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Admin. Law Judge	:	C. Kersten
ORA Project Mgrs.	:	D. Khoury, C.Chan
ORA Witnesses.	:	Chan, Irwin, Fagan/Luckow

Office of Ratepayer Advocates
California Public Utilities Commission

Testimony on Pacific Gas and Electric Company's 2015 Rate Design Window

San Francisco, California
May 1, 2015

MEMORANDUM

This testimony was prepared by the Office of Ratepayer Advocates ("ORA") of the California Public Utilities Commission ("Commission") in response to the Rate Design Window Application of Pacific Gas and Electric Company ("SCE"), A.14-06-014.

Dexter Khoury and Cherie Chan served as ORA's project coordinators in this proceeding, Lee-Whei Tan managed the contract and interactions with Synapse Energy Economics. Gregory Heiden is ORA's counsel. Chris Danforth (Program and Project Supervisor) and Mike Campbell (Program Manager) oversaw this project and the review of this testimony.

List of ORA Witnesses and chapters

Chapter 1	Residential Rate Design Policy	Cherie Chan
Chapter 2	Marginal Energy Costs and LOLE Allocation Among TOU Periods	Bob Fagan/Patrick Luckow
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CHAPTER 1

RESIDENTIAL RATE DESIGN POLICY

CHERIE CHAN

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CHAPTER 1

RESIDENTIAL RATE DESIGN POLICY

CHERIE CHAN

I. SUMMARY AND RECOMMENDATIONS

This chapter presents the Office of Ratepayer Advocates' ("ORA") recommendations in the 2015 Rate Design Window Application ("RDW") of Pacific Gas and Electric Company ("PG&E"), A.14-11-014. In summary, ORA makes the following recommendations:

- ORA continues to support offering a number of optional Time-of-Use ("TOU") rates in the near-term to help inform the transition towards default TOU rates.
- ORA does not object to PG&E's proposal to introduce a new, optional, TOU rate in 2016 (Schedule E-TOU) so long as it is without a customer charge, and it has an excess usage surcharge or baseline credit.
- PG&E should offer additional TOU rates with different TOU periods in their TOU pilots.
- ORA also recommends that schedules E-6 and E-7 not be eliminated at this time as PG&E proposes. ORA's position is consistent with the Residential Rate Design OIR proposed decision ("RROIR PD").[1]

ORA's recommendations above best support the Commission's goal towards a "gradual transition to default time of use rates starting in 2019." [2]

II. PG&E'S PROPOSALS

In summary, PG&E makes three specific requests in this application to:

- Create new TOU Periods with different time and season definitions,

[1] Proposed Decision of ALJs McKinney and Halligan in Rulemaking 12-06-013, entitled "The Decision on Residential Rate Reform for Pacific Gas and Electric Company Southern California Edison Company, and San Diego Gas and Electric Company and Transition to Time-Of-Use Rates," mailed 4/21/2015.

[2] Ibid, page 158.

- Approve new illustrative E-TOU rates that will be updated with more recent revenue requirements and sales assumptions before they are implemented, and
- Close the existing TOU rate schedules, E-6 and E-7.[3]

These proposals will be discussed below.

A. New TOU Periods with Different Time and Season Definitions

PG&E first proposes new TOU definitions[4] to be implemented in early 2016[5] based on anticipated changes to the CAISO net load in 2020, as described in Chapter 2 of ORA's testimony. PG&E's proposed TOU period changes are summarized in the table below:

TABLE 1-1: PG&E'S PROPOSED TOU PERIODS

	Current E-6	**E-TOU, PG&E Proposed**
Summer Season	May 1–Oct. 31 (6 mo.)	June 1– Sept. 30 (4 mo.)
On-Peak	1–7 pm M– F	4–9 pm M– F
Mid-Peak	10–1 am All Days 7–9 pm M-F, 5–8 S/S	N/A
Off-Peak	All Other Times	All Other Times
Winter Season	Nov. 1–April 30 (6 mo.)	Oct. 1– May 31 (8 mo.)
On-Peak	1-7 pm M– F	4–9 pm M– F
Mid-Peak	10–1 am All Days 7–9 pm M-F, 5–8 S/S	N/A
Off-Peak	All Other Times	All Other Times

As discussed in Chapter 2 of this testimony, ORA performed its own independent analysis and finds PG&E's proposed TOU periods for a new, optional rate to be reasonable.

B. PG&E's Illustrative Rates

In this proceeding, PG&E's second request is to seek approval of the Illustrative TOU rates presented, with updated revenue requirements and sales

[3] Pacific Gas and Electric Company Rate Design Window 2015 Prepared Testimony, filed November 25, 2014. Page 1-11, three bullets.

[4] PG&E Testimony, page 1-11, bullet point #1.

[5] Pre-Hearing Conference, Reporter's Transcript, January 14, 2015.

assumptions at the time of implementation.[6] As further described below, these illustrative rates contain an on-to-off-peak ratio of roughly 1.5 to 1 in the summer, and 1.1 to 1 in the winter, as shown below in Table 1-2. They represent a reasonable range for an introductory, voluntary TOU rate.

TABLE 1-2: PG&E'S PROPOSED ILLUSTATIVE RATES[7]

		PG&E Proposal		
		Peak	Off-Peak	Fixed Charge
Rate	Seasonal	cents/kWh		
Non-CARE[8]	Summer	31.0	20.7	$10
	Winter	17.5	15.6	$10
CARE	Summer	21.2	14.1	$5
	Winter	12.0	10.7	$5

However, ORA proposes the E-TOU rate be introduced without a customer charge and with an excess usage surcharge or baseline credit. Such a TOU rate most recently was included in the RROIR PD[9] in the ROIR, and was adopted in the most recent RDW proceeding for Southern California Edison ("SCE"). It also was proposed by ORA in the San Diego Gas and Electric RDW and in the Residential Rate Design Order Instituting Rulemaking ("RROIR" or "R.12-06-013"). The reasons for ORA's proposals will be discussed in Section III.B.

[6] PG&E Testimony, page 1-11, bullet point #2.

[7] Corresponds to PG&E Table 5-1 on page 5-4, Errata dated March 18, 2015.

[8] California Alternate Rates for Energy ("CARE")

[9] Proposed Decision of ALJs McKinney and Halligan, in Rulemaking 12-06-013. The Decision on Residential Rate Reform for Pacific Gas and Electric Company Southern California Edison Company, and San Diego Gas and Electric Company and Transition to Time-Of-Use Rates. Mailed 4/21/2015. Also known as RROIR PD.

C. Eliminating or Closing Existing TOU Periods.

Lastly, PG&E notes that, "if the Commission decides to keep the E-6, and E-7 rates schedules open to customers for a significant period … then PG&E requests that the CPUC authorize it to implement the new TOU period for E-6 and E-7 rate schedules."[10] As noted in section A, PG&E's simplified TOU period proposal is drastically different than the rate structure current TOU customers have elected.

ORA does not support such a drastic, compulsory, structural change to PG&E's existing rate schedule for its existing customers at this time, nor does the recent RROIR PD, which states that "TOU tariffs should include a legacy provision that allows subscribers to remain on their existing TOU tariff (with its original TOU periods) for at least five years. When TOU tariffs are closed, they must be discontinued gradually."[11]

III. DISCUSSION & ORA'S PROPOSALS

The RROIR PD states that it is "well-documented that the larger two IOUs [PG&E and SCE], have been very slow to explore the value of residential TOU rates despite its priority as a state policy goal."[12] It subsequently "direct[s] the IOUs to move quickly to prepare themselves and their customers for implementation of TOU rates." ORA supports this policy goal, and below makes recommendations that help PG&E move forward with transitioning to default TOU in 2019.

A. New TOU Periods with Different Time and Season Definitions

PG&E's proposed new, optional E-TOU rate is based on projections for future generation system conditions projected in the year 2020. As discussed in

[10] PG&E Application, page 1-11, Bullet Point #3.

[11] RROIR PD at 161

[12] Ibid, page 117.

Chapter 2 of ORA's testimony, these new TOU definitions are a reasonable way to address changing market conditions for new customers. From a policy perspective, ORA does not oppose this new optional, simplified opt-in TOU rate with new TOU periods, so long as E-TOU includes the baseline credit as discussed in Section B.

In addition, as described in Chapter 3 of ORA's testimony regarding TOU preferences, customers may prefer a TOU rate with a shorter time period. As PG&E moves forward with implementing E-TOU, ORA also notes that the RROIR PD directed the utilities to follow its first TOU opt-in rate design guideline, which is that it "Offer a menu of different residential rates designed to appeal to a variety of residential customers."[13] ORA agrees with the RROIR PD that "it is essential that all IOUs begin studying residential TOU rates with a focus on TOU periods, duration of TOU periods, customer acceptance and customer response.[14]" PG&E should thus be ordered in its pilot process to evaluate the feasibility of an additional TOU rate with a shorter TOU period that aligns with customer preferences, as described in Chapter 3 of ORA's testimony.

As discussed in Chapter 3, PG&E retained Hiner and Partners to conduct a survey of PG&E customers to determine residential TOU rate structure preferences.[15] PG&E selected the least popular option, a five-hour window, which is preferred by only five percent of the survey respondents.[16] ORA recognizes that the cost of service must be balanced with customer preference, but as PG&E moves forward in evaluating the menu of different residential rates, it should offer TOU options that might attract greater enrollment while residential TOU rates still are voluntary.

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[13] Ibid, page 161, guideline #1.

[14] Ibid, page 164.

[15] Testimony of PG&E, page 4-1.

[16] Testimony of PG&E, Attachment A, TOU Rate Development Conjoint Research Report, page 32.

B. PG&E's Illustrative Rates Must Include a Baseline Credit

1. PG&E's Proposed Peak to On-Peak Ratios Appear to be Reasonable

PG&E presents *illustrative* rates for its proposed optional rate in Table 5-1 on page PG&E 5-4. The illustrative on-peak rates, as displayed, have a rough on-to off-peak ratio of 1.5 to 1 in the summer, and 1.1 to 1 in the winter. They reflect a reasonable difference between on and off-peak rates for an optional TOU rate option for the time-being to promote the general understanding of and acceptance of TOU rates.

ORA's marginal costs, shown in Chapter 2 of ORA's testimony, exhibit on-peak to off-peak ratios that are slightly less than PG&E's. Thus, at some point, the marginal costs and resultant on-peak to off-peak ratios will require further examination. Detailed marginal cost studies conventionally are performed in GRC Phase 2 proceedings, and PG&E's next GRC will occur in 2017. In that GRC, PG&E should fine tune its on-to-off peak ratios, providing a menu of options. As the RROIR PD states, "options for design of TOU rates that must be considered going forward include: a default TOU rate with mild differential intended only to minimize the impact of residential customers on peak periods."[17] ORA highlights further direction provided in the RROIR PD, which states that "going forward PG&E must provide documentation of marginal cost of kWh it is using in setting the TOU rates."[18]

Despite ORA's acceptance of the illustrative optional rates, a number of factors remain unknown, such as revenue and sales assumptions at the time of implementation[19] as well as a final decision in R.12-06-013. Therefore, ORA

[17] RROIR PD page 132.

[18] Ibid, page 164, bullet #3.

[19] PG&E page 5-4 lines 12—13.

understands that PG&E's proposed rates are only an illustrative example based on the information available at the time PG&E filed its application.

2. "**E-TOU Must Include a Baseline Credit**"[20]

In the RROIR, ORA advocated for a "TOU rate that includes a meaningful baseline credit to encourage lower-usage customers to opt into TOU rates, thereby gaining familiarity with TOU rates."[21] The RROIR PD agreed, and found "that a baseline credit is an essential aspect of residential TOU given the mitigation risk caused by the current steeply tired default rate… the baseline credit is a means to make TOU a more reasonable alternative to the default tiered rates for low-usage customers.[22]"

PG&E indicated that its "… intent is that significantly more residential customers opt-in to TOU rate plans over the next several years."[23] Despite these intentions, the RROIR PD noted PG&E's lack of success in persuading its customers to opt-in to its TOU rate plans:

> Despite the installation of sufficient AMI technology over the last five years, PG&E and SCE have established a pattern of avoiding wide deployment of residential TOU. Despite the fact that this proceeding to examine time-variant-rates was opened more than two years ago, and prior proceedings stated that it is Commission policy to encourage time-variant pricing, and despite the fact that in 2012 the legislature passed AB 327 which expressly permits implementation of default TOU, the utilities have taken remarkably few steps in that direction.[24]

[20] RROIR PD, page 164, bullet #5, as listed in its entirety.

[21] Opening Testimony of ORA on 2015 Rates and Beyond" in R.12-06-013. September 15, 2015, page 3-2, lines 8—10.

[22] RROIR PD, pages 163—164.

[23] PG&E Testimony in R.12-06-013, page 2-58.

[24] RROIR PD, page 157.

The RROIR PD also finds that "the baseline credit is a means to make TOU a reasonable alternative to the default tiered rates for low-usage customers.[25]" To accomplish this shared goal, ORA recommends that the TOU rate include a high usage surcharge as shown below.

TABLE 1-3: ORA'S PROPOSED ILLUSTATIVE RATES

		ORA[26]			**PG&E**		
		Peak	Off-Peak	High Usage Surcharge	Peak	Off-Peak	Fixed Charge
Rate	Seasonal	cents/kWh			cents/kWh		
Non-CARE	Summer	27.5	17.2	11.4	31.9	20.4	$10
	Winter	14.1	12.3		18.1	15.5	
CARE	Summer	20.5	13.5	4.5	21.9	14.0	$5
	Winter	11.4	10.2		12.4	10.6	

In its testimony in R.12-06-013, ORA uses the terms "baseline credit" (Chapter 3, PG&E Rates) and "excess usage surcharge" (Chapter 1, Default TOU Rate) interchangeably. This could also be expressed as a "high usage surcharge." All provide the baseline benefit that remains in P.U. Code Section 739(b). They are simply different ways to present the baseline benefit on bills, and may help encourage smaller energy consumers to choose a TOU rate option. Also, expressing the rate as an indicator of high usage might send a stronger signal to conserve energy.[27]

[25] Ibid, page 164.

[26] ORA recommends that PG&E work with ORA and other interested intervenors to implement interim rates with moderate on-to-off-peak ratios prior to the 2017 GRC Phase 2 proceeding.

[27] If PGE's IT systems prevent the implementation of such a change in a cost-effective or timely manner, or it is simpler to implement a baseline credit, then ORA would be open to either option, so long as smaller or more-conserving households are afforded access to cost-effective TOU rates as proposed by ORA and ordered by the Commission

3. PG&E May Apply for a Fixed Charge Option in its 2018 RDW Application

The RROIR PD, if adopted, would effectively close the door to the introduction of fixed charges in the E-TOU rate in the near-future: as stated in Conclusion of Law 41[28], PG&E should be authorized to offer the optional E-TOU rate schedule proposed, with the exception that we approve a minimum bill in lieu of a fixed customer charge." (emphasis added)

PG&E's proposed fixed charge of $5 for non-CARE customers and $2.50 for CARE customers in the RROIR has already been rejected in the ROIR PD; thus, the doubled proposed E-TOU fixed charges of $10 and $5 for non-CARE and CARE customers proposed in this application should also be rejected. The RROIR PD does allow PG&E to re-request *consideration* of a fixed charge covering a *portion* of its fixed charges in a future RDW application.[29]

If PG&E is allowed to offer a variation of the E-TOU rate that includes a fixed charge and excludes a baseline credit, ORA recommends that PG&E provide some simple guidelines to help customers in choosing which E-TOU rate option would be more advantageous to them. For example, SCE has implemented its new optional TOU rate Option A with an easy-to-understand optional baseline credit[30] similar to what ORA recommends in this proceeding. SCE's website indicates that "this rate plan may be more beneficial to customers with usage of less than 700 kWh per month." If more E-TOU rate options are allowed, ORA recommends that similar language with an appropriate threshold (as calculated by PG&E[31] based on the final E-TOU rate) be added to PG&E's E-TOU marketing materials.

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[28] RRDOIR PD, page 300.

[29] Ibid, Ordering Paragraph 7, page 302.

[30] SCE Rate Website https://www.sce.com/wps/portal/home/residential/rates/residential-plan/

[31] ORA understands that all baseline regions are not created equal. For example, customers in the San Francisco Bay area territory T receive a summer baseline quantity of 7 kWh/day, while consumers in the San Joaquin Valley receive 15.6 kWh/day at the lower rate. Likewise,

(continued on next page)

C. Closing or Changing E6 and E7

PG&E proposes to discontinue the current E6 and E7 rates and move its approximately 100,000 TOU customers[32] to its proposed simplified E-TOU rate periods. The proposed E-TOU rate is notably different from the E6 and E7 rates, and would leave only *one* TOU period option available to residential customers,[33] unless they own a plug-in electric vehicle. As shown in the table below, the current E-6[34] rate structure is significantly different from the proposed E-TOU rate.

(continued from previous page)
consumers in SCE's Coachella Valley region 15 receive a daily baseline allowance of 39.8 kWh/day. Yet, despite these inequities, ORA believes the rough guidelines such as those implemented at SCE provide some guidance to help smaller customers choose a TOU rate best suited to their needs, and does not oppose the use of a more fine-tuned message, if PG&E is able to provide one.

[32] Pacific Gas and Electric Company 2014 General Rate Case Phase II Prepared Testimony Exhibit (PG&E-1) Volume 1 Revenue Allocation and Rate Design. Page 3-2.

[33] PG&E also opted not to update the SmartRate™ add-on rider period from 2—7 pm in this proceeding to narrow the focus of this proceeding to the Schedule E-TOU rate plan. PG&E Testimony in this proceeding, Page 1-6.

[34] For simplification purposes, E-7 is not included because it is closed to new customers per D.06-12-025 and D.08-06-011 as described in the E-7 Tariff Sheet listed at http://www.pge.com/tariffs/ERS.SHTML.

TABLE 1-4: PG&E'S CURRENT AND PROPOSED TOU PERIODS

	Current[35]	**E-TOU**
Summer Season	May 1–Oct. 31 (6 mo.)	June 1– Sept. 30 (4 mo.)
On-Peak	1–7 pm M– F	4–9 pm M– F
Mid-Peak	10–1 am All Days 7–9 pm M-F, 5–8 S/S	N/A
Off-Peak	All Other Times	All Other Times
Winter Season	Nov. 1–April 30 (6 mo.)	Oct. 1– May 31 (8 mo.)
On-Peak	1-7 pm M– F	4–9 pm M– F
Mid-Peak	10–1 am All Days 7–9 pm M-F, 5–8 S/S	N/A
Off-Peak	All Other Times	All Other Times

ORA supports the RROIR PD's finding that a five-year transition period would be appropriate for current E-6 customers to transition onto a new rate,[36] and agrees that "a constantly changing TOU period would cause customer confusion.[37]" ORA appreciates this clarity, and supports the RROIR PDs proposal to promote rate stability and understanding of TOU rates, detailed below.

1. Customers who Made the Conscious Choice to Support the Commission's TOU Programs Should not be Punished.

ORA shares the Commission's goal to "maximize the number of residential customers to whom a voluntary TOU rate structure would appeal until residential customers are defaulted onto TOU rates."[38] We also support PG&E's and the Commission's mutual goals of a gradual and careful move towards default TOU

[35] PG&E currently offers a number of Rate options including E6, E7 (which is closed to new customers), and E9, an experimental residential TOU service for low-emission vehicle customers. E6 is used for comparison purposes because it is the only TOU rate available to the overwhelming majority of residential customers. PG&E's SmartRate program is a voluntary rate rider that overlays on top of the base rate regardless of time-variant pricing status.

[36] RRDOIR PD, page 143.

[37] Ibid, page 130.

[38] Opening Testimony of ORA in R.12-06-013 page 3-1, lines 8—9.

rates in general. At the same time, ORA does not wish to alienate the existing, hard-won TOU customers who have already volunteered and took action to support the State's time-variant pricing programs. Alienating these early adopters, who could be PG&E's best partners in promoting TOU rates to their friends, family, and neighbors would be a mistake.

The Energy Division's "White Paper" states the following:

> Achieving meaningful load and cost reductions through TOU rates requires customer acceptance and high recruitment rates. Historically, the three California IOUs have achieved extremely low adoption rates for opt-in time-variant pricing – less than 0.5%. ORA notes that considerable sums have been spent on advertising, marketing, and outreach to encourage voluntary adoption of TOU rates with very low resulting adoption rates.[39]

The Energy Division states above that very few customers have signed up for time-variant pricing in the past, which makes it all the more critical that these few existing customers are not subject to unnecessary changes, especially before the full range of TOU Rate options and pilot programs contemplated in R.12-06-013 become available. The current customers who opted into TOU rates have already made the decision to opt into a rate with seasonal variations and shoulder peaks, regardless of their solar status. PG&E's bill impact analysis shows that on average, NEM customers on the E-6 rate would see average bill increases of 19.29%, with average rates rising from 18.765¢/kWh to 22.384¢/kWh,[40] and more than half of all customers will receive average increases above 20%.

ORA does not oppose targeted outreach to existing TOU and/or current E-1 Net Energy Metering ("NEM") customers explaining the projected shift in system needs. This would help inform them about potential tariff changes that could

[39] California Public Utilities Commission. "Staff Proposal for Residential Rate Reform in Compliance with R.12-06-013 and Assembly Bill 327: Energy Division Staff Proposal on Residential Rate Reform" May 9, 2014, page 69.

[40] PG&E Response to Data Request ORA-01, Question 08. Filename RDW2015_DR_ORA_001_Q08b_Atch01_REV-SUPP2.pdf

occur in the future. ORA also encourages a year of bill protection as described in the RROIR PD[41] for the few existing E-6 and E-7 TOU customers who voluntarily switch to E-TOU. This would encourage customers to opt into the new E-TOU rates during the transition period to default TOU rates or until a suitable replacement for E-7 with on, off, and mid-peak rates is implemented.

Below is a table[42] summarizing PG&E's residential time of use customer base.

TABLE 1-5:

ACCOUNTS BY NEM, TIME-VARIANT PRICING, AND CARE STATUS

Rate	Description	No NEM	NEM	Total
E1	Tiered Rate	4,361,005	57,379	4,418,384
E1L	Tiered CARE	1,499,835	6,896	1,506,731
E6	TOU	6,771	27,480	34,251
E6L	TOU CARE	693	796	1,489
E7	TOU (Closed)	60,075	13,702	73,777
E7L	TOU CARE	7,786	333	8,119

As shown above, E6 and E7 customers represent a diverse and varied customer group. Not all E6 and E7 customers are also net energy metered ("NEM") customers, and not all NEM customers are on TOU rates.

At this point, more than half of PG&E's NEM customers remain on the standard, tiered E1 rate. It is important that we understand why, perhaps because the existing E-7 rate has a daily meter charge of 25.298[43] cents per day, effectively a fixed charge of $7.60 per month. During this transition period, it would be better to understand why the majority of NEM customers prefer tiered

41 RRDOIR PD, page 128.

42 Derived from PG&E Response to ORA Data Request 2, Question 3 as received in attachment RDW2015_DR_ORA_002_Q03_Atch01-CONF.xlsx. The data has been aggregated to avoid potential confidentiality issues. Note that not all accounts or rate options were included in this table (For example, Manufactured Housing, Seasonal Billing, and Electrical vehicle rates were excluded), but this table does represent 98.6% of all residential accounts.

43 Electric Schedule E-6. Effective March 1, 2015.

rates over PG&E's TOU rate with a customer charge. This is especially important as PG&E contemplates and implements new pilot programs as described below.

2. Current Rates and TOU Periods Should Remain Available to TOU Customers until the Full Range of TOU Options Become Available

PG&E's position to consolidate all TOU rates onto a singular set of TOU periods runs counter to the trend expressed in the RROIR PD and the Energy Division "White Paper" to offer customers choices and to study customer behavior. PG&E states that, this year, it "… expects to design and launch the [TOU] pilot in 2015 with final results available no later than 2017"[44] The Energy Division "White Paper" stated that, in the meantime,

> 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 the 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.[45]

The recent RROIR PD further reinforces that that the IOUs must "offer a menu of different residential rates designed to appeal to a variety of residential customers.[46]"

PG&E's website provides some solid, common-sense tips to help households save money, and encourages customers to use programmable thermostats to automatically adjust temperature settings based on time of day, advising customers to "set and forget" their thermostats according to the time of

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[44] Prepared Testimony of PG&E in R.12-05-013. February 28, 2014, page 2-65.

[45] California Public Utilities Commission. "Staff Proposal for Residential Rate Reform in Compliance with R.12-06-013 and Assembly Bill 327 Energy Division Staff Proposal on Residential Rate Reform" May 9, 2014, page 67. (note that per the RRDOIR PD, default TOU will more likely be implemented in 2019)

[46] RROIR page 161, opt-in TOU rate design guideline #1.

day.[47] Reasonable TOU customers who have conscientiously followed PG&E's advice, particularly those who pre-cool their homes or don't closely monitor their usage, or missed whatever notice PG&E provides of the time period change,[48] would be most affected by PG&E's swift change in the existing TOU periods.

ORA also cautions against moving customers from one set of TOU rate structures to a drastically different one without recourse or new options. These same customers may be even more confused if new TOU pilot programs with mid-peak rates are introduced which is contemplated in the Rate Design OIR workshop process. This will likely result in additional marketing, processing, and customer service expenses for PG&E and its ratepayers, customer mistrust of TOU and its programs, and either backlash or apathy from our state's most engaged customers.

ORA applauds PG&E for applying similar common-sense logic when it opted to delay the targeted marketing of E-TOU rates for a few months until the outcome of the new TOU periods could be determined in this proceeding. PG&E correctly stated that "switching TOU time periods soon after enrolling large numbers of potentially new E-TOU participants risks causing dissatisfaction with opt-in TOU that is likely to lead to de-enrollments, and thus would not be a cost-effective approach."[49] ORA agrees with this customer-centric approach, and that subjecting voluntary customers to unnecessary, additional changes during a period of transition would not enhance ratepayer's trust of TOU programs, PG&E, or the CPUC's goals.

PG&E's TOU customers make up a small percentage of the overall system load and customer count, as shown in Table 1-5 below. Thus, grandfathering

[47] "A programmable thermostat can automatically change the temperature of your home to an energy-saving level when you are away from home or sleeping. Once you program the device, the temperature will automatically return to your chosen comfort level at the scheduled times — you can set it and forget it. https://pge.opower.com/ei/app/tip/tip025_install_programmable_thermostat

[48] PG&E did not provide any information, details, or funding requests in this Application regarding how existing customers would be notified or transitioned onto the new TOU periods.

[49] PG&E Reply to Protests, January 8, 2015, page 3.

existing customers into the current rate structures with the existing TOU periods for the time-being would not have a large impact on the shifting peak periods in the near-future.

TABLE 1-6: CURRENT TOU AS A PERCENTAGE OF CUSTOMER COUNT AND LOAD

	Service Agreement Count	% of Customer Count	Annual kWh	% of Residential Load
E6 Total	35,740	0.6%	146,435,015	0.5%
E7 Total	81,896	1.3%	659,015,389	2.1%

3. It is not Reasonable to Change the TOU Period Definitions only for Residential Rate Schedules

PG&E also does not propose to update the TOU periods for its commercial customers in this Application. For example, PG&E's current A-10 (Medium General Commercial Service) Tariff contains summer peak periods from 12:00 noon to 6:00 p.m. and partial peak periods 8:30 a.m. to 12:00 noon and 6:00 p.m. to 9:30 p.m. Monday through Friday (except holidays), which differ even more widely from the projected CAISO system requirements. Large and medium size businesses have the staff, resources, and incentive to understand and respond to changing TOU periods. Imposing new TOU periods onto residential customers first without addressing the commercial classes is neither appropriate nor reasonable.[50]

In summary, ORA supports the OIR PD that rejects PG&E's proposed elimination of the existing E-6 and E-7 rates for the relatively few customers who have already volunteered for time-varying rates in accordance with state policy. "A constantly changing TOU period would cause customer confusion. It would

[50] Scoping Memo And Ruling Of Assigned Commissioner, Dated January 29, 2015. Issue #5. Is it reasonable to change the TOU period definitions only for the residential and not for the non-residential rate schedules? Page 4

also make it difficult for customers to evaluate investments in energy efficiency improvements and rooftop solar."[51] ORA agrees that it would be prudent to allow these limited numbers of customers to remain on their existing rates and TOU periods as the state undergoes the next stage in its transition towards default TOU rates.

IV. ISSUES MORE APPROPRIATE FOR PG&E'S 2017 GRC FILING OR IN RROIR WORKSHOPS AND PILOTS

A. Additional TOU Periods Should be Studied

The RROIR PD states "For a default TOU rate to be successful, the design should be based on empirical evidence that supports both measurable benefits of TOU on the grid, and the acceptance and understanding of TOU rates by the residential customer."[52]

As discussed in Chapter 3 of this testimony, customer preferences should be taken into consideration when designing appropriate TOU periods for testing during the pilot phase of the RROIR, while also taking into consideration the changing market conditions discussed in Chapter 2. In particular, a shorter TOU period as discussed in Chapter 3 of this testimony should be offered during the pilot period.

B. Addressing Potential Very Low Prices during Certain Periods

Simulations of the Plexos model described in Chapter 2 of ORA's testimony have shown some extreme cases of lower prices during what appears to be a spring run-off period when hydroelectric power is at its highest levels. These ideas could be best addressed in a future proceeding such as during the TOU transition pilot evaluation, Long Term Procurement Planning ("LTPP") Proceeding R.13-12-010, or the 2017 PG&E GRC Proceeding.

[51] RRDOIR at page 130.

[52] Ibid, at page 118.

1. Low Prices During Spring Run-off

In these shoulder month periods, ORA would be open to an additional optional rate which could test customer acceptance of discounted spring and/or fall rates, if market conditions call for such a situation.

2. Modify SmartRate to Include an Incentive

Currently, PG&E's PG&E's SmartRate program gives customers a discount of 3¢ per kWh on their summer rate, or the equivalent of 23% off Tier 1 usage. In exchange, customers pay a surcharge of 60¢ per kWh for 2—7 pm usage on 9 to 15 "SmartDays™."

If the conditions as described by Synapse in Chapter 2 persist, ORA encourages PG&E to consider "Renewable Rebate" days that allow consumers to "take" electricity at a steeply discounted rate when notified on a day-ahead basis. Customers would be encouraged to run their dishwashers and/or clothing washers during these special discount day periods, using the existing SmartRate notification mechanism. Anecdotally, information about a free item, sale, or limited time discount is very popular and easy to disseminate.

V. CONCLUSION

In summary, ORA supports offering more opt-in TOU rate options that support customer acceptance of TOU rates. ORA does not oppose PG&E's proposed E-TOU rate with simplified time periods, so long as this rate is offered without a customer charge and with an excess usage surcharge or baseline credit, as directed by the RROIR PD. Rates that benefit smaller or conservation-minded customers as well as those who already volunteered for PG&E's TOU rates should not be eliminated at this time, even if they are closed to new customers. As the Commission transitions towards the adoption of default TOU rates in 2019, ORA champions efforts which popularize and enhance customer's understanding of time-varying rates.

CHAPTER 2

HOURLY MARGINAL GENERATION COSTS

ROBERT M. FAGAN AND PATRICK LUCKOW

SYNAPSE ENERGY ECONOMICS

ON BEHALF OF THE

OFFICE OF RATEPAYER ADVOCATES (ORA)

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INTRODUCTION AND SUMMARY OF FINDINGS

Purpose

What is the purpose of this testimony?

The purpose of this testimony is to present the result of PLEXOS[1] production cost simulation modeling and relative loss-of-load-expectation (LOLE) modeling[2] that informs the estimation of hourly marginal generation costs (MGC) for Pacific Gas and Electric (PG&E).

Marginal generation costs are composed of marginal energy costs (MEC) and marginal capacity costs (MCC).[3] We estimate hourly marginal energy costs directly using the PLEXOS model, for 2020; we also run a PLEXOS sensitivity to estimate hourly marginal energy costs for 2016. Hourly marginal capacity costs are estimated based on a range of fixed costs for a new peaking resource, and the allocation of those costs to high-use hours based on the results of Synapse runs of a LOLE model. The LOLE model estimates relative loss-of-load across the hours of the year; it is not an absolute indicator of loss of load expectation. Its purpose is limited to apportioning marginal capacity costs across hours of the year. We execute the LOLE model for 2020, using PG&E loads and resources; we also run an LOLE sensitivity to assess marginal capacity costs in 2016.

The estimated hourly MGC costs (comprised of MEC plus MCC) are averaged across seasonal and time-of-day periods to produce time-of-use (TOU) period based marginal generation costs. We also present a comparison of our estimated marginal costs to PG&E's marginal costs as estimated in their Rate Design Window (RDW) testimony.[4] We discuss the implications of the marginal generation costs for PG&E's proposed TOU periods.

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[1] PLEXOS is Energy Exemplar's production cost simulation modeling tool. Synapse licenses PLEXOS from Energy Exemplar and performs production cost modeling simulations.

[2] Synapse used the LOLE model provided by Southern California Edison (SCE) in response to discovery (A.14-11-014 PGE-SCE-001 Q.01 Response). SCE used this spreadsheet model in its GRC Phase 2 Marginal Cost proposal (A.14-06-014, June 20, 2014). Synapse used the "shell" provided by SCE, and used its own input assumptions for resources and loads.

[3] Synapse makes no assumptions concerning the effect on marginal costs of different procurement levels for renewables as marginal consumption changes.

[4] PG&E, Chapter 2, Hourly Marginal Generation Costs.

Background Issues - Summary

What are the key issues addressed in your testimony?

The key issues we address include

- the definition of marginal generation costs,
- the methodology for computing marginal generation costs,
- hourly and seasonal time-of-use rate periods considered, and how MEC, MCC, and MGC vary across hours and seasons,
- the relevant time frame (e.g., 2020, or some other year) to use for marginal generation cost for this RDW.

What other issues are relevant to this RDW that might be influenced by the marginal generation costs addressed in your testimony?

A relevant issue is whether or not the requested use of a revised TOU period for residential customers should also affect non-residential customers. PG&E states that their proposed changes to TOU periods are for residential, but proposals for non-residential TOU period changes won't occur until the 2017 General Rate Case.[5] We do not offer an opinion on this issue; our modeling results apply to all wholesale-level, or transmission-level load and thus are applicable to all customers.

Methodology and Modeling Conducted

Please summarize the methodology and modeling you use to estimate marginal generation costs.

We use two mathematical tools to conduct our analysis.

First, we employ PLEXOS modeling to produce hourly estimates of energy prices in the PG&E region, for both 2020 (PG&E used an estimate of marginal costs in 2020 in their testimony) and for 2016. We offer 2016 as a "bookend" energy price analysis since the time frame for PG&E's proposed application of new TOU periods commences in 2016.[6] Hourly energy prices represent marginal costs of procurement for wholesale energy.

Next, to estimate hourly marginal capacity costs, we use the combination of i) an estimated range of fixed costs for a new peaking resource, and ii) the allocation of those costs

[5] PG&E Testimony, footnote 2, Chapter 1, page 1-1.

[6] R.12-06-03 Proposed Decision, Page 164.

over high use hours based on the results of use of an LOLE model. We use the hourly LOLE model introduced in SCE's rate case, adapting it for our own use for the PG&E service territory by using different load and resource inputs. The hourly LOLE model results in an estimate of the relative differences across hours of resource adequacy "tightness" for the PG&E region. It is not an estimator for absolute loss-of-load; its strength lies in its relative simplicity, effectively performing an energy balance for all hours of the year, and doing this repeatedly to reflect the stochastic nature of its load and resource inputs. It produces an alternative to the 250 top load hours PG&E uses to allocate the costs of a marginal unit of capacity resource. We executed this model using load and resource inputs for 2020, based on the same underlying load and resource inputs we used in the PLEXOS model. We also ran a sensitivity for 2016, adjusting the LOLE model inputs to reflect the same underlying 2016 loads and resources used in our 2016 PLEXOS run.

Based on the results of our marginal energy and marginal capacity cost estimation, we create hourly marginal generation costs for 2020, and for 2016. Using the existing and the proposed definitions for TOU periods, we average the hourly values of marginal generation cost to determine an overall marginal generation cost for each of the defined seasonal and on-peak/off-peak periods. We compare these marginal generation costs to PG&E's marginal generation costs.

What is the structure of your testimony?

Below we present summary findings and observations. We then present our full analysis of marginal generation costs, and we compare our results to PG&E's results.

Please summarize your key findings.

We find the following in our modeling of MGC, and comparison to PG&E's marginal generation costs. The next section describes our analysis and findings in full.

1. For the proposed new TOU period definition, for 2020, PLEXOS-based marginal energy costs are lower than PG&E's marginal energy costs for peak periods, but higher than PG&E's costs for off-peak periods. Thus the overall marginal energy cost *differential* between peak and off-peak periods is lower for the PLEXOS model results, compared to PG&E's marginal energy cost estimation method.

2. For both Synapse's PLEXOS modeling, and PG&E's modeling method, using the existing definition for time-of-use periods (i.e., 6 months for summer, and 1-7 PM on-peak; and 6 months for winter, 5-8 PM on-peak) results in marginal energy cost differences between aggregate peak and off-peak periods that are much smaller than seen with the proposed change in TOU periods. This indicates that the proposed TOU periods better captures the differentiation in marginal costs between groupings of hours with similar marginal costs.

3. PG&E's market heat rate model does not calibrate well (with actual historical data) for low and high adjusted net load levels; this implies that the calculated marginal costs are less accurate for low and high adjusted net load levels. It also explains, in part, the differences between PG&E's model results and PLEXOS' model results. The PLEXOS model uses actual available resource characteristics and forecast load to project prices over all hours of the year; PG&E's method extrapolates prices based on an equation.

4. Marginal energy cost modeling with PLEXOS indicates that the patterns of pricing, or hourly marginal energy cost patterns, vary with the seasons and the hours of the day in such a way that PG&E's proposed TOU period shift is not unreasonable and better reflects temporal differences in marginal energy costs than the existing TOU period definition. However, PG&E's proposal should not be construed to necessarily be the best, or most optimal, construction for improved TOU period definition. For example, there could be further differentiation of TOU period pricing – especially for spring mid-day, and winter mornings – but the rationale behind PG&E's proposed periods (4-9 PM weekdays, all year; winter season of 8 months, summer season of 4 months) – simplicity for customers – is not unreasonable.

5. Synapse's LOLE modeling results indicate that the greatest relative loss of load expectation occurs in July, later in the day (peaking at 7 PM standard time, 8 PM prevailing time). Generally the LOLE findings show greatest relative LOLE during summer period, later afternoon hours. These findings generally support PG&E's proposal to shift summer peak-period TOU hours to later in the day when considering the marginal costs of capacity – essentially, the potential need for new capacity arises primarily from usage during the later afternoon and early evening summer hours. While

the LOLE model shows some fraction of relative LOLE in non-summer months, and our allocation of a proportionate share of marginal capacity costs to these non-summer periods follows from this, the dominance of LOLE occurrence during the summer months suggests the importance of allocating most of the marginal capacity costs to these time periods.[7]

6. Combining hourly marginal energy costs and marginal capacity costs allocated (proportionately) to LOLE hours leads to Marginal Generation Costs (MGC) patterns by hour. The hourly patterns for winter and summer are similar across the PLEXOS and PG&E modeling results, lending further support to the general rationale behind PG&E's summer TOU period proposal. The absolute values, and the differences between peak and off-peak periods, for marginal generation costs differ between the Synapse/ORA and the PG&E modeling approach. The differences are reflective of the different energy and capacity cost modeling approaches between our efforts and PG&E's analysis. Table 1 below presents our summary MGC results (2020 and 2016), and compares the Synapse PLEXOS/LOLE approach to PG&E's model construct for 2020. Figure 1 shows a breakdown on a monthly basis of Synapse's and PG&E's MGC results for 2020.

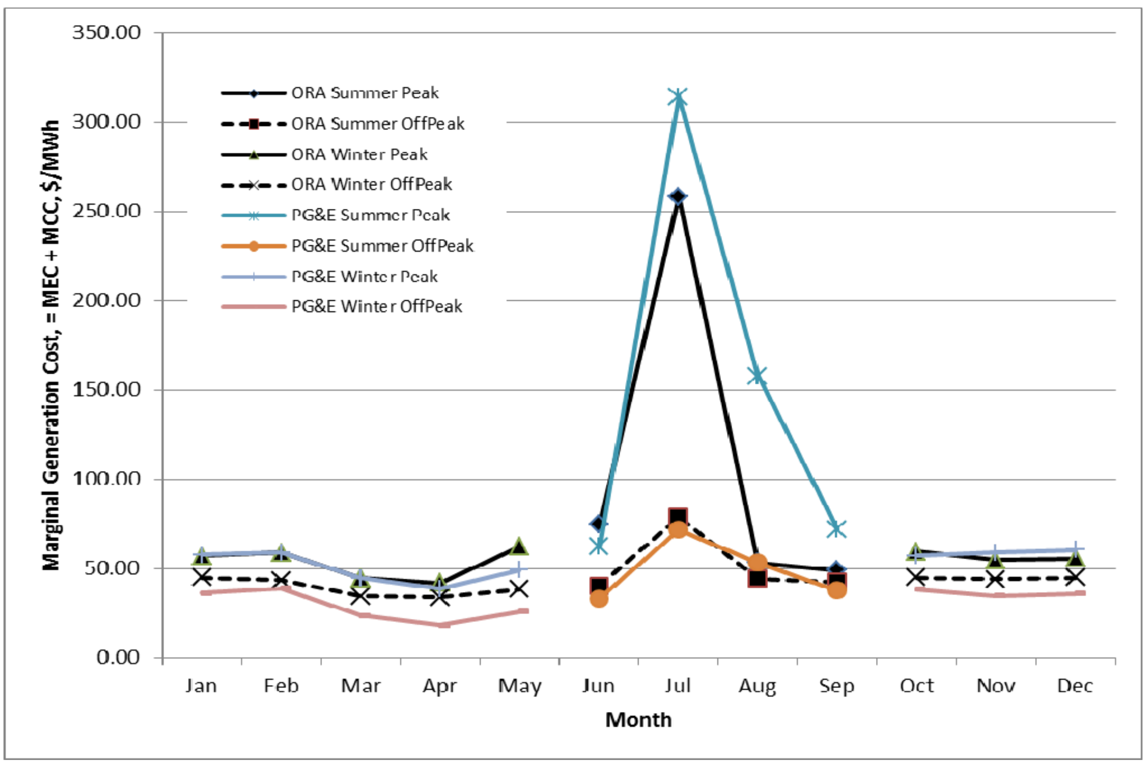
[7] We note that this finding is supported, somewhat, by the results of the modeling conducted in the 2014 LTPP docket (R.13-12-010) and in Track 4 of the 2012 LTPP docket (R.12-03-014). Though the modeling was for 2024 (2014 LTPP) and 2021 (2012 LTPP Track 4), in both cases the capacity shortfall concern was limited to the summer months of July and August. In fact, CAISO indicated that had they modeled 2,315 MW of approved capacity additions from the 2012 LTPP docket, the capacity shortfalls in the 2014 LTPP (for 2024) may have been eliminated. In our opinion, renewable energy curtailment concerns revealed in the 2014 LTPP Phase 1a modeling for spring periods appear to be primarily an economic, and not a reliability issue and thus it is not unexpected that LOLE values for spring hours are relatively low, or zero. Phase 1b of the 2014 LTPP docket will continue to address spring renewable curtailment issues.

Table 1. Overall MGC and Component Modeling Results – 2020 (Synapse and PG&E) and 2016 (Synapse Only)

	2020						2016		
	MGC		MEC		MCC		MGC	MEC	MCC
$/MWh	ORA	PG&E	ORA	PG&E	ORA	PG&E	ORA		
Summer									
peak	112.1	155.2	51.7	68.6	60.4	86.5	90.7	45.3	45.3
offpeak	51.7	49.3	43.0	41.4	8.7	8.0	48.7	38.2	10.6
Ratio Pk-Offpk	2.2	3.1	1.2	1.7	6.9	10.9	1.9	1.2	4.3
Winter									
peak	54.1	53.0	49.6	53.0	4.5	0.0	46.8	44.4	2.5
offpeak	41.2	31.6	39.3	31.6	1.9	0.0	37.4	36.5	0.9
Ratio Pk-Offpk	1.31	1.68	1.3	1.7	2.4	-	1.3	1.2	2.8

Source: Synapse (PLEXOS and LOLE modeling); PG&E (workpapers).

Figure 1. 2020 Overall MGC Patterns by Month, by Peak and Offpeak Periods, ORA and PG&E Models



Note: Peak is 4-9 PM weekdays, summer is June-September.

What are your overall observations on marginal cost and TOU period issues?

The pattern of marginal generation cost variation by hour and by season (as defined by PG&E's proposed 4-month summer season) is similar between the combination PLEXOS/LOLE modeling conducted by Synapse, and PG&E's use of a market heat rate model for energy costs, and a "top 250 hours" allocative approach for the marginal costs of capacity. Thus, we are in agreement that a change to the TOU period structure is indicated by the results of the marginal cost modeling. The four month summer season, and the 4-9 PM weekday period for peak hours is not unreasonable, but we note that the proposed boundaries that define peak and off-peak are not inviolable. This is especially so considering that PG&E does not propose to use a "partial peak" period to further differentiate marginal cost differences that occur outside the relatively limited total of peak period hours (peak period is only 25 of 168 weekly hours, or roughly 15% of hours).

In that vein, we do note that our modeling indicates a potential need for additional or modified TOU period definition at some point in the future: 1) During spring (i.e., March and April) mid-day periods (between late morning and early afternoon), noticeably lower prices exist, illustrating the potential for an additional "off-peak" or even "super off-peak" period to incent new consumption, or a shift of consumption from other periods, during this period. See Figures 4 through 7. 2) Winter early morning periods also exhibit a bump-up in prices, illustrating that this period of time could be considered for peak, or at least partial peak, period pricing (i.e., further TOU period differentiation). See Figures 5a and 5b. 3) Winter weekend prices at "peak" hours of early evening are closer in magnitude to weekday peak period prices than they are to off-peak period prices seen at other times. See Figures 7a and 7b. This is also seen, though to a lesser extent, during summer weekend periods. This illustrates that marginal costs may not differ as much between weekday and weekend periods as has been the case historically. We note that the presence of renewable resources – and especially solar PV with regular, somewhat predictable output patterns – significantly changes the nature of system dispatch, and thus the pattern of marginal costs, relative to historical patterns – it is the key driver behind a shift in summer period, highest marginal energy cost times to later afternoon/early evening.

The overall magnitude of marginal costs, and the difference in marginal costs between on-peak and off-peak periods (for both summer and winter seasons) differs between PG&E's

modeling approach, and Synapse's approach. We recommend that the actual marginal cost values used to allocate revenue requirements between peak and off-peak period usage be based on Synapse's production cost and LOLE modeling. The main implication of using Synapse's modeling is that the difference between peak and off-peak period marginal cost differences is smaller, compared to PG&E's estimation. This will have implications for the resulting changes to rates.

SYNAPSE ANALYSIS OF MARGINAL GENERATION COSTS (MGC)

<u>Development of Marginal Energy, Marginal Capacity, and Marginal Generation Costs</u>

How did you estimate marginal energy costs (MEC)?

We used PLEXOS production cost simulation modeling to produce spot hourly energy prices for all hours of the year, in 2020 and for 2016.

How did you develop the inputs for the PLEXOS model runs?

Starting with the Trajectory case developed for 2024 in the 2014 LTPP docket, we modified loads and resources throughout California and the WECC to develop a 2020 case. We also further modified the input parameters to run PLEXOS for 2016. We used currently planned retirement schedules for once-through-cooling (OTC) resources, and we included planned Track 1 and Track 4 resource additions[8] in our 2020 modeling. Further documentation of our model input development is provided in Appendix A.

How did you estimate marginal capacity costs (MCC)?

We estimated hourly marginal capacity costs by allocating the costs of a marginal unit of capacity to those hours with a relative LOLE greater than zero. This resulted in an assignment of marginal capacity unit costs to a different set of hours than the top 250 hours used by PG&E to assign marginal capacity unit costs. We did this for PG&E's benchmark value for marginal capacity of $57.09/kW-year (in 2020), and for sensitivities around that value of $30/kW-year (low marginal cost of capacity) and $100/kW-year (high marginal cost of capacity).

[8] Pursuant to Decisions in the 2012 LTPP Track 1 and Track 4, D.13-02-015, D.14-03-004.

How did you estimate marginal generation costs (MGC)?

We estimated hourly marginal generation costs by summing the results of the marginal energy and marginal capacity costs across all hours of the year, for both 2020 and 2016.

How did you develop the inputs for the LOLE model?

We used the loads and resources from our PLEXOS modeling inputs for 2020 and 2016 as our starting point for the LOLE model assumptions. This model is fundamentally different from the PLEXOS model, but it does require a stochastic representation of loads, and a stochastic pattern for forced outages for resources. It also uses a stochastic distribution to represent solar and wind output profiles for any given day within each month.

How did you address curtailment issues and the marginal costs, or prices, for curtailment?

The CAISO model allows wind and solar resources to be curtailed in hours of excess generation. To provide a signal that this is occurring, it sets a price in those hours of -$300/MWh. While the current real-time market bid floor is -$150/MWh, and declines to -$300/MWh in the future, there is no expectation that all curtailment hours will hit this floor. For consistency with PG&E's modeled results, which calibrates to recent historical behavior, we used a value of -$30/MWh in all curtailment hours. PG&E used -$30/MWh as the price floor in their model.

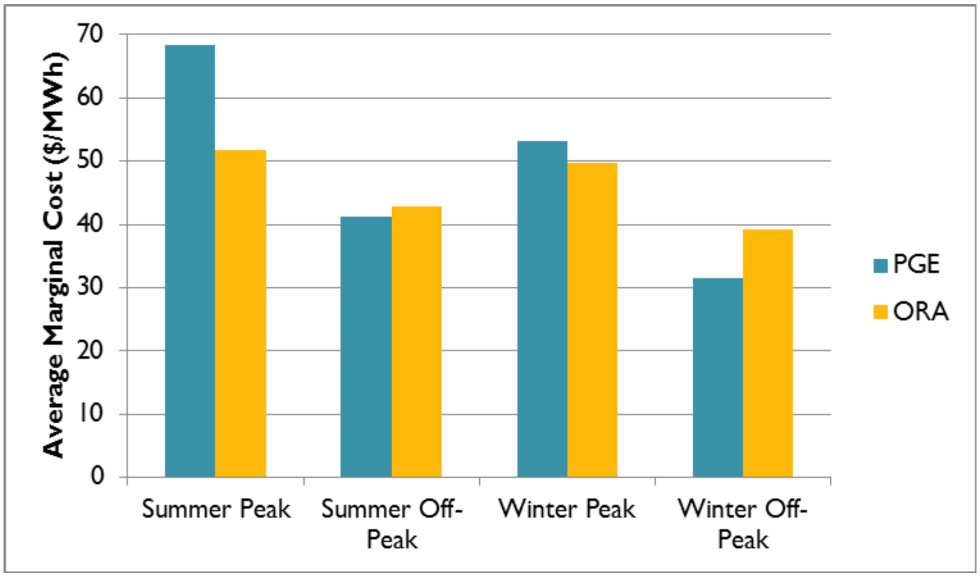
Results of Modeling

Please present and describe the marginal energy cost (MEC) modeling results.

We find the following in our modeling of MEC, and comparison to PG&E's marginal energy costs:

- For the proposed new TOU period definition, for 2020, PLEXOS-based marginal energy costs are lower than PG&E's marginal energy costs for peak periods, but higher than PG&E's costs for off-peak periods. The overall marginal energy cost differential between peak and off-peak periods is lower using the PLEXOS model.

Figure 2. Comparison of Model output energy costs for 2020, averaged by season and time period ($/MWh)



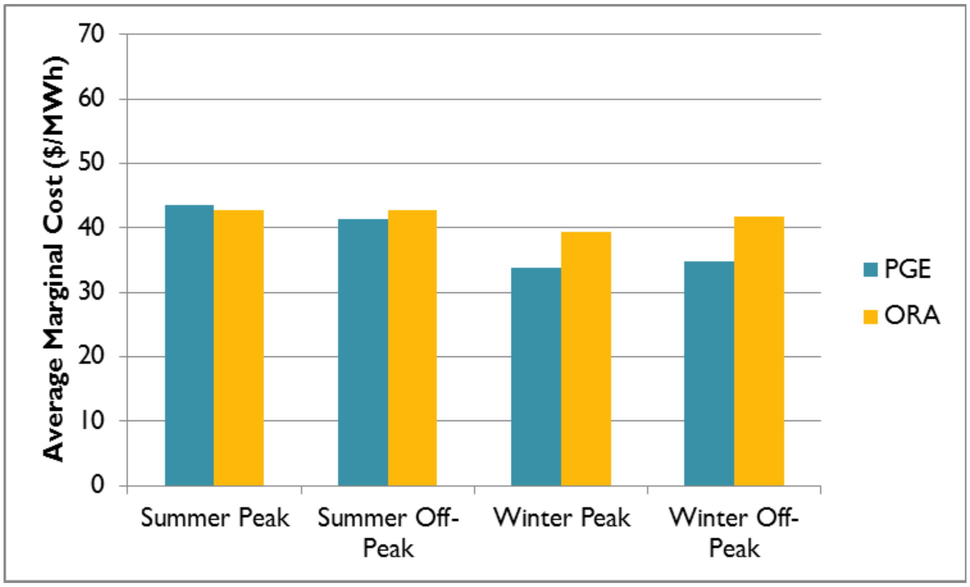
Source/Notes: Synapse PLEXOS modeling; PG&E market heat rate pricing model. Summer is June to September, Peak is 4PM-9PM Pacific Prevailing Time (PPT).

Table 2. Data for Figure 2.

		Peak	Off-Peak
PGE/Market Heat Rate Model	Summer	68.6	41.4
	Winter	53.0	31.6
ORA/Plexos Model	Summer	51.7	43.0
	Winter	49.6	39.3

- Using the existing definition for time-of-use periods, the marginal energy cost differences between peak and off-peak periods are much smaller than that seen with the proposed change in TOU periods.

Figure 3. Comparison of Model output energy costs for 2020, averaged by season and time period ($/MWh)



Source/Notes: Synapse PLEXOS modeling; PG&E market heat rate pricing model. Summer is May to October, Peak is 1PM-7PM Pacific Prevailing Time (PPT).

Table 3. Data for Figure 3.

		Peak	Off-Peak
PGE Market Heat Rate Model	Summer	43.6	41.4
	Winter	33.9	34.8
ORA PLEXOS Model	Summer	42.8	42.7
	Winter	39.4	41.7

What are the hourly energy price, or marginal energy cost, patterns for 2020 and 2016 that result from the PLEXOS modeling?

Figures 4 through 7 below show the average hourly pattern for each month for the winter and summer months, for weekdays and weekends. Results for 2020 and 2016 are shown.

Figure 4a. 2020 PLEXOS Results, Summer Weekdays, June - September

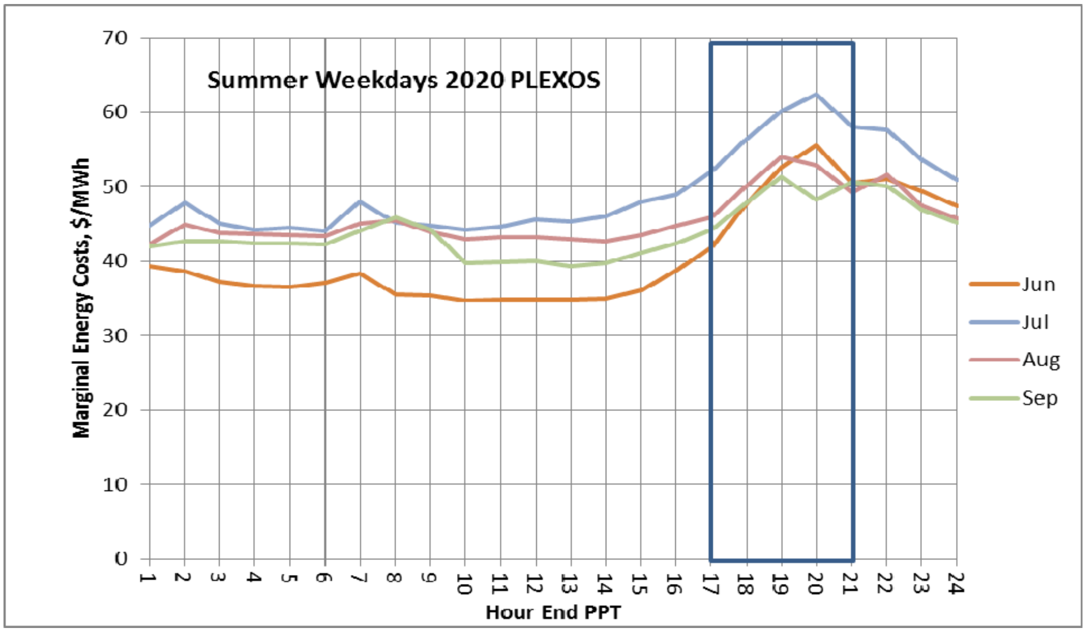


Figure 4b. 2016 PLEXOS Results, Summer Weekdays, June - September

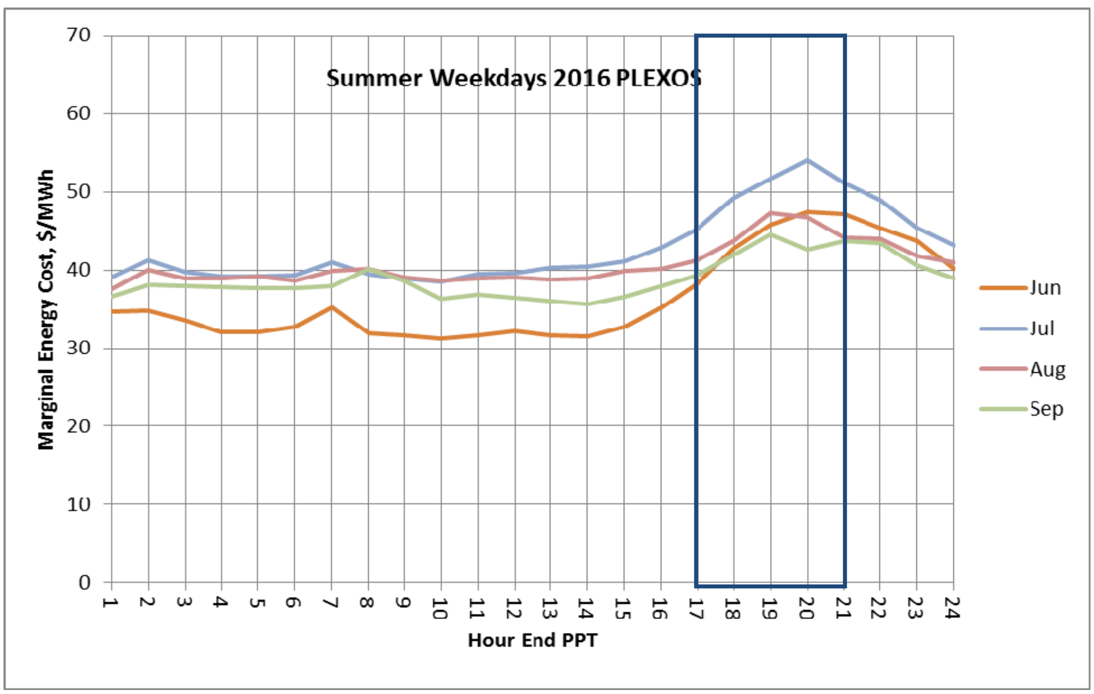


Figure 5a. 2020 PLEXOS Results, Winter Weekdays, January-May, October-December

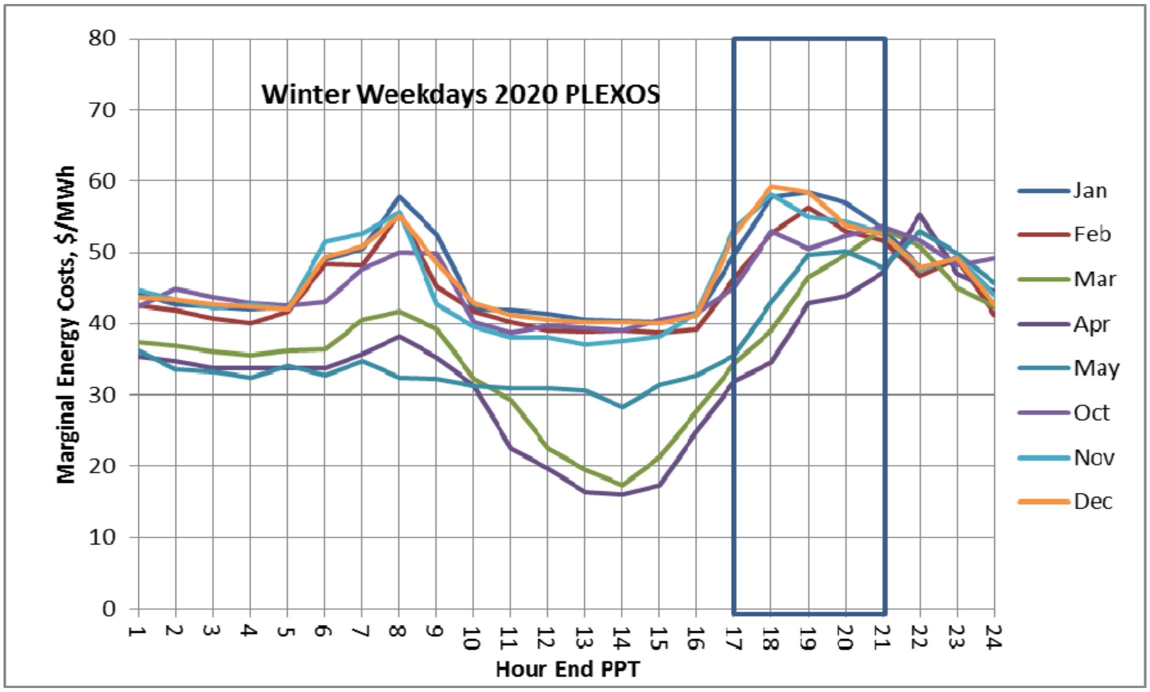


Figure 5b. 2016 PLEXOS Results, Winter Weekdays, January-May, October-December

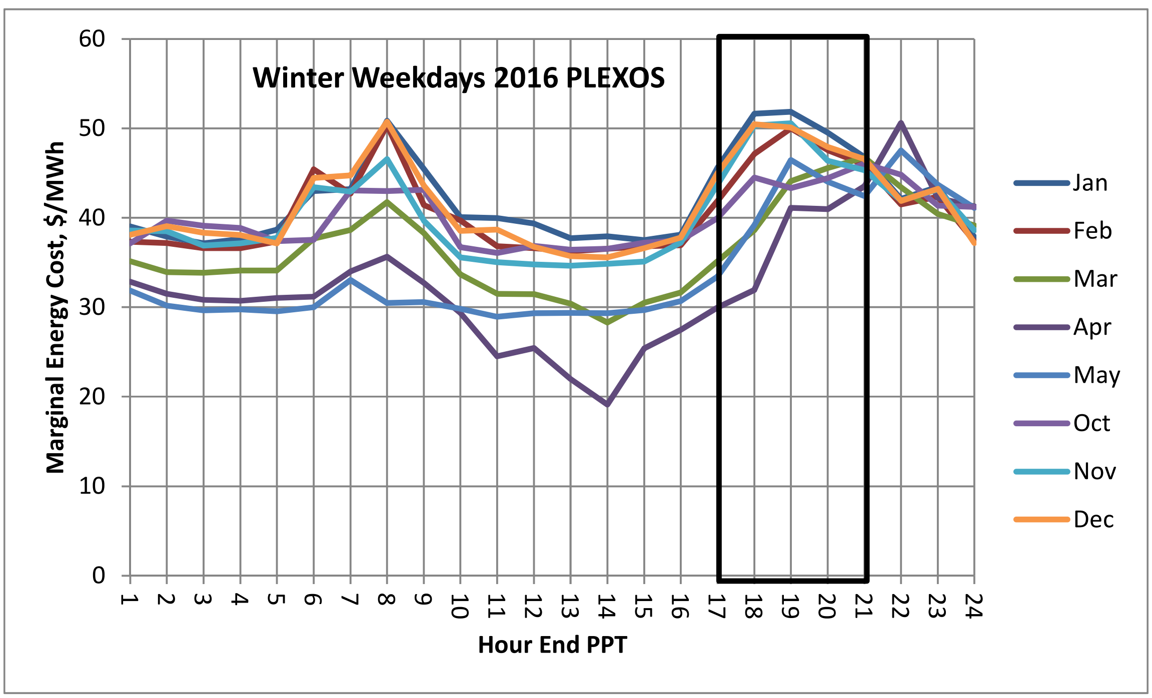


Figure 6a. 2020 PLEXOS Results, Summer Weekends, June – September

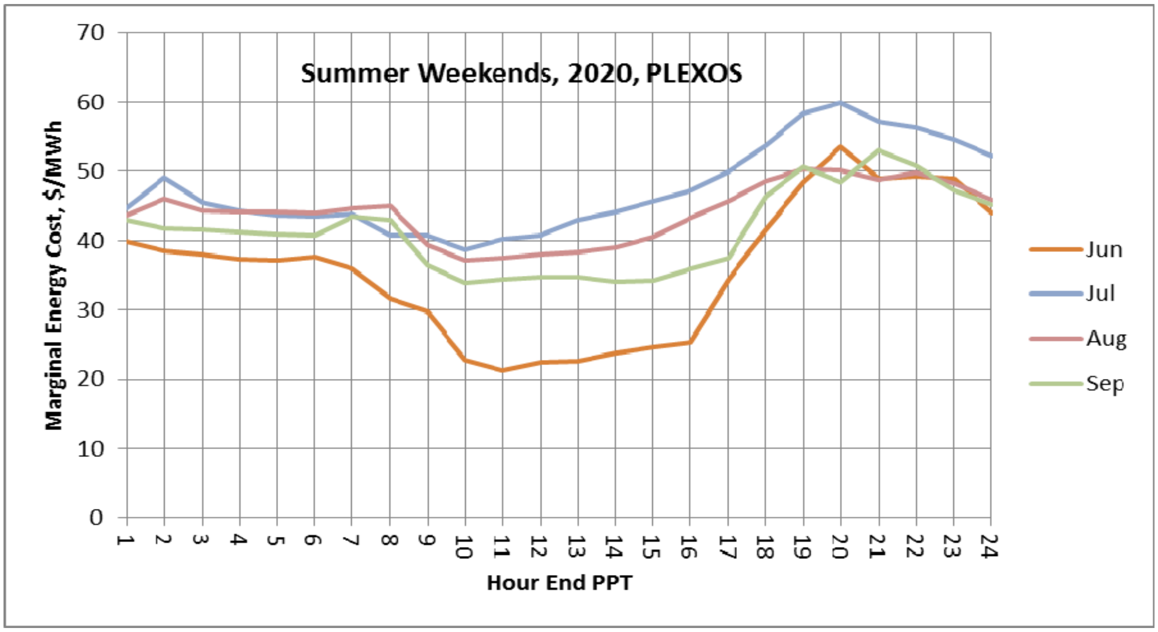


Figure 6b. 2016 PLEXOS Results, Summer Weekends, June – September

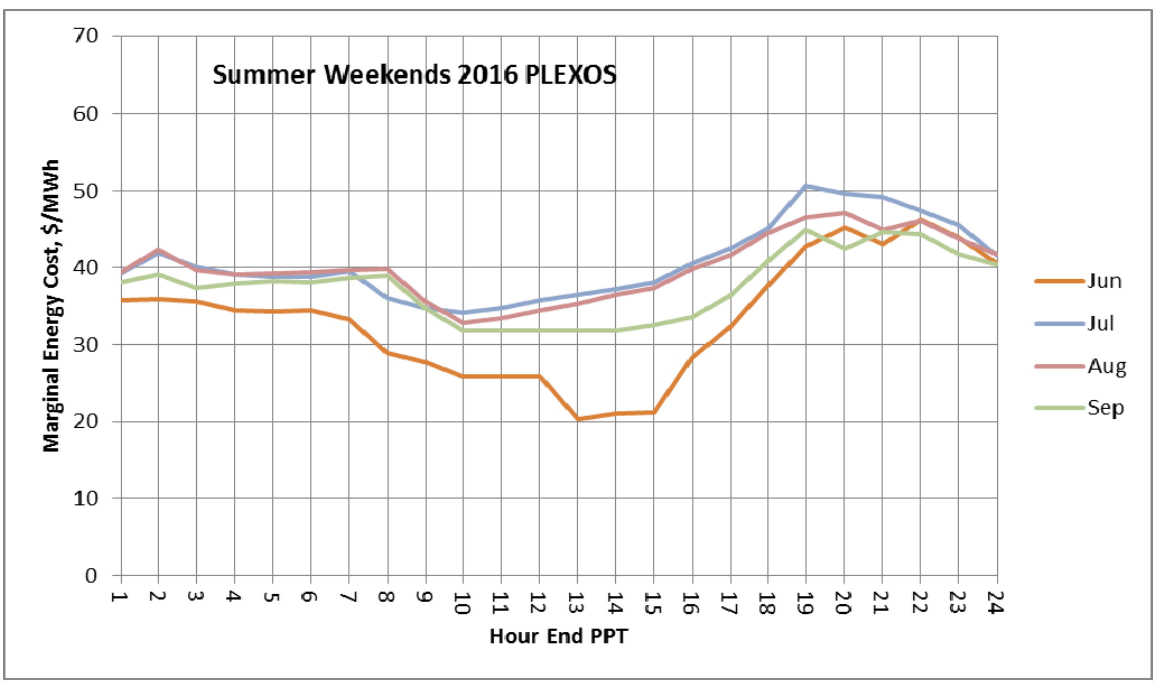


Figure 7a. 2020 PLEXOS Results, Winter Weekends, January-May, October-December

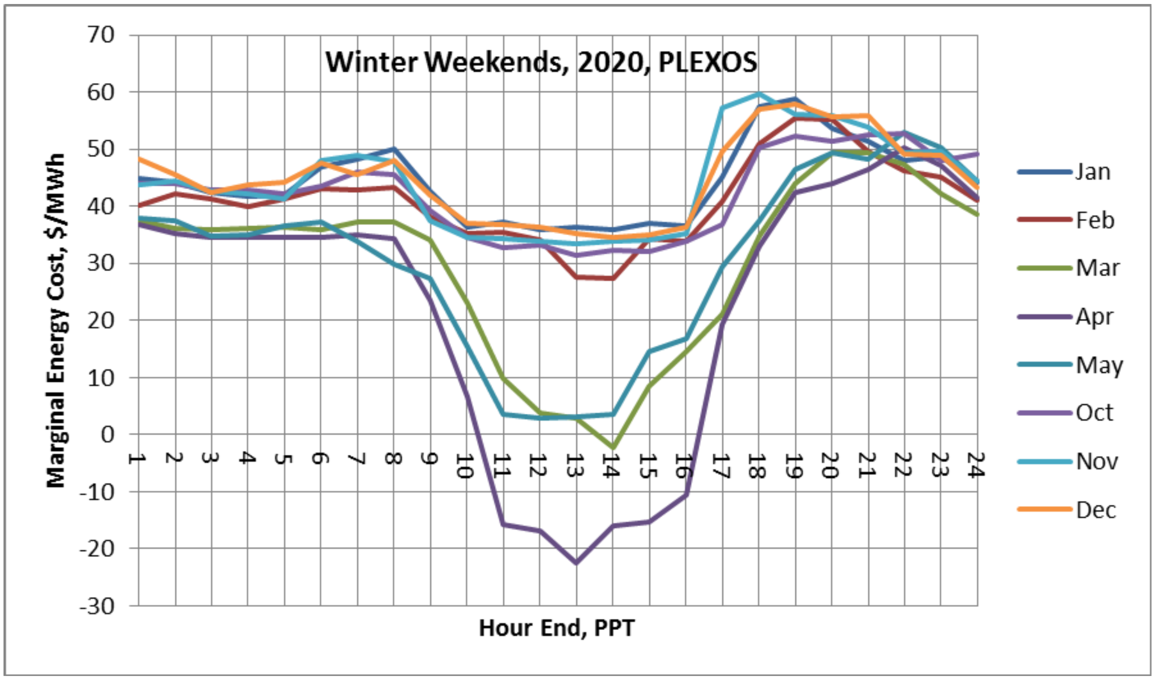
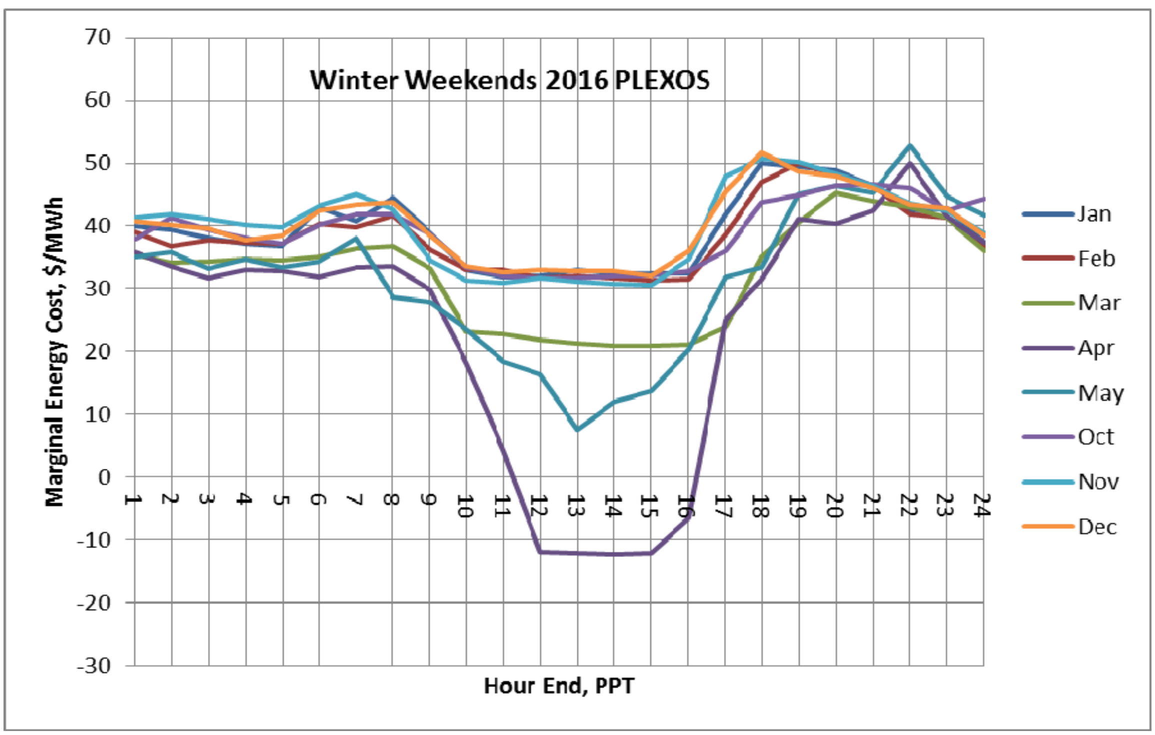


Figure 7b. 2016 PLEXOS Results, Winter Weekends, January-May, October-December



Please explain what Figures 4 through 7 illustrate.

Figures 4 through 7 shows the results of PLEXOS modeling, by month and by hour end (Pacific Prevailing Time) for 2020 (4a, 5a, 6a, 7a) and 2016 (4b, 5b, 6b, 7b). The graphs illustrate a number of points concerning the pattern of marginal energy costs:

1. For summer weekdays (seen in Figures 4a and 4b), the overall monthly and hourly pattern of energy prices is similar between 2016 and 2020, though prices are higher in 2020. For all months, the prices rise from midday to late afternoon / early evening is slightly steeper in 2020, generally reflecting the presence of a greater level of solar PV resources. However, the overall indication (using either 2020 or 2016 as a benchmark) is that marginal energy costs are highest in the later afternoon / early evening, lending support to TOU period pricing that shifts the peak hours to later in the day, even for as early as 2016.
2. For winter weekdays (seen in Figures 5a and 5b), the overall monthly and hourly pattern, as with summer, is similar between 2020 and 2016. Absolute prices are higher in 2020. Noticeably, there is a winter morning peak (November through February) centered around hour ending 8AM that rises to the price level seen in the evening hours. This spike would not be picked up by the proposed winter peak period covering just the evening hours. The chart also illustrates that for the spring months of March and April, there is a noticeable change in marginal costs during midday, as the presence of solar PV resources push the price downward between roughly 11AM and 3PM. There is no separate TOU period considered for these lower marginal cost periods.
3. Summer weekend patterns (Figures 6a and 6b) are not that different than summer weekday patterns, though the absolute price level is somewhat lower and June in particular shows a midday price depression in the late morning to early afternoon period.
4. Winter weekend patterns (Figures 7a and 7b) show noticeably lower prices for the spring months, especially in April where prices are less than zero for a six hour period in 2020 (10AM to 4PM) and for a five hour period (11AM to 4PM) in 2016. Winter weekend peak prices in the four highest priced months (November through February) do not show that much variation from winter weekday prices during the same period.

PG&E MEC Graphs

Please present PG&E MEC results, and compare them to PLEXOS results.

Figures 8 through 11 show PG&E's marginal energy cost patterns.

Figure 8 2020 PG&E Model, Summer Weekdays, June – September

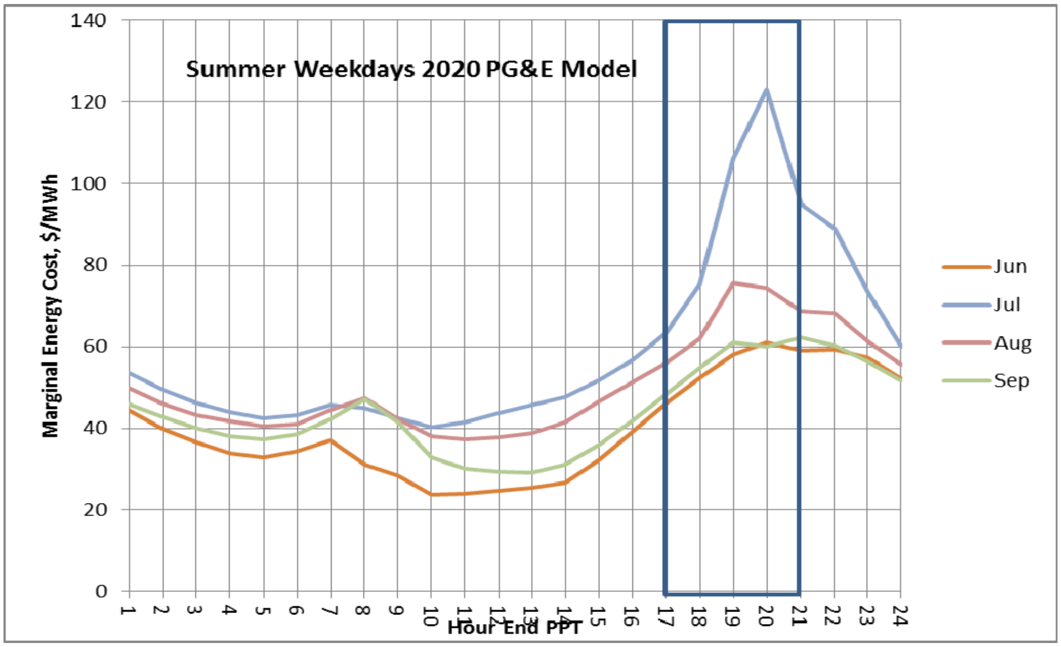


Figure 9. 2020 PG&E Model, Winter Weekdays, January-May, October-December

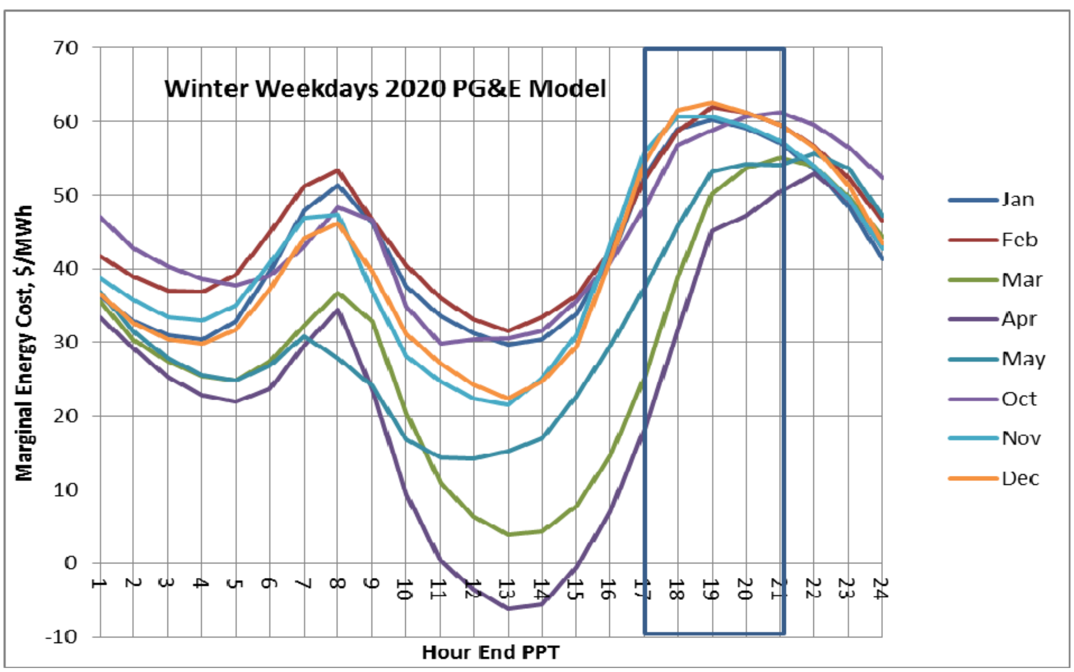


Figure 10. 2020 PG&E Model, Summer Weekends, June – September

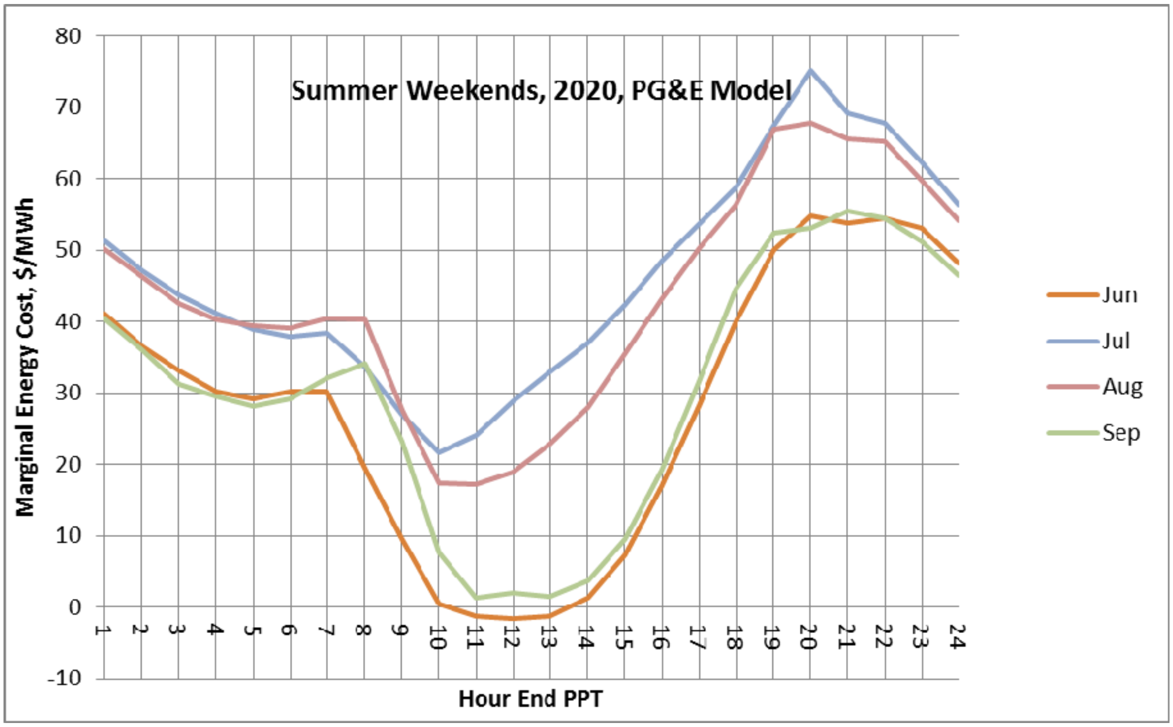
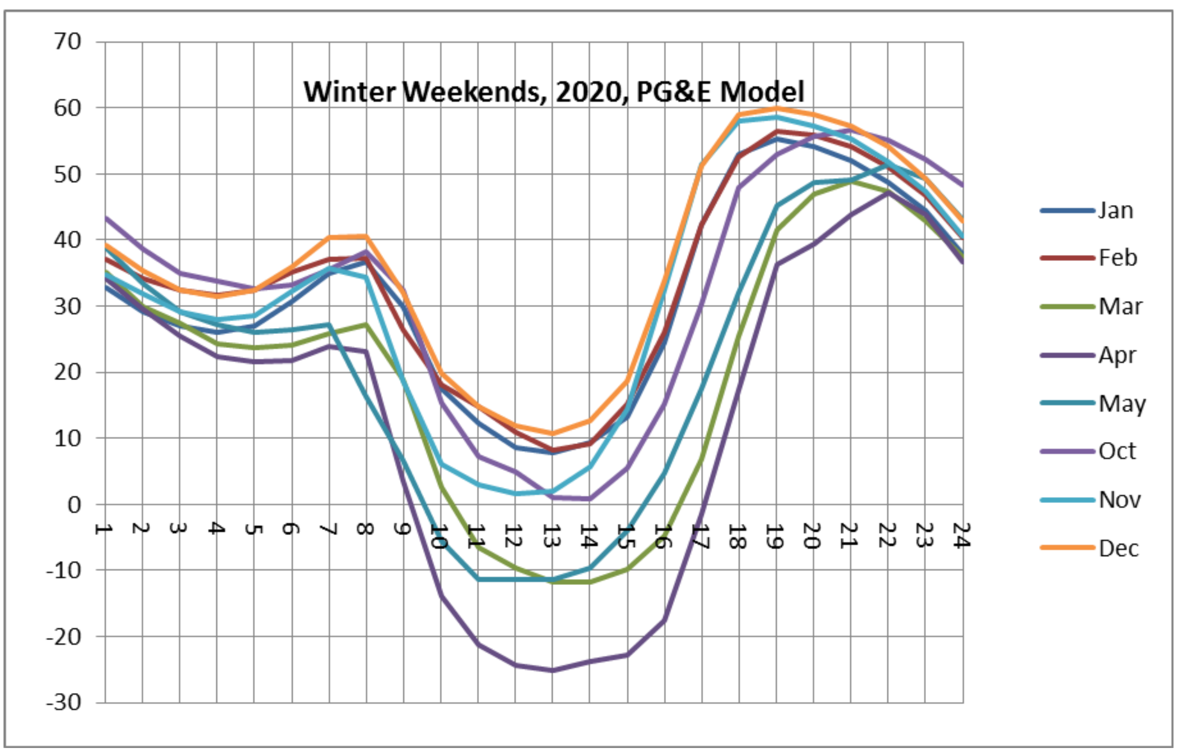


Figure 11. 2020 PG&E Model, Winter Weekends, January-May, October-December



Please explain what Figures 8 through 11 illustrate.

Figures 8 through 11 show the pattern of marginal energy costs (transmission level[9]) computed by PG&E's market heat rate model, for 2020. The prices for the summer weekday peak period (Figure 8) are considerably higher than we computed using the PLEXOS model, and the offpeak period prices are lower than we computed. For winter weekday periods (Figure 9), the PG&E model shows slightly higher peak period prices, and lower off-peak prices. Generally, PG&E's model reflects greater price extremes (between peak and offpeak periods) than what we see in the PLEXOS results.

Why are PG&E's marginal energy costs different from the PLEXOS results?

Based on our review of PG&E's methodology, it appears that the difference lies primarily in how PG&E's market heat rate model forecasts marginal energy costs at the low and high ends of the adjusted net load curve[10]. PG&E's market heat rate model does not calibrate well (with actual historical data) for low and high adjusted net load levels; this implies that the calculated marginal costs are less accurate for low and high adjusted net load levels. The PLEXOS model uses forecast values for all hours, and economic dispatch for all hours, and the result is that the pricing extremes that might otherwise be seen (in a less interconnected system than California) are mitigated. Figure 12 shows that PG&E's calibration of its market heat rate model does not have as many data points for calibration at low and high adjusted net load hours, compared to what occurs during the periods with less extreme adjusted net load values.

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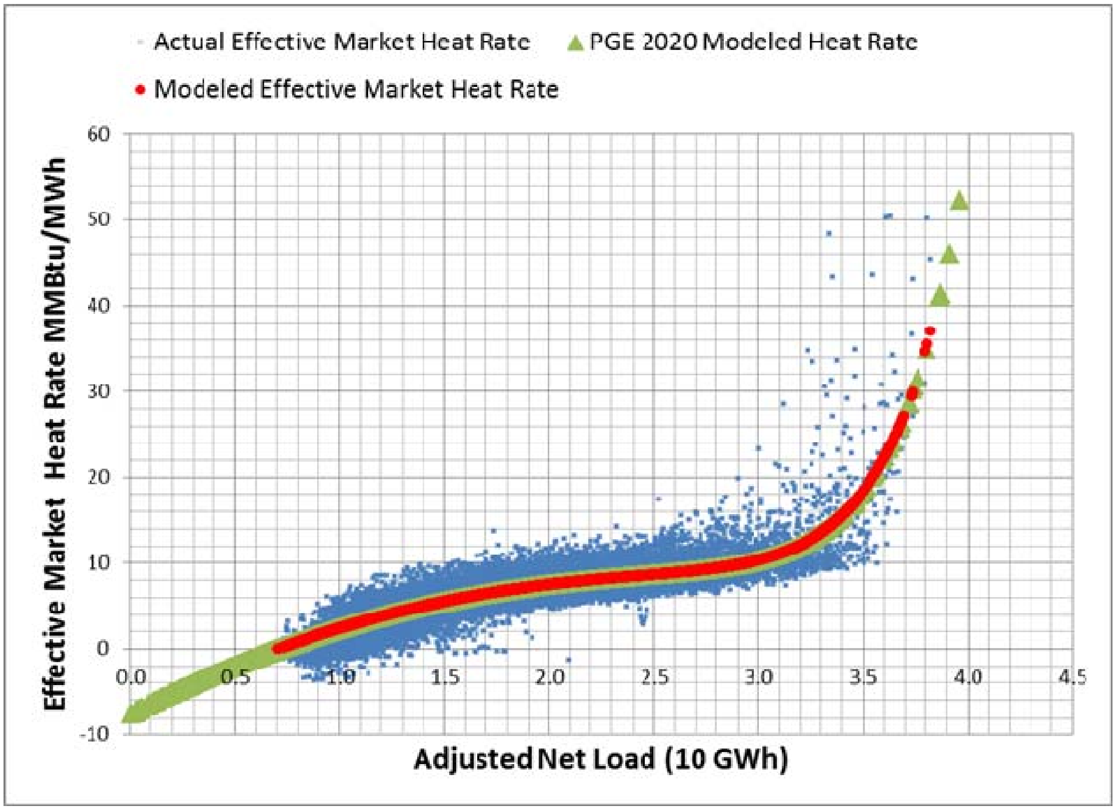
[9] PG&E computed marginal costs at both the transmission level, and at the retail level. The results of the PLEXOS model are effectively computed at the transmission level, and thus for comparison purposes we use PG&E's "transmission" level prices.

[10] Adjusted net load means PG&E's estimate of load net of solar, wind, nuclear and max hydro.

Figure 12.



Source: Synapse, based on PG&E Figure 2-3, "Relationship of Effective Market Heat Rates to Adjusted Net Load".

Can you provide additional information about this?

Yes. In PG&E's modeling data, there were 1,359 hours in 2020 that contained an adjusted net load less than 10,000 MW. There were only 336 hours of data available to calibrate the model on the low end of the adjusted net load curve.

Please describe Synapse's use of a loss-of-load expectation model.

We used a loss-of-load-expectation model to gauge which hours of the year were at greatest relative risk of loss of load. It is the same model used by SCE during its GRC Phase 2 rate case, but initialized with different data that reflects PG&E loads and resources. The model essentially employs a load/resource balance analysis that uses stochastic inputs for forecasted load, wind and solar output, and a stochastic representation of forced outage occurrences for all other resources (thermal, hydro, pumped storage, transmission interconnection).

The model is run for all hours of the year, and randomly combines a wind forecast, solar forecast, and load profile to generate a net load profile for the day. The model calculates the available capacity headroom in each hour by subtracting a daily planned outage schedule from the total capacity. To calculate the LOLE, headroom is compared to a distribution of 10,000 potential forced outage scenarios, randomly generated based on forced outage rates from the LTPP database.

How did you employ the LOLE model results?

We used the LOLE model results to assign relative risk of loss of load to all hours of the year. These hours were then assigned marginal capacity costs, in proportion to the relative risk of LOL. Hours without any relative risk of loss of load were not assigned any marginal capacity costs – the only marginal cost of generation for those hours was the marginal cost of energy. We determined the hourly marginal cost of capacity for a range of unit capacity cost estimates; our benchmark marginal cost of capacity uses PG&E's estimate of capacity cost, $57.09/kW-year. Sensitivities were run for $30/kW-year, and for $100/kW-year.

Please present Synapse's LOLE modeling results.

Figure 13 and Table 4 present the results of our use of the LOLE model. LOLE modeling results indicate that the greatest relative loss of load expectation occurs in July, later in the day (peaking at 7 PM standard time, 8 PM prevailing time). These findings generally support PG&E's proposal to shift peak-period TOU hours to later in the day. Notably, the greatest incidence of relative LOL risk occurs in the summer; there is some scattered risk in non-summer months but more than 83% of all LOLE hours occur between June and September.

Figure 13. Relative Loss-of-Load-Expectation, 2020, Average Monthly Values by Hour

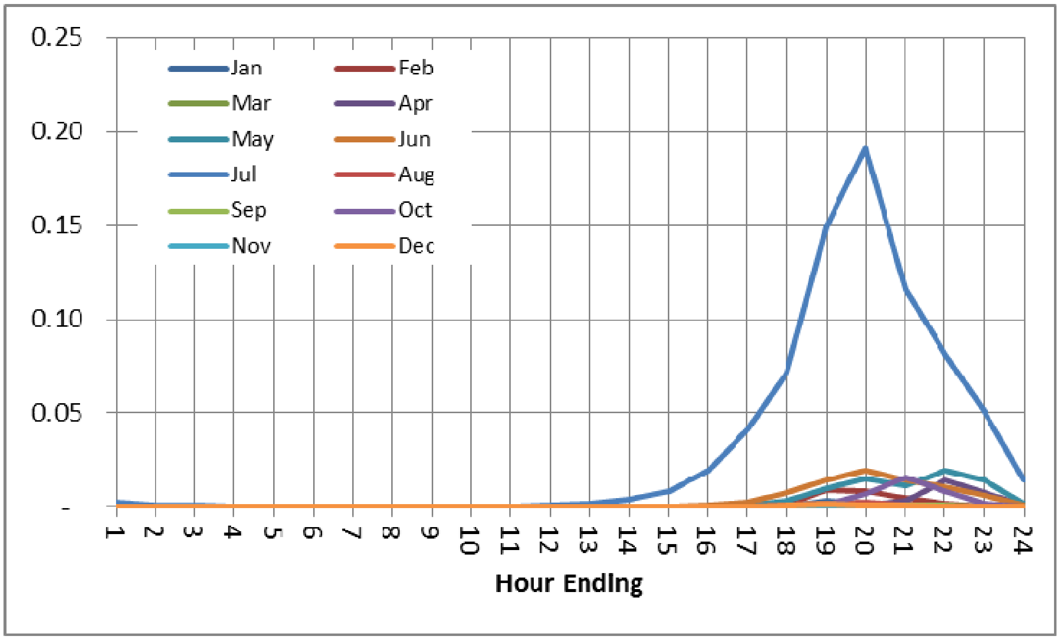


Table 4. Numerical Heat Map – LOLE Findings (adjusting maintenance outages for May)

	Month												
HE	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	-	-	-	-	0.000	0.000	0.003	0.000	-	-	-	-	0.003
2	-	-	-	-	-	-	0.001	0.000	-	-	-	-	0.001
3	-	-	-	-	-	-	0.000	0.000	-	-	-	-	0.000
4	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	0.000	0.000	-	-	-	-	-	-	-	-	-	0.000
9	-	0.000	0.000	-	-	-	0.000	0.000	-	-	-	-	0.000
10	-	-	-	-	-	-	0.000	0.000	-	-	-	-	0.000
11	-	-	-	-	-	-	0.000	0.000	-	-	-	-	0.000
12	-	-	-	-	-	-	0.001	0.000	-	-	-	-	0.001
13	-	-	-	-	-	-	0.002	0.000	-	-	-	-	0.002
14	-	-	-	-	0.000	0.000	0.004	0.000	-	-	-	-	0.004
15	-	-	-	-	0.000	0.000	0.008	0.000	-	-	-	-	0.008
16	-	-	-	-	0.000	0.001	0.019	0.000	-	-	-	-	0.020
17	-	-	-	0.000	0.001	0.002	0.041	0.000	-	-	0.000	-	0.044
18	0.000	0.000	0.000	0.000	0.003	0.007	0.071	0.000	0.000	0.000	0.000	0.001	0.084
19	0.003	0.009	0.000	0.000	0.010	0.014	0.149	0.002	0.000	0.001	0.000	0.001	0.189
20	0.001	0.008	0.000	0.001	0.015	0.019	0.191	0.002	0.000	0.006	0.000	0.001	0.245
21	0.000	0.004	0.000	0.003	0.011	0.014	0.115	0.001	0.001	0.016	0.000	0.001	0.166
22	0.000	0.001	0.000	0.014	0.019	0.010	0.081	0.001	0.000	0.008	0.000	0.000	0.136
23	-	0.000	0.000	0.007	0.014	0.006	0.050	0.000	-	0.002	-	0.000	0.080
24	-	-	-	0.001	0.001	0.000	0.014	0.000	-	0.000	-	-	0.017
Total	0.005	0.023	0.000	0.026	0.075	0.075	0.752	0.006	0.001	0.033	0.000	0.004	1.000

81.9% of all LOLE in HE17-21

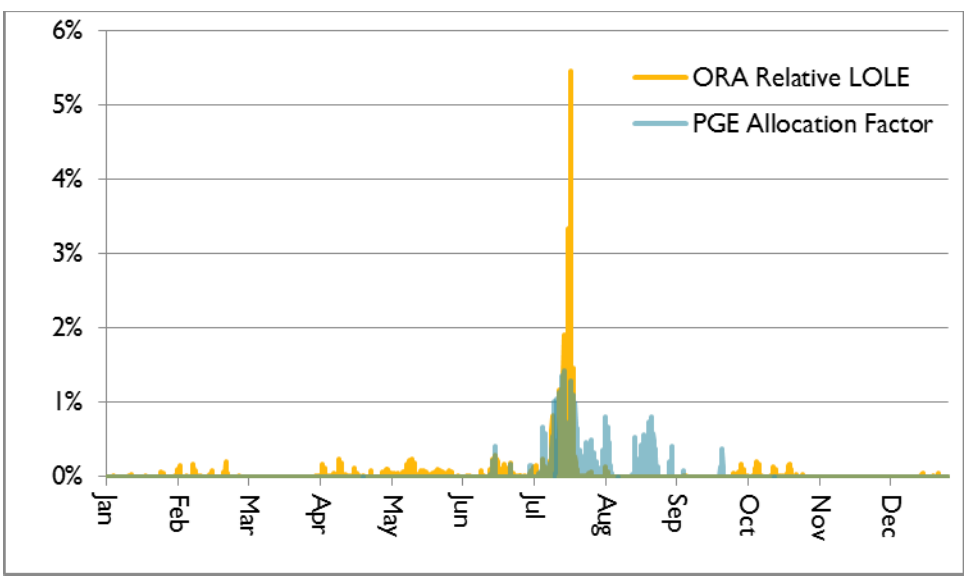
83.3% of all LOLE in June-Sept
68% of all LOLE in peak summer hours

Please compare your LOLE results to PG&E results for allocating marginal capacity costs.

Figure 14 below compares the distribution of hours used to assign marginal capacity costs, for Synapse's use of the LOLE model, and for PG&E. As seen, the use of the LOLE model results in both a wider distribution of hours (across the year) that contain a LOLE greater than zero, and a sharper "needle peak" in July compared to PG&E's "top 250 hours" approach. The effect of these differences changes the hours in which capacity costs are allocated, but both methods place most of the capacity costs in the summer months, in the peak period (4-9 PM).

The LOLE model shows a greater level of LOLE in May compared to September. This is an artifact of how forced outages were incorporated in the inputs of the model. Based on an input unit-specific outage rate, the model calculates a random distribution of 10,000 potential outage outcomes for each month. The randomly generated pattern for May resulted in more very high outage days than September. The model is sensitive to these high outage days in months of moderate to high headroom. Synapse was able to generate scenarios sensitivities where September had more outages than May, and thus more LOLE. The results for July are robust across scenarios, while the shoulder months can vary depending on random parameters such as outages.

<u>**Figure 14. Comparison of Hours for Marginal Capacity Cost Allocation – PG&E Top 250 vs. LOLE Model**</u>



Please present the results of total marginal costs of generation (MGC) and compare with PG&E MGC results.

Combining hourly marginal energy costs and marginal capacity costs allocated (proportionately) to LOLE hours leads to Marginal Generation Costs (MGC) patterns by hour. Table 5 below summarizes the marginal generation cost by summer and winter period, for peak and off peak, for the Synapse/ORA PLEXOS/LOLE modeling approach, and for PG&E's approach. Figures 15-17 that follow show these patterns, for 2020 ORA and PG&E modeling constructs, for a winter month (January), Spring month (April) and a summer month (July).

Table 5 Marginal Generation Costs – Synapse/ORA PLEXOS/LOLE Model and PG&E Model – by Proposed TOU periods

MGC, $/MWh, 2020	**ORA PLEXOS/LOLE**	**PG&E Market Heat Rate**
Summer		
peak	112.1	155.2
offpeak	51.7	49.3
Ratio Peak to Offpeak	2.2	3.1
Winter		
peak	54.1	53.0
offpeak	41.2	31.6
Ratio Peak to Offpeak	*1.3*	*1.7*

Figure 15 July Average Forecast Marginal Cost (Energy + Capacity) 2020

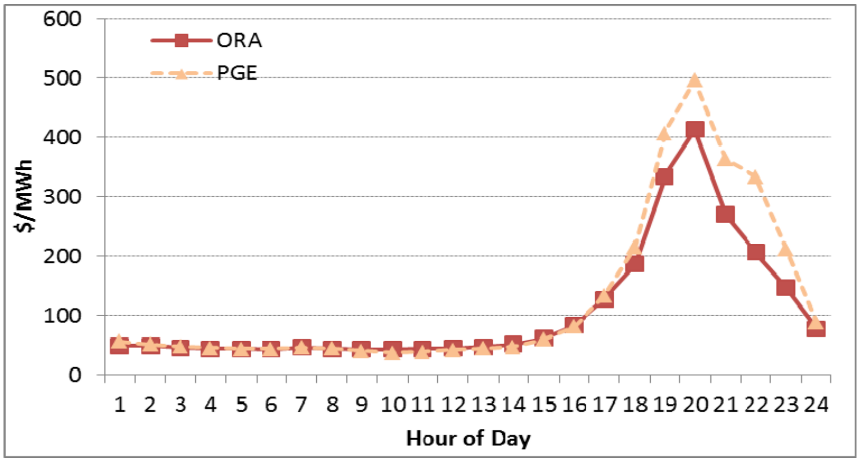


Figure 16 April Average Forecast Marginal Cost (Energy + Capacity) 2020

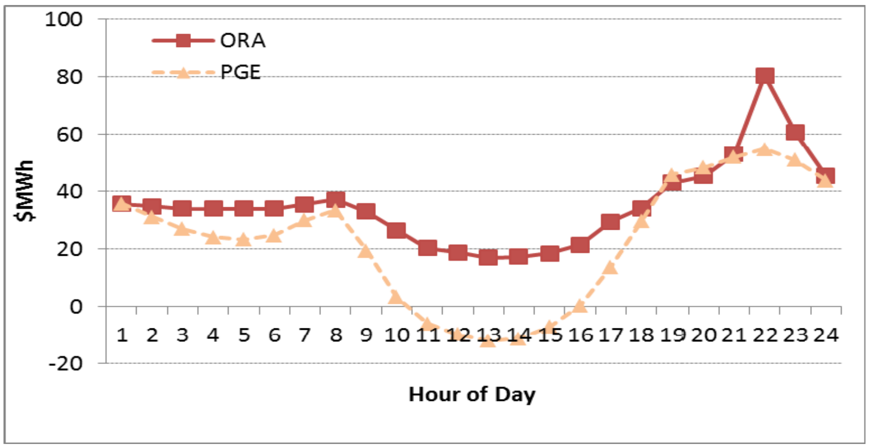
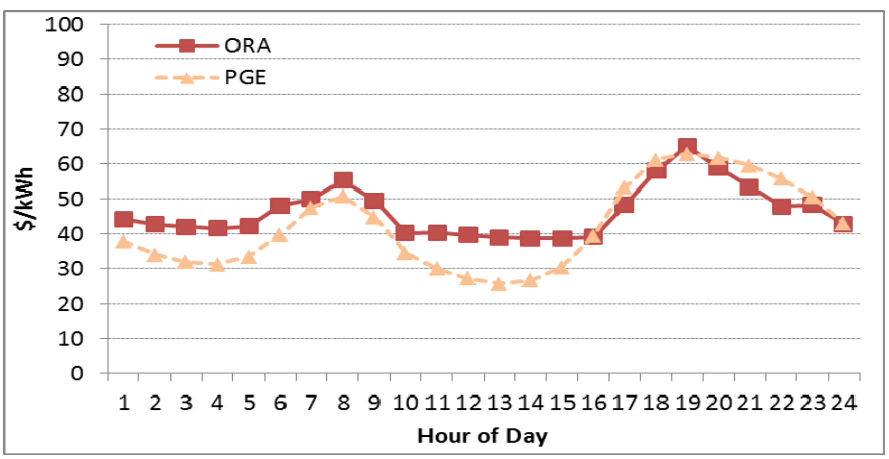


Figure 17 January Average Forecast Marginal Cost (Energy + Capacity) 2020



The results of the overall comparison between MGC as computed by Synapse, and the MGC as computed by PG&E shows similarity in variation of MGC across hours for both summer (seen here in July) and winter (January). There is a more noticeable difference in results for April, with PG&E's model showing much lower mid-day marginal generation costs. The absolute magnitude of marginal generation costs varies between the two modeling methods, as seen in Table 5.

How do the results change when you use different values for the marginal cost of a unit of capacity?

The overall pattern of marginal energy cost, and LOLE, does not change. The MCC, and thus the overall MGC does change, as summer period MGC values in particular are higher or lower than the benchmark value seen in Table 5 (which used PG&E's estimate of $57.09/kW-year). Table 6 shows how the MGC changes with different marginal generation unit cost assumptions.

Table 6 2020 Marginal Generation Costs – Sensitivity to Unit Cost of Capacity – by Proposed TOU periods

MGC, $/MWh, 2020	**ORA PLEXOS/LOLE 57.09/kW-year**	**ORA PLEXOS/LOLE $30/kW-year**	**ORA PLEXOS/LOLE $100/kW-year**	**PG&E Market Heat Rate $57.09/kW-yr**
Summer				
peak	112.1	83.4	157.5	155.2
offpeak	51.7	47.6	58.2	49.3
Ratio Peak to Offpeak	*2.2*	*1.8*	*2.7*	*3.1*
Winter				
peak	54.1	52.0	57.5	53.0
offpeak	41.2	40.6	42.0	31.6
Ratio Peak to Offpeak	*1.3*	*1.3*	*1.4*	*1.7*

Please present the results of total marginal costs of generation (MGC) for 2016

Table 7 presents the Marginal Generation costs based on our PLEXOS and LOLE runs for 2016. Peak hour prices are not substantially different than our 2020 results, as the capacity cost remains the same and the majority of LOLE hours still occur in the peak period.

Table 7 Marginal Generation Costs in 2016

$/MWh	MGC	MEC	MCC (implied)
Summer			
Peak	90.7	45.3	45.3
Offpeak	48.7	38.2	10.6
Ratio Pk-Offpk	*1.9*	*1.2*	*4.3*
Winter			
Peak	46.8	44.4	2.5
Offpeak	37.4	36.5	0.9
Ratio Pk-Offpk	*1.3*	*1.2*	*2.8*

Please present the results of your LOLE study for 2016

Table 7 presents a heat map of our 2016 LOLE modeling for the PGE system. These results show somewhat less relative LOLE in the newly proposed peak hours, 72.7% compared to 81.9% in 2020. They also show a higher concentration of LOLE in the summer months in general – 87.7% compared to 83.3% in 2020.

Table 8. Numerical Heat Map – LOLE Findings for 2016 (adjusting maintenance outages for May)

HE	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	Month												
1	-	-	0.001	0.000	-	-	0.002	0.000	-	-	-	-	0.003
2	-	-	0.000	0.000	-	-	0.001	0.000	-	-	-	-	0.001
3	-	-	-	-	-	-	0.000	0.000	-	-	-	-	0.000
4	-	-	-	-	-	-	0.000	0.000	-	-	-	-	0.000
5	-	-	-	-	-	-	0.000	0.000	-	-	-	-	0.000
6	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	0.000	-	-	-	0.000	0.000	-	-	-	-	0.000
11	-	-	0.000	-	-	-	0.000	0.000	-	-	-	-	0.000
12	-	-	0.000	0.000	-	-	0.001	0.000	-	-	-	-	0.001
13	-	-	0.000	0.000	-	0.000	0.003	0.000	-	-	-	-	0.003
14	-	-	0.000	0.000	-	0.000	0.007	0.000	-	-	-	-	0.007
15	-	-	-	-	-	0.000	0.016	0.000	-	-	-	-	0.016
16	-	-	0.000	0.000	-	0.001	0.029	0.000	0.000	-	-	-	0.030
17	0.000	-	0.000	0.000	-	0.002	0.048	0.001	0.001	-	-	0.000	0.052
18	0.002	0.000	0.000	0.000	0.000	0.006	0.079	0.005	0.003	-	-	0.003	0.098
19	0.005	0.005	0.006	0.000	0.000	0.010	0.154	0.010	0.008	0.000	-	0.003	0.201
20	0.003	0.004	0.009	0.001	0.000	0.012	0.177	0.011	0.006	0.000	-	0.002	0.224
21	0.002	0.002	0.018	0.005	0.000	0.008	0.103	0.007	0.005	0.001	0.000	0.002	0.152
22	0.001	0.000	0.021	0.006	0.000	0.005	0.073	0.007	0.005	0.001	-	0.001	0.120
23	0.000	-	0.012	0.004	-	0.002	0.050	0.002	0.001	0.000	-	0.000	0.071
24	-	-	0.003	0.001	-	0.000	0.015	0.000	-	-	-	-	0.020
Total	0.013	0.011	0.070	0.017	0.000	0.046	0.760	0.042	0.028	0.002	0.000	0.010	1.001

72.7% of all LOLE in HE17-21

87.7% of all LOLE in June-Sept
65.5% of all LOLE in peak summer hours

Does this conclude your testimony?

Yes.

APPENDIX A

Model Documentation

Please describe in detail how you determined 2020 baseline load profiles for modeling.

We started with the CPUC-approved assumptions for the Trajectory scenario of the 2014 LTPP docket. As explained in the Attachment to the Planning Assumptions ACR:

> "The Trajectory scenario is the control scenario for resource and infrastructure planning, designed to reflect a modestly conservative future world with little change from existing procurement policies and little change from business as usual practices."[11]

We make adjustments to the 2024 model provided by CAISO to reflect our best understanding of loads and resources in 2020, based on assumptions in the LTPP Scenario Tool, as well as other sources. The model provided in the LTPP docket was configured for 2024 only – the adjustments we made included:

- Annual Peak Loads and Annual Energy in CAISO, the rest of California, and the rest of WECC
- Revisions to thermal resource additions and retirements, resulting from recent CAISO dockets
- Installed PV capacity
- Storage resources
- Demand response resource
- RPS resources

Thermal resources were set to retire and be added based on more current information than the LTPP dataset. A number of modifications have been made to the

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[11] Attachment to Planning Assumptions ACR, p. 34. Other scenarios, and the order in which the Planning Assumptions ACR indicates they should be studies are: the High Load Scenario ,which explores the impact of higher than expected economic and demographic growth, the High DG [distributed generation] scenario, which explores the implications of promoting high amounts of DG; the 40% [Renewable Portfolio Standard]RPS in 2024 Scenario, which would assess the operational impacts associated with a higher RPS target post-2020, and the Expanded Preferred Resources scenario, which would assess the impact of broadly pursuing higher levels of preferred resources. Attachment to the Planning Assumptions ACR, pp. 37-38.

retirement forecasts required for compliance with the State Water Resources Control Board's once-through cooling (OTC) policy. The updated retirement dates in Table A-1 are based on a CEC progress report issued on August 24th, 2014.[12]

Thermal additions were made based on a number of data sources, and summarized in Table A-2. Large new combined-cycle units will be added in mid-2020 at or near the existing Huntington Beach and Alamitos sites, for a total of 1,284MW of capacity. New combustion turbines will be added at Mandalay, Carlsbad, Stanton, and Pio Pico totaling 1,062MW.[13],[14]

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[12] California Energy Commission. "Once-Through Cooling Phase-Out". August 24th, 2014. http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf

[13] A.14-1-012. Testimony of SCE on the Results of Its 2013 LCR RFO for LA Basin. Table VII-25.

A.14-11-016. Testimony of SCE on the Results of Its 2013 LCR RFO for Moorpark. Table VII-22

[14] Note that Pio Pico was included in the 2014 LTPP analysis. We include it here for completeness.

Table A-1: Thermal Resource Adjustments from LTPP2014 Data set

Facility & Unit	NQC (MW)	Retirement Date
Alamitos 1	175	12/31/2020
Alamitos 2	175	12/31/2020
Alamitos 3	332	12/31/2020
Alamitos 4	336	12/31/2020
Alamitos 5	498	12/31/2019
Alamitos 6	495	12/31/2019
Huntington Beach 1	226	12/31/2018
Huntington Beach 2	226	12/31/2018
Mandalay 1	215	6/1/2020
Mandalay 2	215	6/1/2020
Mandaly3	130	12/31/2020
Ormond Beach 1	741	12/31/2020
Ormond Beach 2	775	12/31/2020
Redondo5	179	12/31/2020
Redondo6	175	12/31/2018
Redondo7	493	12/31/2020
Redondo8	496	12/31/2018

Table A-2: Thermal Resource additions to LTPP2014 Data set

Facility & Unit	NQC (MW)	Install Date
Huntington Beach CC	644	5/1/2020
Alamitos CC	640	6/1/2020
Mandalay Repower CT	262	6/1/2020
Carlsbad CT	400	1/1/2018
Stanton CT	100	7/1/2020
Pio Pico CT	300	12/31/2019

Loads in CAISO as well as the rest of California were adjusted based on the 2014 IEPR forecast (Form 1.5). No adjustments were made to the hourly pattern. Loads in all hours were scaled down based on the ratio of the 2014 IEPR energy forecast for 2020 to the 2013 IEPR energy forecast for 2024, the latter of which was used in the LTPP proceeding. We used the IEPR mid-demand, mid AAEE forecasts. Non-California regions (including the rest of the WECC) were adjusted downwards based on an average of the California adjustment factors. We also compared these results to the EIA's 2014 Annual Energy Outlook forecasts for WECC, which are about 1% lower. However, AEO's forecasts for California itself are also lower than the IEPR forecasts. We rely on the more recent on locally-informed IEPR forecasts.

Behind-the-meter PV resources were adjusted based on the Scenario Tool forecast for 2020 under the Trajectory scenario. These values are based on an IEPR mid load forecast and a mid PV forecast, as developed by Energy Division. The revised values are presented in Table A-4.

Table A-3: Recent IEPR Energy Forecasts (in GWh). IEPR 2013 was used in the LTPP model, while IEPR2014 was used in this analysis

	IEPR2014 Mid-MidAAEE		IEPR2013 Mid-MidAAEE	
	2020	**2024**	**2020**	**2024**
SCE	105,417	106,509	107,249	108,888
IID	4,423	4,670	4,516	4,777
LDWP	29,508	31,002	31,041	32,618
PGE_BAY	46,708	46,895	47,129	47,377
PGE_VLY	62,242	63,311	61,879	63,065
SDGE	21,491	21,452	21,802	21,846
SMUD	18,916	19,917	19,061	20,117
TIDC	2,941	3,069	2,846	2,978

Table A-4: Installed BTM PV Capacity (MW)

	2020	2024
SCE	1147	1564
SDGE	352	534
PGE_VLY	1019	1389
PGE_BAY	786	1072
Total	3304	4559

Storage resources were modeled based on the CPUC Storage Target Decision (D.13-10-040), which forecasts 1,325 MW of storage resources in 2024[15] – this is reduced to 663 MW in 2020. The Scenario Tool only provides statewide installed capacity values – we held the proportion of storage resources in PGE, SCE, and SDGE constant and adjusted values downwards to reach the 2020 target.

Adjustments to demand response capacity are small – based on the Scenario Tool we removed 5 MW of DR resources that were planned to be installed between 2020 and 2024, leaving 2,171MW of DR available to the model.

The reduced loads in the 2020 case mean RPS requirements are also less. Based on the Scenario Tool and a 33% RPS target in 2024, our changes in load would result in a reduction of 200 MW of renewable resources. These were incorporated as reductions in California wind resources.

What forecast of natural gas prices did you use in your analysis?

We used the Energy Division report "Estimating Natural Gas Burner Tip Prices for California and the Western United States", published in November 2014.[16] This report specifies burner-tip prices for 31 locations across the WECC.

[15] This 1,325MW includes 50MW of storage in SCE authorized under Track 1

[16] "Estimating Natural Gas Burner Tip Prices for California and the Western United States" California Energy Division Publication Number: CEC-200-2014-008. November 2014.

Did you use the same methodology for modeling 2016 as 2020?

Yes. We again used the LTPP Scenario Tool for most modifications, including reducing CAISO-wide behind-the-meter PV to 2429MW, reducing new RPS generation by 2,155MW from 2024 levels, and reducing total demand response resources to 2,162MW. Loads were again adjusted based on the 2014 IEPR forecast. We did not believe the assumptions made in the Scenario Tool with regards to Storage resources were realistic – instead we used the more up-to-date PUC Order in Docket 14-10-045, approving the ISO utilities' procurement plans.[17] This order lists storage targets of 120MW for PG&E, 120MW for SCE, and 30MW for SDG&E for 2016.

Did you make additional thermal unit modifications for 2016?

Yes. A number of units slated to be retired in the next several years had to be added back in to the CAISO LTPP model. These include Encina, Moss Landing, Pittsburg, and the Long Beach Peakers. We also modeled the replacement of Broadway 3 with Glenarm5 in June of 2016.

LOLE MODELING

How did you allocate capacity costs to hours across the year?

We used a loss of load expectation (LOLE) model to calculate the relative risk of a generation shortage in all hours of 2020, taking into account uncertainty in both load and resource availability. This is the same framework used by SCE during its GRC Phase 2 rate case. We developed 30 possible peak and energy scenarios, and randomized daily wind and solar generation forecasts against load in each month. To calculate the relative LOLE in each hour, these net loads were compared against a distribution of thermal resource availability, including both forced and planned outages.

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[17] California Public Utilities Commission, Decision 14-10-045. October 16, 2014. "Decision Approving San Diego Gas & Electric Company, Pacific Gas and Electric Company, and Southern California Edison Company's Storage Procurement Framework and Program Applications for the 2014 Biennial Procurement Period". Pg 6.

The model was populated with loads and resources consistent with our PLEXOS energy modeling. A key distinction was the LOLE model was for PG&E's territory only. The model did not include units in the rest of CAISO, or the rest of the WECC. It did, however, include a representation of the availability of transmission resources to serve PG&E's load.

How did you develop the 30 hourly load profiles used in the LOLE analysis?

Thirty unique random scalars were generated for each day of the year – 1 for each profile. This random number was normally distributed with a standard deviation calculated based on the relative variation expected in each month. Each hour of the base load profile (the LTPP profile, adjusted for 2020), was adjusted by this scalar.

CHAPTER 3

CUSTOMER PREFERENCES –TOU TIME PERIODS

LOUIS IRWIN

TABLE OF CONTENTS

CHAPTER 3

CUSTOMER PREFERENCES – TOU TIME PERIODS

LOUIS IRWIN

I. INTRODUCTION

This chapter addresses a single question contained in the Commission's Scoping Memo regarding residential customer preferences on time-of-use ("TOU") time periods. The exact wording is as follows:

> "4. Do PG&E's available studies adequately address customer preferences regarding moving the summer on-peak period into evening hours?"[1]

This question refers to PG&E's TOU proposal to redefine the summer on-peak period to cover 4 pm to 9 pm. The two main existing residential TOU rate plans (Schedules E-6 and E-7) have summer on-peak TOU hours that begin and end earlier in the day:

- <u>Schedule E-6</u>: 1 pm – 7 pm,
- <u>Schedule E-7</u>: 12 pm – 6 pm.[2]

For the next 3 years or more, PG&E's residential TOU rates will be offered as an "opt-in" choice. Therefore, customer preferences regarding TOU time periods will impact the customer participation rates and the ultimate success of the PG&E TOU rate offerings. Although ORA focuses solely on customer preferences regarding TOU time periods in this Chapter, there are other factors, such as generation system conditions that are incorporated into ORA's TOU rate proposals. For a consideration of all factors relevant to ORA's TOU rate proposals, please refer to Chapter 1.

PG&E bases its proposal in part on the findings of a report that it commissioned from Hiner and Partners ("Hiner study").[3] Hiner conducted a

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[1] "Scoping Memo and Ruling of Assigned Commissioner," January 29, 2015, p. 4.

[2] PG&E.com/tariffs.

[3] PG&E Rate Design Window 2015, Prepared Testimony, Attachment A, Residential Rate

(continued on next page)

survey using a marketing technique called “conjoint analysis.” In this chapter, ORA reviews this report and then compares its findings to customer preferences revealed by TOU pilot results provided by the Salt River Project (“SRP”) in Arizona.

II. RECOMMENDATIONS

PG&E does not adequately address customer preferences about moving the summer on-peak hours into the evening, either for existing TOU customers or potential new TOU customers. ORA supports the April 21, 2015 Proposed Decision (“PD”) in R.12-06-013 which grandfathers in the current TOU tariffs. These grandfathered tariffs use earlier on-peak periods. TOU pilots should be conducted to test customer preference for different TOU time periods.

ORA recommends the following:

- The Commission should reject PG&E’s proposals to eliminate schedules E-6 and E-7. These schedules and their existing customers should be grandfathered going forward so as to not alienate these early adopters.
- The Commission should order TOU pilots that consider earlier TOU time periods.

The reasons for ORA’s position on the Hiner study are described in the Discussion section below.

III. DISCUSSION

A. Hiner and Partners Report

The foundation for PG&E’s proposed TOU time period and conclusions about customer TOU summer on-peak time preferences rests on a study that it commissioned from a group called Hiner and Partners (“Hiner study”). This research group designed and conducted a survey to investigate consumer

(continued from previous page)
Plan, Conjoin Analysis,” Hiner and Partners, February 23, 2015.

preferences on a variety of TOU attributes, such as on-peak time period, duration of TOU on-peak hours, on and off-peak rate ratios.[4]

At first glance, it may seem like the Hiner Study is offering the customers a wide variety of TOU time periods, as Table 3-1 illustrates below.

TABLE 3-1:[5] HINER AND PARTNERS SURVEY QUESTION ON TOU TIME PREFERENCE

TOU On-Peak Hours	Selected
5:00pm-8:00pm (3 hours)	32%
4:00pm-8:00pm (4 hours)	21%
5:00pm-9:00pm (4 hours)	8%
4:00pm-9:00pm (5 hours)	5%
3:00pm-9:00pm (6 hours)	6%
3:00pm-10:00pm (7 hours)	5%

This survey presented these six options as choices, as well as a "no preference" option. Although the survey offers six alternatives, the number of choices does not result in a great variety of TOU on-peak hours. For instance, all the "choices" offered TOU time periods that end between 8 pm and 10 pm. They all start between 3 and 5 pm.

Thus the Hiner Study neither surveys customer preferences on the current TOU time periods, nor the preferences regarding strictly afternoon TOU time periods, nor directly on moving to mid-evening TOU time periods. Although there are some variations in the Hiner and Partners TOU offerings, they are on the whole all comparatively later in the day, precluding an investigation of contrasting effects of afternoon versus evening TOU time periods. Thus they do not address the specifics of question #4 in the scoping memorandum, which asks about "moving the summer on-peak period into evening hours." Though PG&E does have some experience with marketing the existing TOU rates, where the summer

[4] Ibid. Attachment B.

[5] Ibid.

on-peak period is in the afternoon, comparing field results for earlier TOU hours with survey results for later TOU hours is difficult.

The report also does not include the use of other information rich techniques such as doing full interviews or focus groups. Nor was a sophisticated simulation game utilized where customers could choose rate plans and see simulated outcomes and impacts on their budgets. One scenario could have been the change from the current status quo to PG&E's TOU proposal. ORA is not certain of what time or budget constraints that PG&E faced for this endeavor. Suffice it to say, that the Hiner study is fairly limited on its investigation of TOU time preferences and should be evaluated on this basis.

The study also does not screen out respondents who are not interested in TOU rates in tallying the results on which TOU period is preferred. Therefore, we cannot truly determine the preferences of those who might actually sign up for a TOU rate. But, taken at face value, it is evident that the choice of TOU hours that PG&E elected (4 pm to 9 pm) only elicited interest from 5% of the respondents, while a slightly shorter period that ended one hour sooner (4 pm to 8 pm) elicited a 21% response. Given the limitations of the Hiner study, PG&E should, in the pilot studies ordered in the PD in R.12-06-013, investigate other time periods that might elicit more participation in TOU opt-in rates. Though such TOU periods may not target as precisely the high cost hours, a possible increase in the aggregate demand response might compensate for this shortcoming.

B. TOU at the Salt River Project[6]

Given that the Hiner study did not investigate afternoon TOU periods, ORA presents in this section information from a Salt River Project ("SRP") pilot to help address question #4 in the scoping memorandum. The SRP created a test pilot program of three alternative TOU rates with three differing TOU time periods.

6 All SRP data was provided by Tanya Mannon of SRP, various dates going back to spring 2014.

The three rate plans all have three-hour TOU periods starting at 2 pm, 3 pm and 4 pm. The middle time period is the default, offered without a participation limit. The early and later alternatives more recently have been offered as test pilot programs. In November 2012, 10,000 account participation quotas were initiated for the two experimental TOU rates. Other than the differing quotas, the three TOU rates are identical except for the time period. This allows interested TOU customers to make a choice solely on the basis of the TOU time period being offered.

The TOU 2014 account distribution for SRP is shown in Table 3-2.

TABLE 3-2
TOU ACCOUNT DISTRIBUTION
SALT RIVER PROJECT

Rate Plan	TOU Peak RateTime Period	January 2014 Account Distribution	November 2014 Number of Accounts	Quota	Percentage Choosing This Option
EZ-3 E-25	2 to 5 pm	10,000	9,179	10,000	8.2%
EZ-3 E-21	3 to 6 pm	85,000	95,769	No quota	85.6%
EZ-3 E-22	4 to 7 pm	5,000	6,933	10,000	6.2%
All Residential Accounts	Various including Non-TOU		905,990	n/a	12% of all Residential are on one of these TOU rates

For the following analysis, ORA leaves aside the uncapped default TOU rate (E-21, covering 3 to 6 pm). Due to its default uncapped status, its participation level (over 95,000 at the end of 2014) clearly dwarfs the participation numbers for the alternative rates with capped participation. The two experimental rates were Schedule E-25, 2 to 5 pm on-peak and E-22, 4 to 7 pm on-peak. At the end of 2014, the earlier TOU plan had attracted 32% more participation than the plan with the 4 to 7 pm on-peak hours.

The statistics in Table 3-2, however, do not reflect the fact that Schedule E-25 (2 to 5 pm) reached its participation quota fairly quickly, while Schedule E-22 (4 to 7 pm) still has not reached its quota after two years since the initial offering.

The earlier data from January 2014 shows that Schedule E-25 had reached its participation quota of 10,000, twice as many as E-22, the later hour TOU plan.[7] SRP did not have estimates of how many customers were turned away from the early TOU rate due to the quota being satisfied. Schedule E-25 had actually reached its quota in early March 2013, less than five months after being offered. So by January 2014 it had been capped for ten months.

The 2014 year-end figures show that the early TOU rate participation has fallen to 9,179. Data was not available on the causes of participation drop. Undoubtedly, there are various possible reasons from moved accounts to customers migrating out of TOU rates altogether. Further investigation did reveal that SRP discontinued the marketing for the early TOU plan once it had reached the quota. Had marketing not been suspended, and had participation not been capped, the participation levels for the earlier TOU period might have been much higher.

Clearly, the SRP study is limited to TOU periods that end no later than 7 pm, and we do not know what the results would have been had another TOU period choice been available that ended at 9 pm, like PG&E's. While data are not available, the trends in the Hiner study suggest that participation might have been significantly lower for later TOU time periods, such as 6 to 9 pm, than even the less popular 4 to 7 pm TOU period. Indeed, the Hiner study suggested that shifting the TOU period merely one hour later (from 4 pm – 8 pm to 5 pm – 9 pm) decreased the response rate from 21% to 8%, nearly a two-thirds decrease.

IV. CONCLUSION

ORA's analysis is that PG&E's available studies could have better addressed customer preference for the current, earlier TOU periods as compared to the later TOU periods. While current TOU customers are allowed to continue

[7] Tanya Mannon of SRP stated that the later TOU time period (4 to 7 pm) drew participants from the work force that worked swing shift and graveyard.

their enrollment in the earlier TOU periods, this does not necessarily address the concerns of potential new TOU customers. Therefore, ORA has recommended that earlier TOU time periods be explored on a pilot basis. While generation costs and environmental consequences may be the primary driving factors for TOU rate design, undervaluing customer preference is clearly not desirable.

APPENDIX A

QUALIFICATIONS OF ORA WITNESSES

LIST OF ORA WITNESSES AND RESPECTIVE CHAPTERS

Chapter 1	Residential Rate Design Policy	Cherie Chan
Chapter 2	Marginal Energy Costs and LOLE Allocation Among TOU Periods	Bob Fagan/Patrick Luckow
Chapter 3	Customer Preferences	Louis Irwin

QUALIFICATIONS OF
CHERIE CHAN

Q.1. Please state your name and business address.

A.1. My name is Cherie Chan. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By whom are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electricity Pricing and Customer Programs Branch of the Office of Ratepayer Advocates.

Q.3. Please describe your educational background and professional experience.

A.3. I hold a Bachelor of Arts degree from the University of California at Berkeley, with a major in Social Welfare and minors in Business and Demography. I have worked as a Billing Analyst at PG&E and as Manager of the Billing Department at Utility.com. At ABB Inc., I helped implement Interval Data Software products for utilities as a Project Manager and Product Engineer. I joined the Commission in 2005 and have sponsored Marginal Cost, Rate Design and advanced metering testimony, departing in 2007 to manage marketing and product management of smart grid programs at eMeter and Oracle. I returned to The Commission in 2009 and have continued to testify in several rate design, advanced metering, and other proceedings.

Q.4. What testimony are you sponsoring in this proceeding?

A.4. I am sponsoring Chapter 1, Residential Rate Design Policy.

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 responsive testimony (jointly, with Patrick Luckow) in the San Diego Gas & Electric Rate Design Window (RDW) docket, Application 14-01-027, on November 14, 2014. 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).

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 responsive testimony (jointly, with Robert Fagan) in the San Diego Gas & Electric Rate Design Window (RDW) docket, Application 14-01-027, on November 14, 2014. 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

QUALIFICATIONS OF
LOUIS IRWIN

Q.1 Please state your name and business address.

A.1 My name is Louis Irwin. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Regulatory Analyst in the Office of Ratepayers Advocates.

Q.3 Please describe your educational and professional experience.

A.3 I have a Master of Arts in Economics from the University of Colorado at Boulder with a focus on environmental, energy and urban issues and a Master of Public Administration from the JFK School of Government in Cambridge, Massachusetts. My thesis, while at C.U. Boulder, focused on natural resource scarcity and pricing. Both degrees included coursework in finance, economics and econometrics that I find relevant to this case. I also have a Bachelor of Arts in Psychology from U.C. Berkeley with a focus on organizational and business psychology applications. My senior project there involved a cost / benefit analysis that used calculus to solve for the inputs that would minimize overall turnover costs of a management training program. Since joining ORA in 1999, I have worked on a variety of energy related issues ranging from distributed generation to cost of capital cases. More recently, I have worked on marginal cost aspects of general rate cases and the Residential Rate OIR. Prior to coming to the Commission, I worked for seven years in economic consulting, regarding socio-economic impacts due to mining and energy facilities, including the proposed high-level nuclear waste site at Yucca Mountain, Nevada. My more recent consulting experience was directly in the energy field, performing productivity and comparative electric rate analyses with Christensen Associates of Madison, Wisconsin, a specialist in these areas.

Q.4 What is your area of responsibility in this proceeding?

A.4 I am sponsoring testimony for Chapter 3, Customer Preferences –TOU Time Periods.