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Witness: Jalal Awan

REDACTED

PREPARED TESTIMONY OF

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PG&E PEAK DAY GAS SUPPLY STANDARD

Submitted on Behalf of

THE UTILITY REFORM NETWORK

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PREPARED TESTIMONY OF JALAL AWAN
ON BEHALF OF THE UTILITY REFORM NETWORK

I. INTRODUCTION

In this testimony I will address portions of Pacific Gas and Electric Company's (PG&E's) application to modify the Peak Day Supply Standard (PDSS) for its natural gas system. The PDSS is intended to determine the amount of gas system capacity (pipeline and storage withdrawal) needed to provide reliable service on a winter peak day that is defined as an extreme cold day expected to be met or exceeded only once every ten years (with a 1/10 or 10% probability of occurring in any given year). This application was filed pursuant to the Commission's direction in the last PG&E General Rate Case (GRC) decision, D.23-11-069, specifically Ordering Paragraph 12 and the discussion at page 159 referenced in the introduction to the testimony of Michel Peter Florio on behalf of TURN.[1]

The Assigned Commissioner's Scoping Memo identified a single issue for this proceeding: "Did PG&E comply with the requirements in D.23-11-069 for updating its Peak Day Supply Standard Analysis?"[2] Based on my analysis below and the facts presented in Mr. Florio's testimony, TURN concludes that PG&E did NOT COMPLY with the requirements of D.23-11-069.

My testimony focuses on PG&E's forecast and methodology for "Core Demand" in its PDSS application.[3] Specifically, my analysis examines whether PG&E's design day analysis,

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[1] TURN-01, p.1 (lines 18-20 and 22-26) and p.2 (lines 1-4).

[2] Assigned Commissioner's April 17, 2025, Scoping Memo, subsequently modified on May 12.

[3] PG&E's Core Demand forecast appears in Line 1 of Table 3 on page 6 of PG&E's testimony, Exhibit PG&E-01.

developed by third-party vendor Marquette Energy Analytics (MEA), accurately predicts 1-in-10 design day core demand across PG&E's service territory. I evaluate best practices in linear regression analysis, including but not limited to, model selection, input data and assumptions on meteorological variability, and modifiers used by PG&E on top of MEA's analysis for future building electrification, and climate-driven warming.[4,5] I conclude that PG&E's Core Demand forecast is unreasonably high because of several methodological issues, unsupported upward adjustments and unreasonable assumptions, resulting in PG&E's failure to comply with the Commission's directive to "resolve uncertainties" and/or "improve its methodology".

My qualifications are included at the end of this testimony.

II. SUMMARY OF RECOMMENDATIONS

I offer the following recommendations in this testimony, which are supported in more detail in subsequent sections of this testimony. The Commission should:

1- Adopt the Most Accurate Regression Model-Based Forecast of Peak Day Core Demand

Specifically, the Peak Day Supply Standard should use 2,500 MDth (thousand decatherms per day) as the winter 2024-2025 peak-day core gas demand initial estimate

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[4] TURN-03-Q012 (explaining that PG&E retained MEA for $26,500 for the peak day demand forecast).

[5] The discovery process regarding core demand was notably irregular. TURN's initial discovery request focused on core demand (2 questions, with 24 subparts) of August 16, 2024, seeking basic information on MEA's demand forecast, was met by PG&E's proposal on September 6, 2024, for TURN to engage MEA at an hourly rate of $370 for responses (TURN-03-Q01 a-d). Subsequently, TURN significantly narrowed its request (2 questions, with 10 subparts) on November 20, 2024. MEA's belated response on January 14, 2025, was followed by PG&E's refusal to provide responses to TURN's targeted follow-up discovery (2 questions, 2 sub-parts). This testimony is therefore based on the limited information TURN was able to obtain from PG&E about MEA's analysis.

(from Model 5), which has the highest R² (98% for all days, 88.3% on cold days).[6] This selection avoids over-reliance on the ensemble's unusually high forecast (2,586 MDth), based on arbitrarily assigned and unsupported regression model weights.

2- Refine the Detrending Methodology and Remove the Winter Severity Adjustment

The Core Demand Forecast should be further improved by more fully reflecting current customer base characteristics in the load detrending approach. As TURN's analysis of unadjusted and "detrended" load shows, MEA's approach to adjusting historical data appears to be inadequate, showing no significant difference between unadjusted and supposedly "detrended" load. At a minimum, the Commission should eliminate the extra 17 MDth "winter severity adjustment" that stacks atop other conservative assumptions and inflates core demand.

3- Revise the Climate Change (CC) Modifier to More Accurately Reflect Core Demand Reduction due to Climate Change

The Core Demand Forecast should incorporate TURN's recommended CC-driven reduction (4–25 MMcf/d by 2030), reflecting more realistic winter warming scenarios under IPCC's SSP3-7.0 scenario.

Table 1 below compares PG&E's Core Demand Forecast (MMcf/d) for Winters 2024-2025, 2025-2026, and 2026-2027 with the alternative forecast that results from TURN's three recommendations.

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[6] See TURN-03-Q02.e, Revised 14, 2025. R² (R-squared), or the coefficient of determination, quantifies the proportion of variance in the dependent variable that is predictable from the independent variable(s) in a regression model. Expressed as a value between 0 and 1 (or 0% to 100%), R² values above 0.90 (or 90%) indicate very strong model fit.

Table 1: PG&E’s vs. TURN’s Core Demand Forecast (MMcf/d)

for Winters '24-'25, '25-'26, and '26-'27

Core Demand (MMcf/d)	Winter 24-25	Winter 25-26	Winter 26-27
PG&E’s Proposed Core Demand (MMcf/d)	2,491	2,491	2,488[7]
Core Demand based on TURN Recommendations 1-3 (MMcf/d)	2,392	2,392	2,387
Difference (PG&E > TURN)	99	99	101

As shown in Table 1, TURN's recommendations result in a combined core demand forecast of 2,392 MMcf/d for winter 2024-25 compared to PG&E's higher forecast of 2,491 MMcf/d. For winter 2025-26, TURN's recommendations yield 2,392 MMcf/d versus PG&E's 2,491 MMcf/d, maintaining the same 99 MMcf/d difference. For winter 2026-27, TURN's recommendations result in 2,387 MMcf/d compared to PG&E's 2,488 MMcf/d, representing a 101 MMcf/d difference.

III. PG&E’S 1-IN-10-YEAR CORE DEMAND FORECAST IS TOO HIGH BECAUSE THE UNDERLYING FORECAST METHOD, ASSUMPTIONS, AND INPUT DATA FAVOR HIGHER CORE DEMAND ESTIMATES

PG&E’s core demand forecast is based on a design day study by MEA, wherein a 1-in-10-year design day condition (or DDC) is defined as an extreme cold day, one that is expected to be met or exceeded only once every ten years. The specific design day weather is characterized by a wind-adjusted temperature (“TempW”) or equivalently a wind-adjusted heating degree day (“HDDW”).[8] This metric incorporates wind chill effects into the heating degree day calculation,

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[7] Note that TURN found a discrepancy in PG&E’s calculation of Winter ’26-’27 core demand of 2,488 MMcf/d, which appears to incorrectly incorporate PG&E’s BE/CC modifiers. Correcting this error yields a PG&E forecast of 2,486 MMcf/d for Winter ’26-’27.

[8] HDD (Heating Degree Day) is a measure of how much the daily average temperature falls below a pre-specified threshold (e.g.65°F), indicating heating demand. HDDW implies post-wind adjustment HDD.

recognizing that gas heating demand rises on windy days even at the same temperature.[9] For PG&E's service territory, MEA calculates a 1-in-10 year, wind-adjusted, design day condition of 34.6°F TempW (or 30.4 HDDW), meaning that, on average, one day in ten years should meet or exceed these conditions. MEA uses this framework to forecast that the Core Design Day demand for the 2024–2025 winter will be approximately 2,588 MDth [10].

The Commission should not adopt the resulting Core Demand Forecast in PG&E's Peak Day Supply Standard Analysis because of the methodological and assumptional flaws that inflate core demand discussed below.

A. MEA's Regression Analysis Makes Incremental Improvements in Model Accuracy, But Ultimately Undervalues the Best Model Fit – TURN's Recommendation 1

MEA employs a suite of 5 regression models and 3 linear fit models to estimate core demand under design day conditions. Rather than relying on a single model, five slightly different regression models (plus supplemental "linear fit" models) are developed and later combined. Each model correlates core gas demand with weather metrics (HDDW, etc.), capturing the relationship between temperature and demand.[11] Importantly, historical load data are first "detrended" to reflect current customer behavior (e.g. baseload usage and heat usage per

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[9] PG&E (with MEA's internally developed methodology) applies a correction formula to adjust HDD for wind: for example, on days with high winds (>8 mph), the effective HDD is scaled up (and scaled down at very low wind) to capture the extra heat loss due to wind (see Exhibit PG&E-01, AtchD-5).

[10] See Table 2 in Exhibit PG&E-01, AtchD-3.

[11] MEA uses historical weather data from 1950-2024 for the analysis, while PG&E erroneously states that it used 1970-2024 data in Exhibit-01, p.7. Moreover, in response to TURN-03-Q01.d (Revised, Jan 14, '25), MEA acknowledges the original statement on weather station weights was "slightly incorrect" and offers only a vague justification - that weights "should be strongly correlated" with load - but provides no supporting data. Due to the irregular DR process (see fn 3), TURN was unable to obtain a follow-up response clarifying the weather station weighting methodology that underpins all subsequent MEA modeling. Notwithstanding this, our subsequent analysis does not attempt to correct for or suggest a different weather data source or weighting methodology.

HDDW) before fitting these models. Detrending is supposed to adjust for changes over time – e.g. population growth, efficiency improvements, electrification – so that older cold-weather data does not overstate today's demand if customer usage per heating degree day (or HDD) has fallen due to increased efficiency or other factors (or understate demand if usage has risen).

1. Base Model, Four Incremental Model Enhancements, and Three Linear Fit Models:

MEA's Model 1 serves as the foundational regression model for forecasting core gas demand. It uses five explanatory variables: a baseload intercept, wind-adjusted heating degree days at 65°F (HDDW65) and 55°F (HDDW55), cooling degree days at 65°F (CDD65), and the change in HDDW from the previous day (ΔMHDDW). These terms help capture both steady-state heating needs and sharper load increases on very cold or rapidly cooling days. The model was fit on 1998–2023 data and achieves a strong R^2 of ~96%, offering a solid starting point for exploring demand under design day conditions.

In practice, MEA follows a forward selection-style approach, incrementally building complexity across four additional models (Models 2–5) to capture different temporal patterns[12]:

- **Model 2** limits the dataset to Monday–Thursday, capturing higher midweek demand and offering an upper bound if a cold snap occurs on a peak weekday.

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[12] TURN-03-Q02.d, Revised 14, 2025. Note that MEA acknowledges that there is no working or peer reviewed paper on the methodology used, and that the code underlying this analysis cannot be provided. Therefore, TURN's analysis focuses solely on methodological gaps based on best practices for linear regression. We have not independently tested statistical assumptions - such as heteroscedasticity, residual behavior, or input variable normality - and assume MEA addressed these prior to applying its regression modeling approach.

- **Model 3** retains all days but adds Fourier terms[13] to model recurring day-of-week (DOW) variation in both baseload and heating response, simulating demand as if the design day occurs on a Wednesday.
- **Model 4** introduces seasonal Fourier terms to reflect day-of-year (DOY) effects, modeling gradual demand shifts across the winter. It simulates five winter dates and selects the highest (typically mid-January).
- **Model 5** combines both DOW and DOY adjustments on top of Model 1, with 21 total parameters. It provides the best statistical fit ($R^2 \approx 98\%$ on all days, ~88% on cold days), simulating cold snaps on Wednesdays across multiple winter dates to find peak demand.

While Model 5 is technically the most accurate, MEA ultimately uses a blended ensemble that gives arbitrarily more weight to simpler models. In addition to its five main regression models, MEA also developed three simpler linear fit models as a cross-check focused specifically on the coldest days. These models fit a straight-line relationship between demand and wind-adjusted HDD (HDDW), using only the coldest 20% of days in the historical record. Importantly, MEA notes that the "the 8 regression models are only used to make the 2023-2024 estimates" and that "the 2023-2024 estimate is adjusted (upwards) based on the forecasted change in baseload and Heatload".[14]

2. MEA's Choice of Model Weights Overestimates Core Demand

After developing these 8 models, MEA does not simply choose one winner. Instead, it performs ensemble forecasting – combining the models' results to get the final design day

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[13] Fourier terms represent cyclical patterns using sine and cosine trigonometric functions, and are frequently used in climate science, signal processing, and energy forecasting.

[14] TURN-03-Q02.e, Revised Jan. 14, 2025.

demand estimate. MEA prioritizes the simpler, all-days models for reasons of robustness: Model 1 and Model 2 each received 5/20 weight (25% each), Model 3 and each of the three linear fits received 2/20 (10% each), and Models 4 and 5 received only 1/20 each (5% each).[15] The linear fit models, which only use a subset of 20% coldest days, are given higher weights (total 30%) compared to the most statistically accurate model (i.e. Model 5 = 5%).[16] This weighting scheme heavily emphasizes Models 1 and 2 (together 50% of the final result) and significantly down-weights the most complex (and accurate) Model 5 despite its superior fit. MEA unconvincingly explains that Models 1 and 2 are intentionally given more influence because they are simpler and used in the detrending process itself.

In summary, MEA's methodology rests on an ensemble of five regression models (with different data filters and seasonal controls) and three cold-day linear extrapolations as a cross-check. Overall, the arguments in favor of the "ensemble" or consensus forecasting suggest that, by averaging across models of varying complexity and data treatments, the hope is to capture the best aspects of each and cancel out individual model biases. The result of this ensemble (and its 95% upper confidence interval estimate) is presented as the final 1-in-10 design day demand forecast.

3. MEA's Ensemble Forecast is 88 MDth Higher Than the Best-Fit Model

MEA's final 1-in-10 peak day forecast for core demand is 2,588 MDth (thousand decatherms per day) for the winter 2024-25 period.[17] This value is notably higher than some of

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[15] Table in TURN-03-Q02.e, Revised Jan. 14, 2025.

[16] TURN-03-Q02.e, Revised Jan. 14, 2025. MEA states that the three linear fits, fitted only on the 20% coldest days, do not allow for the examination of baseload and heatload, and are "deprioritized", but in fact, receive 30% weight.

[17] Exhibit PG&E-01, Table 2, Atch D3.

the individual model estimates – in particular, Model 5 (the most complex model with highest R^2) predicted about 2,500 MDth.. Model 5 also demonstrated the best statistical fit to historical data ($R^2 \approx 88.3\%$ on cold-day validation) among all models. The fact that the chosen ensemble outcome exceeds Model 5 by ~3.4% raises the question of why the highest-fidelity model's result was not given more weight, or even selected outright, in forecasting the design day. Table 2 below summarizes the design day demand estimates from each model and the ensemble:

Table 2: PG&E Design Day Demand Estimates for Regression Models 1-5[18]

Model	**Description**	**1-in-10 Peak Day Demand (MDth)**	**R^2 (fit quality)**
Model 1	Base model (all days)	2,492	96.4% (all days); 81.3% (cold days)
Model 2	Base model, Mon–Thu only	2,560	96.0% (all); 83.8% (cold)
Model 3	Base + Day-of-week (DOW) terms	2,540	96.8% (all); 83.5% (cold)
Model 4	Base + Day-of-year (seasonal) terms	2,441	97.6% (all); 85.7% (cold)
Model 5	Base + DOW & seasonal terms	2,500	98.0% (all); 88.3% (cold)

This ensemble approach results in over-estimating demand relative to what the most accurate model indicates. It is worth noting that Model 5's 2,500 MDth was not an outlier – it lies in the middle of the range of model outputs (which spanned 2,441 for Model 4 to ~2,680 MDth for the Linear Fit 2), whereas the ensemble's 2,560 MDth is higher than the top quartile of that range.[19] While ensemble averaging is a sound practice generally, here it effectively overrides the highest-R^2 model's insight. Model 5 captured both weekly and seasonal peaks (day-of-week

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[18] Source: TURN-03-Q02(c) and (e), Revised Jan. 14, 2025.

[19] Mean of Models 1-5: 2,506 MDTh, Top Quartile (or 75th percentile): 2,540 MDTh.

and day-of-year) and had the best fit on extreme cold days, suggesting it may be the most reliable for extrapolating to a design-day event. The fact that Model 5's estimate was lower could indicate that simpler models (1 & 2) over-predict peak demand by not accounting for diminishing returns at very low temperatures (for which Model 5's extra parameters presumably account). By heavily weighting Models 1 and 2, the ensemble thus may retain that over-prediction. The ensemble's own R^2 on cold days (about 84.9%) is lower than Model 5's 88.3%, confirming that the arbitrarily weighted ensemble outcome may not be as statistically accurate on the tail as Model 5 alone.

Moreover, MEA's reasoning that ensemble forecasting is well-accepted holds when model errors are truly independent, but here all models are built on essentially the same data and similar forms (except the linear fits). Their errors are not independent but rather structurally related. The ensemble might therefore not add as much new information as assumed, and instead just skews the result upward.

B. MEA's Winter Severity Adjustment is Wholly Unjustified - TURN's Recommendation 2

MEA applies an additional 17 MDth "winter severity adjustment" to the final ensemble. MEA explains that in milder gas climates like California's, the regression based on average winters might under-predict usage in an exceptionally cold winter. Several unsupported assumptions underlie this 17 MDth adjustment, including the introduction of a "1-in-5-years winter cold month" parameter, and the use of another arbitrary weighting scheme for Models 1-5 (5/14, 5/14, 2/14, 1/14, 1/14).[20]

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[20] TURN-03-Q02.f, Revised Jan. 14, 2025, states that the adjustment accounts for a deficiency in "territories where the normal total HDDWs per year are less than 5000". It further describes the winter severity adjustment as "the difference between the use/HDDW during a normal winter month and the use/HDDW during a 1-in-5- years winter month multiplied by the HDDW design day condition." MEA

Notwithstanding MEA's tendency to apply corrections only for potential underestimates in its core demand forecast, the multivariate regression models already incorporate seasonal and day-of-week effects using Fourier terms, and the use of wind-adjusted HDD variables using MEA's wind-adjustment equation account for potential wind-chill effects - making any separate "winter severity adjustment" redundant and wholly unjustified.

1. The Detrending Methodology Used by MEA Fails to Adjust Historical Load to Current Customer and End-Use Characteristics

MEA states that: "older historical load data is "detrended" to ensure that forecasts based on the historical data reflect the current customer base characteristics." The goal of detrending is to adjust decades of historical data - in this case data from 27-Feb-1998 to 08-Apr-2024 - to behave as if today's customer base and technology were in place in the past.[21] This is crucial because energy efficiency (EE) improvements and building electrification are reducing per-customer gas usage over time. MEA recognizes this and thus "detrends" older data by comparing regression coefficients over different, unspecified time windows to see how baseload and heatload per HDDW have changed. However, as shown in Figure 1 below, TURN's analysis found that unadjusted and detrended loads *****BEGIN CONFIDENTIAL** [redacted]

END CONFIDENTIAL***. In other words, while core gas demand has likely decreased in recent years due to efficiency and electrification, the current detrending method does not adequately reflect these changes in customer characteristics. The method appears to assume

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uses yet another set of arbitrary weights for models i.e. Model 1 – 35.7%, Model 2 – 35.7%, Model 3 – 14.3%, Model 4 – 7.1%, and Model 5 – 7.1% for the winter severity adjustment. The premise for applying the winter severity adjustment and the six-step method employed rely on multiple unsupported assumptions – such as the definition of a "normal" winter month, "normal" total HDDWs per year or the linear deviation assumption from normal.

[21] See Exhibit PG&E-01, Atch D-6, "Acquisition and validation of load data".

continuity of past trends, whereas California's climate and energy policies portend an inflection point with steeper declines in gas usage.[22]

Figure 1: Unadjusted vs. Detrended Load Correlation Plots[23]

*****BEGIN CONFIDENTIAL**

[redacted]

END CONFIDENTIAL***

2. MEA's "Use per HDDW" Contradicts Historical Trends and Overstates Future "Use per HDDW" by 23%

MEA's analysis shows historical Use per HDDW of 84 MDth/HDDW (2005-2024) and projects an increase to an average of 86 MDth/HDDW for future years (2020-2034), suggesting core demand per heating degree day will rise significantly in future years despite decades of declining core demand trends driven by efficiency gains, electrification trends, and a warming

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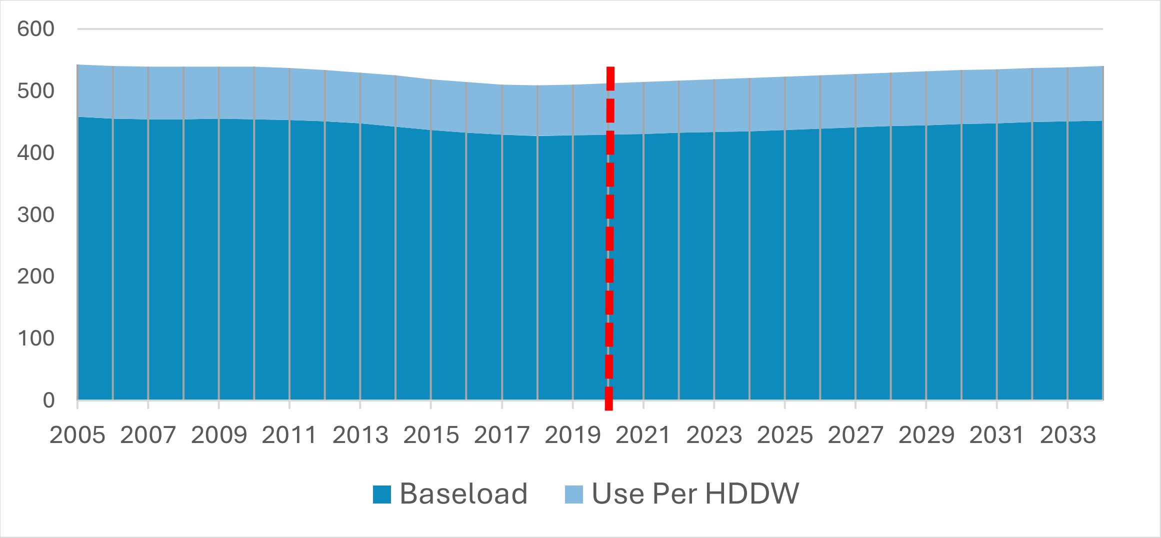
[22] See, for example, SB-1221 that aims to pursue 30 zonal electrification projects across California by 2030. Furthermore, per California Gas Report (p.35), "PG&E's average-year demand is forecasted to decline at an annual average rate of 3.0 percent between 2024 and 2040." Similarly, in A.25-04-004 (p.4), PG&E states that "Gas demand for Northern California customers served by the PG&E gas system is expected to decline at an annual average rate of 3.0 percent per year through 2040."

[23] Source: PeakDaySupplyStandard_DR_TURN_003-Q001Rev01Atch02CONF, tab "2a – Detrended Load".

climate. Specifically, after 2020, both baseload and use per HDDW are projected to depart from previous trends and increase to an average of 86 MDth (User per HDDW) from 2020 to 2034 as shown below in Figure 2. TURN's simple linear regression model - using PG&E-provided data - yields a statistically robust result ($R^2 = 0.855$) that aligns with historical patterns and suggests significantly lower "User per HDDW" i.e. 64.4 MDTh / HDDW compared to PG&E's 86 MDth/HDDW.

Figure 2: Baseload and Use per HDDW Backcast (1999-2024) and Forecast (2025-2034)[24]



TURN evaluated MEA's asserted "Use per HDDW" metric - average of 86 MDth per HDDW for 2020–2034 - using PG&E's provided temperature and core demand data.[25] TURN conducted a linear regression of daily core gas demand against HDD65 from 2005–2024 to derive predicted "Use per HDDW" for comparison against MEA's apparently inflated "Use per HDDW". Notably, a regression of demand against temperature would produce a similar, but

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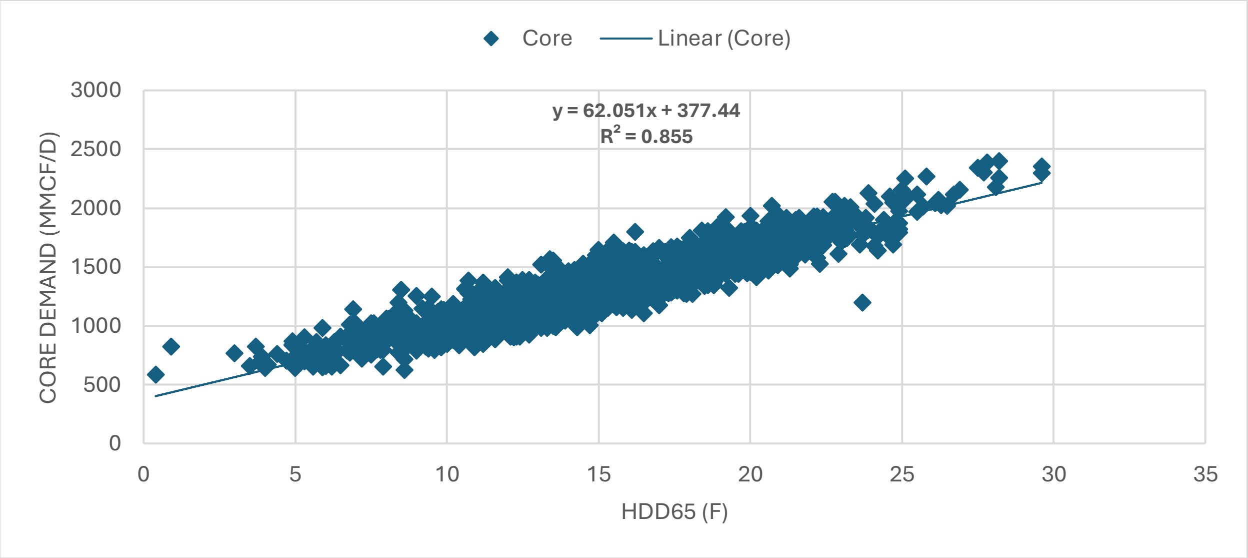
[24] Source: California Gas Report, 2024 WorkpaperpgeDesignDay.xlsx, tab "Baseload and Heatload".

[25] Source(s): PeakDaySupplyStandard_DR_TURN_001-Q024Atch01.xlsx, tab "1- Temp. Data 1999-2024" and PeakDaySupplyStandard_DR_TURN_001-Q002Atch06.xlsx, "2- Combined 2005-2024".

inversely signed, relationship since HDDW and temperature are inversely related. TURN's regression of core demand against HDD65 for 2005-2024 demonstrates a strong relationship ($R^2 = 0.855$) with each heating degree day corresponding to 62.05 MMcf/d (64.4 MDth) of demand as shown below in Figure 3.

Figure 3: Linear Regression for HDD65 vs. Core (2005-2023)[26]



This significant discrepancy between MEA's projected Use per HDDW and TURN's empirically derived "Use per HDDW" coefficient (approximately 23% less than MEA's assumption) further supports TURN's position that MEA's approach systematically overestimates future core demand by ignoring its own historical data and underestimating future efficiency improvements.

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[26] Source: PeakDaySupplyStandard_DR_TURN_001-Q002Atch06.xlsx.

C. PG&E's Climate Change Modifier Does Not Accurately Account for Climate Change Impacts - TURN's Recommendation 3

Table 23 in Exhibit PG&E-01 shows results from PG&E's approach to applying its building electrification (BE) and climate change (CC) modifiers to MEA's unadjusted (forecasted) core demand from 2025-2030.[27] . PG&E states that the CC modifier "utilizes climate models from California's Fifth Climate Change Assessment under the SSP3-7.0 scenario."[28]

The trends in annual global mean temperature increases due to climate change are clear: Annual mean temperatures have increased by ~2.5 degrees Fahrenheit (°F) since 1895. Moreover, warming has increased faster over the past 50 years.[29] Further, the daily core wind and temperature data provided by PG&E show *****BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL*****.[30] PG&E's modifier, based on California's Fifth Climate Change Assessment under the [Shared-Socioeconomic Pathway] SSP3-7.0 scenario, calculates peak temperature changes relative to the 2024–2025 winter, starting at 0°F.[31] However, assuming no temperature change due to climate change in 2025 is erroneous. PG&E's trends underestimate climate impacts compared to even the modest-intermediate range SSP3-7 IPCC scenario, as shown in Figure 4 below. In fact, extrapolating PG&E's assumed temperature

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[27] Exhibit PG&E-01, p. AtchC-72, Table 23. Note that "Core Unadjusted for BE" column in Table 23 represents MEA's design day condition forecast given in Table 2, Atch D-3 in MMcf/d. "Core With BE" in Table 23 gives Core Demand after applying PG&E's BE and CC modifiers, also in MMcf/d.

[28] Exhibit PG&E-01, p. AtchC-72.

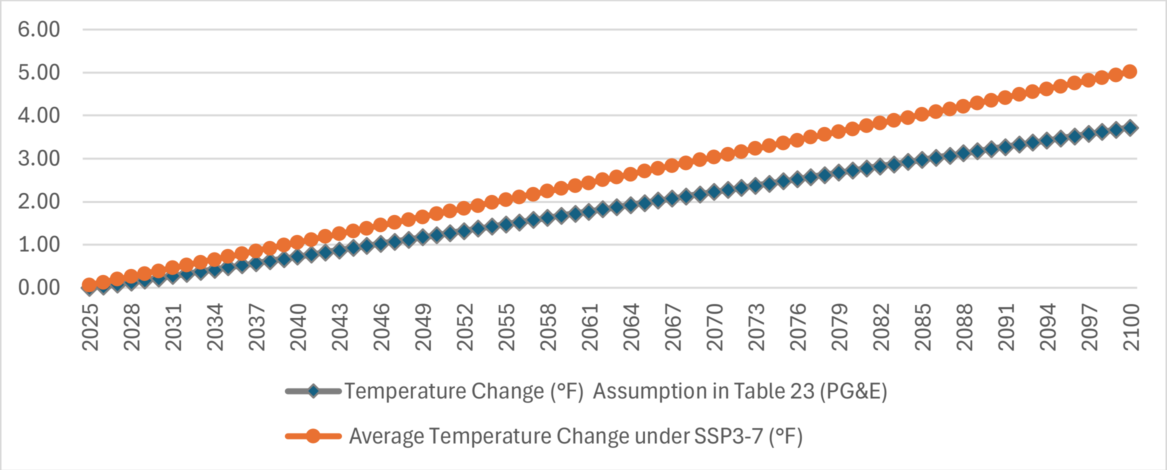
[29] State of California, OEHHA: https://oehha.ca.gov/climate-change

[30] PeakDaySupplyStandard_DR_TURN_003-Q001Rev01Atch02CONF, tab 1c - Temp & Wind.

[31] Exhibit PG&E-01, p. AtchC-72, Table 23, Winter 2024-25 Climate Change Modifier.

change based on regressing core demand on temperature, PG&E’s temperature trend yields a very modest 2.04°F change by 2100, corresponding to the most optimistic SSP1-1.9 scenario.[32]

Figure 4: Avg. Temperature Change in PG&E Table 23 vs. Under SSP 3-7.0, Assuming Linear Increase from 2025-2100.[33]



Similarly, NOAA’s average temperature trends (1900-2024) for California show consistently warming minimum temperatures during December, as illustrated in Figure 5.

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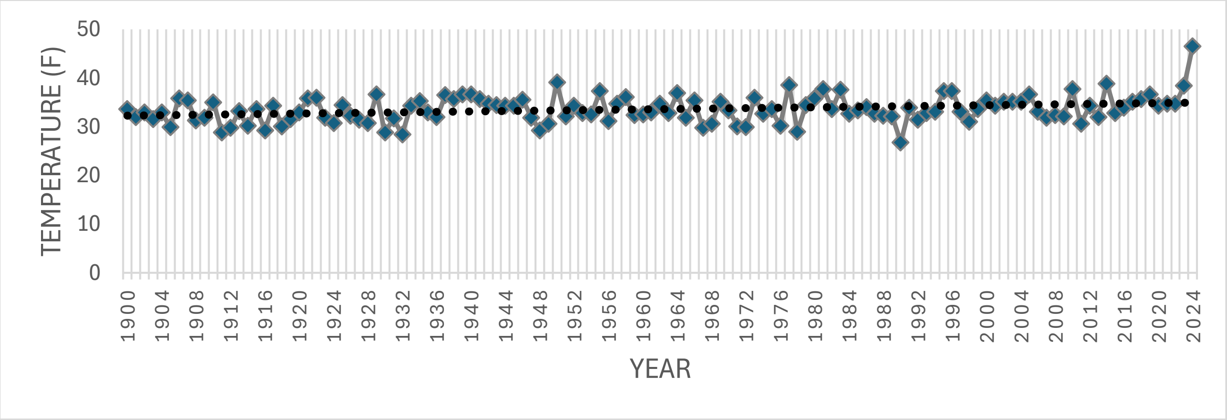
[32] https://sealevel.nasa.gov/ipcc-ar6-sea-level-projection-tool?psmsl_id=1476&info=true#:~:text=SSP3%2D7.0%20is%20a%20medium,and%20ice%20sheet%20mass%20loss.).

[33] Compared to 1850-1900, globally averaged surface air temperature over the period 2081–2100 is very likely (at least a 90% probability) to be higher by 2.8°C (5.04F)–4.6°C (8.28F) under SSP3-7.0. Assuming 5.04F is reached by 2100 gives the dotted orange temperature series. TURN contends that the linear increase of temperature is overly simplistic, but provides a ballpark on average temperature increase during the 21st century. (link: https://sealevel.nasa.gov/ipcc-ar6-sea-level-projection-tool?psmsl_id=1476&info=true#:~:text=SSP3%2D7.0%20is%20a%20medium,and%20ice%20sheet%20mass%20loss.) Note that linear temperature change is assumed in the two projections for simplicity.

Figure 5: 1900-2024 California December Min. Temperature Trend Based on NOAA Data



Using the SSP3-7.0 moderate scenario projections more accurately yields an average temperature increase from 0.07°F in 2025 to 0.40°F in 2030. Given an assumption that a 1°F increase would decrease core demand by 62 mmcf/d, as explained in Figure 3 and the accompanying text, this translates to a demand reduction from 4 MMcf/d in 2025 up to 25 MMcf/d in 2030.[34] TURN recommends using this more reasonable CC modifier to forecast core demand for purposes of the Peak Day Supply Standard. Results of applying TURN's alternative CC modifier are compared to PG&E's CC modified in Table 3.

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[34] PeakDaySupplyStandard_DR_TURN_001-Q024Atch01.xlsx: Regressing core demand on temperature suggests that 1F increase in temp. decreases core demand by 62 mmcf/d.

Table 3: PG&E vs. TURN CC Modifiers and Corresponding Core Demand Reduction

Year	Temperature Change (°F) Assumption in Table 23 (PG&E, Table 23)[1]	Demand Reduction (mmcf/d) using CC Modifier (PG&E, Table 23)	Average Temperature Change under SSP3-7 (°F) - TURN[2]	Demand Reduction (mmcf/d) under SSP3-7 (°F) TURN[3]
2025	0.00	0.00	**0.07**	**4**
2026	0.03	2.00	**0.13**	**8**
2027	0.08	5.00	**0.20**	**12**
2028	0.13	8.00	**0.26**	**16**
2029	0.18	11.00	**0.33**	**20**
2030	0.23	14.00	**0.40**	**25**

D. Overall, Historical "Core Near Design Days" Have Exceeded the Lowest of PG&E's 2024-2027 Core Demand Forecast (i.e. 2,583 MDth) Only Once Since 1950 on Dec. 22, 1998 (2,617 MDth)

Based on analysis of the "Core Historical Near Design Day" and "Core Historical Peak Days" data (1950-2024), only once has actual core demand ever exceeded PG&E's 2024-2027 design day forecast of 2,583 – 2,586 MDth.[35] This single occurrence was on December 22, 1998, when demand reached 2,617 MDth. Even under cold conditions approaching the conservative Design Day Criteria temperature of 34.6°F, such as December 21, 1998 when weather-adjusted temperature (TempW) reached 34.8°F, recorded core demand (i.e. Original Load) did not exceed PG&E's 2024-2027 design day forecast of 2,583 – 2,586 MDth.[36] Figure 6 illustrates this

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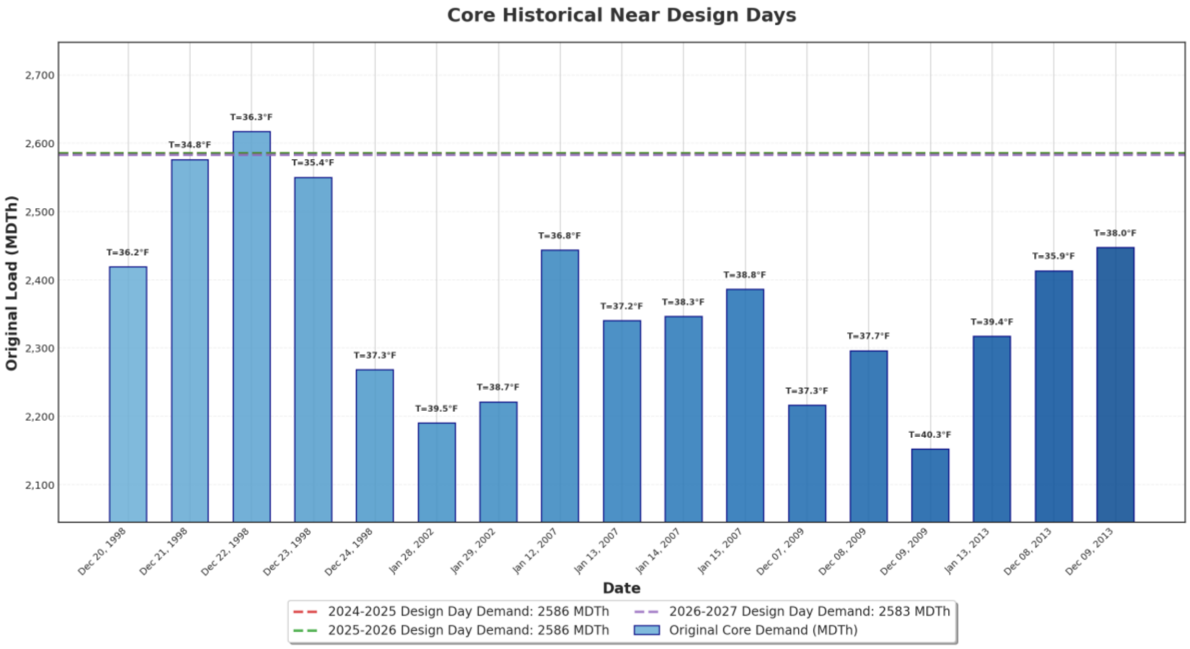
[35] California Gas Report, 2024 Workpaper pgeDesignDay.xls tabs "Core Peak Days" and "Core Hist Wx Days". Note that the analysis uses rows where "Original Load" data is provided.

[36] However, as mentioned in the preceding text, original load did exceed PG&E's core demand forecast on Dec. 22, 1998 – one day after the lowest recorded 34.6°F TempW in the series. The change in HDDW from the previous day (ΔMHDDW) term in MEA's regression may account for this next-cold-day effect, without a 17MDTh winter severity adjustment as proposed by PG&E.

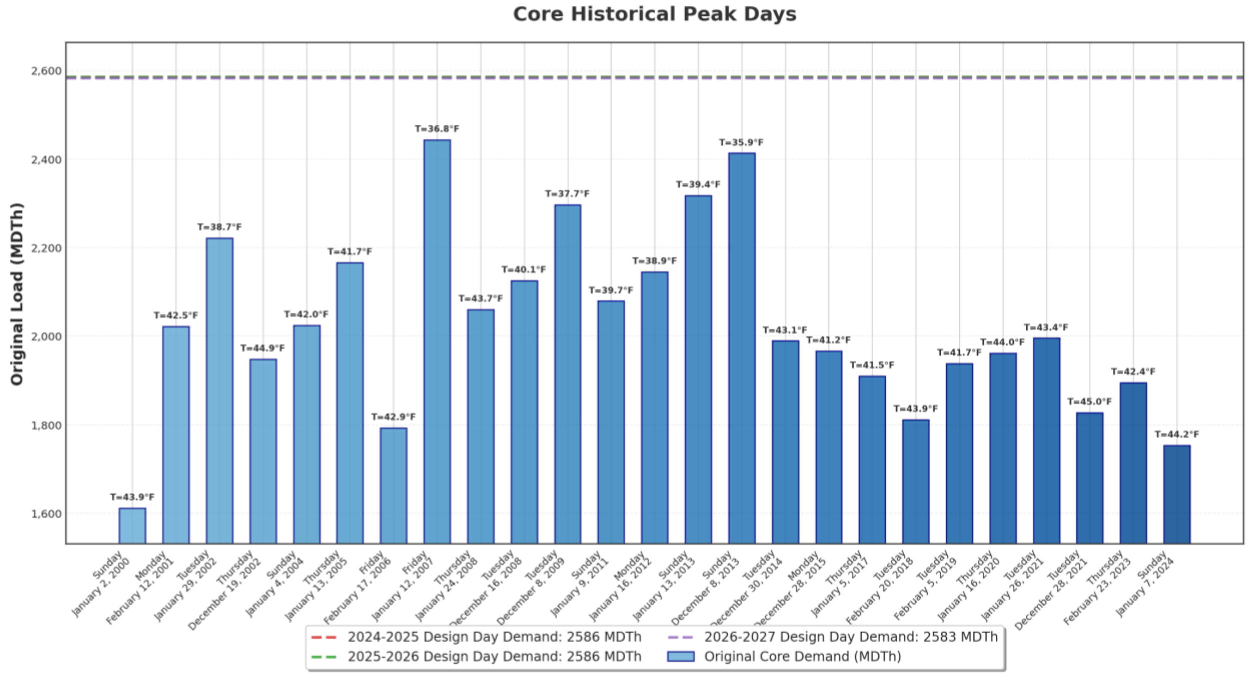
comparison between core historical near design days and PG&E’s design day core demand projections.

Figure 6: Core Historical Near Design Days Compared to Design Day Core Demand Projections (dotted lines)



More recent data (2000 onwards) shows that core demand peaks during this century have consistently remained well below forecast levels, with the highest recent demand being 2,413 MDth on December 8, 2013. These trends, shown in Figure 7 below, accompanied by the fact that climate change has caused global temperatures to increase in the recent past, support the conclusion that PG&E's methodology, which relies heavily on ensemble modeling rather than the best-fit statistical model, systematically overestimates future core demand requirements.

Figure 7: Historical Peak Days for Core Compared to Design Day Core Demand Projections (dotted lines)

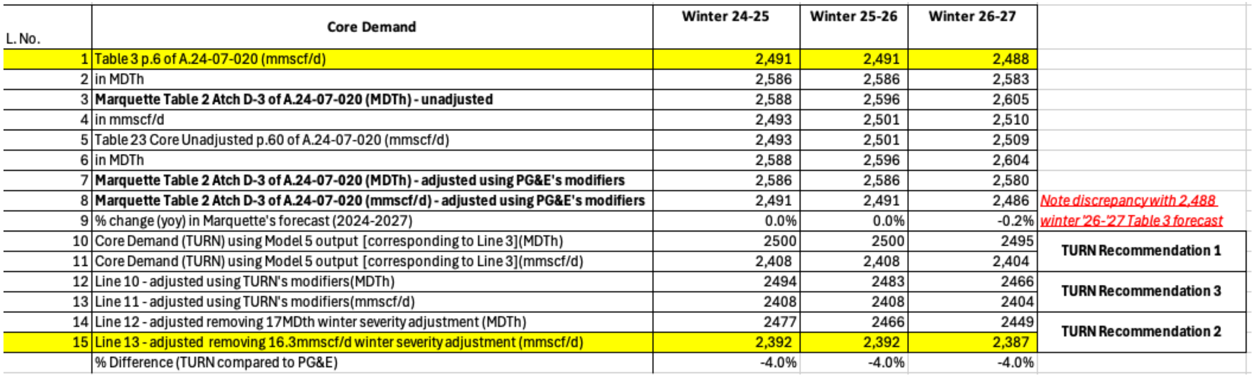


IV. CONCLUSION

In conclusion, my assessment finds that PG&E's methodology contains significant flaws - using ensemble modeling with arbitrary weights, inadequate detrending, and adding an unwarranted 17 MDth winter severity adjustment - all contributing to inflated forecasts. Furthermore, PG&E’s climate modifier underestimates core demand reduction due to future warming. TURN's three recommendations (using Model 5's more accurate forecast, removing the winter severity adjustment, and applying more reasonable climate change modifiers) yield substantially lower core demand estimates: 2,392 MMcf/d for winters 2024-25 and 2025-26, and 2,387 MMcf/d for winter 2026-27, compared to PG&E's higher forecasts of 2,491 MMcf/d, 2,491 MMcf/d, and 2,488 MMcf/d respectively. Moreover, PG&E’s detrending approach should also be refined to reflect the accelerating impact of building electrification, SB 1221, and realistic climate warming trends, resulting in further lowering of core demand forecast.

Incorporating TURN’s 3 recommendations results in the following adjustments to PG&E’s design day forecast for winters 2025-2027 shown in Table 4.

Table 4: Details of TURN's 3 Recommendations and the Resulting Core Demand Forecast (MMcf/d) for Winters '24-'25, '25-'26, and '26-'27



L. No.	Core Demand	Winter 24-25	Winter 25-26	Winter 26-27	
1	Table 3 p.6 of A.24-07-020 (mmscf/d)	2,491	2,491	2,488	
2	in MDTh	2,586	2,586	2,583	
3	**Marquette Table 2 Atch D-3 of A.24-07-020 (MDTh) - unadjusted**	2,588	2,596	2,605	
4	in mmscf/d	2,493	2,501	2,510	
5	Table 23 Core Unadjusted p.60 of A.24-07-020 (mmscf/d)	2,493	2,501	2,509	
6	in MDTh	2,588	2,596	2,604	
7	**Marquette Table 2 Atch D-3 of A.24-07-020 (MDTh) - adjusted using PG&E's modifiers**	2,586	2,586	2,580	
8	**Marquette Table 2 Atch D-3 of A.24-07-020 (mmscf/d) - adjusted using PG&E's modifiers**	2,491	2,491	2,486	*Note discrepancy with 2,488*
9	% change (yoy) in Marquette's forecast (2024-2027)	0.0%	0.0%	-0.2%	*winter '26-'27 Table 3 forecast*
10	Core Demand (TURN) using Model 5 output [corresponding to Line 3](MDTh)	2500	2500	2495	**TURN Recommendation 1**
11	Core Demand (TURN) using Model 5 output [corresponding to Line 3](mmscf/d)	2,408	2,408	2,404	
12	Line 10 - adjusted using TURN's modifiers(MDTh)	2494	2483	2466	**TURN Recommendation 3**
13	Line 11 - adjusted using TURN's modifiers(mmscf/d)	2408	2408	2404	
14	Line 12 - adjusted removing 17MDth winter severity adjustment (MDTh)	2477	2466	2449	**TURN Recommendation 2**
15	Line 13 - adjusted removing 16.3mmscf/d winter severity adjustment (mmscf/d)	2,392	2,392	2,387	
	% Difference (TURN compared to PG&E)	-4.0%	-4.0%	-4.0%	

V. STATEMENT OF QUALIFICATIONS (JALAL AWAN, PH.D.)

I am a full-time Energy and Climate Policy Analyst at The Utility Reform Network (TURN) since November 2023 and have sponsored or co-sponsored testimony in various Commission proceedings on behalf of TURN, including Southern California Edison's 2025 GRC Application (A.23-05-010), SCE's Building Electrification Application (A.21-12-009), Pacific Gas and Electric company's 2024 RAMP Application (A.24-05-008), PG&E's Gas AMI Application (A.24-03-011), PG&E's CSUMB Electrification Application (A.22-08-003) and several ongoing CPUC proceedings such as the Long Term Gas Planning OIR (R.24-09-012). Prior to joining TURN, I worked as an Assistant Policy Researcher at the RAND Corporation in Santa Monica (2017-2023) and as an electrical projects engineer at Engro Corporation in Pakistan (2010-2014 and 2016-2017).

As a policy researcher, I have developed technical reports, conducted mixed-methods research, and presented findings to a diverse range of stakeholders, including the Centers for Disease Control and Prevention and the U.S. National Academy of Sciences (NAS). I completed my B.S in electrical power systems engineering from the University of Engineering and Technology, Lahore (Pakistan) from 2006-2010, my M.S. in green technologies from the University of Southern California (Viterbi School of Engineering) in December 2015 as a Fulbright Scholar, and my M.Phil. and Ph.D. in Policy Analysis at the Pardee RAND Graduate School in 2019 and 2023, respectively. I am a member of IEEE, Six Sigma Green Belt from the American Society for Quality (ASQ) and hold the U.S. Green Building Council certification in Leadership in Energy & Environmental Design (LEED).

My Google Scholar profile can be accessed here: https://scholar.google.com/citations?user=0A3_DZUAAAAJ&hl=en

VI. ATTACHMENTS

1) PG&E Response to TURN-03-Q01

2) PG&E Response to TURN-03-Q01Rev01

PACIFIC GAS AND ELECTRIC COMPANY
Peak Day Supply Standard
Application 24-07-020
Data Response

PG&E Data Request No.:	TURN_003-Q001		
PG&E File Name:	PeakDaySupplyStandard_DR_TURN_003-Q001		
Request Date:	August 16, 2024	Requester DR No.:	TURN-PG&E-03 Revised
Date Sent:	September 6, 2024	Requesting Party:	The Utility Reform Network
PG&E Witness:		Requester:	Hayley Goodson

SUBJECT: DESIGN DAY STUDY FOR CORE

QUESTION 001

Re: Attachment D of Testimony (Marquette Energy Analytics Report, AtchD-1 to AtchD-9):

a) Re: Marquette Energy Analytics Report referenced above, please provide documentation, including workpapers and working / commented code, used to generate the core design day condition forecast in Table 1 (p.3).

b) Re: Table 2 (p.3), please provide the lower confidence interval for the point estimates of Design Day Demand for each year from 2023-2034, for each of the 3 1-in-N scenarios in pgeDesignDay.xlsx (tab: 10-Year). Re: Table 4 (p.8), please provide core prior winter design day demand, along with the upper and lower confidence interval values for prior winter design days from 1998-2023, for each of the 3 1-in-N scenarios in pgeDesignDay.xlsx (tab: 10-Year).

c) Please provide brief explanations for the rows 'Baseload growth from 2024-2025', 'Use/HDDW growth from 2024-2025', and 'Heatload growth from 2024-2025' in the '10-Year' tab of the 'pgeDesignDay.xlsx'.

d) Re: Weather Data set (p.4), please provide an Excel spreadsheet that includes the daily average temperature data from WeatherBank/AccuWeather and NOAA aligned to the gas day, used in the analysis. Please also explain how the data is “aligned to the gas day”.

e) Please specify the regression model used to determine the weights for the six listed weather stations in Table 3 (p.4) and the selection process for these stations. Also, explain how this model accurately represents the PG&E service area.

f) Please explain Equation 1 for Wind-Adjusted Heating Degree Days (HDDW), including any literature references and the derivation specific to PG&E's territory. Also, please provide accuracy metrics (if any) showing how this methodology reduces modeling errors compared to using traditional HDD without wind adjustment.

g) Re: Figure 1 (p.5), please explain how “…(the) red line in the plot represents all combinations of temperature and wind that produce the 1-in-10 DDC…”

h) Re: “detrended load” (p.6), please explain the process of obtaining detrended historical load data, including the selection process for the 5 regression models (p.7) used in this analysis. Please also explain what is meant by “older historical load data”.

ANSWER 001

a-d) As communicated to TURN on August 22, 2024, this request requires Marquette to perform additional analysis not covered by PG&E’s current contact with Marquette. PG&E would be happy to facilitate discussions between TURN and Marquette and if TURN believes additional analyses are necessary to support TURN’s positions in this proceeding, TURN can compensate Marquette for this analyses. Marquette’s hourly contract rate is $370/hour.

e) PG&E does not have access to the records that would indicate which regression model was initially used to create the weights of the six listed weather stations. The original weights were meant to be an optimal weather station distribution based on the populations throughout PG&E’s service territory to accurately forecast what a system wide composite value would be. The six listed weather stations consist of Sacramento, Oakland, Redding, San Jose, Fresno, and Salinas to accurately represent the PG&E service area. Each site is weighted differently based on customer base in geographic locations. PG&E utilizes this composite temperature to forecast core demands based on historical records of composite temperature compared to demands. PG&E will explore if we want to complete another study to update these weather station weights.

f-h) Please see response to “PeakDaySupplyStandard_DR_TURN_003-Q001,” subpart a.

PACIFIC GAS AND ELECTRIC COMPANY
Peak Day Supply Standard
Application 24-07-020
Data Response

PG&E Data Request No.:	TURN_003-Q001		
PG&E File Name:	PeakDaySupplyStandard_DR_TURN_003-Q001Rev01		
Request Date:	August 16, 2024 (Original) November 20, 2024 (Revised)	Requester DR No.:	TURN-PG&E-03 Revised Questions following Meet and Confer
Date Sent:	September 6, 2024 (Original) January 14, 2025 (Revised)	Requesting Party:	The Utility Reform Network
PG&E Witness:		Requester:	Hayley Goodson

SUBJECT: REVISIONS TO TURN-PGE DATA REQUEST #3, Q1-2

QUESTION 001 REVISED 01

Re: Attachment D of Testimony (Marquette Energy Analytics Report, AtchD-1 to AtchD-9):

a) RE Marquette Energy Analytics Report referenced above, please provide working Excel spreadsheets (or equivalent commented code) used to generate the wind-adjusted core design day Temperature (TempW) and Heating Degree Day (HDDW) condition provided in Table 1 (p.3).

b) Please provide brief explanations for the rows 'Baseload growth from 2024-2025', 'Use/HDDW growth from 2024-2025', and 'Heatload growth from 2024-2025' in the '10-Year' tab of the 'pgeDesignDay.xlsx'.

c) RE AtchD-4, Table 3: Please provide daily weather data, in Excel spreadsheet format, from 1950-2024 (for winter months i.e. Dec – Feb) from each of the 6 listed weather stations in Table 3, along with the corresponding weighted average. How is this weighted average used to arrive at the core DDC described in Table 1 and subpart a) above?

d) RE PG&E’s response to DR TURN-03-Q01 e), PG&E states that: “Each site is weighted differently based on customer base in geographic locations.” Please explain how the weights for each of the 6 sites in AtchD4, Table 3 are representative of customer base in the respective geographic location.

ANSWER 001 REVISED 01

One of the attachments to this response is confidential and is provided pursuant to a Non-Disclosure Agreement

a) Marquette Energy Analytics (MEA) has indicated that to the commercially sensitive and proprietary nature of its information, that it cannot provide this code. However, the design day conditions are calculated using the method described in the following attachment "PeakDaySupplyStandard_DR_TURN_003-Q001Rev01Atch01" and available at the following link.

b) Kaftan D, Corliss GF, Povinelli RJ, Brown RH. A Surrogate Weather Generator for Estimating Natural Gas Design Day Conditions. Energies. 2021; 14(21):7118. https://doi.org/10.3390/en14217118

"Baseload growth from 2024-2025" is the growth the models estimate between the 2024-2025 heating season and the heating season of the column header. So, for instance, the models expect a growth in the baseload of approximately 15 MDth between the 2024-2025 heating season and the 2033-2034 heating season. Similarly, "Use/HDDW growth from 2024-2025" and "Heatload growth from 2024-2025" are the model's estimates for the growth in Use/HDDW and Heatload from the 2024-2025 heating season to the heating season of the column header. Note that while "growth" implies an increase in load and the forecast for this area is a positive growth, the "growth" can be negative.

The "Baseload growth" and "Use/HDDW growth" rows are derived from the methods described in response to question 2d. the "Heatload growth" row is equal to the "Use/HDDW growth" times the HDDW DDC (30.4). Please note that excel is rounding the values displayed.

The estimate for a future year is equal to the 2024-2025 estimate plus the baseload growth estimate plus the heatload growth estimate. So, for instance, the 2033-2034 estimate (2,665) is the 2024-2025 estimate (2,588) plus the baseload growth from 2024-2025 (15) plus the heatload growth from 2024-2025 (62).

c) The daily weather data used for this study is in the accompanying excel document on the "1c - Temp & Wind" sheet. Please refer to Tab 1c in the excel attachment "PeakDaySupplyStandard_DR_TURN_003-Q001Rev01Atch02CONF."

Due to MEA's contract with its weather provider, MEA can only provide the composite daily weather data and not the data for the 6 individual stations. To form this data, the daily average temperature for each individual station is calculated from hourly data. This data is aligned to the gas day meaning the daily data reported for January 1, 2024, is the average of hourly weather values between 7AM January 1st and 7AM January 2nd. The composite temperature on a given day is the sum of the individual station daily average temperatures multiplied by the corresponding weights for each station. The composite daily average wind data is calculated similarly. The HDDW values and the TempW values are calculated from the composite daily average temperature and wind data. The equations for HDDW and TempW are provided below:

$$HDDW = \begin{cases} HDD \times \dfrac{72 + Wind}{80}, Wind > 8 \\ \\ HDD \times \dfrac{152 + Wind}{160}, Wind \leq 8 \end{cases}$$

$$TempW = \begin{cases} Temp, & Temp > 65 \\ 65 - HDDW, & Temp \leq 65 \end{cases}$$

The core DDC described in Table 1 is calculated using the method described in response to question 1a performed on the TempW data between November and March and then translated back into HDDW.

d) The quoted statement is slightly incorrect. The weather stations examined to come up with this weighted combination were chosen to be representative of the geographic areas with large populations. However, the weather station weights used in this study were chosen to minimize daily forecast modeling error. This means that the weights should be strongly correlated with where the load is geographically but won't necessarily map perfectly on to the load centers.

For instance, the weighted combination calls for using a 4.2% weight for Redding, CA. This should not be interpreted as 4.2% of the load is in Redding, but instead this should be interpreted as using a small amount of weather from the higher elevation areas in the northern part of the territory reduces the modeling error.