Application No: A.17-10-002
Exhibit No.:
Witness: Sharim Chaudhury

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) Regarding Feasibility of Incorporating Advanced Meter Data Into the Core Balancing Process.	A.17-10-002 (Filed October 2, 2017)

REBUTTAL TESTIMONY OF

SHARIM CHAUDHURY

ON BEHALF OF

SOUTHERN CALIFORNIA GAS COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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REBUTTAL TESTIMONY
OF SHARIM CHAUDHURY

I. PURPOSE

The purpose of my rebuttal testimony on behalf of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) (collectively, Applicants) is to address certain issues pertaining to the Applicants' daily aggregated gas demand forecasts raised by Southern California Generation Coalition and Indicted Shippers (SCGC/IS), Environmental Defense Fund (EDF), and Southern California Edison Company (SCE). Specifically, I will address issues pertaining to: (1) the forecasting errors attributable to the Applicants' daily load forecasting model (DLFM), (2) EDF's proposed alternative forecasting model, and (3) the timing of incorporating daily consumption data from SoCalGas' Advanced Meter Infrastructure (AMI) system into the SoCalGas DLFM.

II. IT IS IMPORTANT TO UNDERSTAND THAT APPLICANTS' DLFM FORECAST ERROR INCLUDES FORECAST ERRORS ATTRIBUTABLE TO DEMAND COMPONENTS BEYOND RETAIL CORE DEMAND

Intervenors imply that Applicants' DLFM forecast error is attributable only to retail core demand. This is not correct. As I stated in my direct testimony, the Gas Acquisition department is responsible for procuring natural gas for the Applicants' retail core customers[1] as well as lost and unaccounted-for gas (LUAF) and company-use gas. Accordingly, the DLFM is designed to produce the combined aggregated daily gas demand forecast for retail core customers, LUAF, and company-use gas.[2] Therefore, any demand forecast errors associated with the Applicants' DLFM reflects not only the errors in the retail core demand forecasts, but also the errors in the

[1] Retail core customers comprise the Applicants' residential, small commercial and industrial, and NGV customers who rely on the Applicants to procure natural gas. Core customers who procure their gas through core transport agents (CTAs) are not considered retail core customers.
[2] Direct Testimony of Sharim Chaudhury at 1-2.

forecasts for LUAF and company-use gas. Although LUAF and company-use gas demand represent a small portion of demand relative to retail core demand, any forecast errors arising from these two components contribute to the DLFM forecast errors. Due to the nature of LUAF[3], forecasting for LUAF gas is particularly challenging; yet, its contribution to overall DLFM forecast errors is likely more than trivial.

The use of aggregated daily estimated actual demand for SoCalGas also introduces some amount of error into the DLFM. As explained above, the variable to be forecasted in the DLFM is combined aggregated daily gas demand. Developing a statistical forecasting model requires historical data on the variable to be forecasted. As stated in my direct testimony, for SoCalGas, the historical data for combined aggregated daily gas demand is estimated demand – not actual demand (I refer to it as "estimated actual"). These aggregated daily "estimated actuals" "are residually derived by subtracting the measured daily gas demand of noncore customers and the estimated daily gas demand of CAT customers from the measured daily total system gas sendout."[4] Any error in estimating the components of the daily estimated actual demand will necessarily impact its accuracy. In summary, it is simply inaccurate to attribute the DLFM forecast error to only retail core customers because the forecast includes other demand components beyond retail core demand that contribute to the overall error of the DLFM.

Since estimated actual daily gas demand is used as a proxy for historical actual daily gas demand in SoCalGas' DLFM, it exhibits more forecast error when compared to SDG&E's DLFM because the latter uses aggregated actual demand data from AMI data for historical data.

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[3] According to American Gas Association (AGA), "[u]tility unaccounted for gas is most likely a result of operational measurement discrepancies of gas moving through the utility system rather than natural gas escaping unburned into the atmosphere." AGA Financial and Operational Information Series, Volume 2018-06, (June 2018), *available at* https://www.aga.org/globalassets/news--publications/fois/public/fois-2018--06-eia-lauf-2016-data.pdf.
[4] Direct Testimony of Sharim Chaudhury at 3.

I expect that the forecast error for SoCalGas' DLFM will become lower once AMI data is incorporated as proposed in the Application.

III. INTERVENORS' CLAIMS THAT APPLICANTS' DLFM MODELS PRODUCE LARGE FORECAST ERRORS ARE OVERSTATED

I address each intervenor's claims relating to the size of the Applicants' DLFM forecast errors below. But I must reiterate that the core "estimated actual demand" is just that, an estimate of actual demand. While estimated actual demand may be useful for general discussion of the issues addressed in this proceeding, it should not be used to evaluate forecast performance on any given day.

A. SCGC/IS

SCCG/IS argues that "there is a great deal of forecast error on a daily basis."[5] SCGC/IS contends that "Applicants' forecasting methodology has been woefully deficient, although there has been some recent improvement."[6] In support of these statements, SCGC/IS produces a plot of DLFM daily forecast errors for the period of January 1, 2011 through April 30, 2018.[7] As SCGC/IS acknowledges, this chart shows that more recent daily forecasts reflect narrower deviations, i.e., the forecasts are closer to estimated actual gas demand relative to previous years. SCGC/IS accurately states that one of the reasons for the improvement in recent forecasts is because the daily gas demand forecasts now provides a forecast for gas demand for the same hours of the day as those used for measuring daily estimated actual demand.[8]

This change is important for understanding the apparent "improvement" in the forecast. Daily estimated actual gas demand estimates daily gas demand for the hours of midnight to

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[5] Direct Testimony of Catherine E. Yap at 49.
[6] *Id.* at 14.
[7] *Id.* at 15 (Figure 2).
[8] *Id.* at 15-16.

midnight, which are the hours for the Measurement Day. Before September 1, 2016, the DLFM forecasted daily gas demand for the hours of 7 a.m. to 7 a.m., which are the hours for the Gas Day, to coincide with the timeframe for Gas Day deliveries. Beginning September 1, 2016, the DLFM was revised to forecast daily gas demand for the Measurement Day hours of midnight to midnight. This means that before September 1, 2016, approximately 29% of the hours forecasted in the daily gas demand forecast were for different hours of the day than those used to calculate the daily estimated actual gas demand. Simply put, only since September 1, 2016 do the hours for the DLFM forecast now match the hours of the daily estimated actual gas demand. This allows for more appropriate analysis of forecast performance against the estimated actual demand, keeping in mind that estimated actuals are only estimates of actual demand and not actual demand. Any assertions about the performance of the forecast based on the differences between the daily forecast and daily estimated actual demand prior to September 1, 2016 are inappropriate.

To highlight the significance of changing the DLFM to forecast midnight to midnight Measurement Day usage, the plot showing the performance of the DLFM forecasts as presented by SCGC/IS in Figure 2 of their testimony has been reproduced below. The plot shows the forecast errors as a percentage of estimated actuals. The period beginning with September 1, 2016 has been highlighted in blue. The blue line shows that the forecast errors have been reduced in magnitude since the DLFM has been synchronized with the Measurement Day.

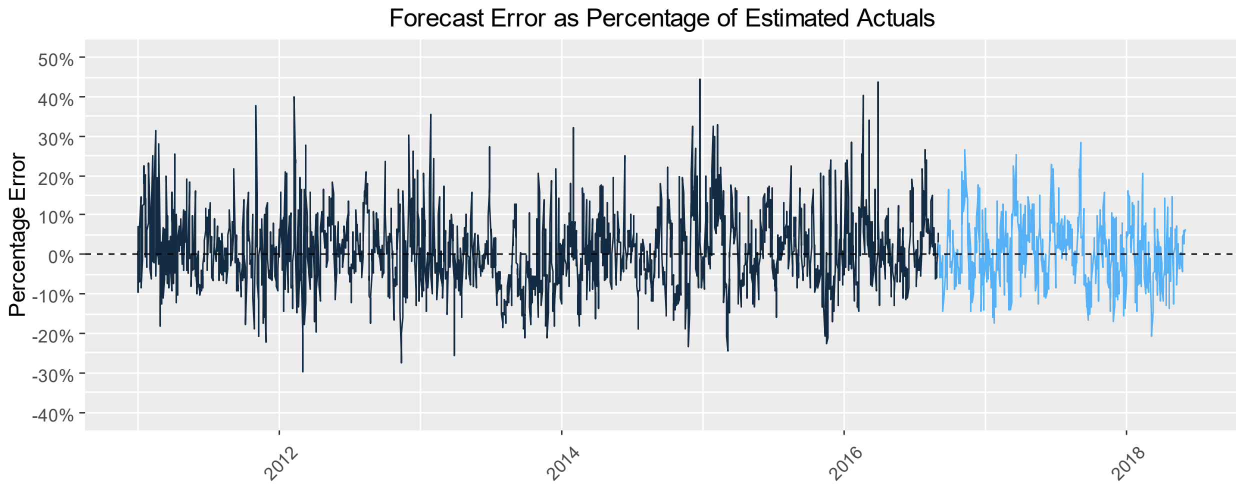

Table 1 below compares the performance of the forecasts since September 1, 2016 to that presented in the intervenor testimony of SCGC/IS, which includes data for the period when the DLFM and the estimated actual demand were not based on the same hours of the day. Examining the period since the synchronization of the DLFM with the Measurement Day provides a more accurate view of forecasting performance, to the extent that estimated actual demand can be used as a proxy for actual demand.

Table 1: DLFM Performance Since Synchronization With Measurement Day

	Time Period Selected by SCGC/IS (January 1, 2011 – April 30, 2018)[9]	**Time Period Since Synchronization to Measurement Day (September 1, 2016 – April 30, 2018)**
MAPE[10]	7.1%	6.5%
Largest Over-Forecast (%)	44.6%	28.3%
Largest Under-Forecast (%)	-29.8%	-20.7%

[9] *Id.* at 14.
[10] Mean Absolute Percentage Error (MAPE) is a standard statistic for measuring the performance of forecasts. MAPE is defined as the mean of the absolute values of the percentage errors of the forecasts. The equation for MAPE for a set of forecasts of size T is:

$$\text{MAPE} = \frac{100}{T}\sum_{t=1}^{T}\left|\frac{forecast_t - actual_t}{actual_t}\right|$$

While SCGC/IS acknowledge improvement in recent forecasts, SCGC/IS is dismissive of its significance.[11] Although it is almost certain that some of the improvement is due to the incorporation of AMI data into SDG&E' forecast, it is also likely that the bulk of the improvement is the result of the shift to forecasting demand for the Measurement Day. SCGC/IS combines calculations of percentage errors for the period before September 1, 2016, which is not appropriate for assessing forecast performance, along with calculations of percentage error after September 1, 2016, which is more appropriate for assessing forecast performance.

Notwithstanding, the second column of the table shows that the DLFM performs better, both on average and at the extremes than what is portrayed by SCGC/IS. The percentage error of the forecasts average 8% better and the largest over-forecast and under-forecast percentages are both approximately one-third less than SCGC/IS' portrayal.

B. SCE

SCE also contends that the Applicants' daily gas demand forecasts significantly deviate from daily estimated actual demand.[12] SCE argues "[i]n fact, during the five-year period between 2011 and 2015, SCG/SDG&E's core usage forecasts deviated from actual usage by at least 5% for about 85% of summer days and 78% of winter days. The deviation has exceeded 10% on nearly 60% of winter days, and by 25% or more on about 20% of the winter days."[13] As explained above, using data prior to September 1, 2016 to calculate these estimated deviations is inappropriate because during that time daily forecasts and estimated actuals were based on different hours of the day. Using data after September 1, 2016 to calculate these estimated

[11] *See* Direct Testimony of Catherine E. Yap at 15-16.
[12] Exh. SCE-01 (Intervenor Testimony of Robert Grimm) at 13.
[13] *Id.*

deviations is more appropriate to assess forecast performance because the DLFM and daily estimated actual demand were synchronized to the same hours of the day.

C. EDF

In its testimony, EDF contends "[u]nder the proposal (we encourage the Commission to direct SoCalGas to adopt as part of this case), reliability is improved because it moves the CTAs and the UGPD away from using guesswork to come into balance on a monthly basis, as is required under the current SoCalGas tariff."[14] When asked in discovery to provide any facts to support this contention, EDF could not. I reproduce Applicants' question[15] and EDF's response[16] below in their entirety:

> Question 5. Referring to page 15, line 27-29, EDF's Intervenor Testimony of Greg Lander:
>
> a. Please describe in detail what EDF means by "guesswork."
>
> <u>EDF's Response</u>:
>
> Given the SoCal Gas' evidenced historical forecast inaccuracy, unless there is an intentional mis-forecasting performed by the utility; the results are little better than guesswork.
>
> b. Please describe in detail all facts to support EDF's contention that the CTA's and SoCalGas and SDG&E's Gas Acquisition Department use "guesswork to come into balance on a monthly basis."
>
> <u>EDF's Response</u>:
>
> See response to 5 a.
>
> c. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses to support EDF's statement that the CTA's and SoCalGas and SDG&E's Gas Acquisition Department use "guesswork to come into balance on a monthly basis."

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[14] Exh. EDF-02 (Intervenor Testimony of Greg Lander) at 15.

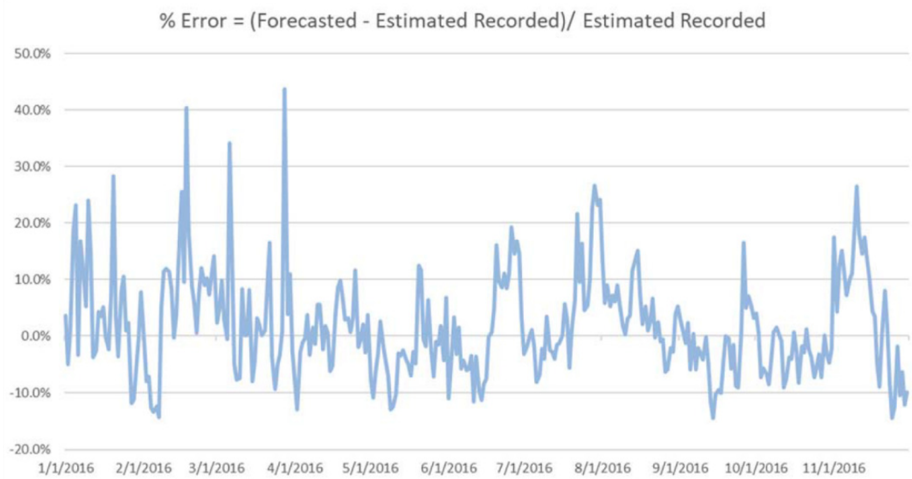
[15] *See* Appendix A: SoCalGas Data Request Set 1 to EDF, Question 5.

[16] *See* Appendix B: EDF Response to SoCalGas Data Request Set 1, Question 5.

EDF's Response: SoCalGas response to SCGC's Data Request Q2.2, showing the Forecast Error Percentage from January 1, 2016 through November 30, 2016 supports this assertion. See below for a graph of the provided data. The range of Forecast Error Percentage for this period was -14.5% to 43.77%, with the Absolute Mean Forecast Percentage Error was 6.9%. Positive figures show Long Days, where SoCalGas over-forecasted for that day. Negative figures represent Short Days, where SoCalGas under-forecasted for that day.

Max Error (Long Day) = 43.77% (March 28, 2016)

Absolute Mean Error = 6.9%



SoCalGas and SDG&E strongly disagree with EDF's characterization. EDF provided no support to show any "intentional mis-forecasting" nor does its discussion of forecast error demonstrate "that the results are little better than guesswork." However, to address EDF's contention that the DLFM is "guesswork," one can look to EDF's own words on the level of accuracy of SoCalGas and SDG&E's core forecasting methodology in recent years:

> With respect to SoCalGas, their accuracy has gotten worse in the winter of 2017/2018 as compared to the winter of 2016/2017. Based upon SoCalGas' response to EDF data requests (EDF-1.17 through EDF-1.20) my analysis determined that assuming SoCalGas' UGPD scheduled to the RDFG's forecast (based upon temperature), that the accuracy of scheduling versus actual temperature showed that the median actual 2016/2017 winter temperatures were 3/100ths of a degree warmer than forecast, while the 2017/2018 median actual temperatures were 2/10ths of a degree colder than forecast which meant that the UGPD would have under-scheduled to actual.

> In addition, during the 2017/2018 winter there were 7 periods where the consecutive days of under-forecast of demand ranged between 4 and 11 days with the average being ~6 consecutive days of under-scheduling (again assuming the UGPD scheduled to forecast). This compares to the 2016/2017 winter where there were 5 periods of consecutive under-scheduling to actual with the average being only 4 consecutive days. This metric shows the under-scheduling to have occurred approximately twice as often during the winter of 2017/2018 than in the winter of 2016/2017. This underscores my recommendation that giving the UGPD the tools and requiring the accountability is sorely needed."[17]

While I find EDF's analysis to be inaccurate, convoluted, and difficult to comprehend, I will only focus on some of the critical flaws underlying EDF's analysis. EDF provides no support for its contention that SoCalGas' forecasting accuracy "has gotten worse in the winter of 2017/2018 as compared to the winter of 2016/2017." EDF provides no analysis of the magnitude of such forecast errors, such as by using a metric[18] yet concludes that a higher number of under-schedulings in the winter of 2017/2018 was due to higher forecast errors in the winter of 2017/2018. Using the MAPE as a metric to directly compare forecast errors, the table below shows that the Applicants' daily forecasting error improved in the winter of 2017/2018 relative to the winter of 2016/2017.

Table 2: Forecasting Evaluation: Winter 2016/2017 vs. Winter 2017/2018

Criterion	Winter 2016/2017 (11/1/2016 – 3/31/2017)	Winter 2017/2018 (11/1/2017 – 3/31/2018)
MAPE	8.1%	6.8%

This improvement in the MAPE indicates that SoCalGas and SDG&E's forecasts were better during the winter of 2017/2018 when compared to the winter of 2016/2018. This data directly refutes EDF's contention. EDF's cited analysis does not underscore its "recommendation that giving the UGPD the tools and requiring the accountability is sorely needed."

[17] Exh. EDF-02 (Intervenor Testimony of Greg Lander) at 27-28.
[18] Examples of metrics include but are not limited to: Mean Absolute Percentage Error, Mean Percentage Error, Root Mean Square Error, Mean Absolute Deviation.

IV. EDF PROPOSES A FORECAST APPROACH AND MODEL THAT ARE INFERIOR TO THE DLFM

I discuss below EDF's proposed forecasting model for SoCalGas and demonstrate why such a model would be inferior to the forecasting model that SoCalGas currently uses. As a starting point, EDF provides no justification for abandoning SoCalGas' statistical forecasting model or any analyses to demonstrate its model outperforms SoCalGas' model for a comparable set of input data. Incorporating AMI data into the forecasting process does not require SoCalGas to abandon its forecasting model in favor of the EDF-proposed model.[19]

A. EDF Greatly Overstates the Number of Hourly AMI Meter Reads Available Per MTU Per Degree of Temperature

Using SoCalGas' hourly AMI data over the period of January 1, 2016 through April 30, 2018, and hourly temperature readings for the Los Angeles International Airport over the same period, EDF purports to show that substantial amounts of data for meter readings at each degree of temperature are available to forecast a mean consumption per meter per degree of temperature.[20] To address the problems with such an approach, one can look to EDF's own words:

> In this distribution, I found that just over 60% of all readings were between 57 degrees and 68 degrees. I further modeled the likely distribution of the 95 Billion estimated readings over this same period and determined that there were approximately 57.7 Billion readings across 11 degrees. With approximately 5.719 Million meters being read by the AMI system, this meant that there was an average of 840 readings by each MTU at each of these 11 degrees. The range of

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[19] SCGC/IS summarized the explanatory variables in the Applicants' short-term daily load forecasting modes: weather, month of the year, day of the week, and weekend. Direct Testimony of Catherine E. Yap at 29. SCGC/IS also noted that the Applicants long-term forecast models include additional explanatory variables, such as, appliance stock, gas rate, and the presence of energy efficiency measures. *Id.* However, SCGC/IS does not propose including these additional variables from the long-term model into the short-term model. If that was the intent, the Applicants agree with SCGC/IS on this issue. Rates remain static during a calendar month and are insignificant in explaining day-to-day variations in consumption. Penetration of aggregate appliance stock and aggregate energy efficiency measures are unlikely to change from day-to-day and are not available on a daily basis.

[20] Exh. EDF-02 (Intervenor Testimony of Greg Lander) at 9-10.

> readings was from approximately 693 readings per MTU per degree to approximately 939 readings per MTU per degree. With this many readings per MTU per degree, the mean consumption predictable per MTU per degree is known within a very small confidence interval (high degree of certainty) given the large number of readings per degree.[21]

I find the resulting potential number of readings per MTU per degree calculated by EDF to be vastly overstated. There are several factors that EDF does not account for that drastically reduce the large number of readings per degree it claims would be available. Once these factors are taken into account, the resulting number of meter reads per degree renders EDF's approach unusable.

EDF's calculates an estimated average of 840 readings by each MTU at each of the 11 degrees (from 57 degrees to 68 degrees) across all 24 hours of the day. This is important to note because consumption per meter even at the same temperature can vary greatly by the hour of the day. For instance, if the ambient temperature is 57 degrees at 4 a.m., then a residential customer is likely to be sleeping and will not turn on their gas space heater. At the same ambient temperature of 57 degrees at 8 p.m., that same customer is likely to turn on his or her gas space heater. An accurate forecasting method should take into account the fact that usage per meter for a given temperature will vary by hour of the day. This would suggest developing models for each hour of the day (or for a subset of similar hours with similar gas usage sensitivity to temperature). To develop models for each hour of the day to account for variance in consumption across hours of the day for the same temperature, EDF's estimate of an average of 840 readings per MTU for each of the 11 degrees would reduce to a much lower average of 35 readings.[22]

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[21] *Id*. at 10.
[22] 840 readings/24 hours = 35.

EDF's approach also ignores forecasts and data when temperatures fall below 57 degrees. Based on EDF's approach and using data it acquired from NOAA for the Los Angeles International Airport,[23] it is clear that the amount of available data is nowhere near the 840 readings per MTU per degree. The table below shows: (1) EDF Approach (average number of readings per meter at each degree of temperature), (2) EDF's approach taking into account hour variance, and (3) the number of hours each day for which there would be no meter reads for temperatures under 57 degrees under EDF's approach with hour variance.

TABLE 3: Temperatures 56 Degrees or Lower: Average Reads Per Meter

Col (1)	Col (2)	Col (3)	Col (4)
Hourly Temperature in Fahrenheit	EDF Approach (Average Number of Readings Per Meter Per Degree)	EDF Approach Accounting for Hour Variance[24]	Number of Hours Without Meter Reads Using EDF Approach, Accounting for Hour Variance[25]
56 degrees	610	33.2	0 out of 24 hours
55 degrees	481	23.3	0 out of 24 hours
54 degrees	416	20.1	0 out of 24 hours
53 degrees	284	15.6	0 out of 24 hours
52 degrees	243	12.5	2 out of 24 hours
51 degrees	157	8.5	6 out of 24 hours
50 degrees	144	7.5	6 out of 24 hours
49 degrees	88	4.8	12 out of 24 hours
48 degrees	69	3.7	13 out of 24 hours
47 degrees	58	3.2	14 out of 24 hours
46 degrees	23	1.3	16 out of 24 hours

[23] *See* Appendix B: EDF response to SoCalGas Data Request Set 1, Question 2.e.

[24] Example: At 50 degrees the following equation is calculated: $\frac{\text{180 reads at 50 degrees}}{\text{24 hours}} = \text{7.5 reads per hour}$

[25] Example: At 50 degrees, there is no data in EDF's dataset for the 6:00pm hour as well as the hours 11pm through 3am. This is 6 hours during the day without any historical data for this temperature.

45 degrees	22	1.1	17 out of 24 hours
44 degrees	15	0.8	17 out of 24 hours
43 degrees	17	0.8	18 out of 24 hours
42 degrees	4	0.3	21 out of 24 hours
41 degrees	2	0.1	21 out of 24 hours

Column 2 shows that, under the EDF Approach, the number of daily meter reads available drops dramatically as temperatures fall. Column 3 shows that, under the EDF Approach with an accounting for hour variance (each hour of the day), the average number of meter reads available for each hour are far lower than EDF's calculations and fall to less than one reading. Column 4 shows that, under the EDF Approach with an accounting for hour variance, there would be zero readings for calculating forecasts at temperatures of 52 degrees or colder for certain hours of the day. The above table shows that, for temperatures below 57 degrees, there is not enough data to produce reasonable forecasts using EDF's approach.

Here is another crucial point. It is of overwhelming importance that core gas use be properly forecasted when gas use peaks. As shown above, EDF's approach would be unable to produce a forecast for the coldest hours of a cold day when SoCalGas and SDG&E's system would be under the most stress. SoCalGas and SDG&E's DLFM, in contrast, can generate forecasts at all plausible temperatures.

Another factor that would result in lowering the number of reads per meter per degree would be the "month effect." SoCalGas and SDG&E have observed consistently over time that, even after controlling for temperature, core gas use increases during winter months and decreases during summer months. This "month effect" should be reflected in any forecasting model for daily core gas use. EDF's approach becomes more unrealistic once the "month effect" is included. Dividing the meter reads across months to properly account for the "month effect" reduces number of readings such that there would likely not be enough data to create a forecast of reasonable quality for any temperature.

B. EDF's Proposed Model Is Inferior to SoCalGas and SDG&E's Statistical Model

EDF's proposed forecasting model requires developing climate zone-specific queries by Gas Acquisition and CTAs using "historic use by hour by rate class of their meters when specific temperatures occurred. From this data the demand forecaster can then determine the mean consumption per meter across all their meters by temperature …. In addition, they can determine from the available data the differences, again by rate class that day of the week makes in such demand at temperature. Then the demand forecaster can obtain tomorrow's hourly temperatures that either they or a commercial service forecasts for the following day and apply those forecasted hourly temperatures to the derived mean consumption per hour for their meters at those historic temperatures to arrive at forecasted daily consumption."[26] EDF contends that "[w]ith the number of reads available throughout the mid-range of historically observed temperatures, Core demand can be estimated with a 99% degree of confidence for a given set of forecasted temperatures."[27]

EDF's proposed model suffers from several deficiencies that make it inferior to the DLFM. One deficiency acknowledged by EDF is fewer AMI meter reads at extreme temperatures. I include EDF's discussion describing its proposed model's ability to forecast core demand at very low temperatures:

> Q. How do very low temperatures and the relatively fewer readings at those temperatures affect the ability to forecast Core demand and its relationship to scheduling from interstate pipelines?

[26] Exh. EDF-02 (Intervenor Testimony of Greg Lander) at 11.
[27] *Id.*

> A. There will be a range of temperatures, probably around 50-52 degrees and lower, when the UGPD and the CTAs will (or should) schedule full interstate capacity because at those temperatures the Core demand will closely approximate or exceed contracted interstate capacity into California; so they will likely schedule the maximum of capacity from interstate pipelines to meet forecasted demand and rely on storage to provide the balance of the supply needed to meet Core demand.[28]

EDF asks a very important question regarding the ability of its model to address colder weather when the system is likely to be under more stress and when it is especially important to have reasonable forecasts for core demand. EDF does not answer its own very important question. As I discussed in detail above, however, it is clear that for low temperatures there would be few to zero readings of the average use per meter per hour per temperature. This directly impacts the ability of EDF's model to develop a forecast core demand at all, without even getting to the issue whether the forecast is more accurate than the DLFM.

As discussed earlier, EDF's proposed model does not account for monthly seasonality effects. I provide a specific example of this inherent weakness in EDF's proposed model which causes it to fail to consider different usage patterns for core customers for the same temperature. The table below shows that the daily aggregate consumption can vary considerably from one month to another for the same temperature.

[28] Exh. EDF-02 (Intervenor Testimony of Greg Lander) at 11-12.

Table 4: Monthly Seasonality Effects

	October 30, 2017 (Monday)	December 11, 2017 (Monday)
System Average Temperature	66 degrees F	66 degrees F
Estimated Actual Usage	825 MDth	1163 MDth
Percent Difference	41% increase in usage comparing December 11, 2017 to October 30, 2017	
	November 2, 2017 (Thursday)	**December 8, 2017 (Friday)**
System Average Temperature	64 degrees F	64 degrees F
Estimated Actual Usage	875 MDth	1212 MDth
Percent Difference	38% increase in usage comparing December 8,2017 to November 2, 2017	

As explained above and shown in the table, gas use increases heading into the winter season, even after accounting for temperature and the difference in gas use between weekdays and weekends. SoCalGas and SDG&E's forecasting model captures this "month effect." EDF's proposed model does not. Ignoring this seasonality would almost certainly lead EDF's proposed model to systematically under-forecast core demand during winter months and systematically over-forecast demand during the spring, summer, and fall months. Furthermore, it is extremely unlikely that EDF's proposed model would be able capture "holiday effects" on core demand, such as for Thanksgiving Day and Christmas, because there exists little data for these infrequently occurring days.

C. EDF Is Inconsistent In Its Proposed Forecasting Models For SoCalGas and SDG&E

EDF proposes a new model for forecasting SoCalGas core demand as I address in detail above. EDF proposes to retain the current model for forecasting SDG&E's core demand.[29] SoCalGas and SDG&E's daily retail core demand forecasting models (DLFM) contain the exact same model specifications. The only difference between the models is that SDG&E uses AMI data for historical aggregate daily consumption data while the SoCalGas model uses estimated actual demand. It is puzzling to me that EDF advocates for SoCalGas to completely reconstruct its forecasting model but at the same time advocates for SDG&E to retain the same model it has been using. It seems that the logical conclusion would be that if EDF considers SDG&E's model to be sufficient because it uses AMI data, then it would follow that EDF should consider SoCalGas' model to be sufficient once it begins using AMI data.

V. INTERVENORS PROPOSE IMMEDIATE INCLUSION OF AMI DATA IN SOCALGAS' FORECASTING PROCESS

I stated previously in my direct testimony that SoCalGas will be able to develop an AMI data-based DLFM model in late 2019 or early 2020.[30] This was based on my reasoning that AMI installation will be complete for all customers by the end of 2018 and therefore enable the development of aggregated actual daily retail core load data for all retail core customers. This estimate reflected my opinion that a minimum of one year of historical AMI-enabled aggregate consumption data for retail core customers was required to estimate SoCalGas' DLFM parameters.[31] I also stated that SDG&E's DLFM parameters had been developed using three years of historical aggregate daily actual consumption data once AMI installation had been

[29] Exh. EDF-02 (Intervenor Testimony of Greg Lander) at 29.
[30] Direct Testimony of Sharim Chaudhury at 9.
[31] *Id.*

completed for all customers,[32] providing three times the historical data than the proposed one year for SoCalGas' DLFM model.[33]

Both SCGC/IS and EDF propose that the SoCalGas' AMI data be included in developing daily demand forecasts model as soon as possible because the AMI system is essentially completed.[34] While EDF does not propose any specific date to incorporate SoCalGas' AMI data into daily forecasting model, SCGC/IS specifically states, "[n]o later than January 1, 2019, Demand Forecasting will have one year's worth of SoCalGas AMI data, which should be incorporated into Demand Forecasting models."[35]

SoCalGas's AMI installation is nearly completed now. As of April 30, 2018, the AMI system was successfully implemented[36] for 99.24% of SoCalGas' total eligible core customers.[37] As of the April 2018 billing month, these AMI-enabled meters captured 98.57% of core load.[38] The lower AMI-enabled usage penetration percentage relative to the AMI-enabled meter penetration percentage indicates that some of the remaining non-AMI-enabled core customers have relatively higher usage.

The speedier deployment of AMI devices than originally anticipated in my direct testimony makes it likely that SoCalGas will be able to incorporate AMI data in SoCalGas's DLFM in early 2019. However, Applicants note that the estimate of SoCalGas' DLFM parameters will be based on a far shorter span of historical daily AMI data compared to SDG&E's DLFM. Additionally, SoCalGas would need to escalate the aggregate historical daily

[32] Excluding core customers who opted out of the AMI program.
[33] Direct Testimony of Sharim Chaudhury at 3.
[34] Direct Testimony of Catherine E. Yap at 10, 13; Exh. EDF-02 (Intervenor Testimony of Greg Lander) at 3, 18 and 26.
[35] Testimony of Catherine E. Yap at 14.
[36] Meaning accurate daily consumption data for these customers were successfully transmitted through the AMI system.
[37] SoCalGas' response to EDF data request EDF-01, Question 6.
[38] SoCalGas' response to EDF data request EDF-01, Questions 7 & 8.

consumption of the AMI-enabled retail core customers to include an estimate of historical daily aggregate consumption data for all of SoCalGas' retail core customers. One method to escalate would be based on the ratio of billing month usage of all core customers to billing month usage for all AMI-enabled core customers. An alternative method to escalate would be based on the ratio of the total number of meters for all core customers, both AMI-enabled and non-AMI-enabled, to the total number of AMI-enabled core meters at the end of December 31, 2017.

VI. EDF'S PROPOSED MONITORING ROLE FOR APPLICANTS' DEMAND FORECASTING GROUP LACKS JUSTIFICATION

EDF proposes that the demand forecasting responsibilities for core customers be transferred to the Gas Acquisition Department and larger core transportation aggregators (CTAs).[39] EDF states that the Applicants' Demand Forecasting Group be "assigned monitoring responsibilities to ensure both the UGPD and the CTA's schedule to AMI-enabled forecasts; as well as adjust schedules to differences between forecast and actual (i.e., "balance to burn");…"[40] EDF also proposes to have Demand Forecasting monitor the accuracy of daily forecasts developed by Gas Acquisition and the CTAs.[41] EDF does not justify the need for a separate group to either monitor the forecasting accuracies of Gas Acquisition and the CTAs or monitor their scheduling activities should these balancing agents would be required to balance against actuals. If the forecasting responsibilities were to transfer to Gas Acquisition and the CTAs, the Applicants' daily and monthly balancing rules provide adequate incentives to Gas Acquisition and the CTAs to monitor the performance of their own forecasts to ensure compliance with

[39] EDF defines larger CTAs as those CTAs whose customers' load represent 5% or more of SoCalGas's annual core load.
[40] Exh. EDF-02 (Intervenor Testimony of Greg Lander) at 4.
[41] *Id.* at 6.

balancing requirements. There would be no need or purpose for Demand Forecasting to monitor forecasting accuracy or scheduling.

EDF also provides a template whereby Gas Acquisition and the CTAs are to provide, on a weekly basis, daily imbalances for the week. According to EDF, "[U]sing this reporting template, the RDFG can not only monitor how accurate the activities of the 5%+LSOs[42] are, but I would expect that SoCalGas would propose remedial measures be taken by individual 5%+LSOs to the extent there is chronic over or under scheduling or just inaccurate scheduling."[43] The Applicants are at a loss to understand the distinction between "chronic over or under scheduling" and "just inaccurate scheduling." As previously stated, SoCalGas' System Operator is already responsible for monitoring compliance with balancing requirements for all customers, including Gas Acquisition, CTAs, and noncore customers. EDF does not provide any evidence to support its proposal to add another layer of imbalance monitoring of only Gas Acquisition and the CTAs by SoCalGas' Demand Forecasting Group.

EDF also proposes "the possible imposition of penalties on the UGPD as well as on CTA(s) that are chronically inaccurate in their respective scheduling versus forecast and versus burn results."[44] EDF proposes that Gas Acquisition and the large CTAs should balance against actual daily core usage just like noncore customers. EDF's approach is selective, however, because the monitoring role for Demand Forecasting would only apply to and impose penalties on Gas Acquisition and large CTAs, and not the noncore customers. EDF provides no justification for this selective treatment. The Commission should also reject this proposal.

This concludes my rebuttal testimony.

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[42] LSO is load serving organizations, 5%+ LSO include UGPD and large CTAs.
[43] *Id.* at 20.
[44] *Id.*

Appendix A: SoCalGas Data Request Set 1 to EDF

DATA REQUEST
SoCalGas Data Request Set 1
Application of SoCalGas and SDG&E Regarding Feasibility of Incorporating AMI Data Into The Core Balancing Process
A.17-10-002

DATE: July 20, 2018

TO: Timothy O'Connor
Environmental Defense Fund

FROM: Joseph Mock
Southern California Gas Company

REQUEST NO.: **SoCalGas Data Request Set 1** **Due Date: August 3, 2018**

Please provide the following information (by August 1, 2018), or as it becomes available but no later than the customary 10 business day due date. If you are unable to provide the information by this date, please provide a written or verbal explanation why the response date cannot be met and your best estimate of when the information can be provided. Please electronically mail all responses that can be so transmitted. If your response includes attachments cannot be electronically transmitted, please notify Joseph Mock (JMock@semprautilities.com) and Edward L. Hsu (EHsu2@semprautilities.com) via e-mail or phone and arrangements will be made for the transmittal of said attachments.

1) Referring to page 11, lines 13, of EDF's Intervenor Testimony of Greg Lander:

   a. Does EDF contend that its proposed "mean consumption per meter" can be used to create forecasts for the daily gas demand for all SoCalGas' "retail core" customers as that term is defined on page 1, lines 18-20, of the Prepared Direct Testimony of Sharim Chaudhury, specifically, "the sum of the gas demands of residential, small commercial and industrial, and natural gas vehicle customers, excluding those who choose Core Aggregation Transportation ("CAT") service"?

   b. If the answer to subpart (a) is in the affirmative,

      i. Please explain how in detail.

      ii. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses to support this contention.

2) Referring to page 10 of EDF's Intervenor Testimony of Greg Lander:

   a. Please provide the time and date period that is covered by the NOAA hourly temperature readings that EDF acquired.

   b. Please provide the following information for the NOAA hourly temperature readings that EDF acquired:

      i. The temperature data in working Excel format
      ii. A detailed description of the data

iii. References to the location from which the data was acquired

c. Please state whether the NOAA hourly temperature readings that EDF acquired for the Los Angeles International Airport are also available for the remaining weather stations used in the 2016 California Gas Report[1] (i.e., Big Bear Lake, Palm Springs, El Centro, LAX, Newport Beach, Santa Barbara Airport, Bakersfield, Lancaster Airport, Fresno, Burbank, Pasadena, Ontario, Rialto, Los Angeles Civic Center, and Santa Ana)? If the answer is in the affirmative, please provide the data in the same manner as requested in subpart (b).

d. Please state whether the same temperature data is available for any other weather stations in SoCalGas' service territory. If the answer is in the affirmative, please provide the data in the same manner as requested in subpart (b).

e. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses used by EDF to develop the plotted distribution of temperatures located on the table entitled "Count of Occurrences of Temperature" on page 10 of EDF's Intervenor Testimony of Greg Lander.

f. Please explain in detail how EDF developed the "estimated readings" referred to on line 8.

g. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses used by EDF to create these "estimated readings."

h. Please explain in detail how EDF "modeled the likely distribution" of "estimated readings" referred to on line 8.

i. Please describe any distribution and method EDF used to model the "likely distribution" of "estimated readings."

j. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses used by EDF to model the "likely distribution" of "estimated readings."

3) Referring to page 10, lines 13-19, of EDF's Intervenor Testimony of Greg Lander:

a. Please explain in detail the basis for EDF's statement that the "mean consumption predictable per MTU per degree" is "known."

b. Please explain in detail the method EDF used to calculate the "mean consumption predictable per MTU per degree."

c. Please state whether EDF used a regression-based approach to calculate the "mean consumption predictable per MTU per degree." If the answer is in the affirmative, please provide the following:

i. The regression technique used
ii. The model specification/equations used
iii. The regression coefficient estimates
iv. Basic regression outputs (standard errors for the coefficient estimates, t-statistics and p-values for the independent variables, R^2, Adjusted R^2, etc.)
v. Plots of the residuals vs the values of the dependent variable and each independent variable

[1] https://www.socalgas.com/regulatory/documents/cgr/SoCalGas_Workpapers_REDACTED_2016_CGR.pdf

d. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses used by EDF to calculate the "mean consumption predictable per MTU per degree."

e. Please define in detail what EDF believes is a "very small confidence interval."

f. Please explain in detail the method EDF used to calculate confidence intervals for the "mean consumption predictable per MTU per degree."

g. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses used by EDF to calculate confidence intervals for the "mean consumption predictable per MTU per degree."

h. Please provide all facts and documents to support EDF's contention that the consumption of non-AMI meters can be estimated "with accuracy" as it states on line 18.

i. Please provide all analyses in working Excel files or other working electronic format to support EDF's contention that the consumption of non-AMI meters can be estimated "with accuracy" as it states on line 18.

4) Referring to page 11, lines 1-28, of EDF's Intervenor Testimony of Greg Lander:

a. Please provide all facts and documents that support EDF's statement that it is "very feasible" to "make accurate Core demand forecasts using the data that the AMI system has within it."

b. Please describe in detail any method and/or model EDF relies on to support its statement that it is "very feasible" to "make accurate Core demand forecasts using the data that the AMI system has within it."

c. Please describe in detail the method and/or model EDF used or believes should be used to make "Core demand forecasts using the data that the AMI system has within it."

d. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses used by EDF to evaluate the feasibility of making "Core demand forecasts using the data that the AMI system has within it."

e. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses used by EDF to evaluate the accuracy of "Core demand forecasts using the data that the AMI system has within it."

f. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses used by EDF to evaluate the usefulness of "SoCal's three Climate Zones" and "rate class" of meters to forecast "Core demand."

g. Referring to lines 16-20, EDF states the following: "Then the demand forecaster can obtain tomorrow's hourly temperatures… and apply those forecasted hourly temperatures to the derived mean consumption per hour for their meters at those historic temperatures to arrive at forecasted daily consumption."

   i. Please define in detail what EDF means by "consumption" for both occurrences of the word used in this statement.

ii. Please explain in detail how the “mean consumption per hour for their meters” can be used to arrive at “forecasted daily consumption” as proposed by EDF.

iii. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses used by EDF to show how the “mean consumption per hour for their meters” can be used to arrive at “forecasted daily consumption.”

h. Please state whether EDF is referring to confidence intervals or prediction intervals when it states “a 99% degree of confidence” on line 27.

i. Please explain in detail the methods EDF believes should be used to estimate the degree of confidence for core demand for a given set of forecasted temperatures.

j. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses to support EDF’s contention on lines 27-28 that “[c]ore demand can be estimated with a 99% degree of confidence for a given set of forecasted temperatures.”

5) Referring to page 15, line 27-29, EDF’s Intervenor Testimony of Greg Lander:

a. Please describe in detail what EDF means by “guesswork.”

b. Please describe in detail all facts to support EDF’s contention that the CTA’s and SoCalGas and SDG&E’s Gas Acquisition Department use “guesswork to come into balance on a monthly basis.”

c. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses to support EDF’s statement that the CTA’s and SoCalGas and SDG&E’s Gas Acquisition Department use “guesswork to come into balance on a monthly basis.”

6) Referring to page 18, lines 4-5, of EDF’s Intervenor Testimony of Greg Lander, EDF states: “Done appropriately, a Balancing Agent can get to a 99% accuracy.”

a. Please describe in detail what EDF means by “99% accuracy.”

b. Please explain in detail the difference between this statement and EDF’s statement on page 11, lines 27-28, that “Core demand can be estimated with a 99% degree of confidence?”

c. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses to support EDF’s statement that “Done appropriately, a Balancing Agent can get to a 99% accuracy.”

7) Referring to page 18, lines 15-24, of EDF’s Intervenor Testimony of Greg Lander:

a. Please provide all facts and documents to support EDF’s contention that there is a “need expressed by SoCalGas to wait until every meter is AMI enable.”

b. Please provide all facts and documents to support EDF’s contention that SoCalGas and SDG&E have stated that they require 100% coverage for AMI as stated on line 22-23?

8) Referring to page 22, lines 16-17, of EDF's Intervenor Testimony of Greg Lander, EDF proposes that on command MTU transmissions only be implemented for a "statistically meaningful random set of MTUs."

   a. Please describe in detail how EDF defines a "statistically meaningful random set of MTUs."

   b. Please describe in detail EDF's proposed method for determining a "statistically meaningful random set of MTUs."

   c. Please provide, in working Excel files or other working electronic format, all data, computer code, and analyses used by EDF to develop and evaluate EDF's proposed method for determining a "statistically meaningful random set of MTU's."

   d. Please describe in detail how EDF proposes to implement its sampling methodology using SoCalGas' AMI system and/or other IT resources.

Appendix B: EDF Response to SoCalGas Data Request Set 1

EDF RESPONSE TO SOCALGAS DATA REQUEST
Data Request Set # 1

Application of SoCalGas and SDG&E Regarding Feasibility of Incorporating AMI Data Into The Core Balancing Process - A.17-10-002

DATE RECEIVED: July 20, 2018
DATE RESPONDED: August 3, 2018

Response to 1 a.

No. EDF does not propose that forecasts only be done for the "retail core" as defined by applicant.

Response to 1 b. ii

EDF objects because this request calls for original work to be performed. Moreover, because Applicant refused to provide hourly temperature forecast and actual hourly temperature data, which if received, would have been followed up with a data request by EDF for hourly send-out by rate class, we did not undertake this exercise. As a consequence, there are no “working Excel files or other working electronic format” to provide.

Response to 2 a.

January 1, 2016 through April 30, 2018

Response to 2 b. i

See Excel file Attachment Response SCG-EDF 2 b. i.xlsx

Response to 2 b. ii

EDF asserts the data provided by EDF in the testimony of Greg Lander speaks for itself. See response to 2 b. iii

Response to 2 b. iii

Skipping Stone accessed the NOAA data at the following link: https://www.ncei.noaa.gov/data/global-hourly/access/
The NOAA Location ID for LAX was 72295023174. The data were found at the link through the subdirectories of “2016”, “2017”, and “2018”, under .csv files with the title of the LAX location ID.

Response to 2 c.

Applicant can go to website referenced in response to 2 b. iii and determine for itself.

Response to 2 d.

See response to 2 c.

Response to 2 e.

See Access database file Attachment - Response SCG-EDF 2 2. .accdb

Response to 2 f.

EDF objects to the nature of this question as it is vague and misleading. EDF provided, in its testimony, a description of the "estimated readings" and how they were developed. Additional work to provide this description "in detail" will require further elaboration by SCG and requires additional time by EDF.

Response to 2 g.

See Excel file Attachment Response SCG-EDF 2 g .xlsx

Response 2 h.

EDF asserts that the model will speak for itself; see response to 2 g.

Response to 2 i.

EDF asserts that the model will speak for itself; see response to 2 g.

Response to 2 j.

EDF asserts that the model will speak for itself; see response to 2 g.

Response to 3 a.

EDF objects to the question as unfair and incorrect characterization of EDF statements. EDF requests clarification of the question.

Response to 3 b.

Skipping Stone did not "calculate mean consumption predictable by degree." Although EDF submitted to SCG a properly construed information request, applicant refused to provide temperature data by hour. As a result of SCG's denial to provide information requested by EDF, EDF did not submit what would have been a follow-up data request to provide aggregated consumption by hour in/for the geographic areas at/to which a responsive provision of the requested temperature by hour data would have been supplied.

Response to 3 c. i., ii., iii., iv., and v.

See response to 3 b.

Response to 3 d.

See response to 3 b.

Response to 3 e.

See response to 3 b.

Response to 3 f.

EDF did not calculate confidence intervals as no data was provided by SOCAL for analysis. Typically, the confidence interval for an estimated mean is determined by the following formula: $\bar{y} = z_{\alpha/2} \cdot s/\sqrt{n}$ with traditional symbol meanings. See response to 3 b.

Response to 3 g.

See response to 3 b.

Response to 3 h.

EDF objects to the question as unfair and incorrect characterization of EDF position. EDF contends that the non-AMI meters in aggregate can be estimated with sufficient accuracy to allow the total system daily gas to be estimated with known accuracy. In addition EDF would note that numerous books, papers, and thousands of pages have been written on the construction of statistical-based forecast models and the methods of characterizing such model's accuracy such that presentation here is impractical.

Response to 3 i.

EDF objects to the question in so far as applicant provided no data, albeit such information was requested by EDF, for the AMI meters. As a result, EDF did not request data for the non-AMI meters. EDF asks for further elaboration by SoCalGas

Response to 4 a.

The principals of statistical-based forecast modeling is widely used and accepted in industry to the point that this question is analogous to asking EDF to provide all the facts and documents that support the statement that "the sun rises in the East". It's simply the application of basic statistical forecasting theory.

Response to 4 b.

See Answer to 4.a.

Response to 4 c.

Skipping Stone and its consultants as well as its network of independent contractors get paid to provide such specifications.

Response to 4 d.

See response to 3 b.

Response 4 e.

See response to 3 b.

Response to 4 f.

On behalf of EDF, Skipping Stone performed analysis that did not use computer models. It is applicant's tariff that sets forth three climate zones. However, rate class would provide an indication of the size of the customer and, with the size of the customer and the usage of other customers in the same rate class, a modeler can undertake modeling to estimate the unknown based upon the known.

Response to 4 g. i.

"Consumption" means gas passing through the meter.

Response to 4 g. ii.

Assuming the modeler has the historic temperature of the historic clock hour and the historic consumption of that historic clock hour; from there at the same forecasted future temperature by clock hour the modeler can infer the same consumption per clock hour, also taking into account day of the week that the clock hour occurred, both historically, and for the to be forecasted period. Here, "clock hour" refers to hours 1 through 24.

Response to 4 g. iii.

See response to 3 b.

Response to 4 h.

With respect to Line 27 on Page 11, core demand could easily be estimated with a 99% confidence interval. That interval would encompass the true or actual core demand experienced by the SOCAL system 99 percent of the time. Given the huge numbers of observations available, the interval should be a tiny fraction of the actual core demand. Unfortunately, as SOCAL did not provide sample hourly data, EDF was not in a position to make any formal calculations of the expected confidence interval magnitude.

Response to 4 i.

EDF objects to this question as vague and ambiguous and requests SCG provide clarification. Notwithstanding this objection, EDF states that the design and construction of a statistical forecast model is based upon the characteristics of the data stream applied or used within the model. As SoCalGas did not provide sample hourly data, EDF was not in a position to make any formal judgments concerning the magnitude of degree of confidence for core demand.

Response to 4 j.

There are no "working Excel files or other working electronic format, all data, computer code" with respect to this question. EDF asserts that the response to question 3 b. answers the question.

Response to 5 a.

Given the SoCal Gas' evidenced historical forecast inaccuracy, unless there is an intentional mis-forecasting performed by the utility; the results are little better than guesswork.

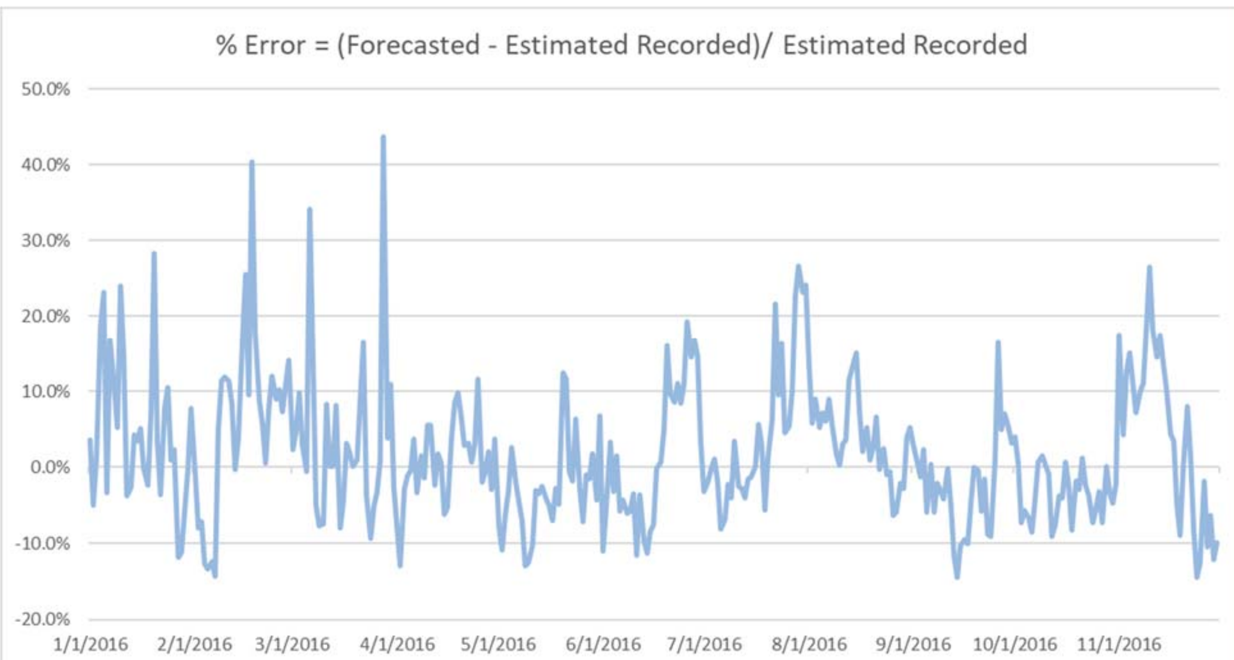
Response to 5 b.

See response to 5 a.

Response to 5 c.

SoCalGas response to SCGC's Data Request Q2.2, showing the Forecast Error Percentage from January 1, 2016 through November 30, 2016 supports this assertion. See below for a graph of the provided data. The range of Forecast Error Percentage for this period was -14.5% to 43.77%, with the Absolute Mean Forecast Percentage Error was 6.9%. Positive figures show Long Days, where SoCalGas over-forecasted for that day. Negative figures represent Short Days, where SoCalGas under-forecasted for that day.

Max Error (Long Day) = 43.77% (March 28, 2016)
Absolute Mean Error = 6.9%



Response 6 c.

See response to 3 b.

Response to 7 a. and 7b.

EDF asserts that the SoCalGas testimony in this proceeding provides the facts and documents that support EDF's contention that there is a "need expressed by SoCalGas to wait until every meter is AMI enable." Specifically:

Referring to the Application in A.17-10-002 at Page 5:
"SoCalGas and SDG&E propose to incorporate SoCalGas' Advanced Meter data into the core forecasting process when SoCalGas' AMI installation is complete and sufficient historical AMI data is available for SoCalGas' retail core customers with which to develop a statistical model."

Referring to the Application in A.17-10-002 at Page 6:
"Mr. Chaudhury proposes that SoCalGas' AMI data be used in the forecasting process when SoCalGas' AMI installation is complete and sufficient historical AMI data is available for SoCalGas' retail core customers with which to develop a statistical model."

Referring to the Application in A.17-10-002 at Page 8:
"SoCalGas' and SDG&E's proposal to incorporate SoCalGas' Advanced Meter data into the core forecasting process when SoCalGas' AMI installation is complete and sufficient historical AMI data is available for SoCalGas' retail core customers with which to develop a statistical model;"

Referring to the Application in A.17-10-002 at Page 13:
"SoCalGas' and SDG&E's proposal to incorporate SoCalGas' Advanced Meter data into the core forecasting process when SoCalGas' AMI installation is complete and sufficient AMI data is available for SoCalGas' retail core customers with which to develop a statistical model;"

Referring to Sharim Chaudhury's Direct Testimony in A.17-10-002 at Page 1 lines 9 through 11:
"that SoCalGas' AMI data be used in the forecasting process when SoCalGas' AMI installation is complete and sufficient historical AMI data is available for SoCalGas' retail core customers with which to develop a statistical model."

Referring to Sharim Chaudhury's Direct Testimony in A.17-10-002 at Page 3 lines 9 through 13:
"SDG&E has completed its AMI system installation for its retail core customers and sufficient historical AMI-based consumption data is available for SDG&E's retail core customers. Therefore, for SDG&E, actual aggregated daily retail core demand data can be derived for recent years from the customer-specific data that have been collected through SDG&E's AMI system."

Referring to Sharim Chaudhury's Direct Testimony in A.17-10-002 at Page 9 lines 7 through 11:
"Without the AMI installations completed in all areas, it is not possible to accurately measure SoCalGas' total actual daily retail core gas usage. SoCalGas plans to continue to use estimates of aggregated retail core gas demand in the forecasting process for SoCalGas because it currently does not have complete actual retail core gas usage data."

Referring to Sharim Chaudhury's Direct Testimony in A.17-10-002 at Page 10 lines 14 through 18: "SoCalGas' AMI installation is not complete and therefore SoCalGas does not currently possess a sufficient history of complete AMI data. SoCalGas proposes that its AMI data be used in the forecasting process once SoCalGas' AMI installation is complete and sufficient historical AMI data is available for SoCalGas' retail core customers to develop a statistical model."

Response to 7 b.

EDF asserts that the SoCalGas application and testimony in this proceeding provides the facts and documents that support EDF's contention that SoCalGas and SDG&E have stated that they require 100% coverage for AMI. Specifically, see passages referred to in 7a.

Response to 8 a.

A statistically meaningful random set of MTUs is one of sufficient numbers such that would facilitate a forecast or prediction of sufficient accuracy for the proposed use. As SOCAL did not provide sample hourly data, EDF was not in a position to make any formal judgments concerning the magnitude of sample sizes at this time. See also response to 4 c.

Response to 8 b.

See response to 4 c.

Response to 8 c.

See response to 3 b.