8) Please explain how customer behind-the-meter generation exported to the grid impacts the class hourly dynamic load profiles. Are the hourly profiles SDG&E calculates net of such generation? Why or why not?

**SDG&E Response:** SDG&E Dynamic Load Profiles are built using net hourly loads, which subtract behind-the-meter generation exports from all the imports. Because DLPs use system load data as a control total to calibrate and adjust, and system load is measured at the point of generation; any exported load becomes imports by non-exporting customers and are not captured by that measurement. Therefore, system load is net load.

The following questions refer to the Revised Prepared Direct Testimony of Jeff P. Stein.

10) Witness Stein states that “In the interest of promoting rate stability consistent with the Commission’s Rate Design Principles (“RDP”), SDG&E is not proposing any updates to the revenue allocations for the Distribution, Commodity, Competition Transition Charge (“CTC”), and Local Generation Charge (“LGC”) rate components established by D.17-18-030, except as needed to accommodate the addition of the Schools-only customer class.” (p. JS-2:19-23) Is SDG&E proposing to update any of the afore-referenced rate components to reflect the sales forecast presented in the testimony of witness Schiermeyer?

* 1. If so, which revenue allocations and why?
  2. If not, why not?
  3. If any of the listed revenue allocations are being updated for the sales forecast, please explain how they have been updated and provide any supporting workpapers for such updates.
  4. If not, please provide revenue allocations for Distribution, Commodity, CTC, and LGC that include the schools-only customer class and are updated for the sales forecast presented in witness Schiermeyer’s testimony but otherwise reflect the methodology established by D.17-08-030. Please also provide supporting workpapers for such revenue allocations.

**SDG&E Response:**

Is SDG&E proposing to update any of the afore-referenced rate components to reflect the sales forecast presented in the testimony of witness Schiermeyer?

No

a) N/A

b) The revenue allocations for the Distribution, Commodity, Competition Transition Charge (“CTC”), and Local Generation Charge (“LGC”) rate components are based on current effective revenue allocations, which were adopted in the Revenue Allocation Settlement of SDG&E’s 2016 GRC Phase Decision D.17-08-030. Because updating the revenue allocations to reflect the current commodity and distribution cost studies could increase bill volatility and cause customer classes to experience rate shock, SDG&E believes that maintaining the current revenue allocations (except as to accommodate the new Schools Customer Class) is the best way to balance the Commission’s adopted RDPs of customer understanding and rate stability in this Application.

c) N/A

d) Distribution, Commodity, and CTC revenue allocations that reflect witness Schiermeyer’s testimony and 2020 sales forecast can be found in the workpapers of witness Saxe (Chapter 5) and witness Montoya (Chapter 6). For LGC, please see the attached document titled “UCAN\_DR01\_Q10d.xlsx”.



The following questions refer to the Revised Prepared Direct Testimony of Kenneth E. Schiermeyer.

13) Please provide monthly historical sales in kWhs as delivered by the grid to customers aggregated by customer class for those customer classes listed in Table KS-1. Please provide these kWh sales for calendar years 2014-2019. Please provide the data in Microsoft Excel format.

**SDG&E Response:** See the embedded xls file named (UCAN\_DR\_2\_SDG&E\_Response\_Q13)

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15) Please provide monthly historical kWhs that were compensated as Net Surplus Energy under the current NEM and NEM-ST tariffs aggregated by customer class for those customer classes listed in Table KS-1. Please provide these kWhs for calendar years 2014-2019. Please provide the data in Microsoft Excel format.

**SDG&E Response:** See the embedded Excel file named NEMSurpluskWh\_Q15.

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43) Please provide the source file(s) for the input data in blue font for the following tabs:

c. Distribution O&M Allocations

**SDG&E Response:**

c. The data in the “Distribution O&M Allocations” tab of the Chapter 5 Workpaper #2 Revised can be found in the accompanying “2019 GRC Phase 2 – FERC - Electric Cust OM 5-Yr Avg Allocation-Revised” file.



The following questions refer to Chapter 6 the Revised Prepared Direct Testimony of Benjamin A. Montoya.

1. Why do the “2020 GRC P2 Shapes” for Summer and Winter shown in Charts BAM-1 and BAM-2 differ so significantly from the actual price shapes, including the following:
2. Much lower prices in the middle of the day around hour ending 13 and 14
3. Later peak price in summer and winter
4. Much higher peak price in winter during evening hours

**SDG&E Response:**

The resulting 2020 GRC phase 2 shapes are a function of the 2020 forward prices used and the net demand profile used to calculate them. The forward prices used in this calculation reflected the market’s view of 2020 prices in February, 2018 when this price profile was calculated. The net demand profile reflected the CEC 2018 hourly bundled load forecast profile net of non-dispatchable generation resources, primarily wind and solar (see the response to Q#45 for a more detailed explanation of net demand). The reasons for the differences noted are:

* 1. Much lower prices in the middle of the day around hour ending 13 and 14 are primarily a reflection of more behind the meter PV penetration forecasted by 2020 than in 2017 and 2018. This reduces the load profile during the day and, thus, the price profile. Any new in-front-of the meter solar projected to be added by 2020 also contributed to this.
  2. The later peak price in summer and winter is primarily a reflection of two things: higher forecasted solar generation in 2020, decreasing the profile during daylight hours, and higher electric vehicle load projections, increasing the profile in the evening hours.
  3. The higher peak price in winter during evening hours is primarily a function of the forward price used (see the response to Q#46 for the forward prices used). As shown in the price table, winter off-peak prices were actually higher than summer off-peak prices.

1. Witness Montoya states that “SDG&E used a forecasted hourly profile for 2020 based upon net demand in the SP-15 market….” (BAM-3:5-6)
2. Please define “net demand”?
3. Why does SDG&E use “net demand” to estimate hourly prices and not total demand?

**SDG&E Response:**

* 1. Net demand is the hourly total demand that SDG&E is forecast to serve minus forecasted non-dispatchable resource generation in those hours.
  2. The reason SDG&E uses net demand to estimate hourly prices and not total demand is that net demand more closely represents the actual price profile. Subtracting non-dispatchable resource generation, like solar and wind, from the load, leaves the net load to be served by dispatchable resources and the market price reflects this. This is the reason market prices are low during high solar hours when there is less remaining load to be served. If total load were used to shape prices, there would be high prices during solar hours and the wrong price signal would be sent to dispatchable resources.

1. Witness Montoya states that “For the development of the average hourly prices, the monthly CAISO on-peak and off-peak forward prices are multiplied by the monthly CAISO on-peak and off-peak hourly demand profiles to arrive at hourly prices.” (BAM-4:6-8)
2. Please provide the referenced monthly forward prices.
3. What is the date and source of the monthly forward prices?
4. Are the forward monthly prices demand-weighted average prices? If so, what forecasted demand is the basis for the demand-weighting?
5. Are the referenced hourly demand profiles reflective of “net demand?” If not, what are they based on?

**SDG&E Response:**

* 1. The monthly forward prices are provided in the workpaper entitled “Ch\_6\_WP#1\_Marg Gen Comm Cost\_Conf\_Revised.xlsx” on tab “Assumptions” cells B31:D43.
  2. These monthly forward prices are the simple average of the Intercontinental Exchange (ICE) 2020 price curves for each trading day in February 2018.
  3. These prices are from ICE and represent an aggregation of numerous views of supply and demand by market participants. SDG&E made no additional modifications to arrive at the prices shown in “a.” other than a simple average of all February 2018 trading days.
  4. Yes, the referenced hourly demand profiles reflect “net demand” as described in Q#45.

1. Witness Montoya states that “The RPS premium is defined as the “Green Value,” calculated by the California Public Utilities Commission’s Energy Division, minus the average annual SP-15 market energy price, then multiplied by the RPS Target for 2020 of 33%.” (BAM-5:14-BAM-6:1)
2. Please provide a reference or citation for the “Green Value” so that it may be verified.
3. What does the “Green Value” represent?
4. Does the “Green Value” represent a REC price? If not, why did SDG&E decide to use this “Green Value” instead of a REC price to estimate the RPS premium?
5. How much of SDG&E’s generation portfolio is estimated will be supplied by renewable resources in 2020, meaning those resources that can be used to meet SDG&E’s RPS mandate?
6. Why did SDG&E decide to use the RPS target of 33% instead of the actual amount of renewable energy in SDG&E’s generation portfolio?

**SDG&E Response:**

1. The “Green Value” is the market price benchmark used to calculate the Power Charge Indifference Adjustment (PCIA) in the Energy Resource Recovery Account (ERRA) proceeding. The Green Value was provided to SDG&E by the Energy Division in an email communication on 11/2/2018 for use in calculating the 2019 PCIA. This value was not published in a citable document that SDG&E is aware of.
2. The green value represents the market value of a renewable energy credit (REC).
3. Yes, the Green value represents a REC price.
4. In 2020, it is estimated that 45-47% of SDG&E’s portfolio will be provided by renewable power.
5. SDG&E chose to use the 33% RPS target to reflect the marginal costs of renewable generation rather than use an estimated value that could potentially inflate marginal costs beyond the stated goal.

1. Please refer to Chart BAM-3 on page BAM-13.
2. Is the x-axis in the chart hour ending or hour beginning?
3. The five hours with maximum LOLE in the chart are hours 19-23. This does not correspond with SDG&E’s standard TOU peak period of 4-9 pm. Does SDG&E intend to change its TOU periods in the future to that represented by hours 19-23? If not, why not?

**SDG&E Response:**

1. The x-axis represents the chart hour ending.
2. SDG&E has filed Advice Letter 3484 stating its intent to adjust its critical peak pricing period to more align with the hours shown in this chart. SDG&E anticipates revisiting base TOU periods in its next GRC Phase 2 if its dead band tolerance range has been exceeded, as required by D.17-01-006.
3. Witness Montoya states that “SDG&E used LOLE results presented in Section VI for generation capacity cost allocation.” (BAM-8:10-11)
4. What is the advantage of using LOLE as opposed to selecting the highest 100 hours of SDG&E’s forecasted system load directly?
5. How is behind-the-meter solar generation treated in SDG&E’s LOLE analysis? Is it a fixed reduction to load or subject to stochastic outages?

**SDG&E Response:**

1. The advantage of using LOLE as opposed to selecting the highest 100 hours of SDG&E’s forecasted system load is that the LOLE allocates marginal capacity costs based on both supply and demand, whereas using only forecasted system load alone provides only a partial representation. For example, if only the highest load hours were used, the highest allocation of marginal capacity costs would occur in the middle of the day when there is already an abundance of solar generation. Marginal capacity costs should be highest in the hours when supply is least available to meet demand and only LOLE analysis provides this.
2. Load is adjusted for behind the meter solar prior to conducting the LOLE analysis. It is not subject to stochastic outages in the LOLE analysis.
3. Witness Montoya states that “Marginal energy cost revenues by customer class are developed by multiplying the applicable marginal energy price by the 2020 forecasted TOU energy usage in each SDG&E Standard TOU period for each customer class.” (BAM-10:1-3)
4. Does the “2020 forecasted TOU energy usage” derive from the sales forecast presented by witness Schiermeyer? If not, what is the source of this energy forecast?
5. Is the referenced “energy usage” the net sales or the delivered sales as described by witness Schiermeyer or something else? Please justify which sales forecast is used.

**SDG&E Response:**

1. Yes, the “2020 forecasted TOU energy usage” derives from the sales forecast presented by witness Schiermeyer.
2. The referenced “energy usage” is net sales for bundled customers. Bundled sales are used because marginal energy costs in Witness Montoya’s testimony apply only to commodity costs, which are only paid by bundled customers.
3. Witness Montoya states that “Marginal capacity cost revenues by customer class are developed by multiplying the unit MGCC by each class’ estimated contribution to the total bundled load based on the top 100 hours with the highest expected need for new resources….” (BAM-10:5-7)
4. Does the “class’ estimated contribution to the total bundled load” derive from the sales forecast presented by witness Schiermeyer? If not, what is the source of this load forecast?
5. Is the referenced “bundled load” the net sales or the delivered sales as described by witness Schiermeyer or something else? Please justify which sales forecast is used.

**SDG&E Response:**

1. Yes, the “class’ estimated contribution to the total bundled load” derives from the sales forecast presented by witness Schiermeyer.
2. The referenced “bundled load” is net sales for bundled customers. Bundled sales are used because marginal capacity costs in Witness Montoya’s testimony apply only to commodity costs, which are only paid by bundled customers.

The following questions refer to Chapter 3 the Revised Prepared Direct Testimony of Gwendolyn R. Morien.

1. Please refer to Table GM-4c, which shows current and proposed Monthly Service Fees (MSF) for small commercial customers.
2. Why do the MSFs vary by demand level?
3. Can a customer receive a different MSF on consecutive bills if its metered maximum demand level occurs in different demand group for each billing cycle? (For instance, if a customer had a 4 kW demand one billing cycle and a 6 kW demand the following cycle, would it be charged a $10 MSF on the first bill and a $16 MSF on the second bill?) If not, what is used to set the maximum demand level for determining the MSF?
4. For simplicity, would SDG&E consider using the 0-5 kW MSF for all customers and collecting the remaining revenue from a demand rate or peak TOU energy rate? Why or why not?

**SDG&E Response:**

* 1. MSFs (called basic service fee (BSF) for billing purposes) for Small Commercial customers vary by demand level because there are customers on SDG&E’s small commercial rate tariffs that have demands higher than 20 kW, although SDG&E’s Small Commercial class is for customers with maximum demands less than 20 kW. To take service on Schedule TOU-A (the default Small Commercial rate), a customer must not have maximum monthly demand equivalent to, exceeding, or expected to exceed 20 kW for 12 consecutive months or must not have a maximum monthly demand that exceeds 200 kW in 2 out of 12 consecutive months. Differentiating BSFs by demand is more reflective of cost basis than a single BSF for all Small Commercial customers.  Customers with higher demand levels require higher cost transformers, service drops, and meters (TSM customer costs) to serve them, which is why the BSFs are a higher amount for higher demand customers.
  2. Per SDG&E’s Schedule TOU-A tariff Special Condition #2, a customer’s BSF will be determined each month based on the customer’s Maximum Annual Demand.  Under the example proposed, if the customer’s maximum annual demand (highest demand over the prior 12 months) was 4 kW and the customer’s demand is 4 kW the next month, then the customer’s BSF or MSF for this month would be $10.  If, in the following month, the customer’s maximum demand was 6 kW, then the customer’s BSF or MSF for this month would be $16 because the customer’s maximum annual demand is now 6 kW.
  3. As stated in SDG&E’s response to Question 52(a), many customers who take service on SDG&E’s Small Commercial customer class rates have maximum monthly demands that far exceed 20 kW. Recovering distribution customer costs through a BSF that is reflective of the differences in TSM customer costs for these customers is more cost-based than a small BSF that recovers the remaining revenue through an on-peak TOU energy rate. SDG&E’s marginal distribution cost study (Chapter 5 – Saxe testimony filed January 15, 2020) shows that the current BSFs for the Small Commercial class are well below cost-based levels. The table below compares the current effective BSFs (1/1/2020 rates) to SDG&E’s 2019 GRC Phase 2 Marginal Distribution Customer Cost rates. Applying the same BSF to all Small Commercial customers, regardless of demand, is moving further from cost-based rates, not closer.

|  |  |  |
| --- | --- | --- |
| Secondary Service | Current Effective BSF 1/1/2020  (Schedule TOU-A) | Small Commercial Class EPMC Distribution Rate (Chapter 5 testimony of A.19-03-002) |
| 0-5 kW | $10.00 / month | $33.34 / month |
| > 5 – 20 kW | $16.00 /month | $66.94 / month |
| > 20 – 50 kW | $30.00 / month | $163.13 / month |
| > 50 kW | $75.00 / month | $246.02 / month |

1. Witness Morien states that “The summer on-peak to off-peak ratios for the TOU energy rates of both Small Commercial and Small Agricultural customers are well below cost-based levels. For Small Commercial and Small Agricultural customers, the on-peak to off-peak ratio of the current standard 2-period TOU rates is set at 1.81:1.”
2. What is the “cost-based” summer on-peak to off-peak ratio for TOU energy rates and how is this determined?
3. How was the 1.81:1 ratio determined?
4. How long has SDG&E used a 1.81:1 TOU period price ratio for the standard 2-period rate?

**SDG&E Response:**

1. The commodity cost-based summer on-peak to off-peak ratios for the default 2-Period TOU is 5.51:1. This is determined by allocating all on-peak capacity costs to the summer on-peak period instead of setting the current summer on-peak to off-peak TOU differential of 1.81:1.
2. The 1.81:1 commodity summer on-peak to off-peak differential was implemented on May 1, 2014 as an optional rate (Schedule TOU-A) with SDG&E’s 2012 GRC Phase 2 implementation. The differential was adopted in D.14-01-002 as part of a Revenue Allocation and Rate Design Settlement Agreement between SDG&E, the Division of Ratepayer Advocates, San Diego Consumers Action Network, The City of San Diego, California Farm Bureau Federation, Federal Executive Agencies, California City-County Street Light Association, and Solar Energy Industries Association. The purpose of a milder differential than the cost-based differential at the time, as proposed by SDG&E in A.10-07-009, *Application of SDG&E for Approval of Its Proposals for Dynamic Pricing and Recovery of Incremental Expenditures Required for Implementation*, was to smooth the transition for Small Commercial customers to a TOU rate, as the default rate at the time was a flat seasonal rate and was not time-differentiated. Additionally, a smaller differential was designed for small non-residential customers of less than 20 kW since this customer segment was assumed to have a reduced ability to respond to price signals. The settlement agreement proposed the same TOU structure for agricultural customers with less than 20 kW (small agricultural customers).
3. The 1.81:1 commodity summer on-peak to off-peak TOU differential has been in effect since May 1, 2014.

The following question refers to SDG&E’s data request response to SEIA dated 4-29-2019.

1. SDG&E’s response to question 7 states that SDG&E’s distribution system “is designed to meet the combined maximum demand of customers…regardless of when that maximum demand occurs” and that this design process is “standard” and used “throughout the industry” and that SDG&E “must incur costs to meet the maximum demand of all customers on a circuit, regardless of when that demand occurs.”
2. Please provide copies of any supporting documents that show designing the system to meet the combined maximum demand of customers is standard throughout the utility industry.
3. Please provide a copy of SDG&E’s distribution system planning manual and provide citations that show SDG&E designs its system to meet the combined maximum demand of customers regardless of when that maximum demand occurs.

**SDG&E Response:**

a) There are no supporting documents. This language was based on testimony from witness Baranowski in A.15-04-012, which was based on conversations with counterparts from other utilities that planned the system in the same manner. Current practices may be slightly different based on current forecasting/planning methods (post Distribution Resources Plan), but SDG&E must still serve each area based on the demand in that area.

b) Distribution planning does not have a formal planning manual. Witness Baranowski provides additional detail regarding system design in A.15-04-012.

1. Please provide copies of any state or federal regulatory agency regulations or applicable law that requires SDG&E to incur costs to “meet the maximum demand of all customers on a circuit, regardless of when that demand occurs.”

**SDG&E Response:**  SDG&E objects to this request on the grounds that: (1) it calls for a legal conclusion rather than the production of evidence or clarification of a factual matter, and (2) it calls for the production of documents that are in the public domain and equally available to UCAN.