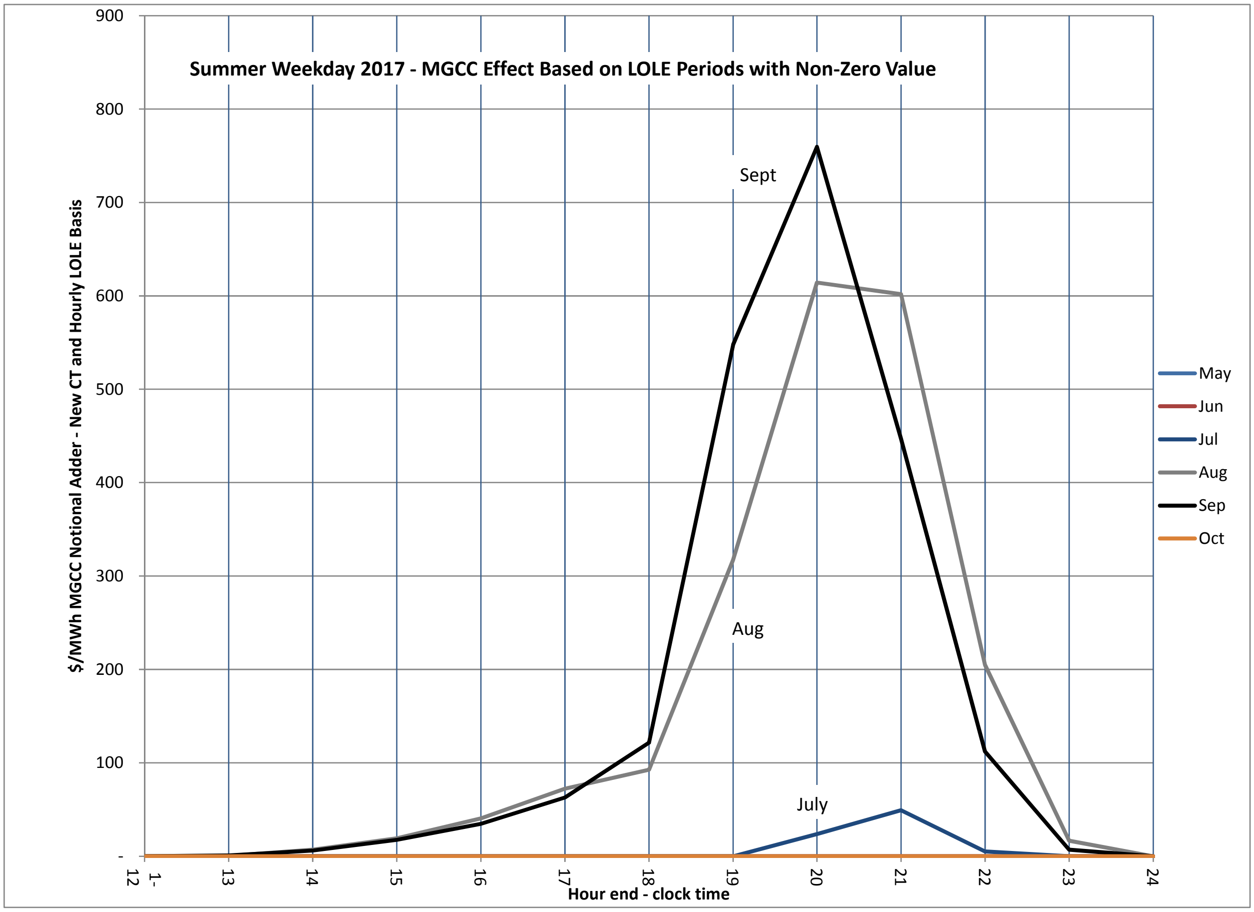
Does Table 2 provide an indication of the value of reducing load during the periods with non-zero LOLE?

No, it would not on its own. However, the table does show – to the extent that the LOLE analysis is reflective of San Diego system conditions – which time periods would drive any new need for capacity and in which periods new capacity would less likely be needed. As can be seen, for example, there is no expectation of relative loss of load for any hours in May, June and October for the summer weekday periods. This should influence consideration of which months, and which hours, define summer weekday TOU periods, to the extent that relative loss of load is given weight when assessing marginal commodity costs that include capacity.

Can you assign the marginal costs of capacity to these periods?

Yes, we can at least for the purposes of identifying the rough magnitude of this driving factor. The total annual hours of non-zero LOLE periods shown in Table 2 above is 821, based on Dr. Barker's data. If marginal capacity costs were to be spread solely across those hours, in proportion to the LOLE shares shown, a proxy "spot capacity" average value can be obtained for each summer month, for weekday periods, by hour. Figure 1 below shows this pattern for the hourly LOLE distribution in the summer weekday portion of Table 2. Only July, August and September exhibit hours with non-zero LOLE. Thus, in this depiction, no marginal capacity costs are allocated to the months of May, June, or October.

Figure 1
Marginal Generation Capacity Cost (MGCC), Summer Weekday, 2017 SDG&E Basis for LOLE



Source: Synapse computation and graphing; hourly LOLE values from Barker_RDW-Workpapers-LOLE_Results.xls.

How did you arrive at the notional capacity adder depicted in the graph?

Since there is no hourly capacity market akin to the hourly energy market, we needed to identify the importance of avoiding a need for capacity at an hourly level. We used a three-step process to do this.

- First, we used an estimate of marginal costs of a MW of capacity based roughly on the costs of a new combustion turbine, using a benchmark value of $100/kW-year. We note that for any real requirement for new capacity, there exists a range of possible costs. We use this value solely to roughly gauge the effect on critical hours of allocating marginal capacity costs to a relatively limited number of hours. As will be seen in the results, the consideration of TOU periods based on marginal capacity cost effects is not very sensitive to the actual cost of a new MW of capacity.

- Next, we allocated the total costs of this marginal MW of capacity according to the LOLE percentages seen in the LOLE results. Those results were hourly, and by monthly weekday/weekend period.
- Last, we divided these total costs by the number of hours contained in each monthly/weekday or weekend hourly period. Generally, this means a range of 20 to 23 weekday periods per month.

These steps result in a notional $/MWh value of capacity (for each hour, for each month) for the summer weekday periods. Table 3 below shows the data supporting Figure 1. We note that this does not imply support for any particular allocation of capacity costs to load. There are many factors to consider, as part of larger rate design issues, when allocating utility revenue requirements to load.

Table 3. Assigning Marginal Capacity Costs ($/MWh) to Periods with Non-Zero LOLE, in Proportion to the Relative LOLE Share, for SDG&E 2017 Analysis

	Hour End - Clock Time												
Summer - Weekday	**1-12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
May	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	0	24	49	5	-	-
Aug	-	0	7	19	40	72	93	317	614	602	205	17	-
Sep	-	1	6	18	35	63	122	547	760	447	112	7	-
Oct	-	-	-	-	-	-	-	0	0	-	-	-	-
Summer - Weekend													
May	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	0	3	-	-	-
Aug	-	-	-	-	-	-	-	4	102	150	19	-	-
Sep	-	-	-	-	-	-	5	178	253	153	22	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-
Winter - Weekday	**1-12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	0	0	-	-	-	-	-
Jan	-	-	-	-	-	-	27	65	4	-	-	-	-
Feb	-	-	-	-	-	-	-	3	-	-	-	-	-
Mar	-	-	-	-	-	-	-	-	-	-	-	-	-
Apr	-	-	-	-	-	-	-	-	-	-	-	-	-
Winter - Weekend													
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	-	-	-	-	-	-	-	-
Apr	-	-	-	-	-	-	-	-	-	-	-	-	-

Source: Synapse computation from Barker_RDW-Workpapers-LOLE_Results.xls.

If the E3 LOLE results were used to allocate marginal capacity costs, how would the patterns seen in Figure 1 differ?

The E3 results differ from SDG&E's results. They show non-zero LOLE only in summer hours, and mostly (96.6% of the time) during weekday, rather than weekend hours. This is seen in Table 4 below.

Table 4. E3 2020 Statewide LOLE Relative share

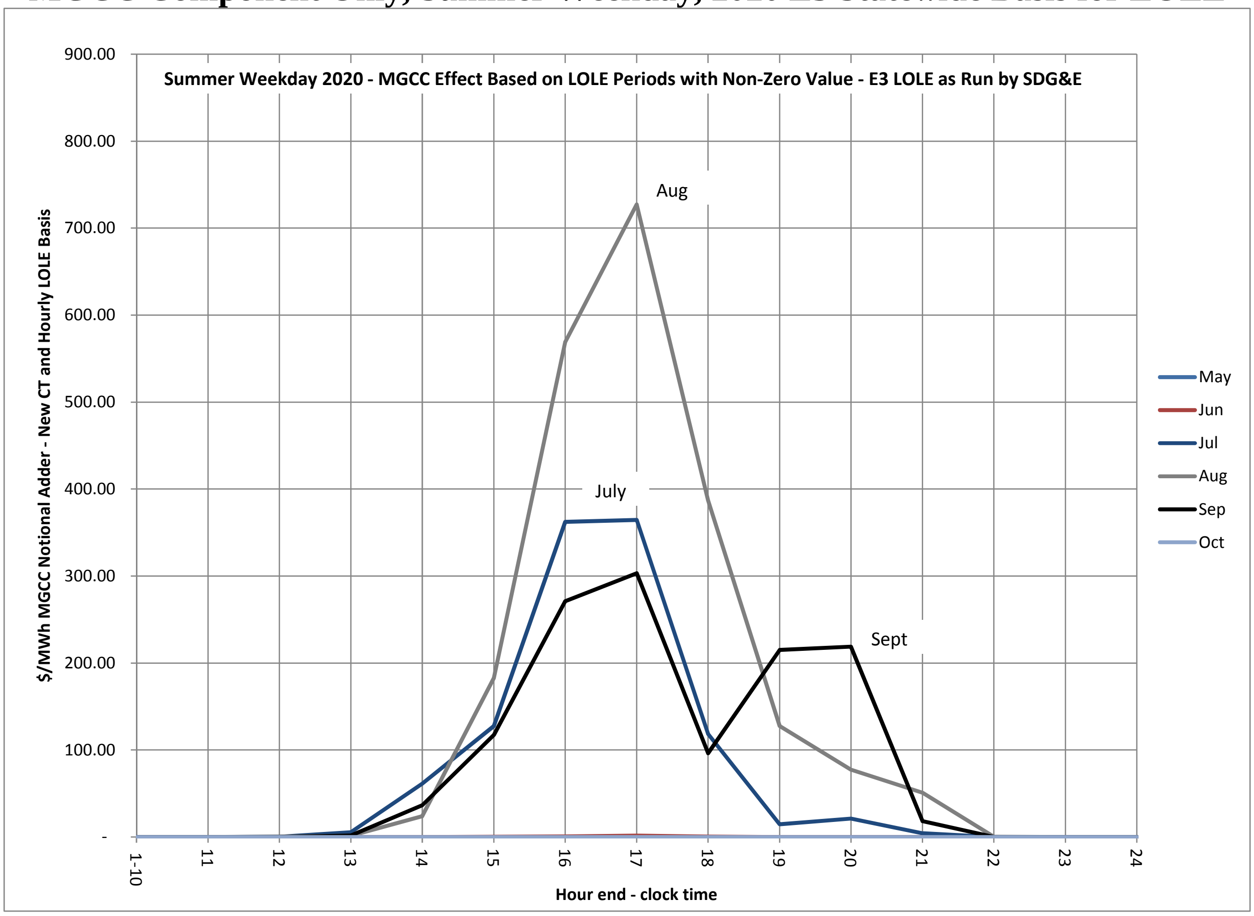
	Hour End - Clock Time													
Summer - Weekday	**1-12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**Total All hours**
May	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
June	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
July	0.0%	0.1%	1.2%	2.5%	7.2%	7.3%	2.4%	0.3%	0.4%	0.1%	0.0%	0.0%	0.0%	21.6%
August	0.0%	0.0%	0.5%	4.2%	13.1%	16.7%	8.9%	2.9%	1.8%	1.2%	0.0%	0.0%	0.0%	49.4%
Sept	0.0%	0.0%	0.7%	2.3%	5.4%	6.1%	1.9%	4.3%	4.4%	0.4%	0.0%	0.0%	0.0%	25.6%
Oct	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
All months	0.0%	0.2%	2.5%	9.1%	25.8%	30.1%	13.2%	7.5%	6.6%	1.6%	0.0%	0.0%	0.0%	96.6%
Summer - weekend														
May	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
June	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
July	0.0%	0.0%	0.3%	0.7%	1.1%	0.7%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%
August	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Sept	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Oct	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
All months	0.0%	0.0%	0.3%	0.7%	1.1%	0.7%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	3.4%

Source: David Baker, Workpapers, SDG&E LOLE Analysis for 2017. Note: shaded areas are SDG&E proposed TOU peak periods. Winter LOLE values are zero for all months and all hours in the E3 analysis.

Figure 2 below shows the pattern of marginal capacity costs allocated across these hours, proportional to the LOLE hourly values (from Table 4 above). As seen, the magnitude is similar to the magnitudes seen in Figure 1, since the relative LOLE is also concentrated in a small number of hours, as is seen with SDG&E's results. However, the E3 results show earlier time period "price" spikes compared to the periods seen in SDG&E's analysis.

Table 5 follows Figure 2 below, and contains the data that form Figure 2.

Figure 2.
MGCC Component Only, Summer Weekday, 2020 E3 Statewide Basis for LOLE



Source: Synapse computation from Barker_RDW-Workpapers-LOLE_Results.xls.

Table 5. Assigning Marginal Capacity Costs ($/MWh) to Periods with Non-Zero LOLE, in Proportion to the Relative LOLE Share, for E3 2020 LOLE Analysis

	Hour End - Clock Time														
Summer - Weekday	**1-10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
May	-	-	-	0	0	0	0	0	0	0	0	0	-	-	-
Jun	-	-	0	0	0	0	1	1	0	0	0	0	0	-	-
Jul	-	0	0	6	61	127	362	365	119	15	21	4	0	-	-
Aug	-	0	1	2	24	183	569	727	387	128	77	51	0	0	-
Sep	-	0	0	2	37	117	271	303	96	215	219	18	0	-	-
Oct	-	-	-	0	0	0	0	0	0	0	0	-	-	-	-
Summer - Weekend															
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	0	3	-	-	-
Aug	-	-	-	-	-	-	-	-	-	4	102	150	19	-	-
Sep	-	-	-	-	-	-	-	-	5	178	253	153	22	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Winter - Weekday	**1-10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	0	0	-	-	-	-	-
Jan	-	-	-	-	-	-	-	-	27	65	4	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-
Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Winter - Weekend															
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Source: Synapse computation from Barker_RDW-Workpapers-LOLE_Results.xls.

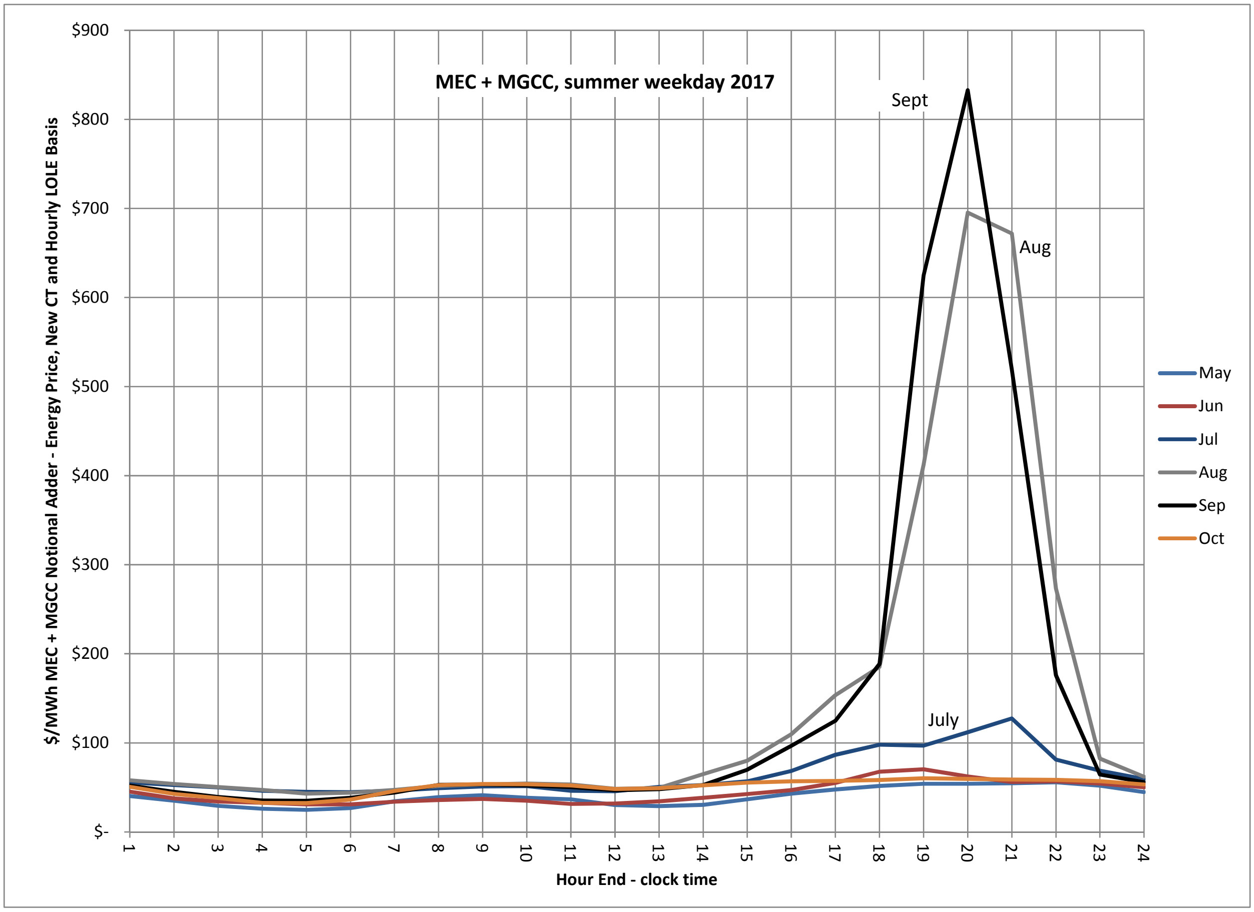
How do the data on LOLE for San Diego for 2017 differ from the statewide LOLE data for 2020?

The statewide 2020 patterns show the highest LOLE for summer weekday hours that are 3 hours earlier (3-6 PM) than the highest LOLE hours seen in SDG&E's 2017 analysis (6-9 PM window).

Can you overlay SDG&E's energy price data with your notional "capacity spot price" adder?

Yes. Figure 3 shows the combination of energy and capacity price signals for the summer weekday period, based on SDG&E's 2017 data.

Figure 3 Combination of MEC and MGCC Patterns, Summer Weekday, 2017



Source: Synapse computation from Barker_RDW-Workpapers-LOLE_Results.xls, and Barker_RDW-Workpapers-TOU_Energy_Prices_2017.xls.

Please explain what Figure 3 shows.

Figure 3 depicts the combination of marginal energy and marginal capacity costs when marginal capacity costs are assigned to hours only with non-zero relative LOLE, using SDG&E's 2017 LOLE results. It illustrates, notionally, the marginal benefit of avoiding consumption in a few key hours (during summer weekdays) relative to other hours of the day. It can be used to discern the relative weight between marginal energy and marginal capacity effect by inspecting the patterns in the early morning hours (no marginal capacity component) versus the later afternoon/early evening hours, and by comparing months with marginal capacity cost components (July, August, September) to months without marginal capacity cost component (May, June and October).

As seen by inspection of the figure, the marginal costs of capacity (assuming the relative LOLE distribution from SDG&E's analysis) far outweigh the marginal costs of energy, since the capacity costs are allocated to relatively few hours. We also observe that even if marginal capacity costs were, say, one-half the $100/kW-year values that ORA used, the spike would still be well-defined for key later-afternoon and early evening hours.

Please summarize your observations based on examining marginal energy and marginal capacity cost indicators for consideration of efficient peak TOU periods during summer weekdays.

The results indicate narrower TOU periods – both daily and seasonal – would send "better" price signals if the focus was primarily to avoid new capacity costs, essentially giving greater weight to marginal capacity cost concerns. If greater weight is given to energy price patterns, then the TOU peak period definition would be composed of more hours and include lengthier seasonal characteristics.

Why does ORA suggest an optional, 3-hour duration TOU period, for just three months?

The data indicate that the largest relative risk of loss of load in the SDG&E territory in 2017 occurs during a shorter window of time than the seven hour duration proposed by Dr. Barker. The 6 PM to 9PM summer weekday window contains much higher relative LOLE values than the 2-6 PM periods. A review of the 2017 energy price patterns seen in Chart DTB-7 indicates that weekday hourly prices in July and August exhibit highest prices in the 4 to 8 PM window. These two data patterns suggest consideration of a tighter TOU period, since the price signal during these times would be higher, and the customer response potentially greater, than what would be seen with a price signal associated with a seven-hour TOU period duration. For these reasons, ORA supports an additional TOU peak period definition, associated with an optional (opt-in) 3-hour duration TOU period for the summer weekday, between 6 and 9 PM. ORA suggests the 6-9 PM period rather than an earlier start period as an way to emphasize the importance of avoiding the potential need for new capacity in those hours.

Please comment on ORA's suggested 3-hour duration optional TOU period as it would affect non-event based demand response.

Synapse notes that Dr. Barker indicates "Demand response can be tailored to shorter periods within the TOU period targeted towards specific types of critical events that may be in the afternoon or the evening depending on state of local conditions"[14]. However, price signals for *non-event-based* demand response – i.e., customer load shifting that arises from TOU period pricing – are diluted when the duration of the TOU period is longer than is necessary to avoid marginal capacity costs. A longer, rather than shorter, TOU period will likely lessen the amount of non-event-based demand response that could be captured with shorter-duration TOU periods.

In general, do you find the analysis conducted by SDG&E is reasonable?

Yes, in general the analysis is reasonable. The patterns seen for future energy prices and relative LOLE appear generally consistent with the information we have seen during our participation in the LTPP dockets (both 2014 and 2012). There are always different scenario analyses and sensitivities than can be run that would produce different energy price and LOLE values than the ones presented by SDG&E, and it's important to not overlook such potential variation in these parameters. Yet, on the whole, the shifting of peak periods of concern from earlier to later in the afternoon (and early evening) is representative of fundamental shifts in the electric power sector in California. Changing TOU periods to reflect these shifts is sensible. However, we do note SDG&E does not offer explicit linkage between the results seen, and the specific hours proposed for the new TOU periods. In particular, there are a number of other potential TOU period start and stop times, duration, and seasonal differences that can also be considered reasonable when viewing the data provided, which is what our analysis offers.

[14] Barker at DTB-28: 20 to DTB-29: 2.

The initial results of CAISO modeling from Phase 1a of the 2014 LTPP docket[15] suggest concern with possible future curtailment of renewable energy. Please comment on how this is related to TOU periods under consideration in this docket.

In phase 1a of the 2014 LTPP docket, CAISO testimony indicates that in a number of scenarios, there is a risk of curtailment of renewable energy, particularly during the midday springtime hours, but also in midday hours in other periods. While additional modeling is still to be considered in that docket[16], and such results may further inform the patterns for potential renewable curtailment, what is clear from the initial modeling is that, during midday hours when load is generally lower (such as in springtime), curtailment potential exists, along with low or even negative prices. While further analysis is required to assess the extent to which separate "spring" TOU seasons should be defined, at this point including March and April in the winter TOU periods suggested by Dr. Barker is reasonable. While it may be that some form of a separate midday super-offpeak period might make sense for these particular spring months, given the data available in CAISO modeling for 2024, it is not clear that the patterns of potential curtailment and the lower CAISO prices seen during these periods (in the 2014 LTPP modeling) will be directly applicable to SDG&E for 2017.

As Dr. Barker references in his testimony, "the impact of solar on the net load shape will be substantial" by 2017.[17] He includes as Chart DTB-1 the CAISO so-called "duck graph" that shows, as part of the duck's belly, a "significant midday decrease in net load may result in having too much electricity on the grid, which could result in low or negative prices".[18] Dr. Barker's inclusion of his Chart DTB-2 also shows that net load

[15] See Phase I.A. Direct Testimony of Dr. Shucheng Liu and Dr. Karl Meeusen of CAISO, Docket 13-12-010, August 13, 2014. Especially, Dr. Liu at 38: 4-13.

[16] See 2014 LTPP, Reply Testimony of Robert M. Fagan and Patrick Luckow, Synapse Energy Economics, October 24, 2014, Docket R.13-12-010.

[17] Barker, DTB-7: 9.

[18] Barker, Chart DTB-1, and text embedded in a bubble in the chart.

peaks (across all California) in July over time (between 2012 and 2017) shows a shift towards the later hours (peaking at hour 20 in 2017, compared to hour 16 or 17 in 2012).

This changing pattern of net load peak, and relatively lower midday energy prices, is directly related to consideration of the start time for any revised TOU period. SDG&E proposed a 2PM start time, three hours later than the 11AM start time currently seen in SDG&E's TOU rate design. However, from the technical perspective and assuming a focus on local area (San Diego) concerns, it is not clear that charging a higher TOU peak period rate during the 2-4 PM hours starting in 2015, as suggested by SDG&E's proposal, is necessary since SDG&E shows very low LOLE in these hours (based on 2017 modeling), and net peak load levels are still relatively low, as seen in Chart DTB-13. Synapse notes that there may be non-technical reasons, tied to other rate-setting concerns that could support the earlier summer peak period start time associated with SDG&E's proposal. We also note that later year (2020) statewide indications (based on E3's LOLE analysis) do show greater relative LOLE concerns in these earlier hours.

Does the information available in the LTPP docket inform the choice of TOU periods for the San Diego area?

Yes, at least directionally. The analysis was conducted for 2024, and earlier analyses undertaken for 2020 (2010 LTPP) and 2022 (2012 LTPP) showed statewide results that also revealed net peak load concerns later in the afternoon than has been seen historically[19]. The data available on potential capacity shortages indicate that the periods of greatest concern are the later afternoon hours of summer weekdays. For example, in CAISO's "high load" scenario in the 2014 LTPP docket, the hours with the highest prices on the peak day of the year (July 19, 2024) indicating a potential shortage of capacity occurred during hour ending (HE) 16 to HE 21, or 3 PM to 9 PM. In the trajectory scenario, the peak day showed potential shortages during just HE 18 through HE 20 (5 PM to 8 PM). This finding indicates that, during the summer period, the hours of greatest

[19] 2010 LTPP, Docket RM10-05-066, Trajectory and high-load case results showing 3-4 PM shortage hours on summer peak days. 2012 LTPP, Docket R.12-03-014, base case results showing tightest hours between 4-7 PM on summer peak day.

stress, or potential risk of loss of load, occur later in the afternoon and early in the evening.

IV. RECOMMENDED TOU PERIODS

What does ORA recommend for TOU periods for San Diego in the near term, 2015 through roughly 2019?

ORA recommends that SDG&E offer an additional "opt-in" TOU summer peak period for residential and smaller commercial customers that is of shorter duration (3 hours) and later start (6 PM) than their proposal. This will allow those customers who have at least some ability to shift load to do so during the times of greatest system stress. ORA also offers a "default" proposal that retains the six months long for the summer period but excludes the creation of a super offpeak period. Table 1 outlines ORA's proposal.

In summary, how does your analysis, and the underlying data provided by SDG&E, support this recommendation?

The underlying data shows increasingly higher energy prices, and increasingly higher risk of LOLE, in periods later in the afternoon. From the perspective of relative LOLE, the highest concentrations of relative risk occur in the later afternoon and early evening hours. While there is some relative LOLE indicated in hours 2 PM through 6 PM, the values for 6 PM to 9 PM are significantly higher, as seen in Table 2. This finding supports ORA's opt-in proposal.

Does this complete your testimony?

Yes

.

APPENDIX A

WITNESS OF QUALIFICATION

PREPARED TESTIMONY AND QUALIFCATIONS
OF
ROBERT M. FAGAN

Q1. Please state your name, position and business address.

A1. My name is Robert M. Fagan. I am a Principal Associate with Synapse Energy Economics, Inc., 485 Massachusetts Ave., Cambridge, MA 02139. I have been employed in that position since 2005.

Q2. Please state your qualifications.

A2. My full qualifications are listed in my resume, on the following pages. I am a mechanical engineer and energy economics analyst, and I have examined energy industry issues for more than 25 years. My activities focus on many aspects of the electric power industry, especially economic and technical analysis of electric supply and delivery systems, wholesale and retail electricity provision, energy and capacity market structures, renewable resource alternatives including on-shore and off-shore wind and solar PV, and assessment and implementation of energy efficiency and demand response alternatives.

I hold an MA from Boston University in Energy and Environmental Studies and a BS from Clarkson University in Mechanical Engineering. I have completed additional course work in wind integration, solar engineering, regulatory and legal aspects of electric power systems, building controls, cogeneration, lighting design and mechanical and aerospace engineering.

Q3. Have you testified before the CPUC before?

A3. Yes. I submitted pre-filed modeling rebuttal testimony in October 2014 in Docket R.12-06-013 (jointly, with Patrick Luckow). I submitted pre-filed modeling testimony in August 2014 in the 2014 LTPP docket (R.13-12-010; jointly, with Patrick Luckow). I also testified in Track 1 and Track 4 of the R.12-03-014 proceeding, and in the A.11-05-023, Application of San Diego Gas & Electric Company ((U902E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Energy Center. I have been involved in California renewable energy integration and related resource adequacy issues as a consultant to the ORA since the late fall of 2010. I have also testified in numerous state and provincial jurisdictions, and the Federal Energy Regulatory Commission (FERC), on various aspects of the electric power industry including renewable resource integration, transmission system planning, resource need, and the effects of demand-side resources on the electric power system.

Q4. On whose behalf are you testifying in this case?

A4. I am testifying on behalf of the California Public Utilities Commission's Office of Ratepayer Advocates (ORA).

PREPARED TESTIMONY AND QUALIFICATIONS
OF
PATRICK LUCKOW

Q1. Please state your name, position and business address.

A1. My name is Patrick Luckow. I am an Associate with Synapse Energy Economics, Inc., 485 Massachusetts Ave., Cambridge, MA 02139. I have been employed in that position since I started work at Synapse in 2012.

Q2. Please state your qualifications.

A2. I am an Associate at Synapse, with a special focus on calibrating, running, and modifying industry-standard economic models to evaluate long-term energy plans, and the environmental and economic impacts of policy/regulatory initiatives.

Prior to joining Synapse, I worked as a scientist at the Joint Global Change Research Institute in College Park, Maryland. In this position, I evaluated the long-term implications of potential climate policies, both internationally and in the U.S., across a range of energy and electricity models. This work included leading a team studying global wind energy resources and their interaction in the Institute's integrated assessment model, and modeling large-scale biomass use in the global energy system.

I hold a Bachelor of Science degree in Mechanical Engineering from Northwestern University, and a Master of Science degree in Mechanical Engineering from the University of Maryland.

Q3. Have you testified before the CPUC before?

A3. Yes. I submitted pre-filed modeling rebuttal testimony in October 2014 in Docket R.12-06-013 (jointly, with Robert Fagan). I submitted pre-filed modeling testimony (jointly, with Robert Fagan) in August 2014 in the 2014 LTPP docket (R.13-12-010).

Q4. On whose behalf are you testifying in this case?

A4. I am testifying on behalf of the California Public Utilities Commission's Office of Ratepayer Advocates