Hydraulic Modeling Input Data Development: Peak Day Design and Hourly Gas Demand Profiles

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11/13/2019

Workshop Outline (Part I)

- Introduction
- Near Term Peak Day Design
  - Introduction
  - California Gas Report 2018
  - SoCalGas Core Customers
  - SDG&E Core Customers
  - Wholesale and Noncore Customers
  - Conclusions
  - Discussion

Workshop Outline (Part II)

- Long Term Peak Day Design
  - California Gas Report 2018
  - Historical Trends and Comparison
  - California Gas Report Methodology
  - CPUC Verifications
  - Conclusions
- Hourly Core Gas Demand Profiles
  - Methodology and Sample
  - Conclusions
  - Next Steps
- Discussion

Introduction

Introduction: Workshop 2

- Workshop 1 (6/20/2019), which was the first workshop after publishing the final scenarios framework, presented CPUC input on the upstream end of SoCalGas pipeline network, i.e. the receipt points and the utilization at these receipt points during peak days.
- Today's workshop (11/13/2019) focuses on the downstream end of the pipeline network, namely the gas demand and hourly demand profiles.
- Both boundaries (upstream and downstream) are essential inputs (boundary conditions) to model the natural gas flow inside pipelines (using Synergi or any other software package) and hence the need for underground storage.

Introduction: Purpose of Workshop 2

- Peak Day Design:
  - To verify the forecasts of SoCalGas and SDG&E for near term and long term average, peak, and extreme peak natural gas demand of Core, Noncore NonEG, and Wholesale customers. These estimates were based on the 1-in-10 and 1-in-35 reliability standards as well as assumptions about energy savings programs.
- Core Customers Hourly Gas Demand Profiles:
  - To create hourly gas demand profiles for SoCalGas customers and identify the hourly peak(s) across the different ZIP codes (load factors), which is a key factor in system operation.

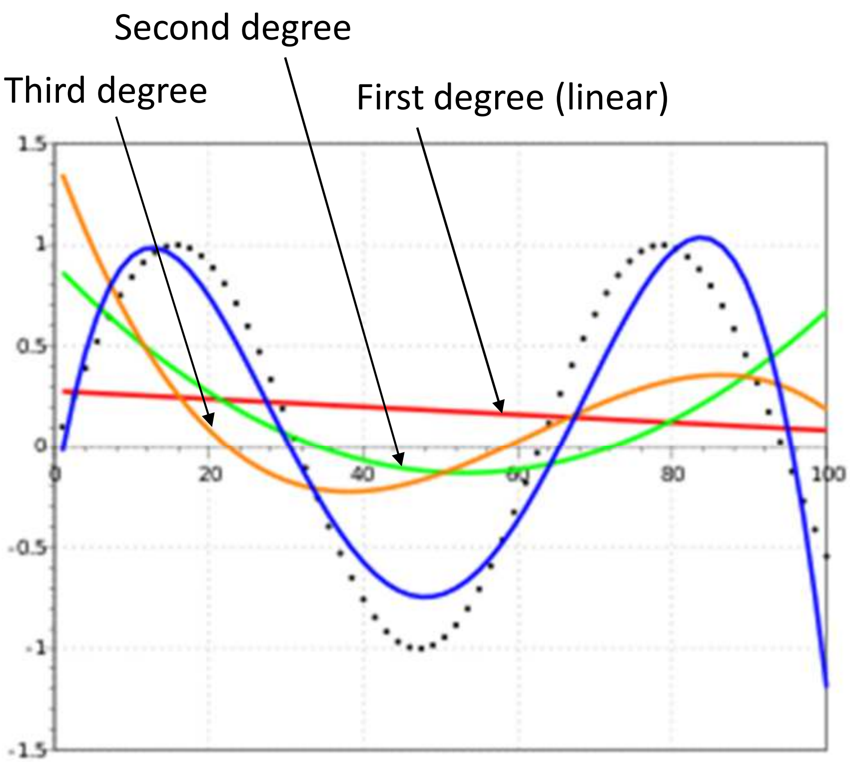
Introduction: General Approach

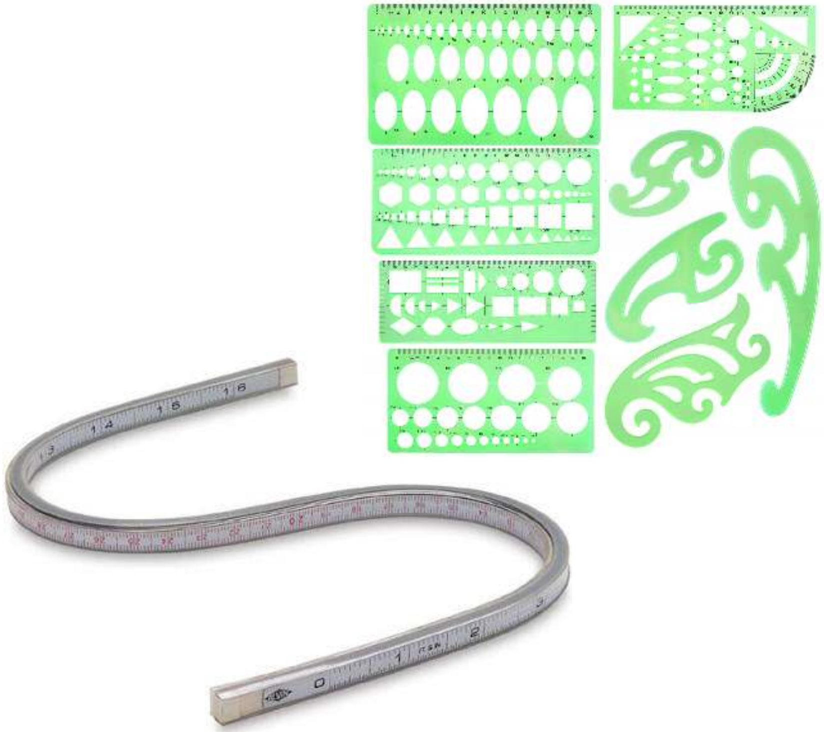
- CPUC staff needed to obtain gas demand data.
- CPUC staff issued a series of data requests to SoCalGas.
- These data requests are primarily:
  - Data Request #3 (Synergi input data).
  - Data Request #5 (Advanced Meter Infrastructure (AMI) data).
  - Data Request #6 (Gas demand and customer counts).
  - California Gas Report 2018 Workpapers.

Introduction: General Approach

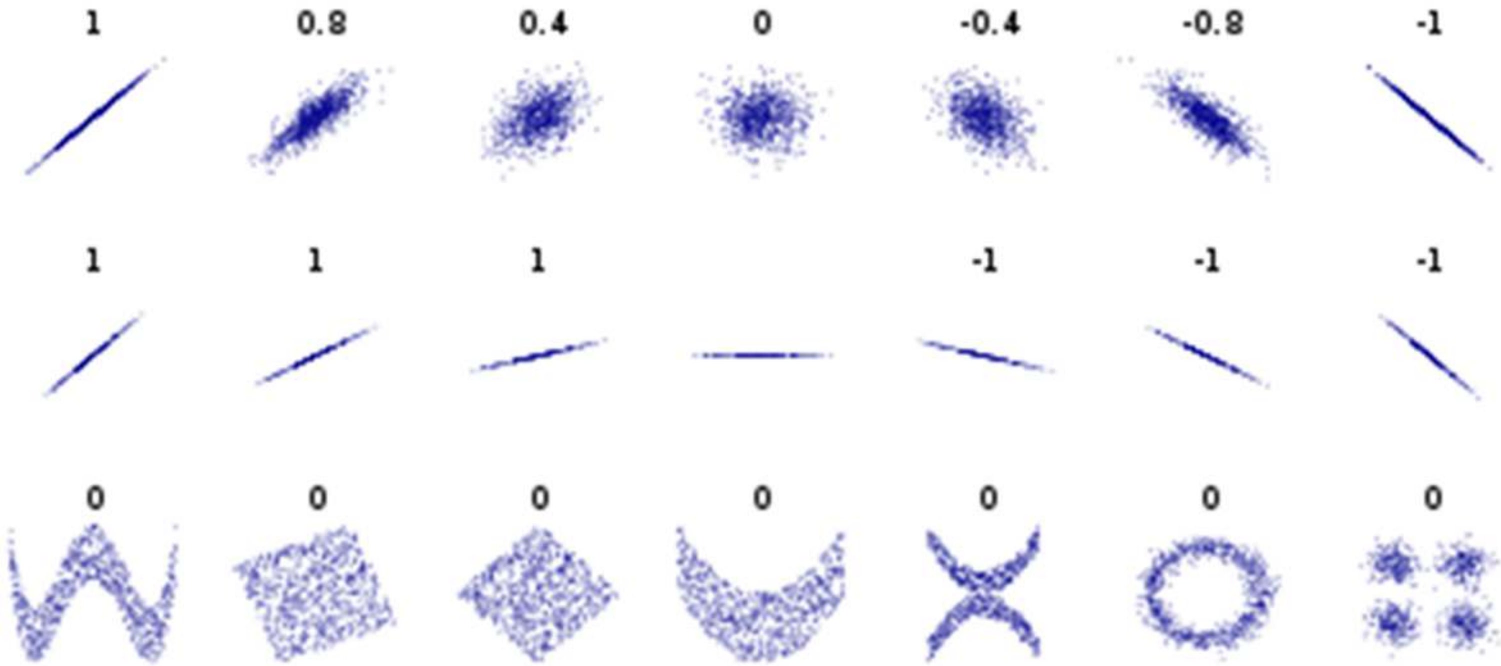
- CPUC staff used multiple tools to verify and produce various results, as for example:
  - Regression analysis to verify short term gas demand of Core SoCalGas and SDG&E Core customers.
  - Historical data of hourly meters readings to verify short term gas demand of Noncore NonEG and Wholesale customers.
  - Sensitivity analysis and regression to validate assumptions regarding the long term forecasts.
  - Statistics and R programming to create hourly gas demand profiles.

Introduction: Regression 101
Curve Fitting





Introduction: Regression 101
Correlation Coefficient (r)



Numbers indicate the value of the correlation coefficient (r).

Figure from: https://en.wikipedia.org/wiki/Pearson_correlation_coefficient

Several sets of (x, y) points, with the correlation coefficient of x and y for each set. Note that the correlation reflects the non-linearity and direction of a linear relationship (top row), but not the slope of that relationship (middle), nor many aspects of nonlinear relationships (bottom). N.B.: the figure in the center has a slope of 0 but in that case the correlation coefficient is undefined because the variance of Y is zero.

Introduction: Regression 101
Coefficient of Determination (R^2)

- Coefficient of Determination (R^2) is that it is a statistic to give some information about the goodness of fit, i.e. how well the regression predictions approximate the real data points.
- An R^2 of 1 indicates that the regression predictions perfectly fit the data.
- R^2 represents the proportion of the variance in the dependent variable (e.g. gas demand) that is predictable from the independent variable(s) (e.g. temperature, day of the week).
- A value such as $R^2 = 0.7$ may be interpreted as follows:
  - 70% of the variance in the response variable (e.g. gas demand) can be explained by the explanatory variables (e.g. temperature).
  - The remaining 30% can be attributed to unknown, lurking variables or inherent variability.

Peak Day Design, Near Term

Introduction

2018 California Gas Report Forecasts: 1-in-10 (Winter Peak Day)

CGR 2018 Page 97

Winter Cold Day Demand Condition
(MMcf/Day)

Year	1 SoCalGas Core (1)	2 SDG&E Core (2)	3 Other Core (3)	4 Noncore NonEG (4)	Electric Generation (5)	Total Demand
2018	2,838	384	100	658	985	4,965
2019	2,822	382	101	654	989	4,949
2020	2,802	381	102	654	1,048	4,987
2021	2,781	379	102	651	1,036	4,950
2022	2,753	375	103	647	1,030	4,908
2023	2,708	373	104	639	979	4,804
2024	2,672	372	104	632	99[illegible]	4,771

Will be computed through Production Cost Modeling (unconstrained case)

Notes:
(1) 1-in-10 peak temperature cold day SoCalGas core sales and transportation.
(2) 1-in-10 peak temperature cold day SDG&E core sales and transportation.
(3) 1-in-10 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach and City of Vernon.
(4) Noncore-Non-EG includes noncore Non-EG end-use customers of SoCalGas, SDG&E, Southwest Gas Corporation, City of Long Beach, City of Vernon, and all end-use customers of Ecogas.
(5) UEG/EWG Base Hydro + all other Cogeneration customers

Minimum Design Temperature:
SCG: 42°F
SDG&E: 44.5°F

2018 California Gas Report Forecasts: 1-in-35 (Extreme Peak Day)

CGR 2018 Page 96

Core Extreme Peak Day Demand (MMcf/Day)

Year	SoCalGas Core Demand 1/	SDG&E Core Demand 2/	Other Core Demand 3/	Total Demand
2018	3,003	407	117	3,527
2019	2,987	406	118	3,511
2020	2,966	405	119	3,490
2021	2,945	403	120	3,468
2022	2,916	398	120	3,435
2023	2,870	396	121	3,388
2024	2,833	395	122	3,350

3,285MMcfd for 1-in-10
6.2% Increase

Minimum Design Temperature:
SCG: 40.3
SDG&E: 42.8

Notes:
(1) 1-in-35 peak temperature cold day SoCalGas core sales and transportation.
(2) 1-in-35 peak temperature cold day SDG&E core sales and transportation.
(3) 1-in-35 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach and City of Vernon.

Data Request #6: Daily Sendout Data

- Sendout is the volume of gas that was "sent" to the customers, usually expressed in MMcf/day or MMcf/hour. Daily sendout is the gas use on a given day.
- CPUC issued a data request for daily sendout in order to perform a regression and validate the peak gas demand estimates.
- Data request issued on March 20, 2019. Initial response received on May 24, 2019.
- Date range is 2010-2019. Data set contains:
  - Daily forecasted Core sendout (Question 1).
  - **Daily estimated actual Core sendout (Question 1).**
  - Daily forecasted "system-wide" temperature (Question 11).
  - **Daily actual "system-wide" temperature (Question 11).**
  - Customer counts and billing information.
- Multiple subsequent follow-ups to complete, refine, and clarify the data request (see Appendix).

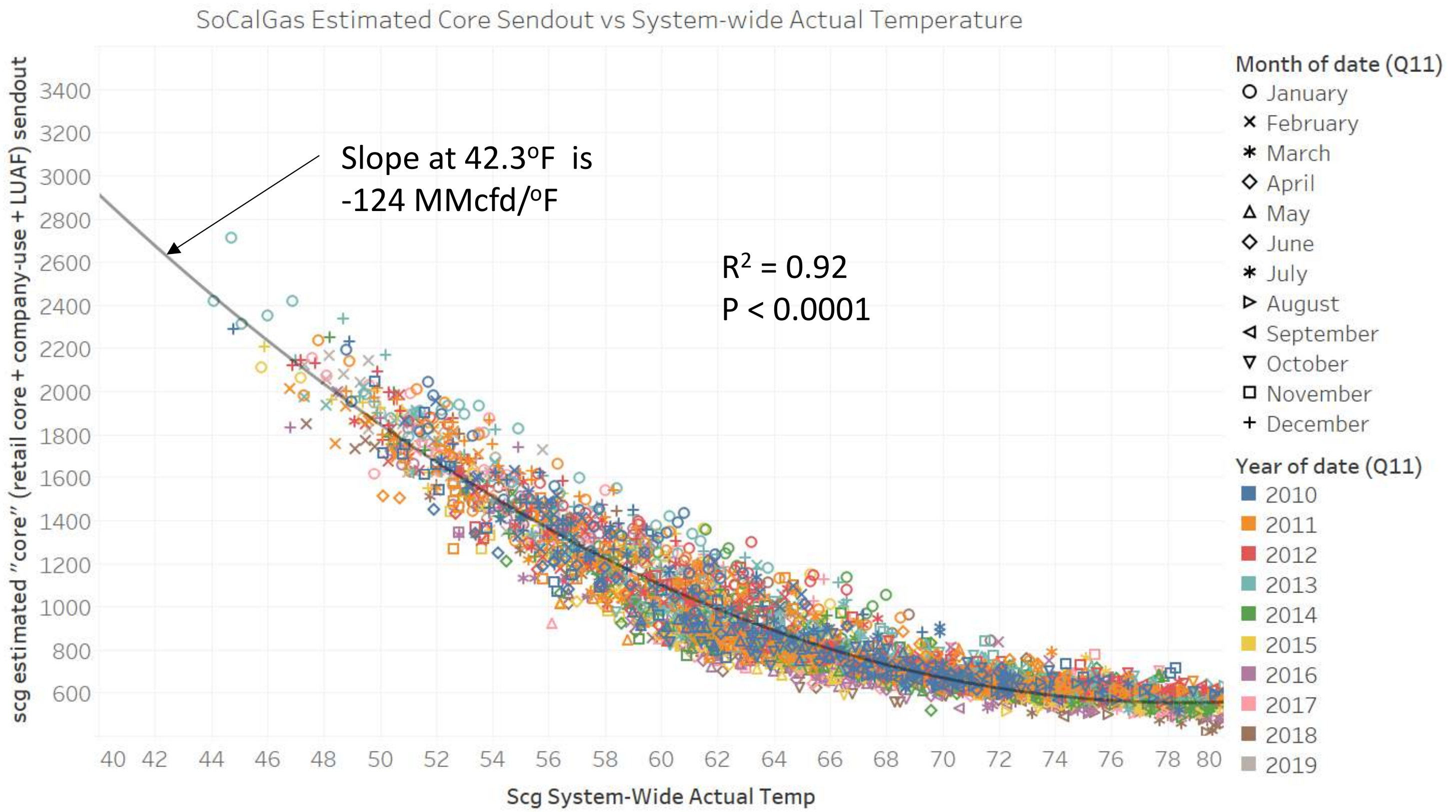
Peak Day Design, Near Term

SoCalGas Core Customers

Peak Day Design, Near Term

- Using data request #6, plot the daily sendout to SoCalGas Core customers vs the system-wide temperature.
- Staff performed curve fitting (regression) to find the best model.
- Extrapolate or predict the sendout at the minimum design temperature.
- Investigate the sensitivity of the data to various factors such as the month, the day of the week, or the year.
- Verify 2018 CGR estimates.

SoCalGas Core Customers Estimated Actual (Entire Data Set)



Scg System-Wide Actual Temp vs. scg estimated "core" (retail core + company-use + LUAF) sendout. Color shows details about Year of date (Q11). Shape shows details about Month of date (Q11). The data is filtered on Weekday of date (Q11), which keeps 7 of 7 members. The view is filtered on Month of date (Q11) and Year of date (Q11). The Month of date (Q11) filter keeps 12 of 12 members. The Year of date (Q11) filter keeps 10 of 10 members.

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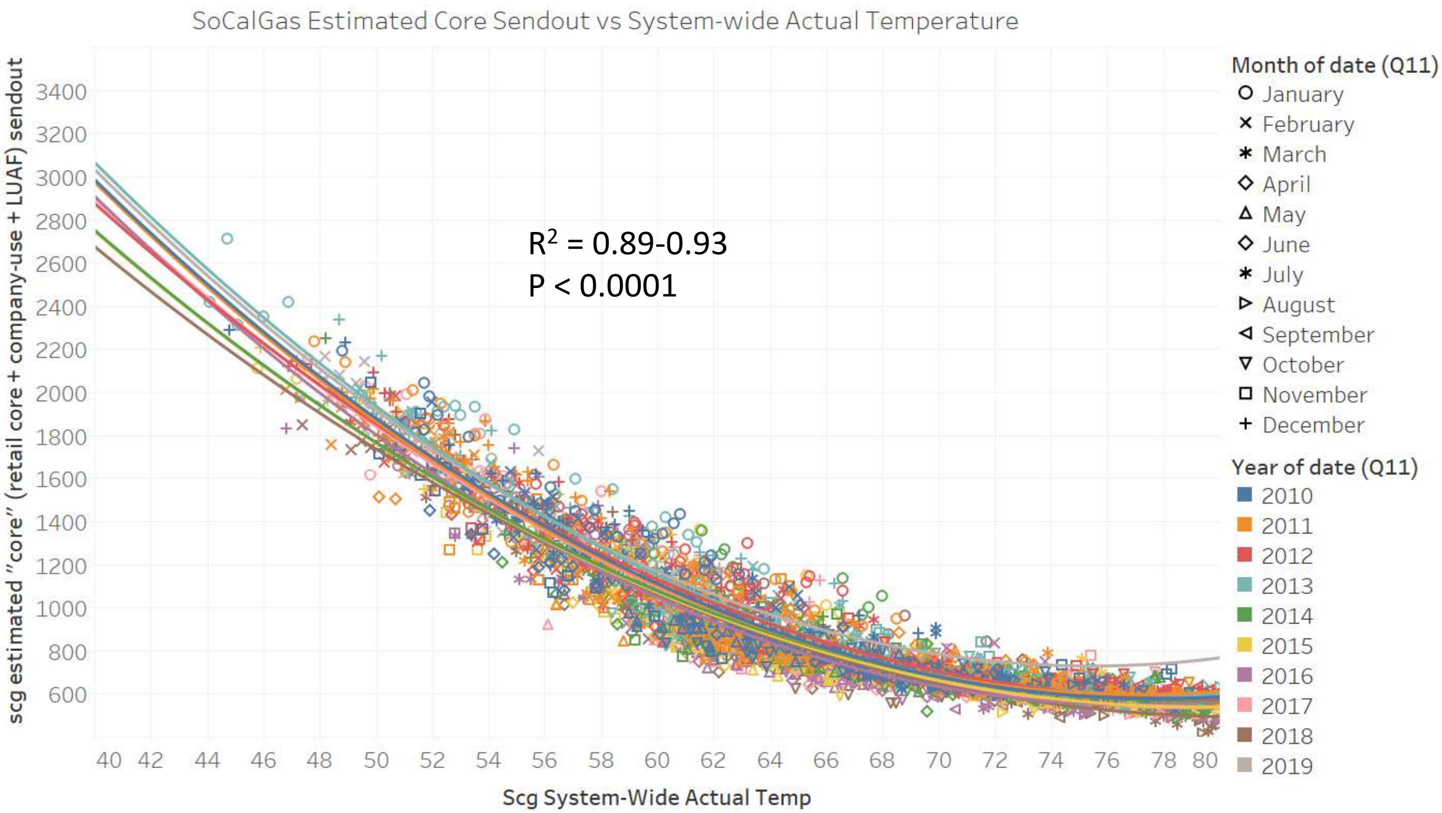

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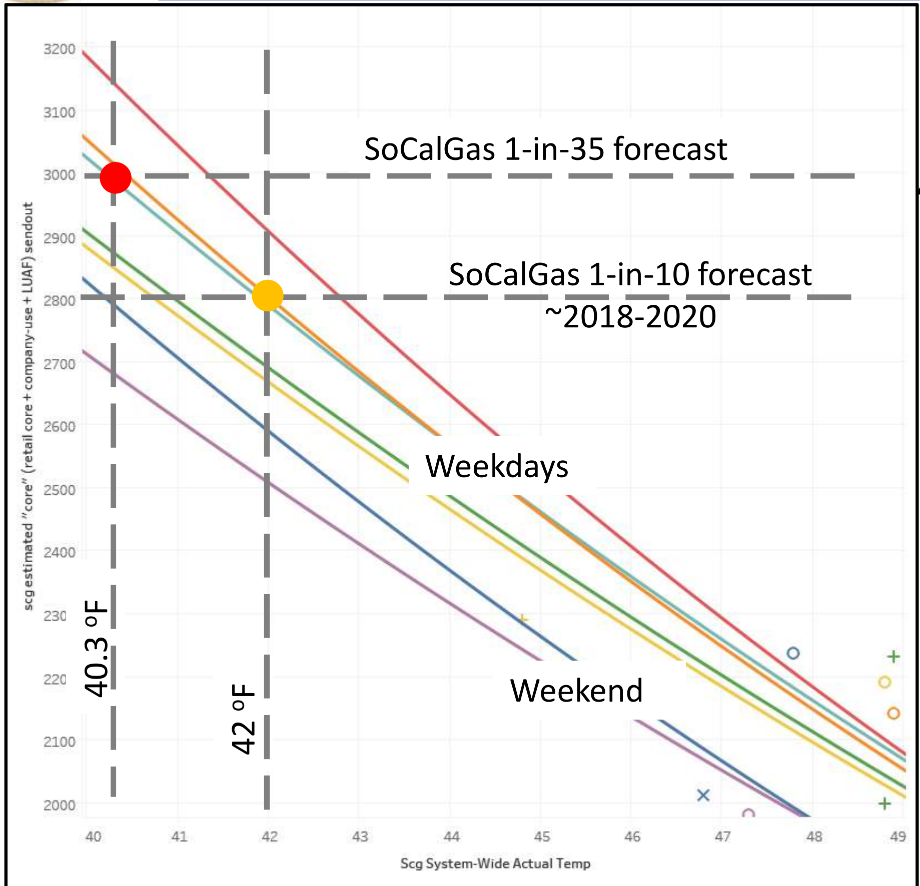
SoCalGas Core Customers Estimated Actual Cold Months of 2010 & 2011 (HDD = 1442 & 1591)



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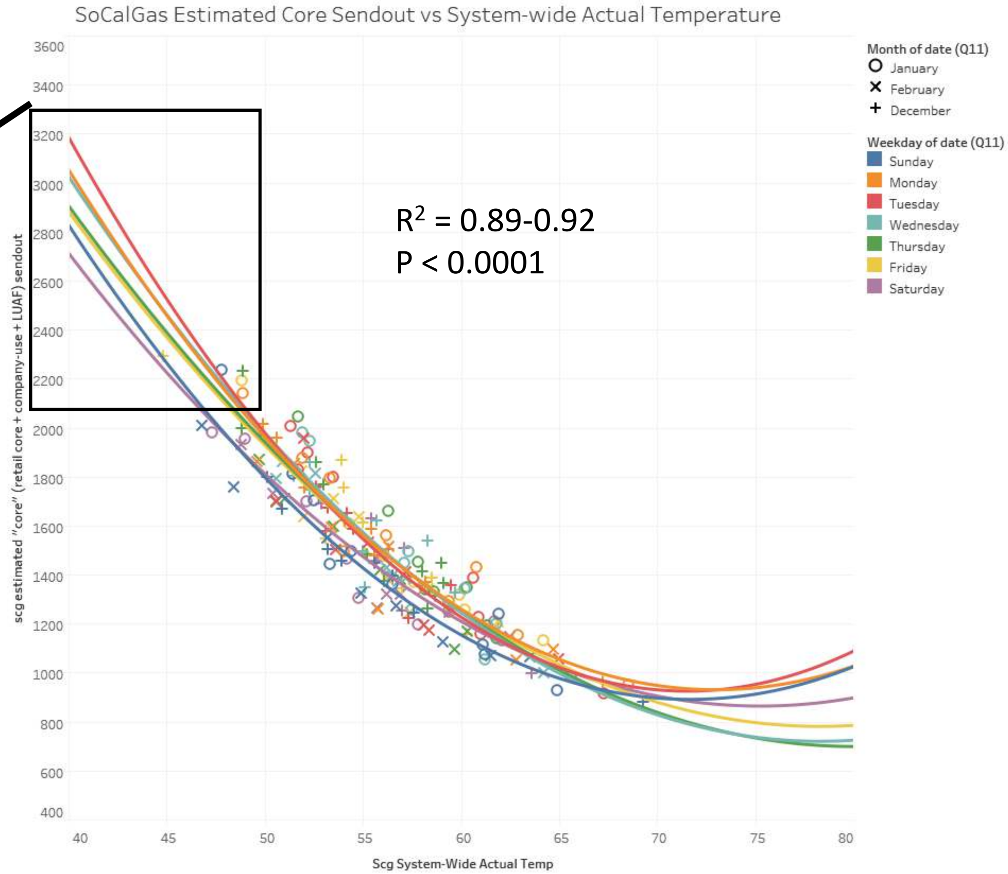

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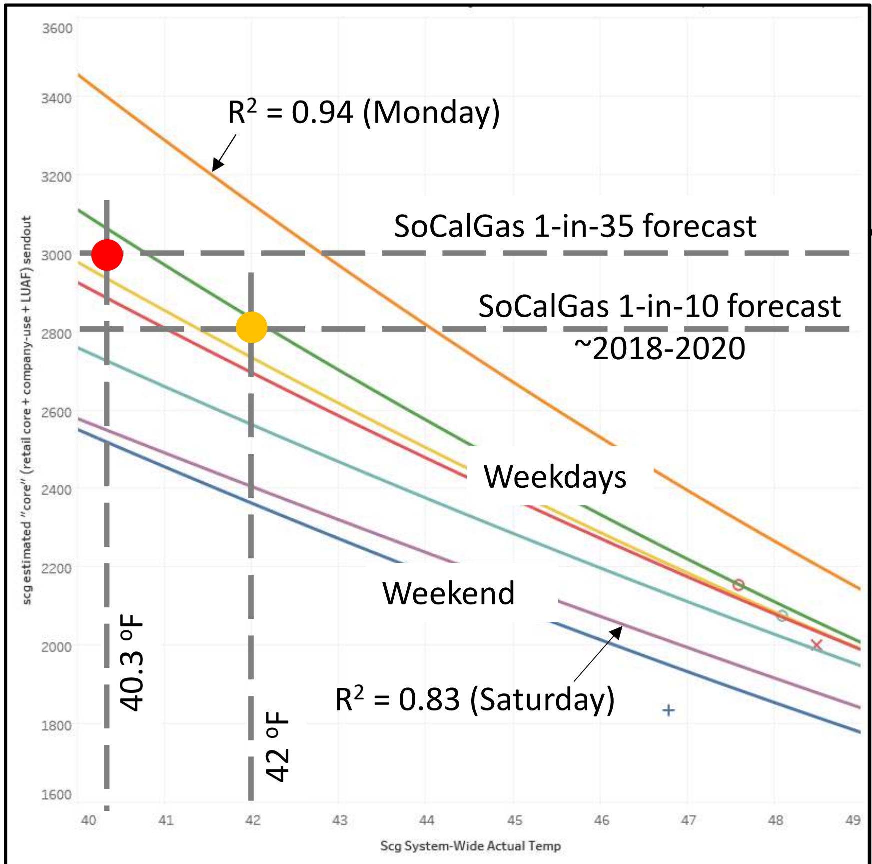
SoCalGas Core Customers Estimated Actual Recent Winters of 2016 & 2017 (HDD = 1012 & 967)



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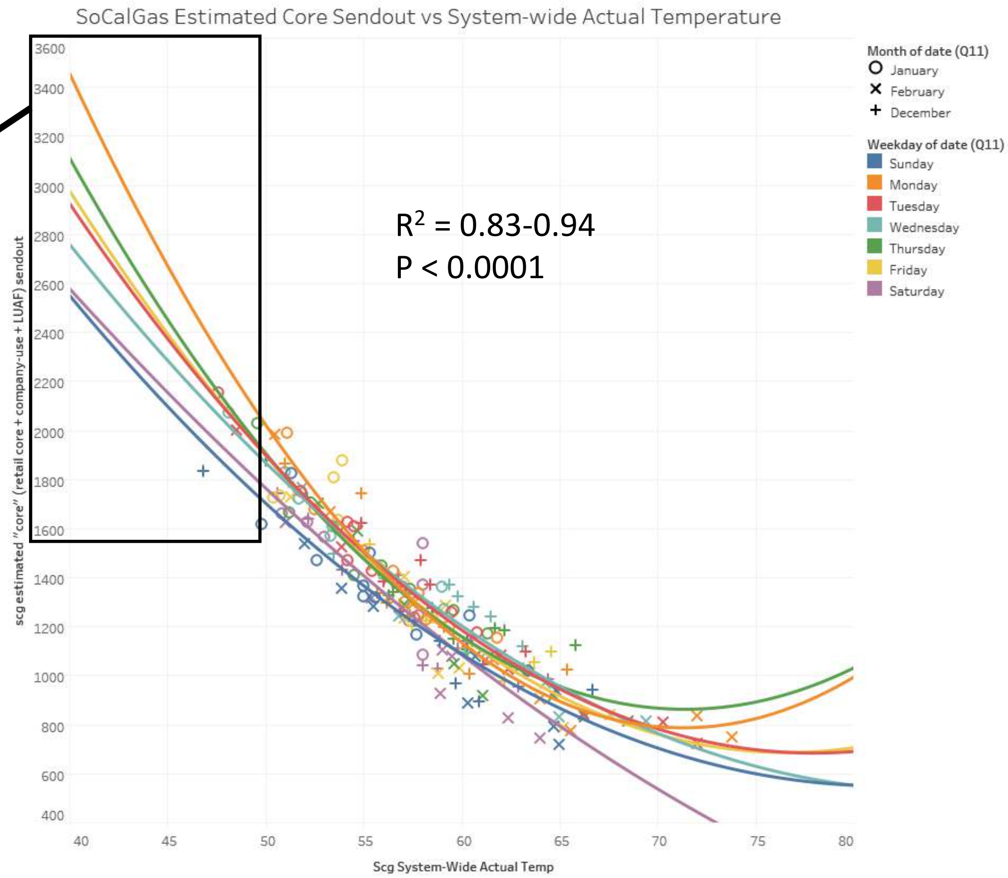

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SoCalGas Core Customers Estimated Actual (Winters of 2016-2017)

- Quadratic Regression

$$V_{gas} = AT^2 + BT + C\text{, where}$$

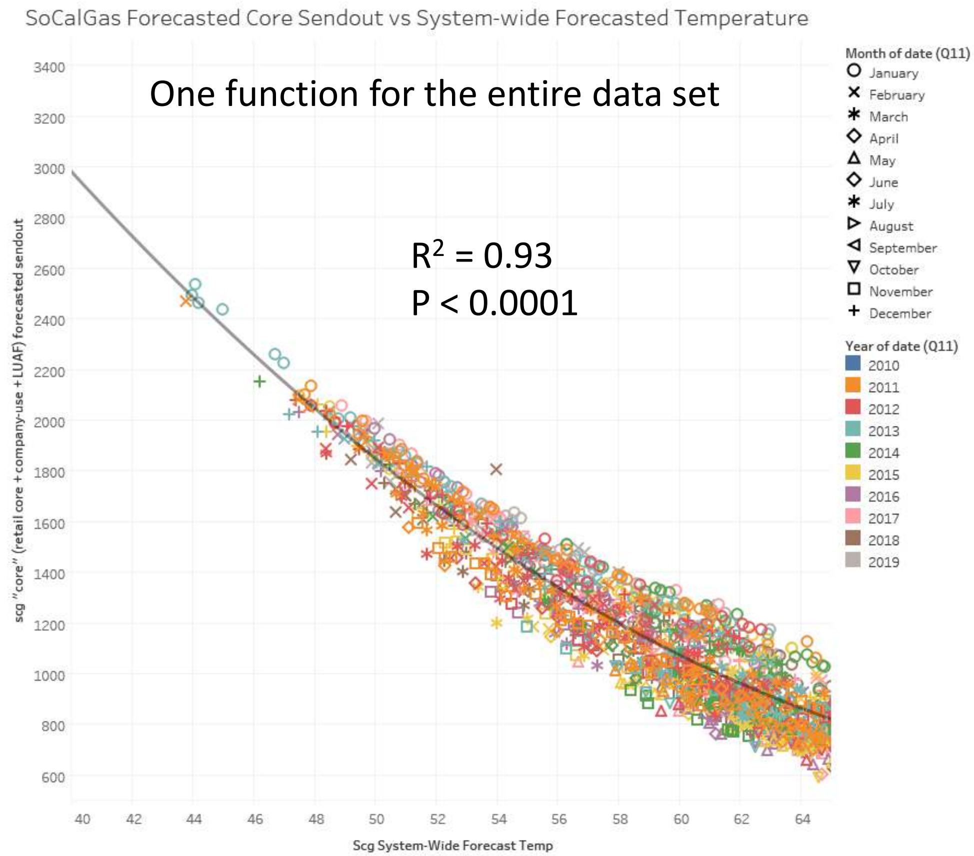
V is the gas volume in MMcfd (1e+06 cubic feet)

T is the temperature in Fahrenheit (°F)

SoCalGas Design Point for 2020
1-in-10 (42.0°F): 2,802 MMcfd
1-in-35 (40.3°F): 2,966 MMcfd

	A	B	C		T	Slope	Gas Use 1-in-10		T	Slope	Gas Use 1-in-35
	MMcfd/F²	MMcfd/F	MMcfd		°F	MMcfd/°F	MMcfd		°F	MMcfd/°F	MMcfd
Su	1.16	-188.94	8,254		42.0	-92	2,361		40.3	-96	2,521
Mo	2.72	-388.31	14,631		42.0	-160	3,125		40.3	-169	3,404
Tu	1.55	-242.31	10,131		42.0	-112	2,694		40.3	-117	2,889
We	1.13	-190.71	8,579		42.0	-96	2,562		40.3	-100	2,728
Th	2.28	-325.42	12,482		42.0	-134	2,832		40.3	-142	3,067
Fr	1.71	-261.74	10,713		42.0	-118	2,733		40.3	-124	2,939
Sa	0.67	-141.30	7,163		42.0	-85	2,404		40.3	-88	2,551

SoCalGas Core Customers Forecasting Model (2010-2019)



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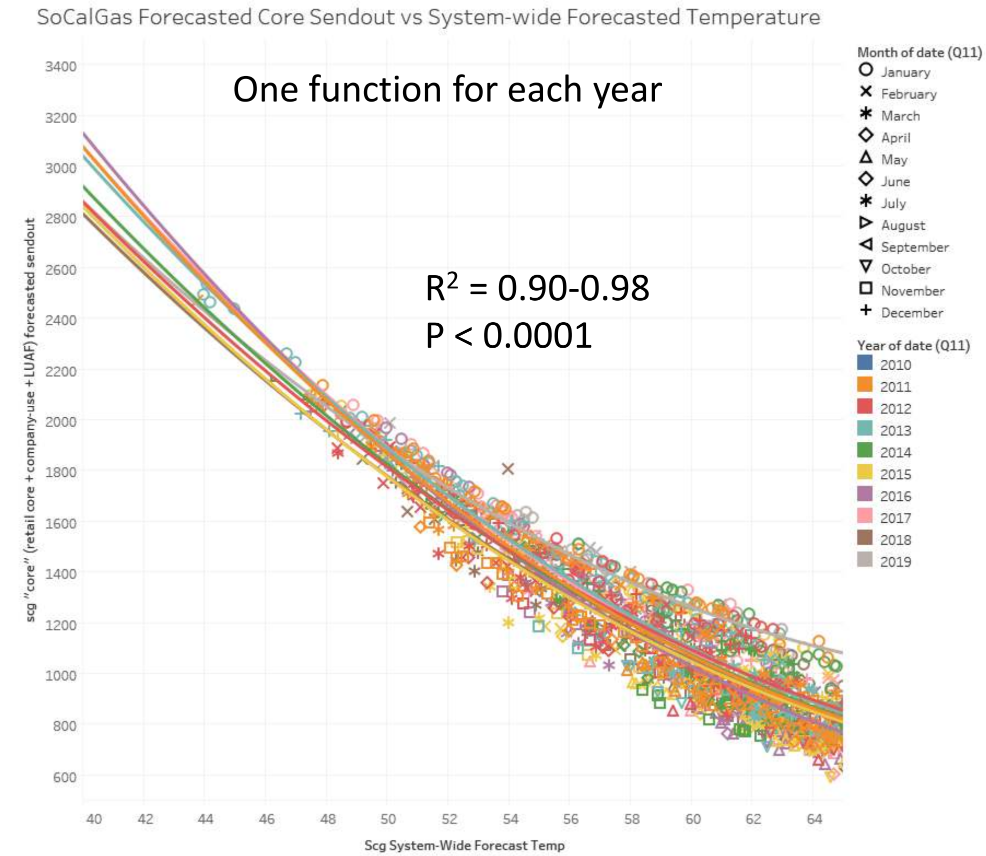

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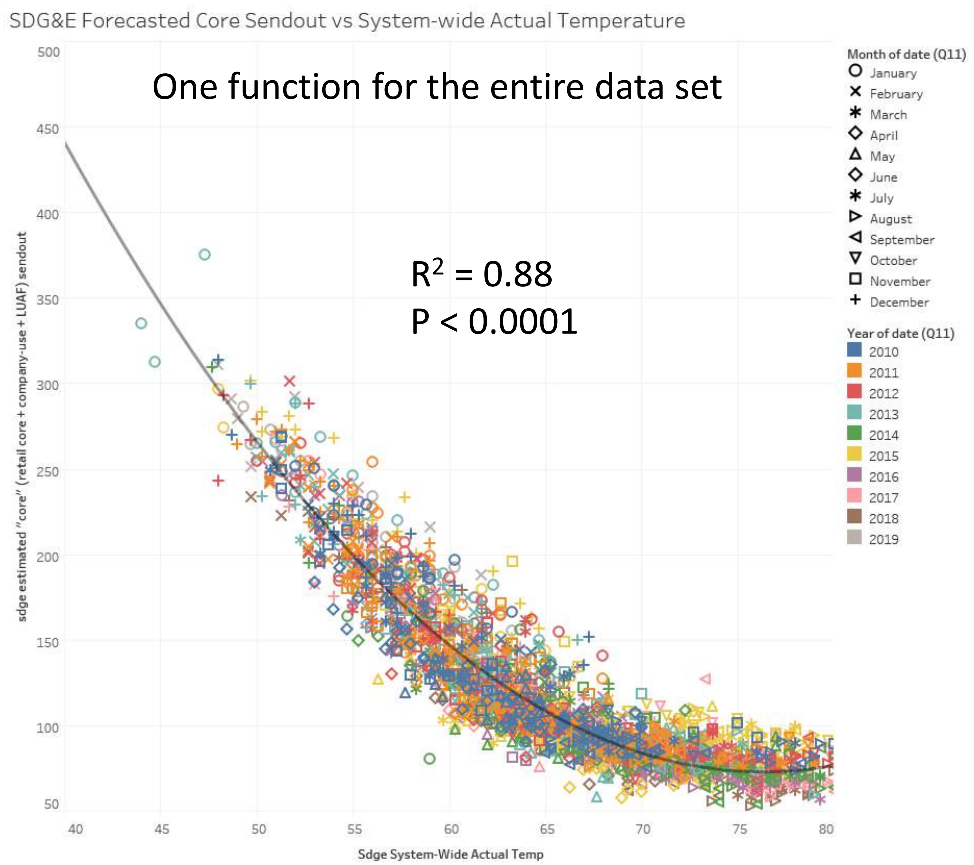
Peak Day Design, Near Term

SDG&E Core Customers

SDG&E Core Customers Estimated Actual (2010-2019)



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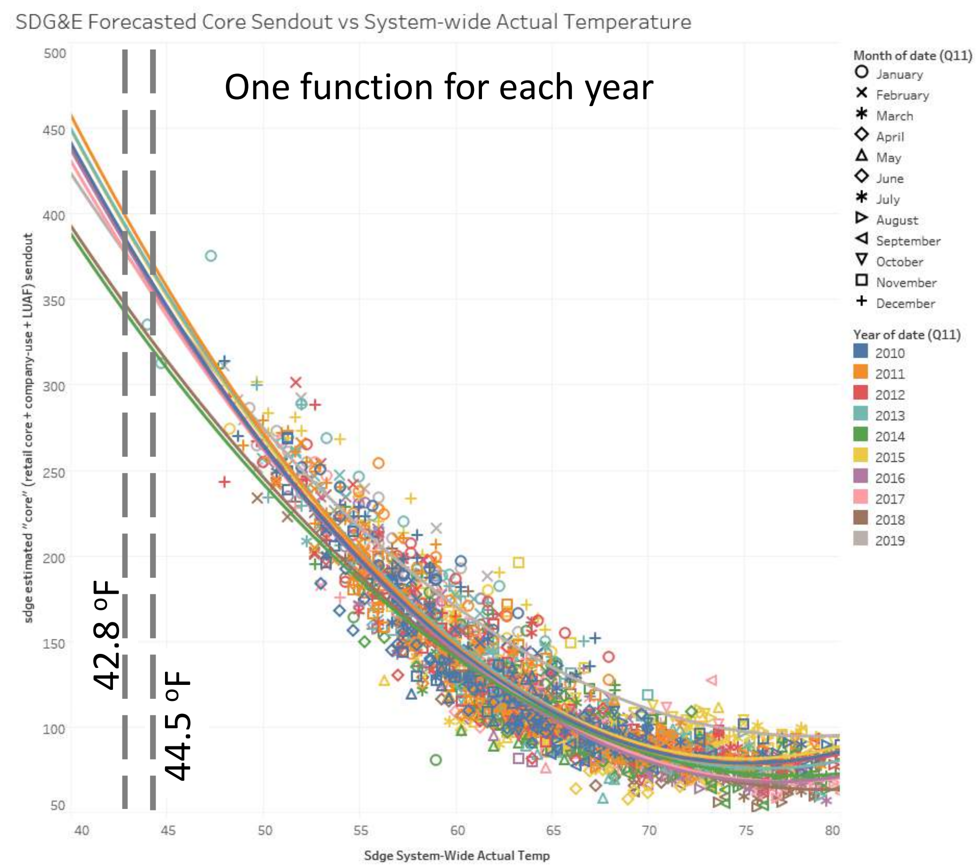

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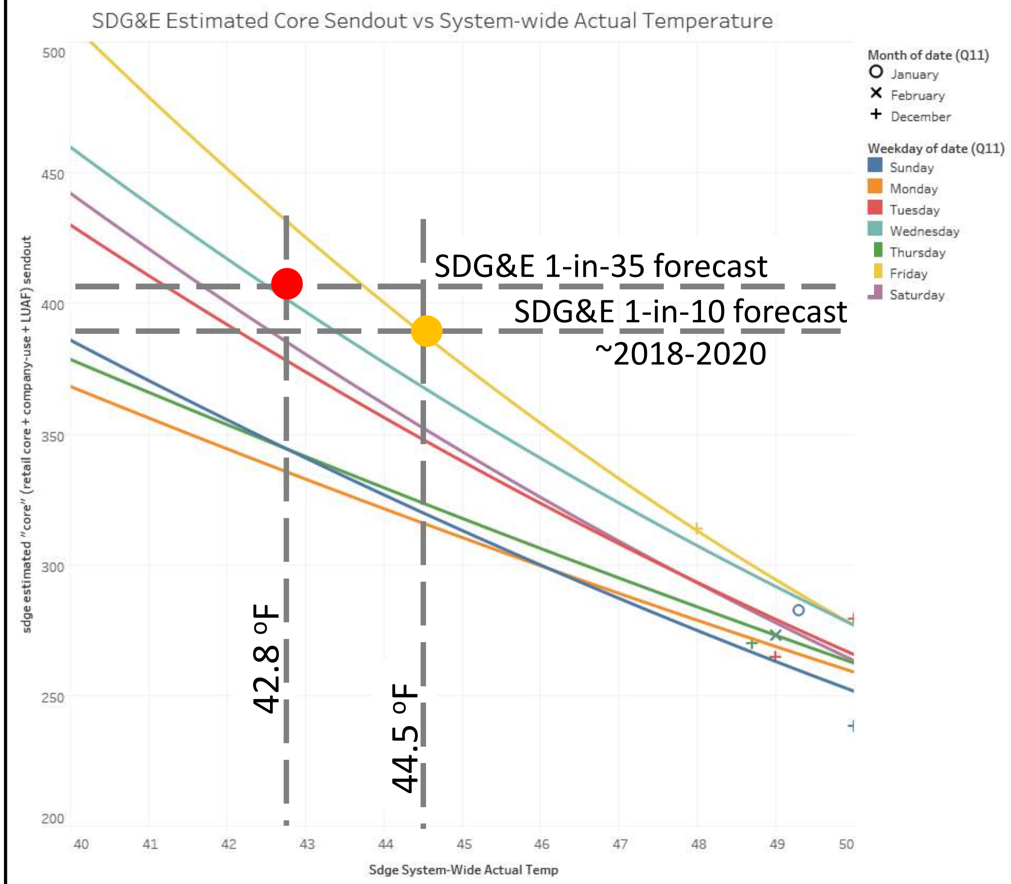
SDG&E Core Customers Estimated Actual (Winters of 2010-2011)



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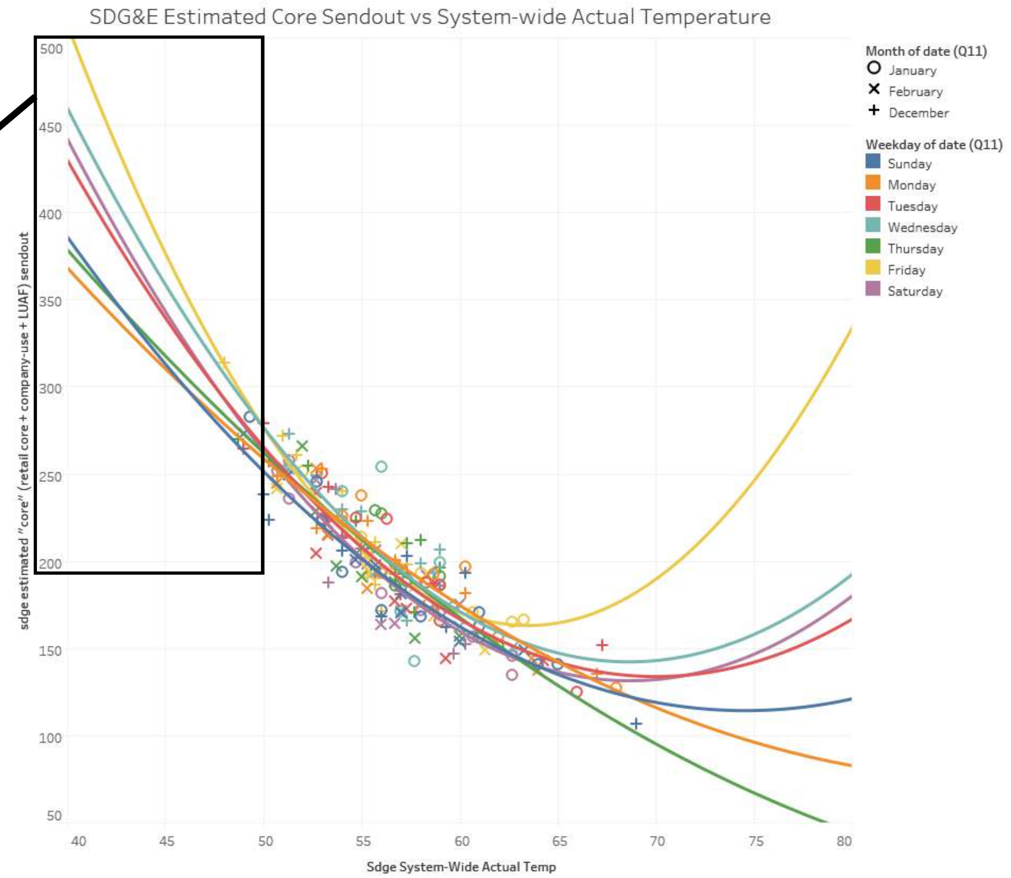

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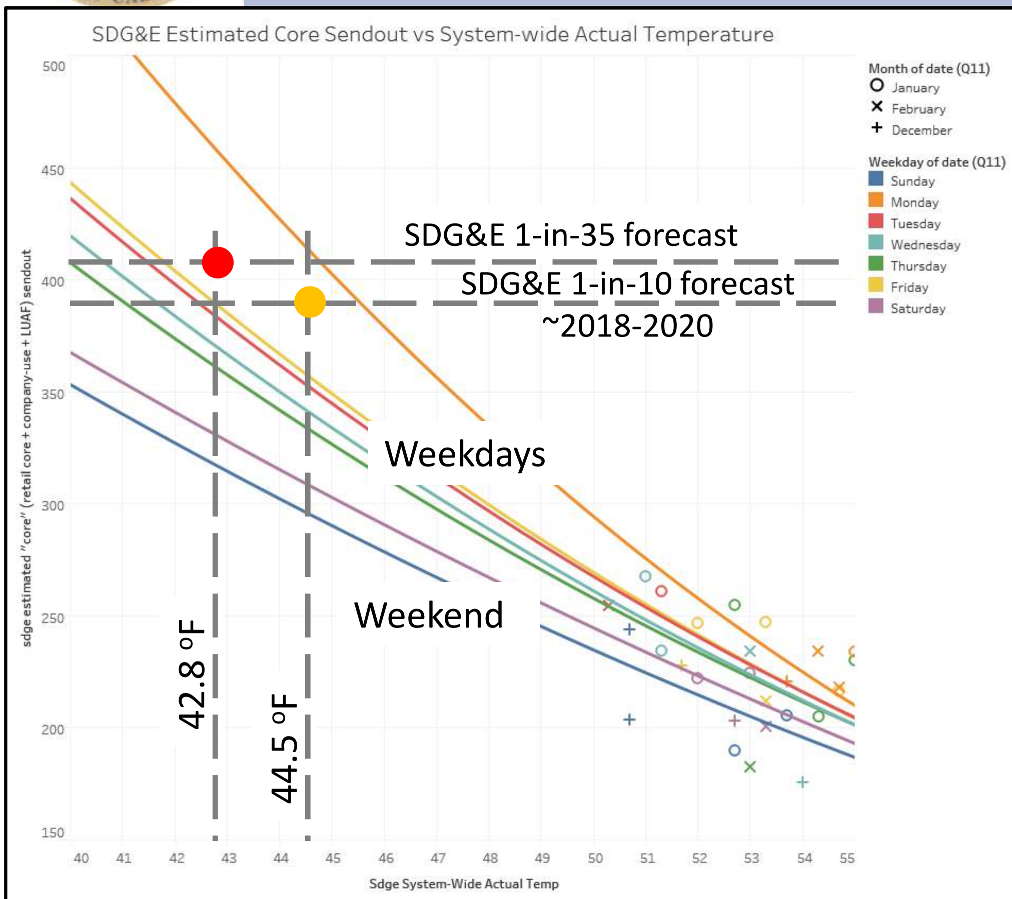
SDG&E Core Customers Estimated Actual (Winters of 2016-2017)



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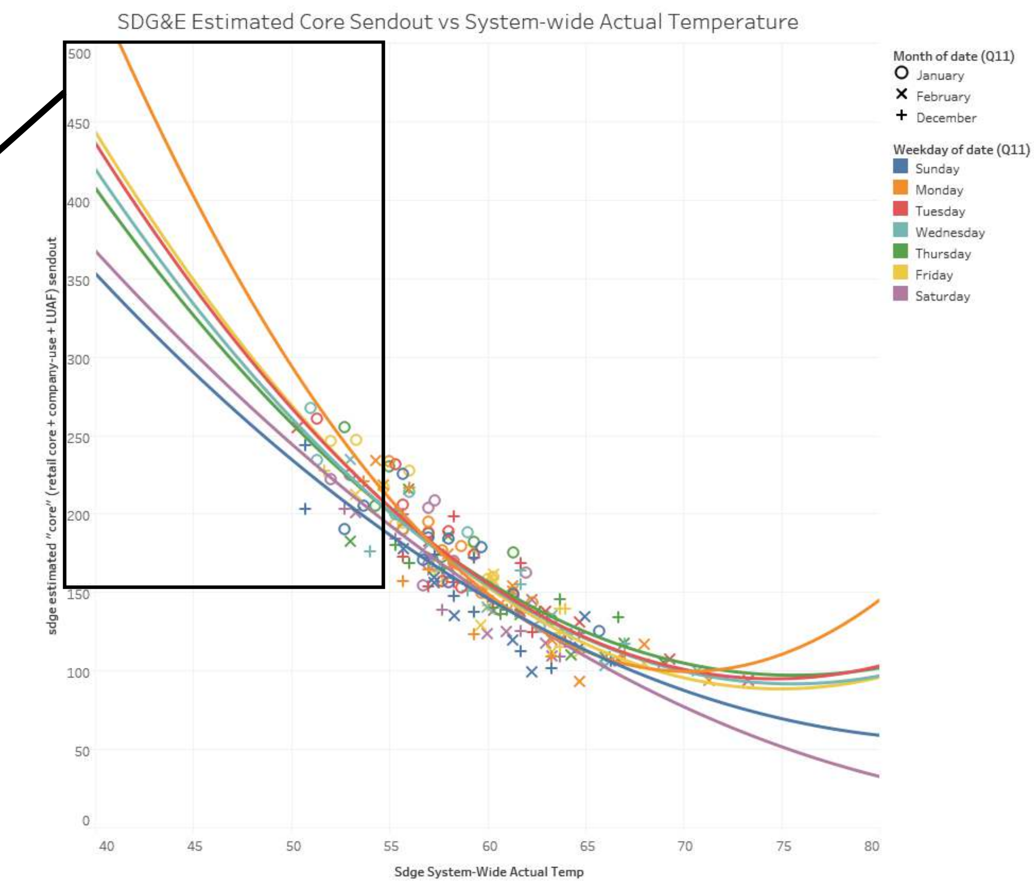

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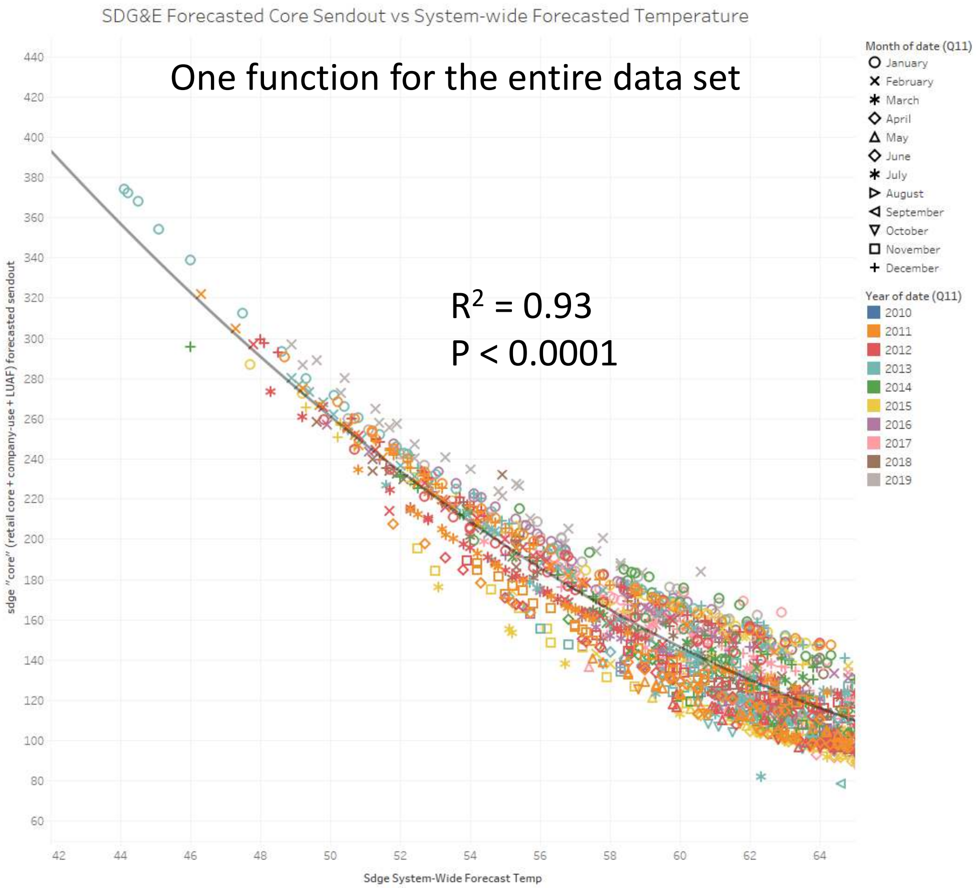
SDG&E Core Customers Forecasting Model (2010-2019)



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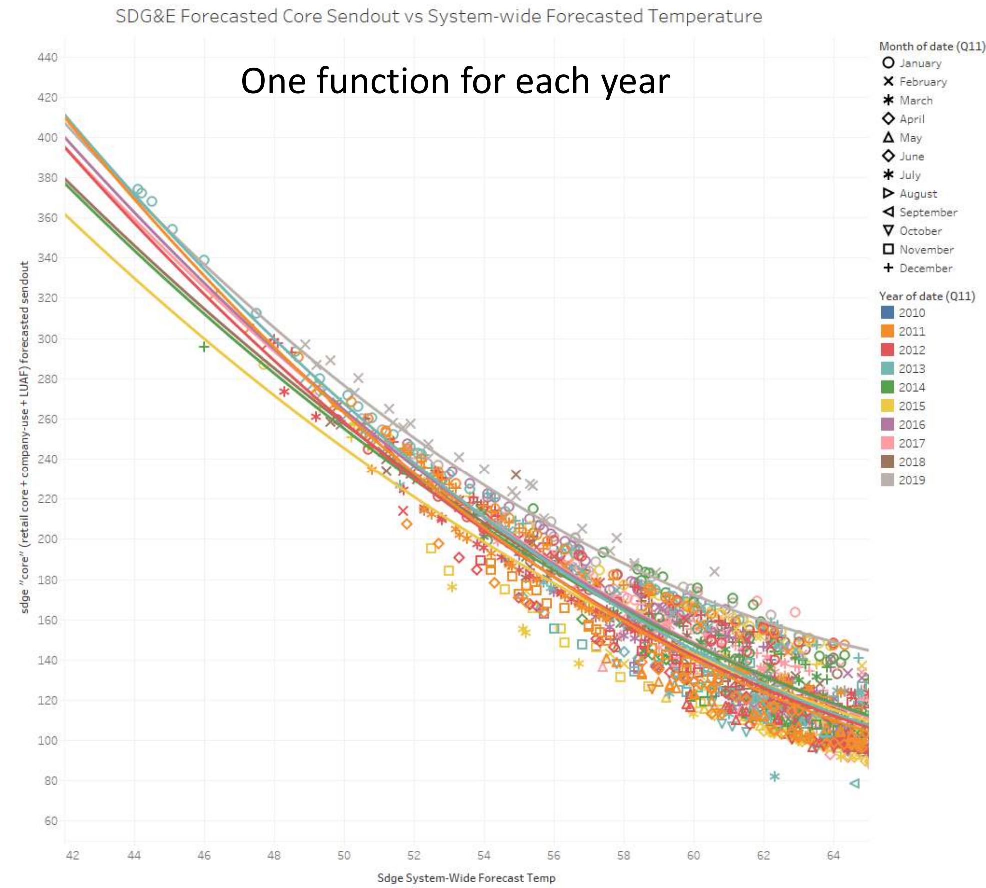

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Peak Day Design, Near Term

Wholesale and Noncore Customers

Wholesale and Noncore Customers

- Using hourly meter data, investigate the historical gas use of Wholesale and Noncore customers.
- Derive the coincident peak.
- Verify 2018 CGR.

Noncore EG Customers

Noncore EG Customers Average Daily Gas Use from AMI (MMCF)

The trend of sum of Daily Volume (MMCF) for Date Month. Color shows details about Subclass. The view is filtered on Subclass, which keeps ELECTRIC GENERATION.

AMI Peaks (MMcfd)
July 2018: 953
October 2018: 484
November 2018: 424

SoCalGas Design Point for 2020
1-in-10 (42.0^{O}F): 1048 MMcfd
1-in-35 (40.3^{O}F): 0 MMcfd

Conclusions: Peak Day Design, Near Term 2020

- A 2nd degree polynomial fitting provided the best fit for correlating the estimated actual core demand vs. the system-wide temperature.
- Many other fitting curves were considered and provided a worse fit (smaller R^2), such as linear, 3rd degree, logarithmic, power, and exponential.
- A linear fit may be possible but only if warm temperatures (higher than 50^oF) are excluded from the data set.

Conclusions: Peak Day Design, Near Term 2020 SoCalGas and SDGE& Core Customers

- CPUC analysis **verifies** SoCalGas estimate of their Core customers demand of:
  - **2,802MMcfd @42.3^{o}F** for the 2020 1-in-10 peak.
  - **2,966MMcfd @40^{o}F** for the 2020 1-in-35 extreme peak.
- CPUC analysis **verifies** SDG&E estimate of their Core customers demand of:
  - **381MMcfd @44.5^{o}F** for the 2020 1-in-10 peak.
  - **405MMcfd @42.8^{o}F** for the 2020 1-in-35 extreme peak.

Conclusions: Peak Day Design, Near Term 2020 SoCalGas Core Customers

- Using only recent warm winters (2016 & 2017) in the regression analysis shows that the **peak** and **extreme** peak of SoCalGas Core demand for these years would lie between **2,562-3,125MMcfd @42.3ºF** and **2,550-3,450MMcfd @40ºF** with the lower end of the range corresponding to weekends and the higher end corresponding to Mondays and Thursdays.
- The wide range observed above is primarily due to the shorter time period considered (2016 & 2017 only), the inclusion of only 3 months (January, February, and December), and other independent factors not considered in the regression (customer behavior, wind speed, cloud coverage, etc…).
- If all years (2010-2019) and all 12 months are used in the regression, the range of SoCalGas **peak** and **extreme peak** Core demand is **~2,500-2,880MMcfd @42.3ºF** and **~2,700-3,100MMcfd @40ºF** which is a tighter and lower range than that considering only recent warm winters.

Conclusions: Peak Day Design, Near Term 2020 SDG&E Core Customers

- Using only recent <u>warm</u> winters (2016 & 2017) in the regression analysis shows that the **peak** and **extreme** peak of SDG&E Core demand for these years would lie between **290-425MMcfd @44.5^{o}F** and **340-475MMcfd @42.8^{o}F** with the lower end of the range corresponding to weekends and the higher end corresponding to Mondays.
- The wide range observed above is primarily due to the shorter time period (2016 & 2017 only), the inclusion of only 3 months (January, February, and December) in the regression, and other independent factors not considered in the regression (customer behavior, wind speed, cloud coverage, etc…)
- If all years (2010-2019) and all 12 months are used in the regression, the range of SDG&E **peak** and **extreme** peak Core demand is **~325-375MMcfd @44.5^{o}F** and **~340-400MMcfd @42.8^{o}F** which is a tighter and <u>lower</u> range than that considering only recent <u>warm</u> winters.

Conclusions: Peak Day Design, Near Term 2020 Other Core and Noncore NonEG Customers

- CPUC analysis of 2018 AMI data **verifies** SoCalGas estimate for the **peak** and **extreme peak** demand of the remaining Other Core customers of **102MMcfd @42.3°F** and **119MMcfd @40°F**.

- CPUC Analysis of 2018 AMI data **verifies** SoCalGas estimate for the **peak** demand of Noncore NonEG customers of **654MMcfd @42.3°F**.

Thank you

Discussion

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Peak Day Design, Long Term

2025, 2030, and beyond

SoCalGas Forecasts: Core Gas Demand

- Core Residential: The residential load is expected to decline on average by **1.4% per year** from 238 Bcf in 2017 to 186 Bcf in 2035* **(i.e. 16.75% decrease from 2017 to 2030)**.
  - The decline is explained by conservation, improved building and appliance standards, aggressive energy efficiency programs, and demand reductions anticipated as the result of the deployment of the Advanced Meter Infrastructure in Southern California.
  - These forecasts do not include building electrification explicitly.
  - Over the forecast period, the demand per meter is expected to decline at an average annual rate of 2.2 percent.
- Core Commercial: The average **annual rate of decline** from 2018 to 2035 is forecasted **at 1.6%** (Energy Efficiency and Title 24)*.
- Core Industrial: Demand is projected to **decrease by 2.5% per year** from 21.2 Bcf in 2017 to 13.6 Bcf in 2035+.

*California Gas Report 2018, P. 69

+California Gas Report 2018, P. 72

SoCalGas Historical: Core Gas Demand

- Based on average yearly historical data for the 2007-2017 period, CPUC notes the following*:
  - Yearly Core residential demand fluctuates, but has decreased on average by 1.5% per year (σ=6%).
  - Yearly Core commercial demand fluctuates, but has decreased on average by 0.3% per year (σ=4%).
  - Yearly Core industrial demand fluctuates, but has decreased on average by 1.5% per year (σ=3%).

*Multiple California Gas Reports (2012, 2014, and 2018)

Historical vs Forecast Core Gas Demand

	Recorded (2007-2017)	Forecast (2018-2035)	Average Daily Use in 2017
Core Residential	-1.5%	-1.5%	565 MMcfd
Core Commercial	-0.3%	-1.6%	214 MMcfd
Core Industrial	-1.5%	-2.5%	55 MMcfd

- SoCalGas forecasts align with historical data and show more aggressive decline for Core commercial and industrial sectors.

Peak Day Design, Long Term

Methodology

Peak Day Design

- Goal: Determine the peak gas use that maintains the reliability standards mandated by the CPUC (1-in-10 & 1-in-35).
- Two Important Parameters:
  - The number of Heating Degree Days (HDD) in an average temperature year (i.e. the number of degrees that a day's average temperature is below a base temperature (65°F for SoCalGas & SDG&E) in a given year).
  - The minimum design temperature (T_{Design}), which is either the 1-in-10 or 1-in-35 temperature depending on the reliability standard (currently 42°F and 40.3°F for SCG, 44.5°F and 42.8°F for SDG&E).

Peak Day Design

- Four verification exercises done by CPUC staff
- Methodology used by SoCalGas:
  - Step A: Calculate the Heating Degree Days (HDD) for average, 1-in-10, and 1-in-35 years and as follows:
    - Get historical daily temperature for 6 climate zones for a selected time period (1998-2017), by averaging readings from multiple weather stations in a given climate zone.
    - Calculate a weighted average of yearly HDD (HDD_{avg}) among the 6 climate zones. The weights are the proportions of gas customers within each climate zone.
    - Calculate the standard deviation (σ) of the sample yearly HDD.

Verification Exercise I

Verification Exercise II

Peak Day Design

Verification Exercise II

- Step A (continued):
  - Calculate the 1-in-10 yearly HDD as:
    $$HDD_{1-in-10} = HDD_{avg} + 1.328\sigma$$
  - Calculate the 1-in-35 yearly HDD as:
    $$HDD_{1-in-35} = HDD_{avg} + 2.025\sigma$$
  - Identify the coldest month of the year, i.e. the month with the highest number of HDD (December) and calculate its average HDD ($HDD_{mo,avg}$).
  - Calculate the 1-in-10 monthly HDD ($HDD_{mo,peak}$) and 1-in-35 monthly HDD ($HDD_{mo,extreme}$) from yearly HDD using historical HDD percentages of that month.

Peak Day Design

- Step B: Calculate the peak day demand as follows:
  - Calculate yearly forecasts using End User (EU) Forecaster (SAS statistical package) for an average year and a 1-in-35 cold year.
  - Verification Exercise III — Parcel out monthly forecasts from annual forecast using calculated weights.
  - Verification Exercise IV — Calculate the HDD sensitivity (Slope) for that month, i.e. how much extra gas is needed for each 1 HDD (MDth/HDD)
  - Calculate the peak day usage using the following formula:

$$E_{peak} = E_{Avg} + Slope * (HDD_{mo,peak} - HDD_{mo,avg})$$

$$E_{extreme} = E_{Avg} + Slope * (HDD_{mo,extreme} - HDD_{mo,avg})$$

$(65 - T_{Design})$ $(9.2^{o}F)$

$(55.8 - T_{Design})$

Peak Day Design, Long Term

CPUC Verifications

Peak Day Design Verification I: Climate Zones Weights

Climate Zone	SCG Weights	CPUC Weights	% Difference
1	0.0058	0.0059	1.25%
2	0.0385	0.0381	-1.08%
3	0.1854	0.1857	0.14%
4	0.0716	0.0729	1.72%
5	0.3831	0.3825	-0.17%
6	0.3156	0.3151	-0.17%
Sum	1.0000	1.0000	

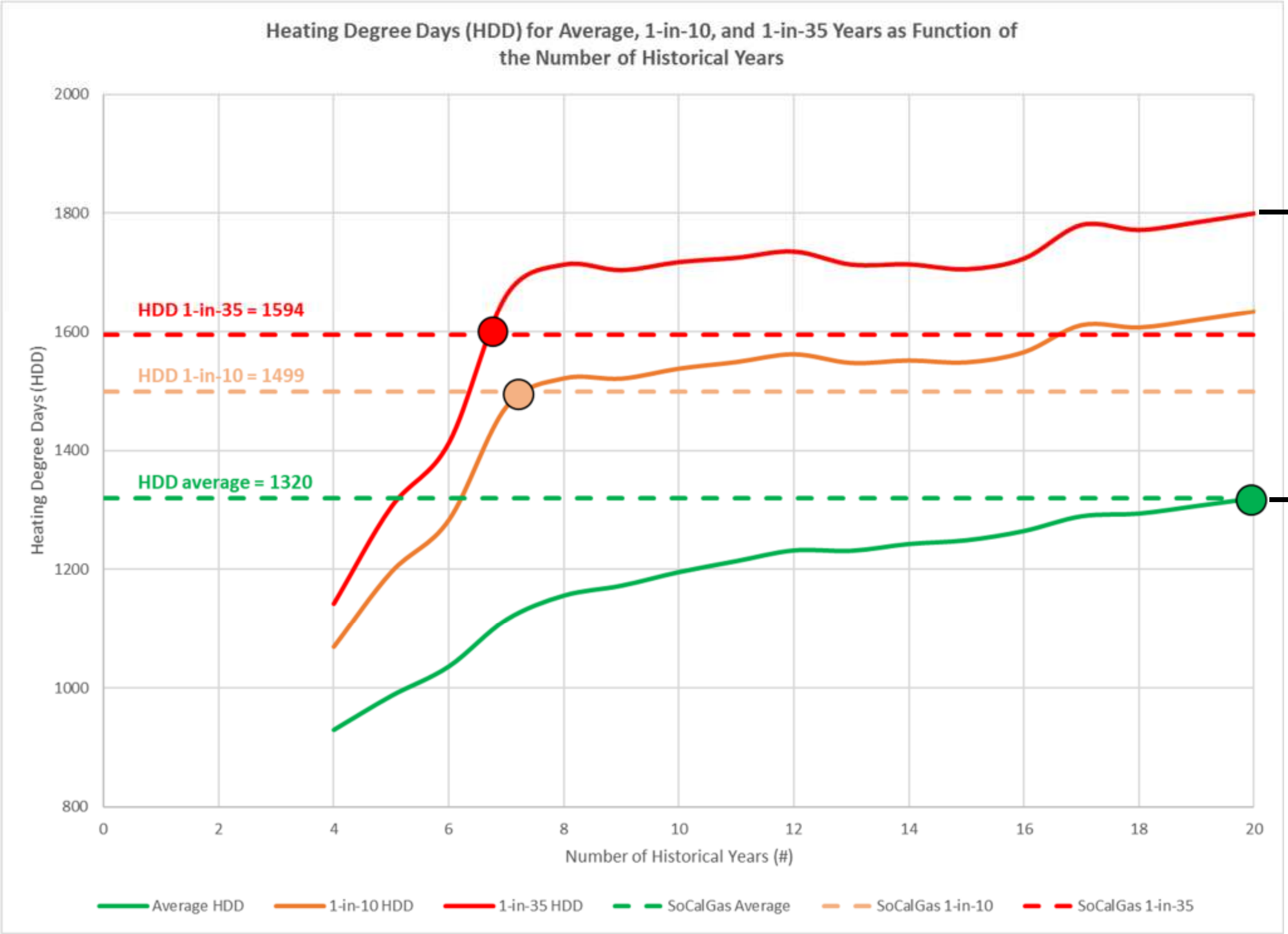
Difference could be a result of different approximations. CPUC weights were based on SCG Core Customers excluding industrial, while using the monthly average of customer counts in year 2017*. SoCalGas may have included Noncore customers or excluded other subclasses.

* Data based on Data Request 6, Question 5 & Question 11.

Peak Day Design Verification II: Sensitivity to Historical Data

- What if a fewer number of years was used in deriving the average HDD (HDD_{avg}), and the Standard Deviation (σ)?
  - Perform a sensitivity analysis on the number of historical years included in the calculation.
  - Select a number of historical years to be included, starting with only 4 years (2014-2017), increasing to 20 years (1998-2017).
  - For each sensitivity case, calculate HDD_{avg}, σ, $HDD_{1-in-10}$, $HDD_{1-in-35}$.

Peak Day Design Verification II: Sensitivity to Historical Data



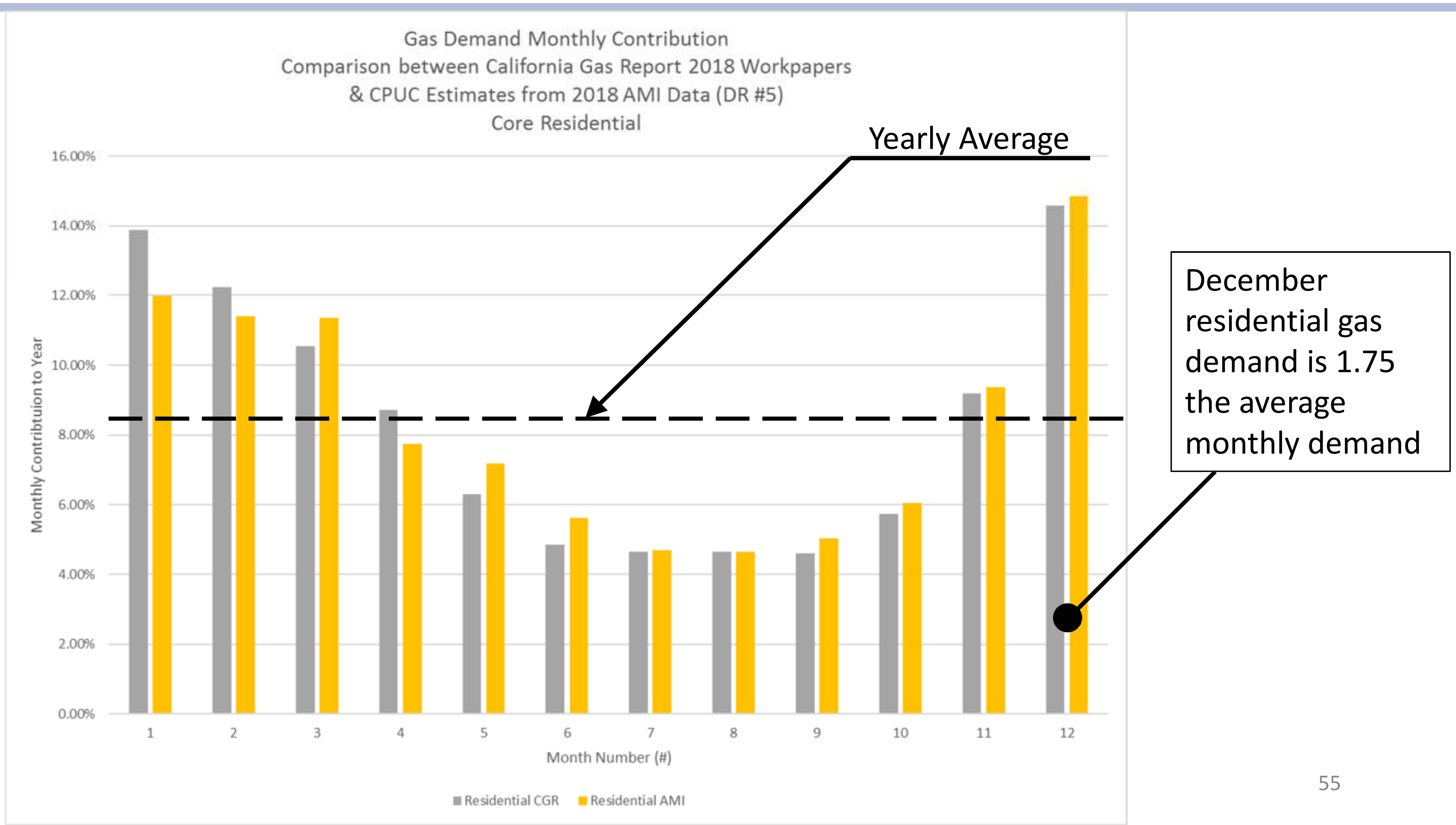
Higher uncertainty due to warming weather. Standard deviation is 236 HDD

SoCalGas model results in a Standard deviation of 135.1 HDD

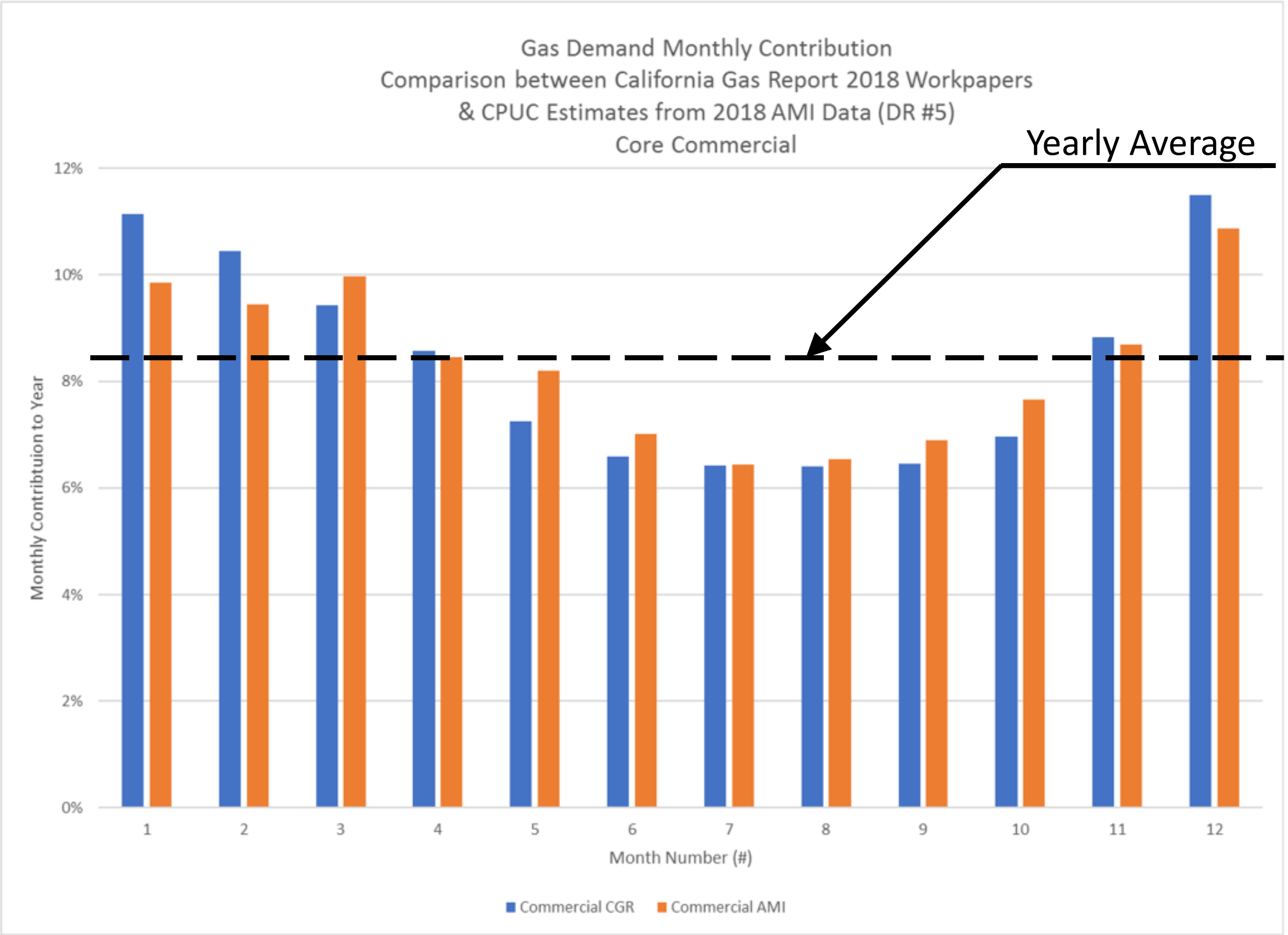
Peak Day Design Verification III: Monthly Gas Demand Percentages

- Using Advanced Meter Infrastructure data (Data Request #5), average monthly gas use was calculated (using the 45^{th}-55^{th} percentile) for a set of customers (10% or more) of the ZIP code.
- Using the number of customers in a given ZIP code (Data Request #6), the gas use was scaled upwards to obtain the gas use by all customers in that ZIP code.
- A summation over all the ZIP codes was performed and the monthly percent of gas use was obtained.

Peak Day Design Verification III: Monthly Gas Demand Percentages



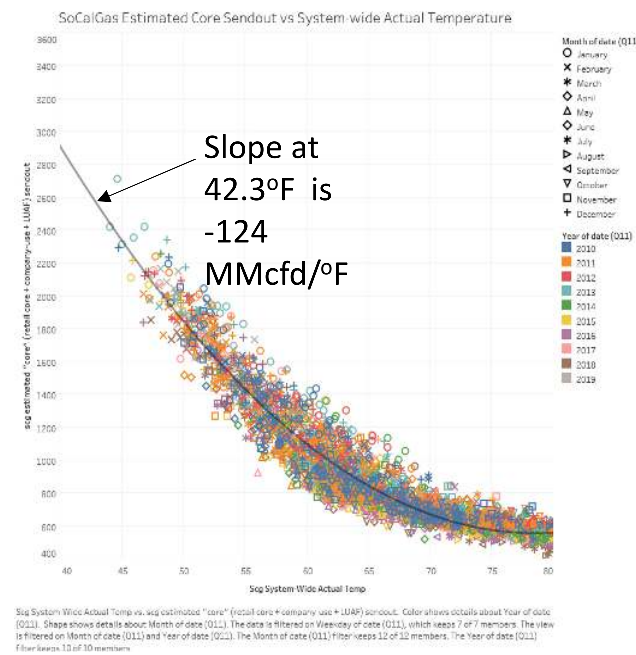
Peak Day Design Verification III: Monthly Gas Demand Percentages



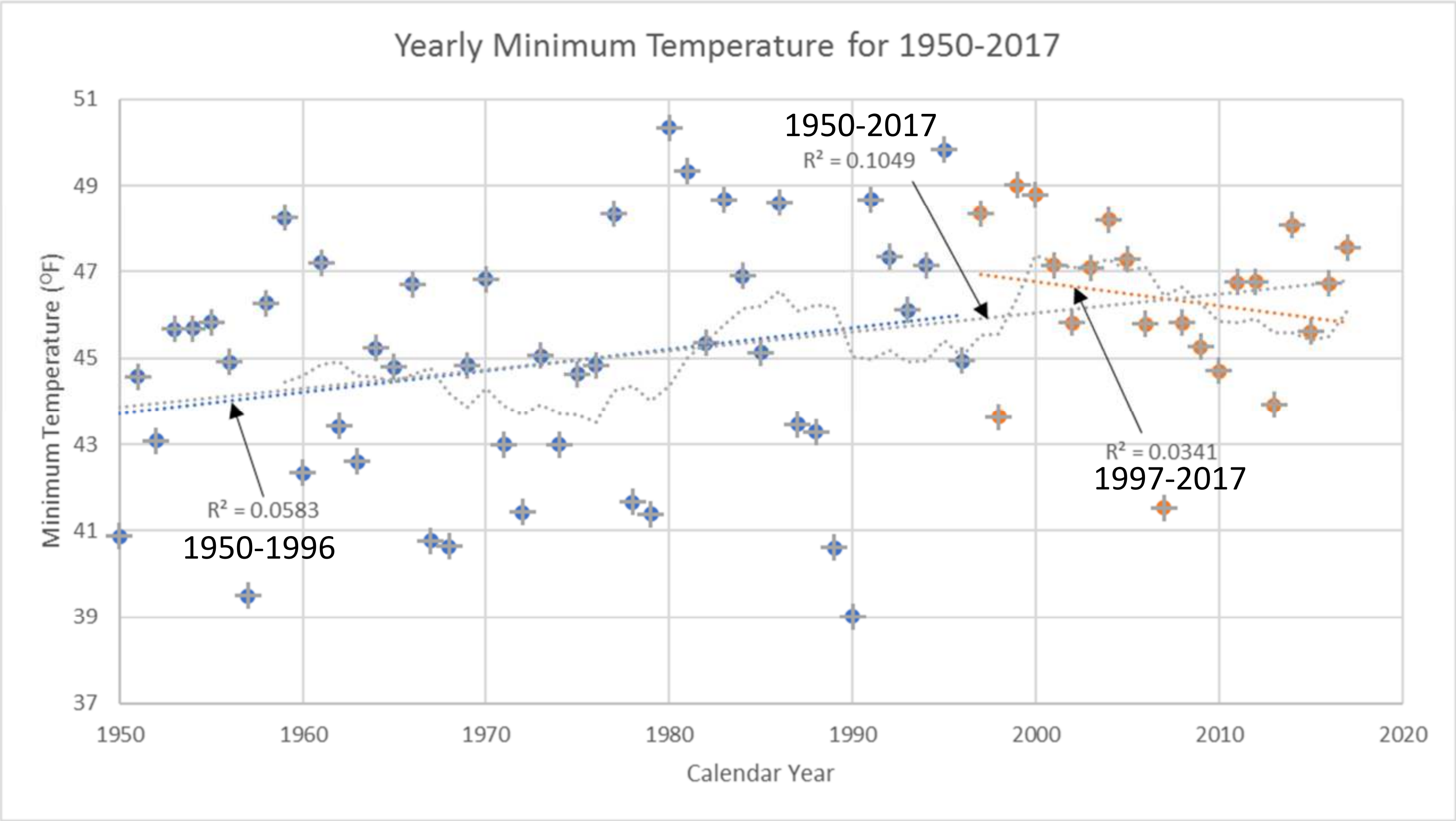
Peak Day Design Verification IV: HDD Sensitivity

- Using information from the 2018 California Gas Report, the following slopes for customers can be found:

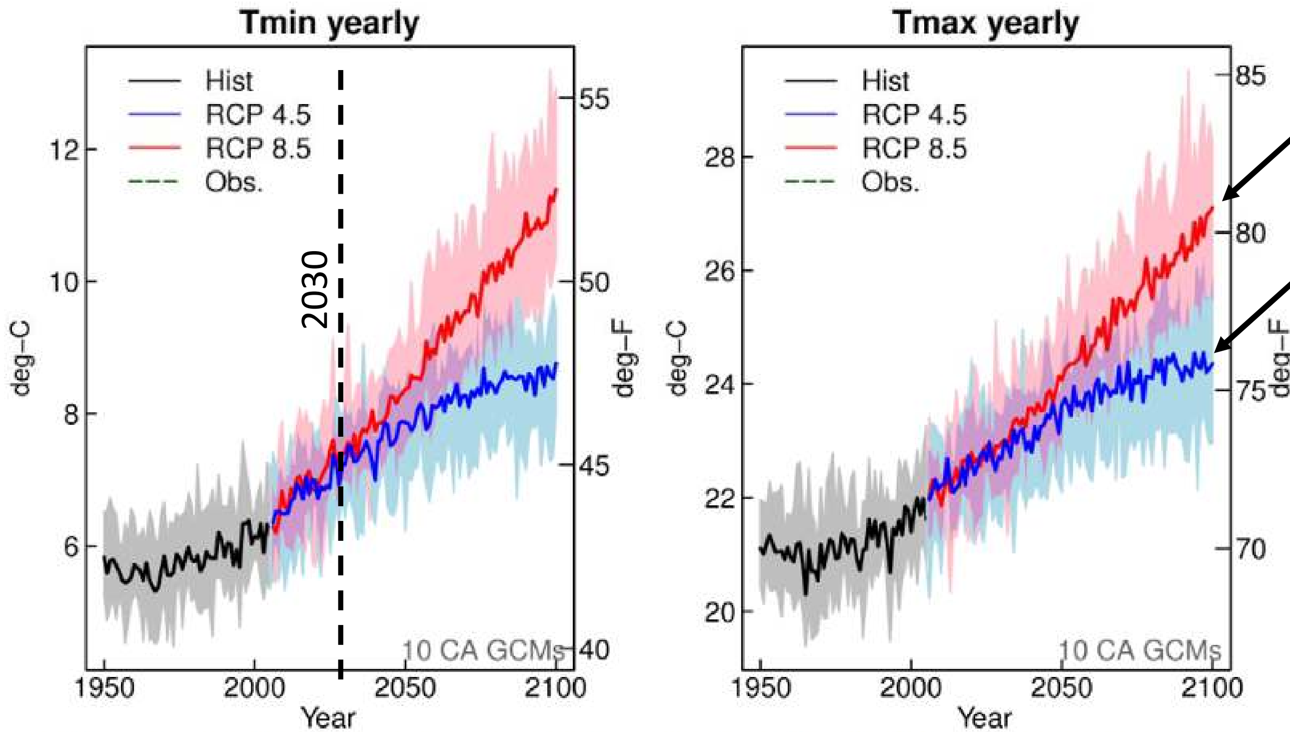
	Slope (Mdth/HDD)		
	2020	2025	2030
Core Residential	85.56	82.94	80.44
Core Commercial (G10)	13.29	13.29	13.29
Core Industrial (G10)	1.28	1.22	1.13
GAC	0.00	0.00	0.00
GEN	0.00	0.00	0.00
NGV	0.00	0.00	0.00
Total	99.99	97.45	94.87



Minimum Yearly Temperature



California's Fourth Climate Change Assessment (August 2018)



Business As Usual Scenario

Medium Emissions Scenario
2-4°C increase by 2100
3.6-7.2°F increase F by 2100
~1-2°F increase by 2030
~125-250 MMcfd decrease in SCG core gas demand

Figure 7. California statewide, annually averaged Tmin (left) and Tmax (right). The dashed green line shows the observations from Livneh et al. 2014. The grey region shows the envelope of the 10 California GCMs over the historical period. The red (RCP 8.5) and blue (RCP 4.5) lines show the multi-model average from 2006 to 2100. The pink and light blue regions show the envelope of the 10 California models over the future period, for RCP 8.5 and 4.5, respectively. This envelope represents one measure of uncertainty in the future temperature projections.

CPUC Recommendation

- Include a warming climate scenario or assumption in the California Gas Report.
  - PG&E is building an assumption of climate change:
    - 2% decrease in HDD by 2022
    - 9% decrease in HDD by 2035
  - PG&E also uses the past 20 years to calculate average HDD.

Conclusions: Peak Day Design, Long Term

- While the years 2014-2017 show some evidence of warming winters, treating the historical data with a simple linear regression results in a higher uncertainty and therefore colder peaks.
- Sensitivity analysis shows that in order to obtain a “higher” certainty from the historical data, only 7 years should be included (2011-2017), which is fewer than what is used by both SoCalGas or PG&E (20 years). Only continuing warming (or constant) weather will provide higher confidence in milder winter peaks.
- Based on historical data, the CPUC analysis **verifies** current SoCalGas forecasts of Core customers demand, which is **1.5%, 1.6%, and 2.5% decrease per year** for Core residential, commercial, and industrial, respectively, for the 2017-2035 period.

Conclusions: Peak Day Design, Long Term

- Simply fitting the minimum yearly temperature data results in a very poorly fit linear curve (R^2=0.0583 for the 1950-1996 period and R^2=0.034 for the 1997-2017 period). In other words, either more years must to be considered for forecasting, or more sophisticated models must be used.
- For example, California's Fourth Climate Change Assessment (CCCA, August 2018) projects 2-4°C increase in the minimum temperature experienced in California (not Southern California) by 2100 under medium emission scenario, which translates to about ~1-2°F increase by 2030 or ~125-250 MMcfd decrease in SoCalGas Core gas demand by 2030 (4%-8% total, or 0.3%-0.64% per year).
- Therefore, CPUC staff is recommending that SCG includes a warming climate scenario in the upcoming California Gas Report (2020).

Hourly Core Gas Demand Profiles

Methodology and Sample

Hourly Core Gas Demand Profiles

- Why derive hourly gas demand profiles?
  - Running transient simulations requires time-varying boundary conditions, i.e. the varying hourly gas demand must be introduced in order to determine its effect on gas flow and pressure (drop or spike). The flow is assumed to have a periodicity of one day, hence profiles need to be derived for only 24 hours.

Date Request #5: Advanced Meter Infrastructure

- Data request issued on March 15, 2019
- Template and sample received on April 18, 2019
- Hard drive received on July 18, 2019
- Data set contains hourly AMI readings for:
  - Core customers, by subclass (residential, commercial, and industrial)
    - 10% of customers for ZIP codes with more than 1000 customers (random sample)
    - 100 customers for ZIP codes with fewer than 1000 customers
    - All customers for ZIP codes with fewer than 100 customers
  - Noncore and wholesale customers
    - 100% of customers
- Data set is larger than 90GB.
- SDG&E not received. Data Request issued 10/18. Expected 11/18.

Hourly Core Gas Demand Profiles

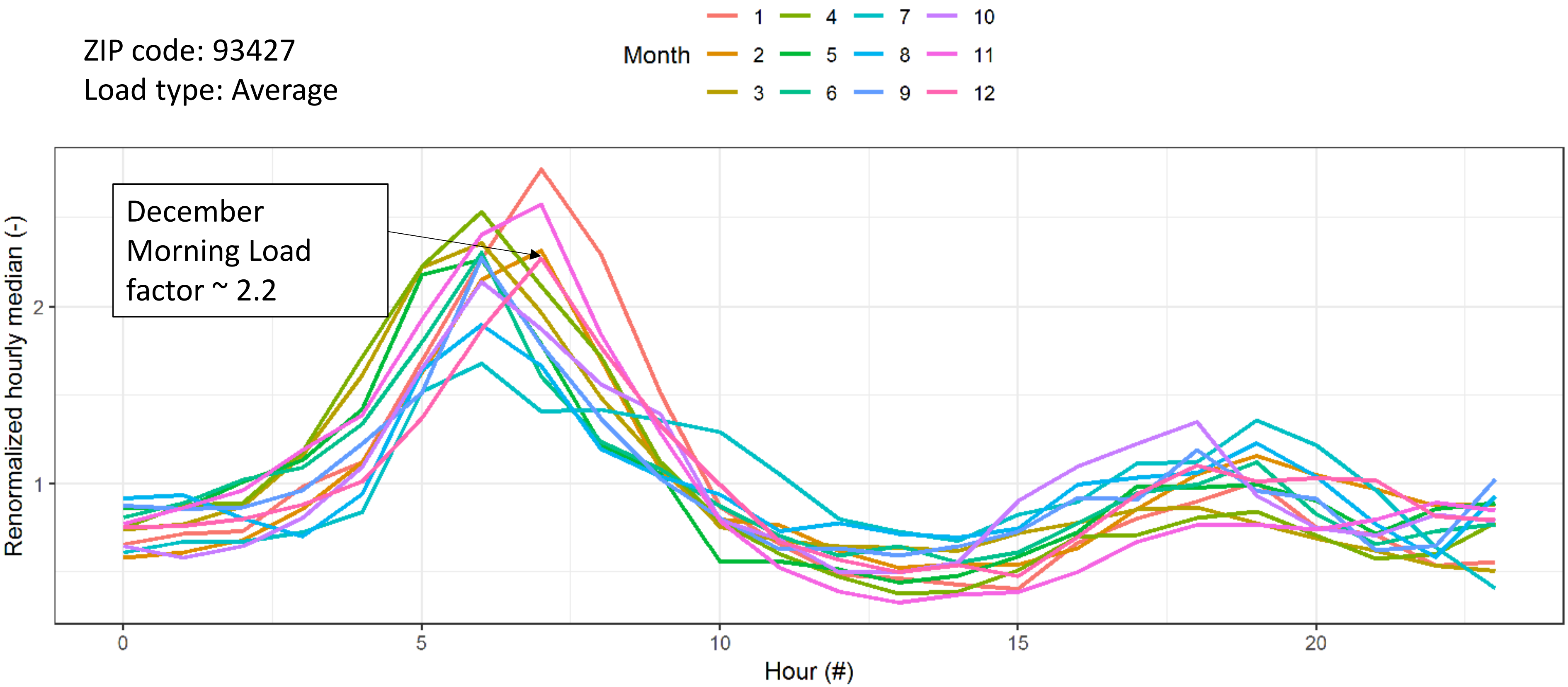
- Methodology: For each Core customer subclass, each ZIP code, and each month
  - Filter out weekends.
  - Calculate the <u>daily</u> gas demand for all customers (within that ZIP code and subclass).
  - Assign the daily gas demand to 1 of 3 bins:
    - Average demand: 45th to 55th percentile (mid-point is 50% (average gas demand).
    - Peak demand : 87.5th to 92.5th percentile (mid-point is 90% (1-in-10 gas demand).
    - Extreme demand : 94.3th to 100th percentile (mid-point is 97% (1-in-35 gas demand).
  - For each of the 3 bins:
    - Normalize the daily profile by the hourly mean (i.e. set the daily usage to 1 by dividing the hourly use by the mean hourly use (total daily use/24)).
    - For each hour, pick the median among all the days in that bin.
  - Renormalize the curves using their means.
  - The result is 3 normalized profiles for each ZIP code, each month, and each subclass.

Hourly Core Gas Demand Profiles

- If only 2018 AMI data is used, this methodology results in approximately 3 days being used to derive the average hourly gas profile and 1-2 days to derive the peak and extreme peak hourly gas profiles. The days may vary by month, ZIP code, and customer class.
- If 2017 and 2018 AMI data is used, the number of days used to generate the profiles will double, but some difficulty will arise due to the varying number of customers who are AMI-enabled. CPUC decided to use only 2018 data.
- A **higher load factor** doesn't necessarily reflect a higher peak demand (CCF/hr) because the gas demand profiles are **normalized**. In other words, a ZIP code with a (mean-to-peak) load factor of 1.4 and daily demand of 100CCF, will have a higher peak than a ZIP code with a load factor of 1.7 and daily demand of 50CCF/day (100/24*1.4 > 50/24*1.7)

Sample Gas Demand Profile (Residential)

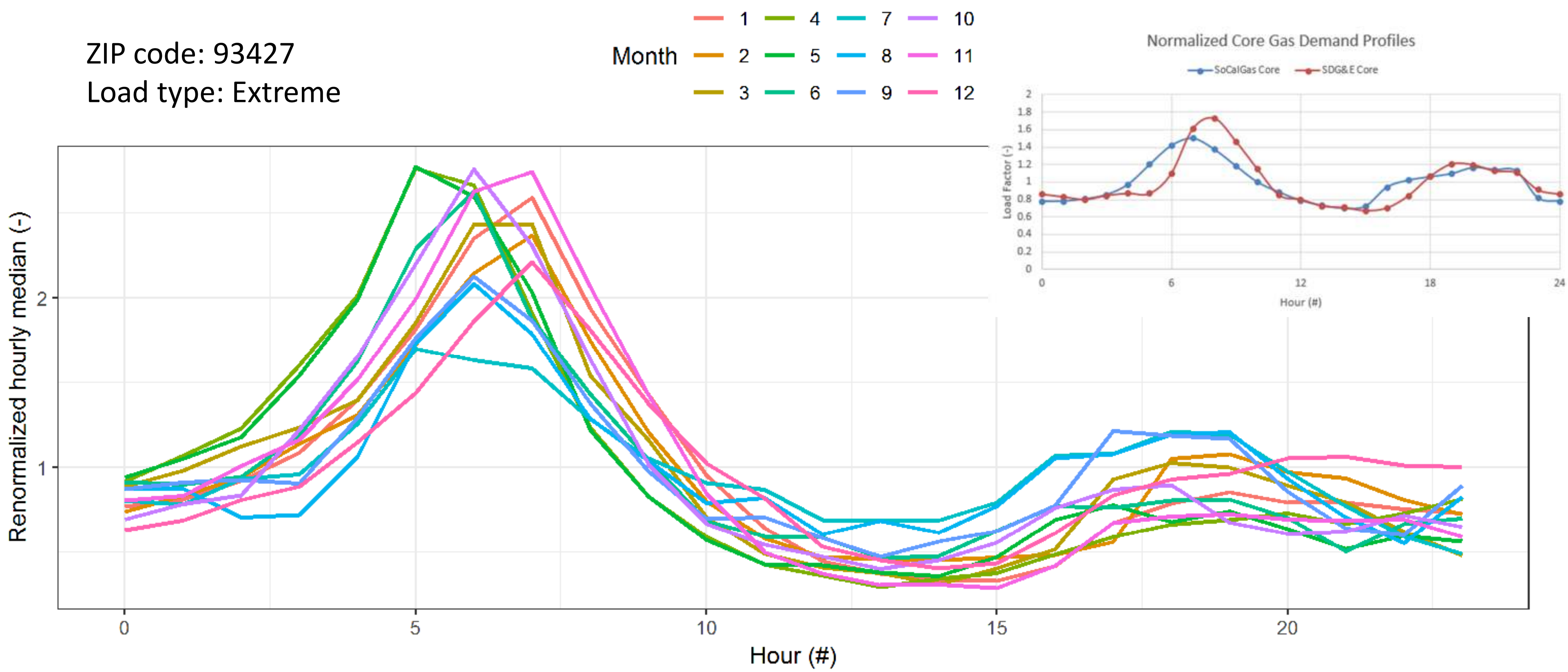
ZIP code: 93427
Load type: Average



Source: Data Request #5: AMI_RES_10PERCENT_DATA_ZIPS50.csv

Sample Gas Demand Profile (Residential)

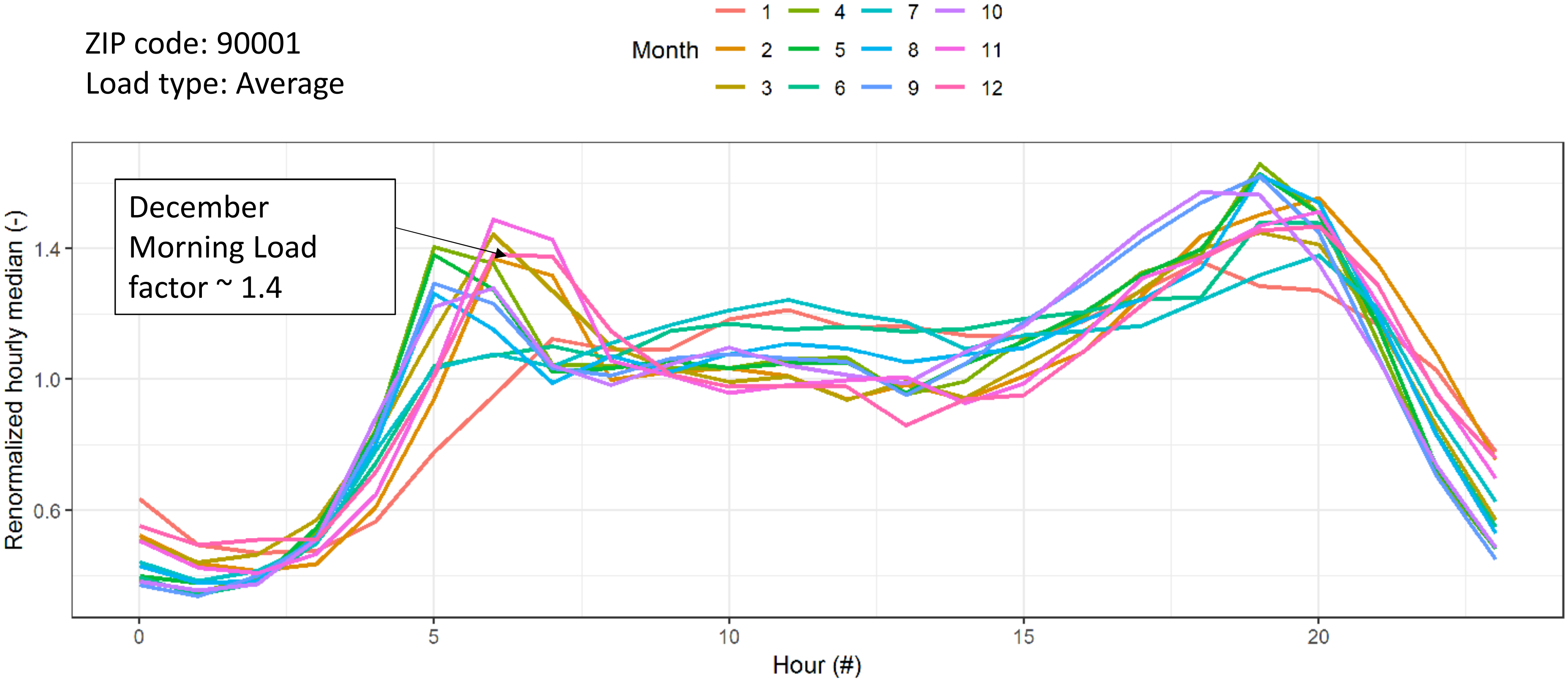
ZIP code: 93427
Load type: Extreme



Source: Data Request #5: AMI_RES_10PERCENT_DATA_ZIPS50.csv

Sample Gas Demand Profile (Residential)

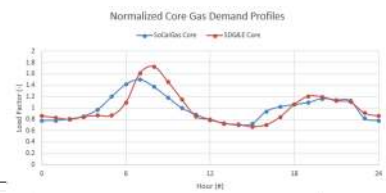
ZIP code: 90001
Load type: Average

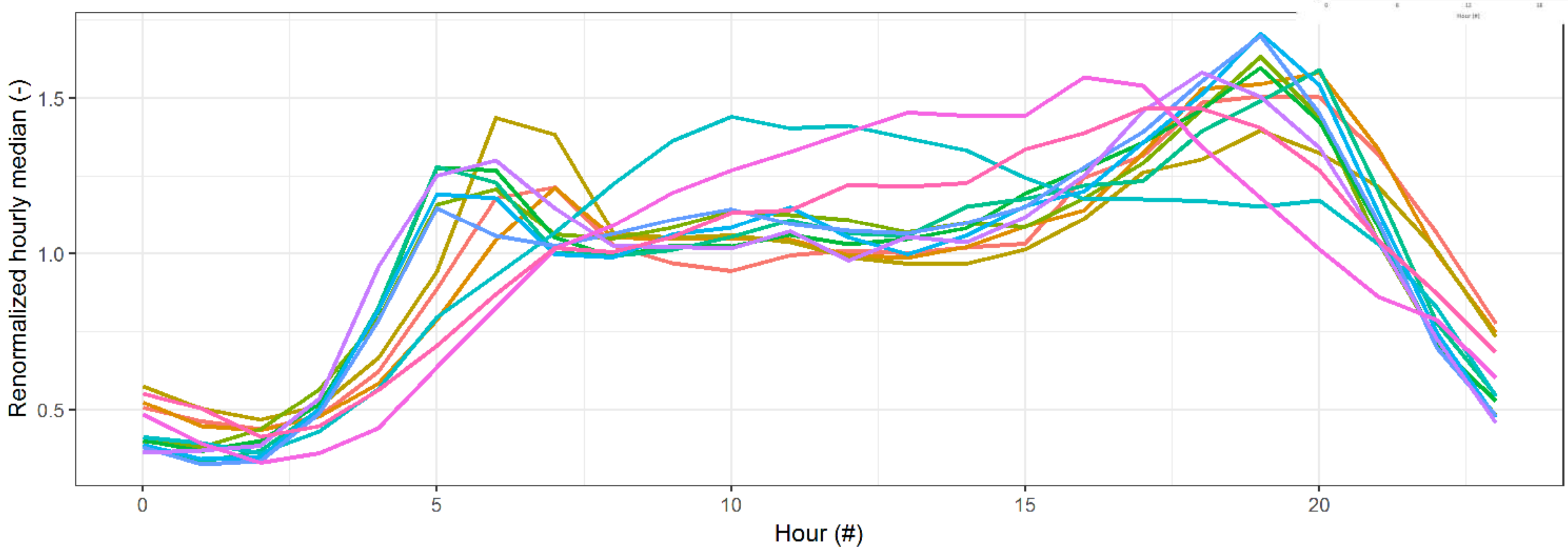


Source: Data Request #5: AMI_RES_10PERCENT_DATA_ZIPS01.csv

Sample Gas Demand Profile (Residential)

ZIP code: 90001
Load type: Extreme





Source: Data Request #5: AMI_RES_10PERCENT_DATA_ZIPS01.csv

Conclusions: Hourly Core Profiles

- Analysis of 2018 AMI data shows a lot a variability across the different ZIP codes and months which merits the inclusion of such geographical and seasonal granularity in the hydraulic modeling.
- Compared to SoCalGas Core hourly profile, some ZIP codes have a higher load factor, while other ZIP codes have a lower load factor.

Next Steps: Merging Hourly Profiles

- Synergi (the hydraulic modeling software) has a limitation on the number of profiles that can be used in a single run (~2,000 profiles).
- Profiles of subclasses of Core customers must be merged together to reduce the number of total profiles.
- More merging may be possible by climate zones or by geographical proximity of ZIP codes. Merging profiles by ZIP code will also average out outliers.
- Sensitivity on the percent of customers that would yield a correct representative profile.

Thank you

Discussion

Appendix

Data Request #6, Question 1 Follow up

- CPUC: What is the methodology used to obtain the “estimated sendout” of Core and Noncore customers that SoCalGas sent in DR6 Question 1?
- SoCalGas: Question 1, is primarily the sum of the gas usage of each of our Noncore customers as measured by their meters. If a Noncore meter does not read correctly on a particular day, an estimate of the usage for that meter will be used. The sum of these estimates makes up the rest of the “estimated sendout” for the Noncore customers in DR 6, Question 1.

Data Request #6, Question 1 Follow up

- SoCalGas Continued: The “estimated sendout” for a given day for the Core customers in DR 6, Question 1, is residually calculated according to the below steps:
  - The “estimated sendout” of the entire Noncore customer group is subtracted from the measured total sendout.
  - An estimate of the total gas usage of CTA customers is also subtracted from the result of step 1. This CTA customer usage is estimated based on the historical usage per meter for CTA customers adjusted by meter growth assumptions for those customers.
- The remaining quantity is taken as the "estimated sendout” for the retail Core. This estimate is composed of the Core usage of the customers of SoCalGas’ Gas Acquisition department, company use fuel, and lost and unaccounted for gas (LUAF). Any unknown measurement errors in the previously described metered usages or any errors in the previously described estimates will lead to error in the “estimated sendout” of the retail Core.

Date Request #6, Question 11 Follow up

- How is the "system-wide" temperature calculated?
  - Get the daily maximum and minimum temperature for 15 weather stations.
  - Calculate the average daily temperature as the midpoint of the maximum and the minimum.
  - For each of the 6 climate zones (High mountain, Low Desert, Coastal, High Desert, Interior Valleys, and Basin), average the readings from the different weather stations with <u>equal</u> weights.
  - Calculate a <u>weighted</u> average across all 6 climate zones using the proportion of gas customers in 2017 within each climate zone.
  - This is the same temperature used in the California Gas Report Workpapers to calculate the number of Heating Degree Days (HDD).

Forecasts vs Actuals (SoCalGas vs PG&E)