PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

July 25, 2014

Advice Letter 4429-E

Brian Cherry
Vice President, Regulation and Rates
Pacific Gas and Electric Company
P.O. Box 770000
San Francisco, CA 94177

**SUBJECT: SMART GRID SHORT TERM DEMAND FORECASTING PILOT PROJECT –
PHASE 1 STATUS REPORT, PURSUANT TO D.13-03-032**

Dear Mr. Cherry:

Advice Letter 4429-E is effective as of June 29, 2014.

Sincerely,

Edward Randolph
Director, Energy Division

Brian K. Cherry
Vice President
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

Fax: 415.973.7226

May 30, 2014

Advice 4429-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Smart Grid Short Term Demand Forecasting Pilot Project - Phase 1 Status Report, Pursuant to Decision 13-03-032**

Purpose

The purpose of this advice letter is to comply with Ordering Paragraph (OP) 9 of Decision (D.) 13-03-032, *Decision Granting, in Part, and Denying, in Part, Pacific Gas and Electric Company's Application for Smart Grid Pilot Deployment Project*, which directs Pacific Gas and Electric Company (PG&E) to submit a status report via a Tier 2 Advice Letter within 14 days of the completion of each phase of each approved Smart Grid pilot. The Smart Grid Short Term Demand Forecasting Pilot Project (STDF Pilot) has completed the objectives and successfully met the milestones as described in Advice Letter 4227-E[1], and anticipates to fully conclude Phase 1 during the summer of 2014. Therefore, PG&E submits this status report for review and approval to commence Phase 2 of the STDF Pilot.

Background

On November 21, 2011, PG&E filed Application (A.) 11-11-017 requesting authorization to recover costs for implementing six Smart Grid Deployment Pilot Projects over four years. The Smart Grid Deployment Pilot Projects seek to advance the modernization of PG&E's electric grid consistent with California's energy policies as described in Senate Bill (SB) 17 and PG&E's Smart Grid Deployment Plan which was filed on June 30, 2011 and approved on July 25, 2013.

On March 27, 2013, in D.13-03-032, the California Public Utilities Commission (Commission or CPUC) approved four of the Smart Grid Pilot projects proposed by PG&E in its November 2011 application: the Smart Grid Line Sensor Pilot Project, the Smart Grid Voltage and Reactive Power (Volt/VAR) Optimization Pilot Project,

---

[1] PG&E's Advice Letter 4227-E, *Smart Grid Pilot Deployment Projects Implementation Plan, Pursuant to D.13-03-032*, submitted for filing on May 22, 2013 and approved effective June 21, 2013 by the CPUC's Energy Division.

the Smart Grid Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Pilot Project, and the Smart Grid Short Term Demand Forecast Pilot Project. OP 9 of D.13-03-032 states:

> "Within 14 days of the completion of each phase of each approved pilot, PG&E shall submit a status report via a Tier 2 Advice Letter to Commission staff. Each status report must include a) details of the activities occurring in the phase; b) a detailed breakdown of the costs of those activities; c) the results of the phase including evaluation and measurements of pre-selected metrics to portray the success or failure of the pilot phase; and d) a recommendation and rationalization of whether the pilot should advance to its next phase. PG&E should ensure that status reports are detailed, both quantitatively and qualitatively. Funding for subsequent phases, although approved in this decision, may not be spent by PG&E until the Advice Letter for the current phase is submitted and approved."

Phase 1 has achieved its key milestones as described below and in Attachment 1, and the only remaining Phase 1 activities are those that are not material to the key milestones. By submitting this Advice Letter upon completion of its major Phase 1 milestones and key project continuation success criteria, PG&E will allow for timely evaluation of the Phase 1 work and a smooth transition of work from Phase 1 to Phase 2 without costly project stop and re-start activities.

Discussion

Overview of the Short Term Demand Forecasting Pilot Project

PG&E procures short-term electricity on behalf of its bundled customer demand in the California Independent System Operator (CAISO) markets.[2] PG&E's current short-term forecast model for its bundled customer demand is driven by actual load, actual weather, and forecasted weather.

PG&E currently utilizes a "top-down" methodology for forecasting its bundled customer demand. The total load in PG&E's service area is based on the sum of in-area generation and net flows on transmission lines that interconnect PG&E with other control areas. Next, PG&E makes adjustments to account for transmission losses and to account for unbundled and wholesale customer load in

---

[2] PG&E also offers supply into the CAISO markets on behalf of its utility own generation and portfolio of third-party owned facilities that are under contract to PG&E. Despite having both generation (supply) and load (demand) in its portfolio, all electricity is cleared through the CAISO markets. This pilot project is focused on the demand portion that is procured through CAISO.

order to convert the forecasted service area load to its forecasted bundled customer demand. PG&E's load forecasts currently rely on a weather forecast that is weighted-averaged across the service territory.

PG&E proposes to determine through the STDF Pilot whether using new granular sources of data improves the accuracy of PG&E's short term electricity forecasts for its bundled customer demand. PG&E intends to base the total local area load on distribution level load taken from the Supervisory Control and Data Acquisition (SCADA) system on PG&E's lower voltage distribution network, as well as SCADA data from load connected directly to the transmission system. PG&E will use the data as input to a local area forecast model. PG&E will then apply adjustment factors to exclude non-PG&E electric customers (e.g., wholesale customers, municipalities who supply or acquire their own electric power, or Direct Access customers) from the total local area load. Within this new approach, PG&E will also utilize local area weather data in the forecast model to capture the impact of micro-climates on load forecasts.

The Smart Grid STDF Pilot will test this new granular data driven process in two local areas in PG&E's service territory and the results of the pilot will inform any recommendations for broader or full deployment of this new forecasting methodology for the entire PG&E service area. In the planned three phases of the Smart Grid STDF Pilot, PG&E will analyze, build, and pilot the new forecasting methodology by incorporating granular sources of data to forecast PG&E's local area demand. If the pilot is successful, this same methodology may be deployed across the PG&E service area by leveraging and scaling the developed pilot systems.

Short Term Demand Forecasting Pilot – Analysis Phase

The key objectives and milestones associated with Phase 1 of the STDF Pilot were to select the pilot areas for the Pilot, evaluate the granular sources of data to be used in the new forecasting methodology and provide a recommendation regarding whether or not to proceed with Phase 2. PG&E has achieved these objectives as of May 1, 2014 by:

- Identifying appropriate local areas for the Pilot (electrically isolated, sufficient penetration of interval meters, etc.), and

- Demonstrating that the initial set of data meets the data quality criteria.

PG&E identified two areas that met the location selection criteria for selection as the pilot areas. The granular data sources for these two areas have been evaluated and have satisfied the data quality criteria as described in Attachment 1. Attachment 1A contains certain confidential customer information and is being

submitted under confidential seal to the Energy Division. A declaration supporting confidential treatment is found in Attachment 2.

Based on the success of the Analysis Phase, PG&E recommends proceeding to the Build Phase (Phase 2).

Short Term Demand Forecasting Pilot – Build and Pilot Phases

In the Build Phase (Phase 2), PG&E will build the infrastructure to integrate the granular data sources into a central repository. The data will be processed and housed for input into a demand forecasting process for the local areas.

In the Pilot Phase (Phase 3), PG&E will forecast local area demand for the two local areas using granular data sources for the areas selected for the pilot.

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than June 19, 2014, which is 20 days after the date of this filing. Protests must be submitted to:

> CPUC Energy Division
> ED Tariff Unit
> 505 Van Ness Avenue, 4th Floor
> San Francisco, California 94102
>
> Facsimile: (415) 703-2200
> E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

> Brian K. Cherry
> Vice President, Regulatory Relations
> Pacific Gas and Electric Company
> 77 Beale Street, Mail Code B10C
> P.O. Box 770000
> San Francisco, California 94177
>
> Facsimile: (415) 973-7226
> E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

PG&E requests that this Tier 2 advice filing become effective on regular notice, **June 29, 2014**, which is 30 calendar days after the date of filing.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the service list for A.11-11-017. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs

Brian Cherry /sw

Vice President, Regulatory Relations

Attachments

cc: Service List A.11-11-017

CALIFORNIA PUBLIC UTILITIES COMMISSION
ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. Pacific Gas and Electric Company (ID U39 E)

Utility type: ☑ ELC ☐ GAS ☐ PLC ☐ HEAT ☐ WATER	Contact Person: **Shirley Wong** Phone #: **(415) 972-5505** E-mail: **slwb@pge.com and PGETariffs@pge.com**
EXPLANATION OF UTILITY TYPE ELC = Electric GAS = Gas ☐ PLC = Pipeline HEAT = Heat WATER = Water	(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: 4429-E   **Tier: 2**

Subject of AL: Smart Grid Short Term Demand Forecasting Pilot Project - Phase 1 Status Report, Pursuant to Decision 13-03-032

Keywords (choose from CPUC listing): **Compliance**

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other _____

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: **Decision 13-03-032**

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: **No**

Summarize differences between the AL and the prior withdrawn or rejected AL:

Is AL requesting confidential treatment? **Yes.**

If so, what information is the utility seeking confidential treatment for: **Confidential Attachment 1A**

Confidential information will be made available to those who have executed a nondisclosure agreement: **Yes.**

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: **Laura P. Lowe, (415) 973-8144**

Resolution Required? ☐ Yes ☑No

Requested effective date: June 29, 2014   No. of tariff sheets: **N/A**

Estimated system annual revenue effect (%): **N/A**

Estimated system average rate effect (%): **N/A**

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected:

Service affected and changes proposed:

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division **ED Tariff Unit** **505 Van Ness Ave., 4th Floor** **San Francisco, CA 94102** **E-mail: EDTariffUnit@cpuc.ca.gov**	**Pacific Gas and Electric Company** **Attn: Brian K. Cherry, Vice President, Regulatory Relations** **77 Beale Street, Mail Code B10C** **P.O. Box 770000** **San Francisco, CA 94177** **E-mail: PGETariffs@pge.com**

Pacific Gas and
Electric Company®

ATTACHMENT 1

Pacific Gas and Electric Company

Smart Grid Short Term Demand Forecasting Pilot Project
Completion of Phase 1 (Analysis) Key Milestones Report

Advice 4429-E

May 30, 2014

Attachment 1

Pacific Gas and Electric Company

**Smart Grid Short Term Demand Forecasting Pilot Project
Completion of Phase 1 (Analysis) Key Milestones Report**

May 30, 2014

This status report presents a summary of Phase 1 (Analysis) of the Smart Grid Short Term Demand Forecasting Pilot Project (STDF Pilot). In Phase 1, PG&E selected two pilot areas for the new forecasting methodology and evaluated the granular sources of data to be used as part of the new methodology. Based on those findings which are described in detail below, PG&E has recommended approval to proceed with Phase 2 (Build Phase) of the STDF Pilot.

Goals and Objectives

The STDF Pilot investigates a new demand forecasting methodology using more granular sources of data as inputs to the short term forecast model for PG&E's bundled customer demand. In order to inform the recommendation to implement this new forecasting methodology for the broader or entire service area, the STDF Pilot will analyze, build, and then pilot systems to test the model in localized portions of PG&E's service area.

The objectives for Phase 1 (Analysis Phase) were to:

- Select the pilot area(s) for the STDF Pilot

- Evaluate the granular sources of load data to be used in the new forecasting methodology

- Provide a recommendation regarding whether or not to proceed with Phase 2 of the Pilot

Technology Characteristics

a) New application of an existing technology   [x]

b) Development of a new technology   [   ]

c) Integration of new/existing technologies   [x]

d) Other   [   ]

This pilot project is possible because of the Smart Grid technology that has been deployed throughout PG&E's service area in the past several years. Specifically, in 2012 PG&E embarked on a 5-year plan to accelerate the deployment of real-time SCADA data on the transmission and distribution system from about 68% deployment to 100% deployment at the T&D substation level. Currently the deployment level at the T&D substations is about 80%. Similarly, PG&E has deployed approximately 5.4 million electric interval meters since 2007.

The new granular sources of data that are being used in the STDF Pilot are (1) SCADA data from PG&E's transmission and distribution network ("SCADA_New"[1]), (2) customer demand data from interval meters, and (3) local area weather data. Diagram 1 illustrates the relationship of the SCADA_New and interval meter data.

1. SCADA_New: As illustrated in Diagram 1, this pilot is using local areas that are electrically isolated with transmission and distribution substation banks. SCADA data (aka SCADA_New) from the substation banks represent the total local area load of all customers, i.e., those that are PG&E retail electricity customers as well as those entities who do not have PG&E as its load serving entity. The near real-time SCADA_New data will be used as input to a new short term demand forecasting model. Since PG&E procures electricity on behalf of only bundled customers, a key component of this Pilot is to remove non-PG&E customers' load from the total local load area forecast.

Diagram 1

---
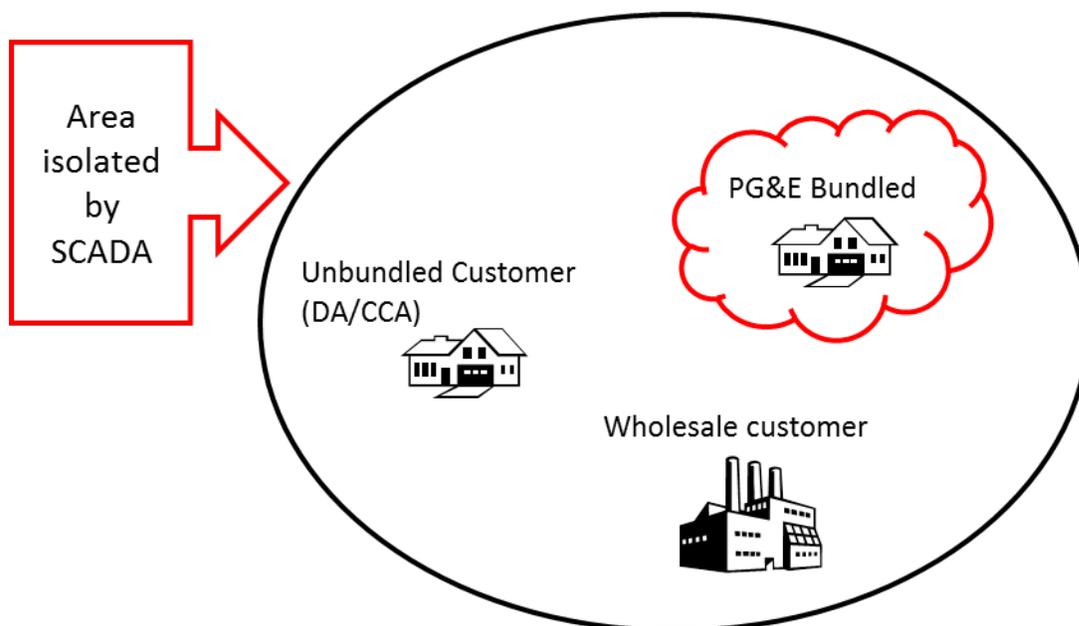
[1] We use the term SCADA_New to distinguish this SCADA from the data that has existed previously at the transmission level

2. Interval meters: Interval meter data is normally available a day after the current day. Interval meter data for PG&E bundled customer load will be used to develop calibration factors to remove non-PG&E customers' load from the total local load forecast. The calibration factors will be updated to reflect current interval meter data to adjust the total local area demand forecast that was based on SCADA_New information.

    The isolation of PG&E bundled electric load can be represented by the following relationship:

    PG&E's Bundled load forecast = total local load forecast from model X calibration factor

    Where, calibration factor = Interval meter (Bundled)/SCADA_New total actual local area load

3. Local Area Weather: The new methodology will rely on local area weather which will enable PG&E to capture the impact of micro-climates on local area demand. Local area weather data will be collected as part of Phase 2, at which point a model will be developed to incorporate local weather station data into its forecast of local area load.

Prospective Vendors

None in Phase 1

Pilot Area Location Selection and Rationale

PG&E examined all areas in the PG&E service territory and used the following location selection criteria, described in Advice Letter 4227-E, to identify local areas for the pilot.[2]

- Region with a maximum of 500,000 customers.
- Region with available transmission historical demand data.
- Region with a high percentage of deployed interval meters
- Region where the interval meters, distribution substations, and transmission substations can be electrically isolated.
- Region with as much historical data (preferably with at least three years of data) as possible for the above items.

---

[2] One additional criteria, "Region with a high percentage of deployed distribution automation systems" was not considered because these systems (e.g., to remotely monitor and control line re-closers, switches, capacitor banks, for load control) do not impact load forecasting.

For the local areas that met these criteria, SCADA_New and interval meter data were collected, processed, and analyzed. To ensure that the area definition used to extract interval meter data was consistent with the area defined by SCADA_New, the interval meters by feeders were individually mapped to a substation bank in the SCADA_New area and the data sets were compared.

This analysis resulted in the identification of two pilot areas that satisfactorily met the location selection criteria described in Advice Letter 4227-E as shown in Table 1.

Table 1: Pilot Areas Selection

Location Selection Criteria	Peninsula and DeAnza Areas
Region with a maximum of 500,000 customers	Criteria met. Peninsula: ~300,000 customers DeAnza: ~220,000 customers
Region with available transmission historical demand data	Criteria met. SCADA_New has been collected since November 2013 for the two local areas. SCADA_New_Bank has been collected since January 2014.
Region with high percentage of deployed distribution automation systems	Criteria not used. This criteria (i.e., RTU) is not considered as a data source since these systems (e.g., to remotely monitor and control line re-closers, switches, capacitor banks, for load control) do not impact load forecasting.
Region with high percentage of deployed interval meters	Criteria met. Peninsula: ~97.4% DeAnza: ~97.5%
Region with interval meters, distribution substations, and transmission substations that can be electrically isolated	Criteria met.
Region with as much historical data (preferably with at least three years of data) as possible for the above items	Criteria met. SCADA_New data is a new data source. The two pilot areas are the only areas in PG&E service territory that currently have this type of historical data collected. For future deployment, these data can be collected for other areas.

Project Phases, Milestones and Expected Timelines

Table 2 provides updated project phases, milestones, and expected timelines for the STDF Pilot. While preliminary planning per the initial Advice Letter estimated a January 2014 completion of Phase 1, additional time was deemed necessary based on more detailed planning to allow for sufficient time for the data to be collected and analyzed since the SCADA_New data were not available until January of 2014. The Phase 2 completion date, originally estimated for December 2014 has also been shifted based on refined planning so that two summer periods instead of one summer can be collected and analyzed. During the summer, customer demand profiles typically have more variations due to temperature than during the winter period. The shift in completion dates for Phase 1 and 2 do not delay the completion of Phase 3. The completion of Phase 3 and the completion of the Pilot remains estimated as December 2016.

Table 2: Project Phases and Expected Completion Dates

Phase	Description	Dates
Phase 1 – Analysis Phase	PG&E has selected two appropriate local areas and has extracted, collected, and evaluated granular data for data quality. Key milestones associated with Phase 1 have been met as of May 1, 2014 to inform PG&E's recommendation to proceed to Phase 2.	September 2013 – Summer 2014 • key milestones reached May 2014
Phase 2 – Build Phase	PG&E will integrate the new data sources, including local weather data, into a central repository where it will be processed and housed for input into a demand forecasting model for a local area. PG&E will design and build new systems & processes to incorporate the new sources of data in developing the local bundled demand forecast.	Summer 2014 – December 2015 • Pending approval of this Advice Letter
Phase 3 – Pilot Phase:	PG&E will execute the new Short-Term Demand Forecasting process by forecasting daily sub-area loads for the selected local area using the granular sources. Processes will be in place to send/receive sub-area load and local weather information to the vendor. During the course of Phase 3 the model should automatically re-learn and be adjusted based on actual loads that are provided on an hourly basis.	December 2015 – December 2016 • Pending results from Phase 2

Project Cost

Actual costs by category for Phase 1 are as follows:

Phase 1 Expenditures ($'000)

	Q2 2013	Q3 2013	Q4 2013	Q1 2014	Q2 2014*	**Total**
Energy Procurement Expense	$18	$24	$21	$48	$355	**$466**

  * Q2 2014 includes actual + forecasted costs to close-out Phase 1. May include a small amount
  of information technology costs.

Total expenditures for Phase 1 of $466,000 is significantly under the originally
forecasted budget for Phase 1 of $2.5 million. This is in part due to careful sequencing
of activities by which PG&E sought to minimize spending until data quality had been
tested. In particular, instead of designing and setting up a data repository in Phase 1,
PG&E decided to use a more manual, but lower cost, process to examine the data
quality. The bulk of the savings from Phase 1, relative to what was planned in May
2013, was the shifting of the information technology costs from Phase 1 to Phase 2,
when the data repository will now be designed and set up with insights gained from
Phase 1. However, as can be seen in the forecasted budget for Phases 2 and 3, the
entire project is expected to come in at or under the approved budget of $12.98 million.

($'000)	Phase 1	Phase 2	Phase 3	**Total**
Forecasted Budget** as of May 2013	$2,476	$6,771	$3,737	**$12,984**
Forecasted as of May 2014	$466	$7,470	$3,602	**$11,539**

  ** Per Advice Letter 4227-E (May 22, 2013) budget was forecasted by year rather than
  by phase. This table assumes, in the top row, that Phase 1 = 2013; Phase 2 = 2014;
  Phase 3 = 2015+2016. For the bottom row, it is assumed that Phase 1 = 2013 + H1
  2014; Phase 2 = H2 2014 + 2015; Phase 3 = 2016.

Measureable data, performance tests

In Phase 1, the SCADA_New and interval meter data for the two local areas were
collected, processed, and analyzed for data quality for the period of February 3, 2014
through April 13, 2014. In addition to SCADA_New, there were three other SCADA
data sets. These additional datasets were used to check the data quality of
SCADA_New and interval meter data. Each dataset is described below:

- SCADA_New: The values are the aggregation of telemetry data[3] at transmission
  and lower voltage distribution substation banks that electrically isolate the two pilot

---

[3] If telemetry data is unavailable for the individual substation banks, values are State Estimated.

areas. The values have been stored in four second intervals in a data warehouse since November 2013. This is the new granular data that will be used as input into the local demand forecasting model. The data were processed into average hourly values for analysis in Phase 1.

- SCADA_Old: The values are a calculation based on the sum of in-area generation and net flows of power into the local area. The values have been stored in four second intervals in a data warehouse. Though the telemetry locations for this calculation are not from the same source as those used for the SCADA_New calculation, the two data sets should have similar results. SCADA_Old was used to check the data quality of SCADA_New since they are expected to be comparable.

- SCADA_New_Bank: The new telemetry data[4] for individual substations banks that define the local areas. The values have been stored in four second intervals in a data warehouse since January 2014. The individual telemetry data were needed for data quality analysis to correctly map the interval meter data to the substation banks that define the local area.

- Sum of SCADA_New_Bank: This dataset is the sum of SCADA_New _Bank and should equal SCADA_New. This data are not stored in the data warehouse but are calculated values in the analysis process. The interval meters by feeders were individually mapped to a substation bank and the data sets were compared. This level of data was necessary to ensure that the area definition used to extract interval meter data was consistent with the area defined by SCADA_New_Bank.

- Interval meter: Customer usage data from interval meters were aggregated by substation to check the quality of data. The interval meter data are the new granular data that could be used to develop the calibration factors in the local area demand forecasting process. The interval meter data were collected as average hourly values by the following subcategories and purposes:

  - Bundled/unbundled customer: identifies the interval meter data quantities to be used to adjust the total area load forecast to PG&E bundled load forecast

  - Primary/secondary service: to apply the appropriate distribution loss factors for the distribution level so that the interval meter data is equitable to transmission level usage

  - Delivered/Received: to calculate net loads for energy delivered to customers or received from customers.

---

[4] If telemetry data is unavailable for the individual substation banks, values are State Estimated.

Data Collection and Analysis Procedures

See Exhibit 1 for the data quality check process diagram used by PG&E to collect and analyze the SCADA_New data and interval meter data. In summary, the process is:

- Compare the SCADA_New calculation to an existing SCADA_Old calculation

- Verify that the area definition used to extract interval meter data is consistent with the area defined by SCADA_New

- Compare the SCADA_New data to the aggregated interval meter data

Performance Test Results

The data quality of the SCADA_New and interval meter were acceptable using the following rationale:

- SCADA_New is comparable with the SCADA_Old with the differences between the two datasets less than 4%.

- SCADA_New and the interval meter data for both local areas had similar hourly profiles.

- In Phase 1, PG&E determined that there were differences in the two datasets. PG&E recommends continuing on to Phase 2 in which PG&E will develop methodologies to resolve these differences. For example, the majority of the differences might be due to customers without interval meters and/or wholesale customers that were not included in the interval meter data used in the analysis. The interval meter profiles could be used to profile the remaining customers (i.e., without interval meters) monthly metered load. The issue with wholesale customers may be resolved by excluding them from the analysis once PG&E has confirmed which wholesale customers are indeed in the pilot area.

Each pilot area met the data quality criteria in an acceptable manner.

Data Quality Criteria

Performance Criteria – Data Quality	Results
The difference between the SCADA_Old and SCADA_New should be within 5%.	Criteria met. Differences were less than 4% for the sample weeks.
Comparison between SCADA_New and interval meter data	Criteria met. The relationship between SCADA_New and aggregated interval meter data is reasonable since the data sets have consistent similar profiles as illustrated in the

	graphs (see Attachment 1A). PG&E is continuing to analyze the cause of the differences in the two datasets and anticipates that the data discrepancies will be resolved or that a work around will be developed to calibrate the total local area load to PG&E bundled load for the area.
Mapping of interval meter data at distribution feeders and transmission circuits for local area must be consistent to that area that is electrically isolated by SCADA for the pilot	Criteria met. The interval meter data has been successfully mapped to substation banks for each area.
The customer meter data can be used to develop load adjustment factors to convert the forecasted total local area load to PG&E bundled load for the area.	The interval meter data does have a category that can be used to identify the bundled and unbundled customers in the area. Additional analysis will be needed in Phase 2 to create the methodology of developing calibration factors to adjust total local area load to PG&E bundled load for the area using interval meter data and other data (e.g., for customers without interval meters).

Detailed graphs and statistical results from each Pilot area are presented in Attachment 1A, which has been marked as Confidential pursuant to Public Utilities Code, Section 583 under D.11-07-056 because it can be used to derive energy usage information of individual customers.

Recommendations for Pilot Program Changes or Course Corrections

Based on the results, PG&E does not see any significant course corrections at this time. As mentioned earlier, PG&E has made shifts to the timeline for Phases and anticipates that the overall Pilot Project will still be completed by December 2016, per D.13-03-032. In addition, PG&E has contemplated as part of the original filing that more than one location may be determined suitable for the pilot and based on results of Phase 1, has identified a second viable location to pilot the granular load forecasting. With these minor enhancements and modifications, PG&E still anticipates following the originally proposed scope and costs under the original proposed budget.

Recommendation for Continuing to Phase 2

PG&E recommends proceeding to Phase 2 which is the Build Phase of the Smart Grid – STDF Pilot, based on the successful completion of the key milestones for Phase 1.

The results of Phase 1 indicate that it is feasible to use granular data to prepare a local demand forecast. As noted above, PG&E recommends proceeding to Phase 2 with the two local areas selected as the pilot areas for the following reasons:

- o The location selection criteria was met by both local areas

- o Each local area met the data quality criteria in an acceptable manner

- o There is little incremental cost to examining two local areas since the majority of the build cost for the first area can also serve the second area

- o The second location will provide additional insight for full system deployment

The remaining work to complete Phase 1, which includes continued collection of data and analysis and pre-planning for Phase 2 (such as developing a high level work plan, resource plan, defining IT requirements and establishing a preliminary budget), does not impact the fact that the key milestones from Phase 1 have been completed.

In the Build Phase, PG&E will integrate data sources into a central repository where the data will be processed and stored for input into the demand forecasting process and will work with a vendor to train the local demand forecasting model.

Interim Data Collection and Analysis Procedure

SCADA_Old
In area generation + Net flows SCADA → EMS point telemetered/calculated → Aggregate EMS data for Area → PI System – Original method → Query data for area → Calc average hourly SCADA_Old data for the area → 1

SCADA_New
Substation/Bank SCADA → EMS point telemetered/calculated → Aggregate EMS data for Area → PI System – Alternate method → Query data for area → Calc average hourly SCADA_New data for the area → 1

SCADA_New_Bank
Start. * Mapping of customers @ D-Feeders & T-customers must be consistent with PI by Substation. PI System – by Bank → Query data for area → Calc average hourly PI data by substation → Sum SCADA_New_Bank data for the area by hour → 1 / 2

Smart Meter
Granular Data. Customer Smart Meter/MV90 data → Teradata → Customer Connected to Distribution Feeder? — Y → Query data aggregated by Distribution Feeder (sub catogories-ie. bundled/unbundled) → Apply loss Primary/Secondary Loss factors → Calc aggregate D-feeder Data by substation. Map customer meters to D-Feeders. Map D-feeders to substations *. Combine T&D customer data by substation → 2. Aggregate Smart Meter for area → 1.
Customer Connected to Distribution Feeder? — N → Wholesale customers on Transmission circuit — N → Query data by SA_ID → Map transmission customer to substation → Combine T&D customer data by substation.
Wholesale customers on Transmission circuit — Y → Document customers excluded.

Comparison of Aggregated data
1 → Calculate diff between SCADA_New and other aggregated values for area → Differences acceptable or explainable? — Y → End.
Differences acceptable or explainable? — N → Stop? — Y → 2. Stop? — N → Document difference → Modify comparison based on explanations → 1.

Comparison by Substation
2 → Calculate diff between SCADA_New_Bank and Smart Meter by substation → Difference acceptable or explainable? — Y → 1.
Difference acceptable or explainable? — N → Find explanation & document → Modify comparison based on explanation → 2.

**DECLARATION OF LAURA P. LOWE
SEEKING CONFIDENTIAL TREATMENT
FOR CERTAIN DATA AND INFORMATION
CONTAINED IN ADVICE LETTER 4429-E
(PACIFIC GAS AND ELECTRIC COMPANY - U 39 E)**

I, Laura P. Lowe, declare:

1. I am presently employed by Pacific Gas and Electric Company (PG&E) and have been an employee at PG&E since 1979. My current title is Expert Day Ahead Analyst within PG&E's Energy Procurement organization. In this position, my responsibilities include the evaluation of PG&E's load forecast used for short-term electricity procurement on behalf of its bundled customer demand.   Through this experience, I have become familiar with the type of information considered confidential.

2. Based on my knowledge and experience, I make this declaration seeking confidential treatment of "Attachment 1A to Advice Letter 4429-E," submitted on May 30, 2014. PG&E is seeking this Commission's approval of this Advice Letter for PG&E to proceed to Phase 2 of the Smart Grid Short Term Demand Forecasting Pilot Project.

3. PG&E is seeking confidential treatment of the graphs and statistical results from the pilot areas in Attachment 1A. The material PG&E is seeking to protect constitutes information that should be protected as confidential customer energy usage information under Public Utilities Code § 583 and the Commission's Customer Privacy Rules under D.11-07-056 because the energy usage of individual customers can be identified and derived from the information. In particular, the wholesale customer component of the data represents a very small number of individual wholesale customers. Finally, PG&E states that: (1) the information is not already public; and (2) the data cannot be aggregated, redacted, summarized or otherwise protected in a way that allows partial disclosure.

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct. Executed on May 30, 2014 at San Francisco, California.

/s/ Laura P. Lowe
Laura P. Lowe

PG&E Gas and Electric
Advice Filing List
General Order 96-B, Section IV

AT&T	Douglass & Liddell	Occidental Energy Marketing, Inc.
Alcantar & Kahl LLP	Downey & Brand	OnGrid Solar
Anderson & Poole	Ellison Schneider & Harris LLP	Pacific Gas and Electric Company
BART	G. A. Krause & Assoc.	Praxair
Barkovich & Yap, Inc.	GenOn Energy Inc.	Regulatory & Cogeneration Service, Inc.
Bartle Wells Associates	GenOn Energy, Inc.	SCD Energy Solutions
Braun Blaising McLaughlin, P.C.	Goodin, MacBride, Squeri, Schlotz & Ritchie	SCE
CENERGY POWER	Green Power Institute	SDG&E and SoCalGas
California Cotton Ginners & Growers Assn	Hanna & Morton	SPURR
California Energy Commission	In House Energy	San Francisco Public Utilities Commission
California Public Utilities Commission	International Power Technology	Seattle City Light
California State Association of Counties	Intestate Gas Services, Inc.	Sempra Utilities
Calpine	K&L Gates LLP	SoCalGas
Casner, Steve	Kelly Group	Southern California Edison Company
Center for Biological Diversity	Linde	Spark Energy
City of Palo Alto	Los Angeles County Integrated Waste Management Task Force	Sun Light & Power
City of San Jose	Los Angeles Dept of Water & Power	Sunshine Design
Clean Power	MRW & Associates	Tecogen, Inc.
Coast Economic Consulting	Manatt Phelps Phillips	Tiger Natural Gas, Inc.
Commercial Energy	Marin Energy Authority	TransCanada
Cool Earth Solar, Inc.	McKenna Long & Aldridge LLP	Utility Cost Management
County of Tehama - Department of Public Works	McKenzie & Associates	Utility Power Solutions
Crossborder Energy	Modesto Irrigation District	Utility Specialists
Davis Wright Tremaine LLP	Morgan Stanley	Verizon
Day Carter Murphy	NLine Energy, Inc.	Water and Energy Consulting
Defense Energy Support Center	NRG Solar	Wellhead Electric Company
Dept of General Services	Nexant, Inc.	Western Manufactured Housing Communities Association (WMA)
Division of Ratepayer Advocates	North America Power Partners	