Docket No.: A.13-12-012

Exhibit No.: ____________

Date: August 11, 2014

Witness: William A. Monsen

TESTIMONY OF WILLIAM A. MONSEN ON BEHALF OF COMMERCIAL ENERGY CONCERNING PACIFIC GAS & ELECTRIC'S 2015 GAS TRANSMISSION AND STORAGE RATE APPLICATION

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I. Introduction and Summary of Testimony

Q. Please state your name and business address.

A. My name is William A. Monsen. I am a Principal and Executive Vice-President at MRW & Associates, LLC (MRW). My business address is 1814 Franklin Street, Suite 720, Oakland, California.

Q. Please describe your professional background.

A. I have been an energy consultant with MRW since 1989. During that time, I have assisted independent power producers, electric consumers, financial institutions, and regulatory agencies with issues related to power project development, project valuation, purchasing electricity, and regulatory matters. I have directed or worked on projects in a number of states and regions in the United States, including California, Oregon, Colorado, New England, Wisconsin, and Nevada. Prior to joining MRW, I worked at Pacific Gas and Electric Company (PG&E). At PG&E, I held a number of positions related to energy conservation, forecasting, electric resource planning, and corporate planning. I hold a Bachelor of Science degree in engineering physics from the University of California at Berkeley and a Master of Science degree in mechanical engineering from the University of Wisconsin-Madison. Additional information about my qualifications is provided in Attachment A.

Q. On whose behalf are you testifying?

A. I am submitting testimony on behalf of Commercial Energy of Montana, Inc., dba Commercial Energy of California (hereinafter Commercial Energy or CE). Commercial Energy was created in May 1997 in Montana to serve the natural gas and electricity supply needs of businesses. After capturing over 50% of the Montana business marketplace, they opened an Oakland office in December 2004 as a CTA in the PG&E service territory. Since expanding into California, Commercial Energy has grown to serve nearly 10,000 meters and nearly 2,900 businesses on the PG&E system. These customers range from relatively small end users such as almost 700 restaurants, to food processors, nursing homes, hospitals, hotels, apartment complexes, schools, colleges, cities, and hundreds of office buildings. Commercial Energy does not sell to residential homeowners, unless they are employees or associated with a business client. Its founders, Ron Perry and Barbara Ranck-Perry, and its employees still privately hold Commercial Energy.

Q. What is Commercial Energy's role in this proceeding and whose interest is Commercial Energy representing?

A. Commercial Energy's role in the Gas Accord is as the energy advocate for its clients. In these proceedings, the medium sized businesses that Commercial Energy serves often feel overwhelmed by the enormity of the proceedings and the esoteric nature of the process. They are occasionally also concerned about the ramifications from their local utility representative if they are perceived as directly taking a position that is contrary to the utility. Therefore they trust Commercial Energy to propose changes to PG&E tariffs and rates that currently disadvantage such customers, and to bring in the experts such as myself to support Commercial Energy's proposals.

Q. What is the purpose of your testimony in this phase of the proceeding?

A. The purpose of my testimony in this phase of the proceeding is to respond to certain PG&E proposals regarding CTAs. In addition, I make several proposed changes to the CTA program that will enhance the operation of the program.

Q. How is your testimony organized?

A. After this introduction, my testimony consists of four additional sections. Section II addresses PG&E's proposed revision to its pipeline and storage allocation procedures for CTAs. Section III presents my proposal to phase in a modification to the definition of Noncore customers. Section IV presents my proposal to allow CTAs to obtain market-based backbone and storage services and to phase out the stranded costs that they currently pay. Finally, Section V presents several changes to operational issues related to CTAs.

Q. Please summarize your recommendations.

A. In this testimony, Commercial Energy makes the following recommendations regarding PG&E's CTA proposals and overall CTA program modifications:

1. The Commission should reject PG&E's proposal to revise its pipeline capacity allocation for CTAs to be based on a Seasonal Capacity Factor rather than a January Capacity Factor. This modification to the capacity allocation methodology is contrary to established ratemaking policy and would assign CTAs a much higher percentage of stranded capacity costs throughout the year, resulting in a 40% increase in costs to the average CTA.
2. The Commission should revise PG&E's current pipeline capacity allocation for CTAs to be based on Peak Day demand, which is the primary design criterion by which PG&E plans its system. Such an allocation methodology will determine the proportionate share of the overall Peak Day usage of all CTAs, and will serve as a reasonable and fair tool for proper cost allocation, consistent with long-standing Commission policy and PG&E's prior assertions regarding the gas ratemaking cost causation principle.
3. The Commission should revise the definition of the Noncore customer class to reduce the usage ceiling of 250,000 therms/year per meter to 100,000 therms/year per meter if those customers have alterative fuel capabilities. The gas marketplace has changed dramatically since the current ceiling was established in 1986, and customers at 100,000 therms/year usage level and above with alternative fuel capability are sophisticated energy consumers and can understand the opportunities and risks associated with becoming a Noncore customer. Changing the definition of Noncore in this way will allow such customers to benefit from the ability to pay market prices for storage, pipeline capacity and natural gas, as existing Noncore customers do today.

4. The Commission should allow the CTAs to procure storage and backbone capacity at market prices in order to eliminate the effectively permanent stranded cost recovery mechanism by which PG&E over-procures capacity for the Core, but is then able to force CTAs and their customers to absorb the full cost of the excess capacity, even when it is of no use to the CTA customers.~~;~~

5. The Commission should require modifications to certain PG&E operational procedures involving CTAs, including the treatment of payments to CTAs from customers who request special payment plans from PG&E; changes to PG&E's existing Core load forecasting methodology that financially harms CTAs; and changes that will improve and accelerate the delivery of key customer data from PG&E to the CTAs so that CTAs can reasonably manage their obligations on the PG&E system.

II. PG&E's Proposed Revision to Its Pipeline Capacity Allocation For CTAs Should Be Rejected

Q. How does PG&E presently determine CTA Capacity Allocation?

A. ~~As described above,~~ PG&E currently determines the *pro rata* share of firm pipeline capacity to be allocated to CTAs three times a year for four-month intervals, November to February, March to June, and July to October. During each period, PG&E calculates the amount of pipeline capacity to be allocated to each CTA based on each CTA's market share by volume for the prior January. For example, if a CTA's current customers used 20% of all the Core gas that was shipped in the prior January, that CTA would be allocated 20% of the transmission and storage held by PGE Core Supply, which is referred to as that CTA's January Capacity Factor. That percentage allocation would apply for the relevant ~~four month~~four-month period. If market share changed in the next period, the CTA's Capacity Factor would adjust accordingly. The CTA's Capacity Factor dictates its portion of costs or benefits from the Core firm capacity reserved for PG&E's Core customers by pipeline and month.[1]

Q. What changes to the capacity allocation methodology is PG&E proposing?

A. Rather than using a January Capacity Factor in the calculation for determining a CTA's capacity allocation, PG&E is proposing using a Seasonal Capacity Factor, which, unlike the January Capacity Factor which is calculated by aggregating each customer's historical January usage and dividing by PG&E's forecasted Core January load, would be calculated by aggregating the most recent historical load for CTA customers during the months in the allocation period and dividing by the most recent historical load of all of PG&E's Core customers for the same months.[2] PG&E maintains that using a Seasonal Capacity Factor in the determination of capacity allocation would "more closely align the allocation with the respective customer loads served by CTAs during the period covered by the allocation."[3]

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[1] PG&E Gas Schedule G-CT, January 4, 2014, Sheet 7. See Attachment B.

[2] Prepared Testimony Volume 2 of 2 of Pacific Gas and Electric Company ("PG&E Testimony"), served in Docket No. Application (A.)R.13-12-012, December 19, 2013, p. 19-17.

[3] PG&E Testimony. p. 19-16.

Q. Did PG&E discuss this change with the CTAs before filing it in testimony?

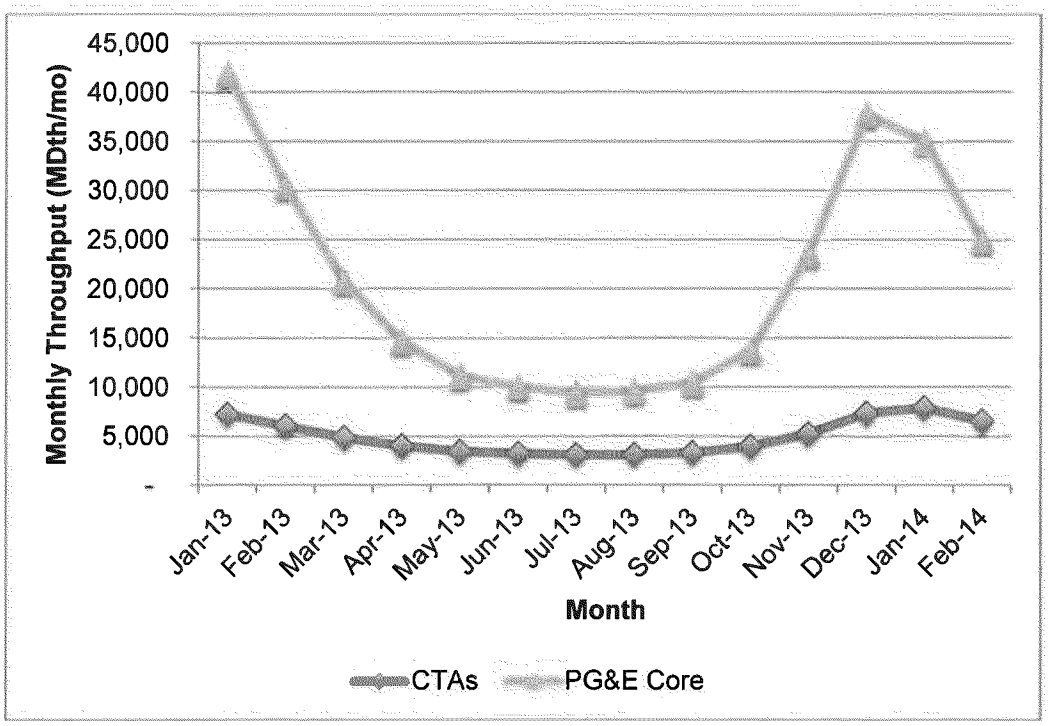
A. To my knowledge and that of my client, Commercial Energy, no CTA was presented with this idea until it was included in the initial filing. In past Gas Accords, these types of ideas were presented in a workshop between PG&E and the CTAs where they discussed not just cost allocation issues but also customer support issues. It is my understanding~~,~~ that no such meetings were offered or held by PG&E in the past year.

Q. How does PG&E's proposed change in capacity allocation increase costs for CTAs?

A. Under PG&E's proposal, CTAs would be allocated a much higher percentage of stranded capacity costs throughout the year. This occurs because CTA customers generally have less seasonal variation in loads than do PG&E's Core customers. The difference in seasonal load is clearly shown in the following figure, which compares PG&E Core and CTA historic and forecasted throughput for the period from January 2013 through February 2014.[4]

[4] PG&E Response to Commercial Energy Data Request Set 3, Question 9, Attachment 1. See Attachment C.

Figure 1: PG&E Core and CTA Throughput



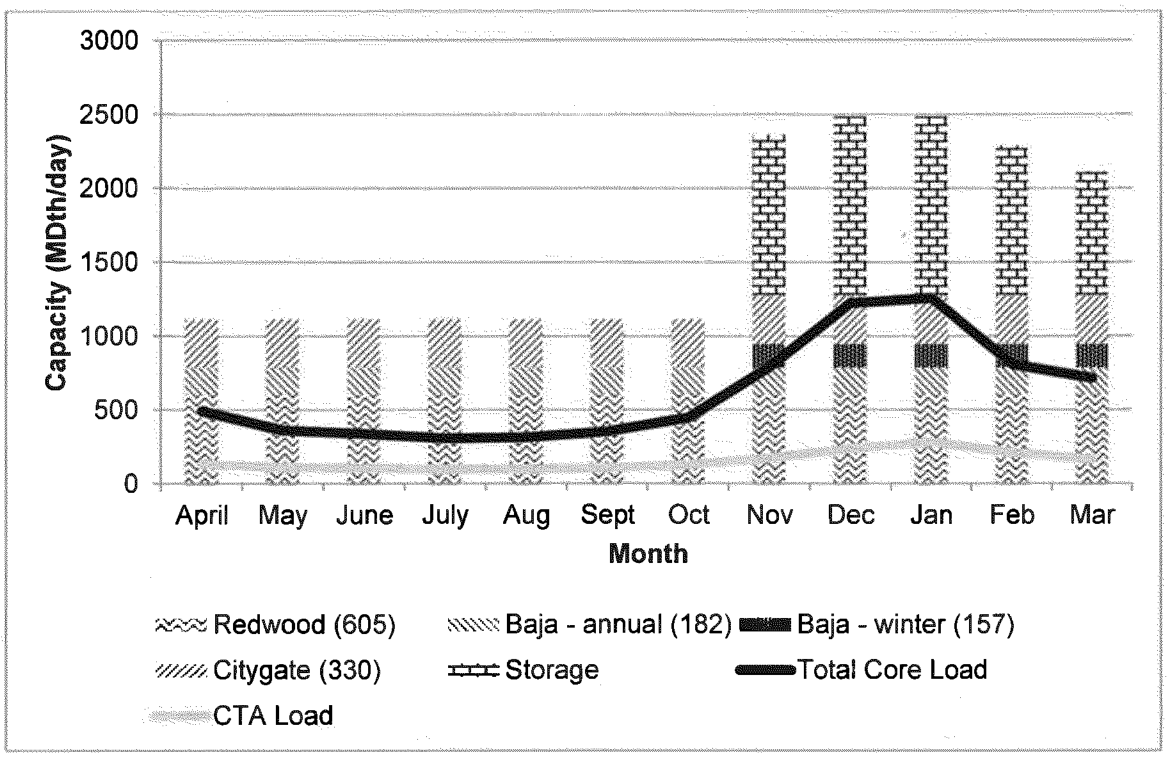
The minimum monthly PG&E Core load is about 25% of the maximum load over this 14-month period. The minimum monthly CTA load is about 39% of the maximum over the same period. The annual load factor for the period from March 2013 to February 2014 for PG&E Core is 49%, while the annual load factor for CTAs is 59% over the same period.[5] Thus, it is clear that PG&E's Core has a much higher winter peak relative to its summer minimum than do CTAs as a group.

Q. Why would the higher CTA load factor result in a higher allocation of stranded costs under PG&E's proposal?

[5] Derived from PG&E Response to Commercial Energy Data Request Set 3, Question 9, Attachment 1. See Attachment C.

A. PG&E Core Procurement has three assets that it assigns to CTAs: interstate pipeline capacity, backbone pipeline capacity, and storage capacity. The following figure presents PG&E's held backbone capacity and storage versus monthly-average daily load for the Core (both PG&E and CTAs).[6]

Figure 2: Core Backbone and Storage Capacity Compared to Core and CTA Loads



As can be seen from this figure, backbone pipeline capacity is relatively constant across the year (varying from about 1,117 MDth/day to 1,274 MDth/day) and storage capacity is primarily held for the winter months. Also, CTA load is much more constant across the year than is total Core load. Total Core load (i.e., PG&E plus CTA load) is relatively

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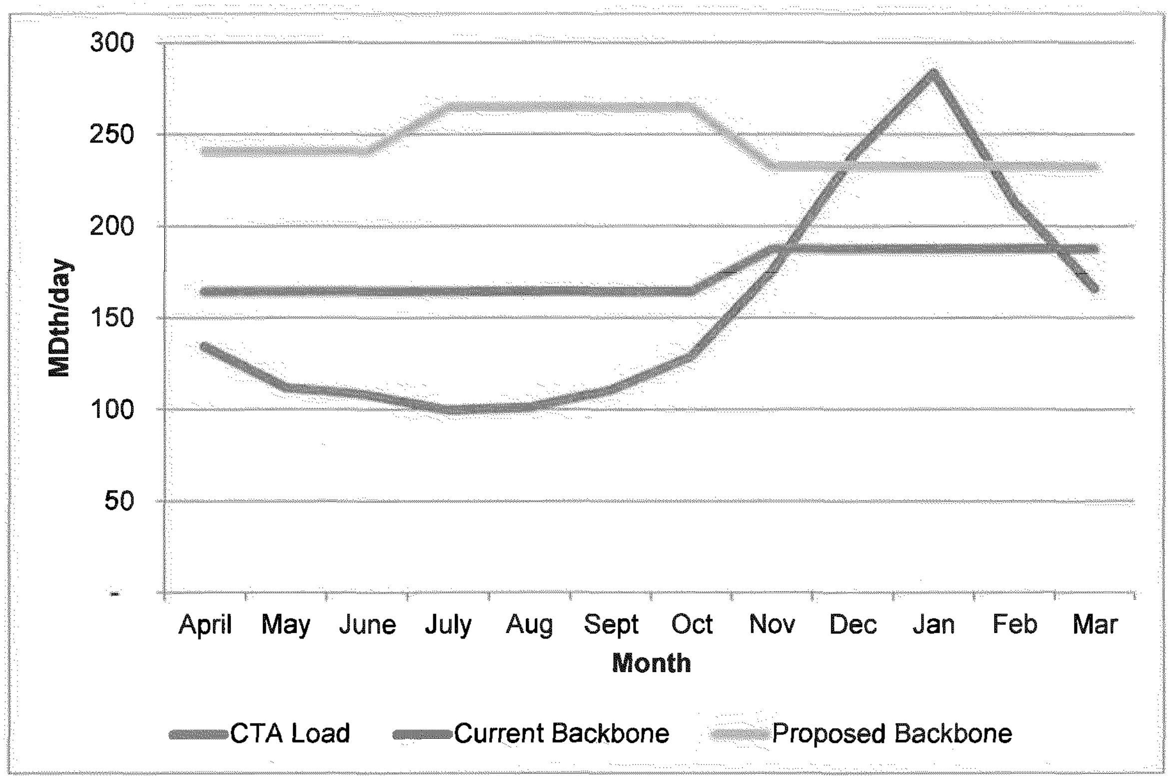
[6] Pipeline and storage capacity from PG&E Testimony, Table 19-5, p. 19-14. Load data derived from PG&E Response to Commercial Energy Data Request Set 3, Question 9 (~~Exhibit~~ Attachment C); and PG&E Response to Tiger Natural Gas Data Request, Set 2, Question 2, Attachment 1. See Attachment D.

similar to total capacity, which means that PG&E's Core load is better--suited ~~for~~to be served by PG&E Core Procurement's total capacity procurement than CTA load. Finally, it is clear that PG&E Core Procurement has capacity well in excess of what is needed to meet Core load.

The following figure presents CTA loads and their allocated backbone pipeline capacity under the current approach and under PG&E's proposed approach.[7]

Figure 3: Allocation of Backbone Capacity to CTAs Under Current and Proposed Approach



As can be seen, under the current allocation approach, CTAs have adequate pipeline capacity in the summer months and need to supplement their pipeline capacity in the

[7] Derived from PG&E Response to Commercial Energy Data Request 3, Question 9. See Attachment C.

winter months with storage (which is allocated to CTAs by PG&E). The higher load factor of CTAs is sufficiently served by a fixed annual allocation of pipeline capacity. Under PG&E's proposed approach, CTAs would be allocated between 24% and 61% more backbone pipeline capacity even though CTAs have no need for such capacity. As also seen in the figure, PG&E's proposal would increase pipeline capacity allocation to CTAs in the summer months when CTA loads are the lowest.

Q. Have you calculated what financial effect these changes would have on the CTAs?

A. Yes. Based on last year's rates, PG&E's proposed change in capacity allocation would result in an increase in costs to CTAs of over $10 million.[8] To put this in perspective, this is more than a 40% increase in costs to the average CTA. Note that this increase is based on the allocation factors in place last year, which assigned approximately 59% of the stranded capacity costs to CTAs pursuant to the settlement in the last Gas Accord.[9] After the end of the Transition Period (i.e., April 1, 2015), CTAs are scheduled to bear 100% of the stranded capacity costs, which means that the incremental cost of PG&E's proposed capacity allocation scheme will cost CTAs (assuming current market share) almost $17 million per year.[10] This is clearly rate shock and will have an enormous effect on CTAs.

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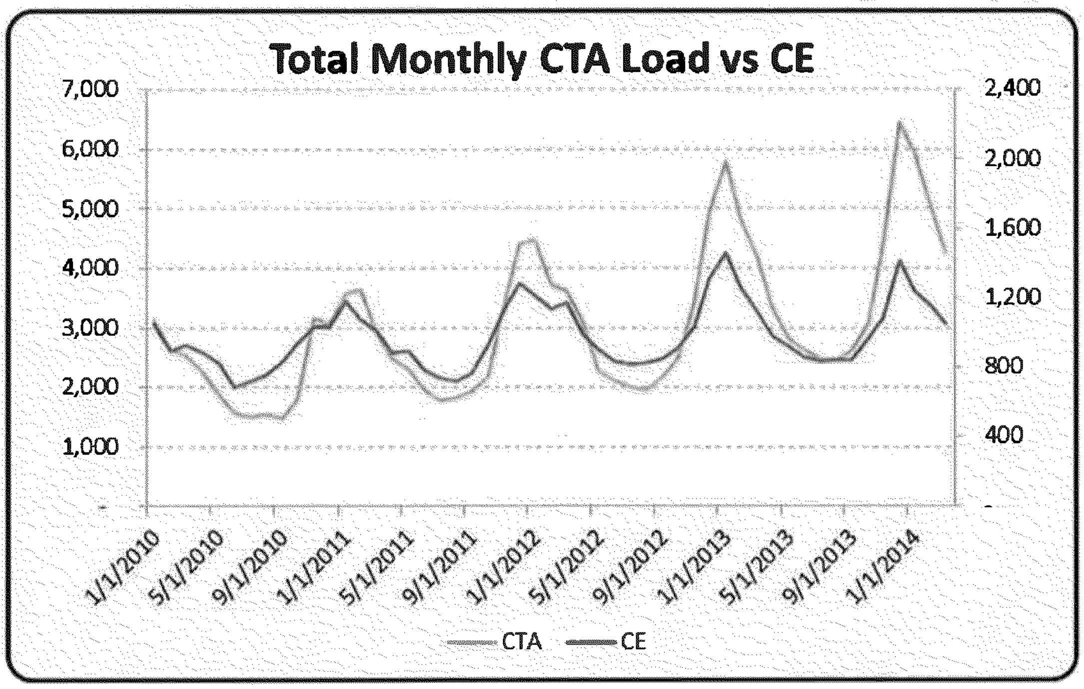
[8] See ~~Exhibit~~ Attachment E, which presents the details of this analysis.
[9] CTAs are approximately 19.4% of the Core market. Currently, CTAs pay approximately 11.4% of these stranded costs. 59% = 11.4%/19.4%
[10] $17 million = $10 million / 59%

Q. Does PG&E's proposed new method have the same effect on Commercial Energy as it does on other CTAs?

A. Commercial Energy serves almost exclusively businesses taking service under Schedule GNR-1 and master-metered apartments and condominiums taking service under Schedule GM. As a result, Commercial Energy has an extremely high load factor, which is higher than CTAs on average. The following figure presents Commercial Energy's load and average CTA loads.[11]

Figure 4: Comparison of CTA and Commercial Energy Loads (Dths)



[11] PG&E Response to Tiger Natural Gas Data Request, Set 2, Question 2, Attachment 1. See Attachment D.

As the figure shows, Commercial Energy's load is more constant across the year than the average CTA. Because of this, the effect of PG&E's proposed change in allocation will have an even greater effect on Commercial Energy than CTAs as a class.

Q. Based on the information above, do you agree with PG&E's proposed changes to the CTA capacity allocation methodology?

A. No. Using a Seasonal Capacity Factor to determine CTA capacity allocation will reduce the pipeline capacity allocation to customers with high winter peaks and low summer loads even though such customers cause a greater need for backbone capacity on the PG&E system as a whole during peak demand periods (i.e., during the winter). This would also increase pipeline capacity allocations to customers with level load factors, even though they have not contributed nearly as much of a demand on the system as PG&E's Core customers. As a result, PG&E's proposed Seasonal Capacity Factor is not consistent with cost causation. In fact, the proposed Seasonal Capacity Factor is inconsistent with long-standing cost allocation principles adopted by the Commission in PG&E proceedings for many years.

Q. How should PG&E allocate capacity among CTAs?

A. Commercial Energy proposes to revise the current pipeline capacity allocation for CTAs to calculate a capacity factor based on Peak Day usage for all CTAs as a proportion of Peak Day usage for all Core customers, as opposed to peak month (January) consumption. Each individual CTA's Peak Day usage will determine their proportionate share of the overall Peak Day usage of all CTAs. Peak Day usage can be determined by

PG&E's Core Load Forecast model and with the modifications suggested below, will serve as a reasonable and fair tool for proper pipeline capacity allocation consistent with cost causation principles. This should occur on April 1, 2016, per the Gas Accord IV settlement.

Q. Is it possible to determine Peak Day usage for CTAs?

A. Yes. PG&E has shown that it is possible to forecast and measure Peak Day consumption in aggregate for Core customers.[12] Also, PG&E meters CTA customer usage. Thus, it is possible to base capacity allocation to CTAs on Peak Day consumption. In addition, it is possible to develop robust models of individual CTA demands. For example, Commercial Energy, for proprietary internal usage, has developed a multivariate regression model that uses various explanatory variables and forecasts daily gas load for Commercial Energy's clients to a very good degree of accuracy. Thus, it is clearly possible to estimate Peak Day usage for CTAs.

Q. How would you determine the Peak Day for each CTA?

A. The mission of the Core Load Forecast (CLF) model is to assess and determine Peak Day. Despite its flaws (discussed in more detail below), we propose that the Peak Day determined by the CLF be used as the initial determination. Each CTA should have the ability to discuss modifications to their particular forecast based on their unique customer characteristics.

[12] PG&E Response to Commercial Energy Data Request Set 3, Question 25(a) and 25(b). See Attachment C.

Q. How would the allocation of transmission and storage be computed?

A. The aggregate CTA Peak Day forecast is created from the sum of the individual CTAs. The ratio of that amount to the Core system Peak Day is the allocation of costs to be borne by the CTAs and their clients. Within the CTA group all net costs (or benefits) after the auction results are then assessed in the same manner as currently in tariffs.

Q. What is your estimate of the impact on rates to the Core Supply group?

A. Today, the CTAs are bearing approximate 80% of the transmission and capacity costs assigned to them by PG&E. Starting in April 2015, CTAs will bear 100% of the transmission capacity costs assigned to them. We estimate that going to a Daily Peak load allocation method will lower CTA costs 20% in aggregate since they have a higher load factor than the Core. However, the combination of CTAs absorbing a greater percentage of the transmission costs assigned to them by PG&E, coupled with the smaller portion of costs assigned to CTAs as a result of moving to ~~me~~ my proposed Peak Day capacity allocation approach would mean that costs offset each other to a certain extent. This would mitigate a portion of the rate impact to the Core ratepayers compared to current rates.

Q. Why would allocation of backbone capacity based on Peak Day usage be appropriate?

A. Such an approach would be consistent with how PG&E designs its system. It would also allocate costs to customers based on how their demands drive capacity ~~expansion,~~expansion; thereby more closely aligning capacity allocation with cost causation.

Q. Why do you say that capacity allocation based on Peak Day demand is consistent with how PG&E plans its system?

A. As stated in PG&E's own Gas Transmission and Distribution Systems Capacity planning documents, the primary design criteria that PG&E must use to plan its system to meet the entire daily Core demand is an "Abnormal Peak Day" (APD).~~[13]~~ This is defined by PG&E as "the coldest temperature that may be exceeded one in every 90 years, on average."[14] PG&E's system must be able to meet all expected Core customer demand during an APD, with Noncore demand assumed to be fully curtailed.[15] PG&E's system must also be designed to accommodate all less extreme Core and Noncore customer demand on a Cold Winter Day (CWD), where the temperature is the coldest that may be exceeded every two years, on average.[16]

Further evidence that PG&E plans its system based on Peak Day demand is provided in its Gas Transmission and Distribution Systems Capacity Planning Procedures, also

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~~13 PG&E Gas Transmission and Distribution Systems Capacity Planning Requirements, June 5, 2012, p. 2. See Attachment F.~~

14 PG&E Gas Transmission and Distribution Systems Capacity Planning Requirements, June 5, 2012, p. 2. See Attachment F.~~PG&E Testimony, pg. 10-8 to 10-9~~

15 PG&E Testimony, pg. 10-9

16 PG&E Gas Transmission and Distribution Systems Capacity Planning Requirements, June 5, 2012, p. 2. See Attachment F.

published June 2012. In this document, PG&E states that its calculation for determining a "near-constrained system," defined as a system that has a calculated utilization of greater than or equal to 95 %~~percent~~ on a given design day, is based on several values, including the system minimum design pressure of typically an APD or CWD.[17]

Q. How does the American Gas Association recommend accounting for cost-causation in gas ratemaking?

A. In the Fourth Edition of its *Gas Rate Fundamentals* textbook, the American Gas Association states that one of the two general principles underlying utility ratemaking is that rates should not be "unduly discriminatory," meaning that "all customers served on a utility's rate schedules must be treated on a consistent and fair basis."[18] Utilities account for this principle by taking into account customer cost-causation in rate design, under which the cost components that comprise a utility's cost of service are allocated on the basis of the relative demand, consumption, and service requirements of the various customer classes.[19]

Q. Has PG&E recognized that it is appropriate to link rates to cost causation?

A. Yes. PG&E has recognized that it is appropriate to link rates to cost causation on several occasions, including the following:

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[17] Gas Transmission and Distribution Systems Capacity Planning Procedures, June 5, 2012, p. 6. See Attachment G.

[18] American Gas Association Rate Committee, *Gas Rate Fundamentals*, Fourth Edition, 1987, Arlington, VA: American Gas Association, p. 132. (Proprietary).

[19] *Gas Rate Fundamentals*, pp. 136-138.

- In its application in A.13-06-011, PG&E acknowledged that having "customers pay the costs they cause the utility to incur," is a fundamental ratemaking principal.[20]
- In its testimony in R.12-06-013, PG&E asserted that establishing a monthly fixed fee to recover fixed costs of utility service "is a key tool for fulfilling the very important ratemaking principle that rates should be based on cost-causation."[21]
- In its testimony in A.10-03-014, PG&E proposed that the Commission adopt its marginal cost proposals "to foster equitable and economically efficient ratemaking by ensuring that rates are substantially aligned with cost causation, so that customers bear the costs that they cause."[22]
- In a case against the U.S. Federal Energy Regulatory Commission before the U.S. Court of Appeals, PG&E stated that "'[i]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.'"[23]

Q. What do you recommend if the Commission is unwilling to adopt your proposal to allocate pipeline capacity based on Peak Day demands?

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[20] Supplemental Testimony of Pacific Gas and Electric Company, served in Docket No. A.13-06-011, October 15, 2013, p.2-7. See Attachment H.
[21] Prepared Testimony of Pacific Gas and Electric Company in Phase 1, served in Docket No. R.12-06-013, February 28, 2014, p. 2-6. See Attachment I.
[22] Update to Prepared Testimony of Pacific Gas and Electric Company Exhibit (PG&E-15) Marginal Cost, served in Docket No. A.10-03-014. January 7, 2011, p. 7-22. See Attachment J.
[23] U.S. Court of Appeals, On Petitions for Review of Orders of the Federal Energy Regulatory Commission, Docket No. 03-1025, July 9, 2004, pp. 8-9. See Attachment K.

A. If the Commission is unwilling to adopt my recommended Peak Day allocation, then I recommend that the Commission reject PG&E's proposed revision to its pipeline capacity allocation for CTAs. PG&E's proposed approach moves in the wrong direction and would be a significant departure from capacity allocation based on cost causation. The net result would be higher capacity costs for customers and CTAs who did not cause the need for additional investment in peak capacity.

III. Revision to Definition of Noncore Customers is Appropriate

Q. When did the Commission establish the differentiation of customer classes of "Core" and "Noncore"?

A. In 1986, the Commission split gas utility customers into two main groups: Core and Noncore.[24] Core customers are primarily residential and small commercial customers who typically receive all services bundled from the regulated natural gas utility. The bundled services include procurement, transmission, storage, distribution, metering, and billing. Noncore customers are primarily large commercial, industrial, and electric generation customers who usually procure their own natural gas supplies. Noncore customers may use the utility's transmission and distribution system and other services on an unbundled cost basis. The utilities are obligated to provide storage for their Core customers only. Noncore customers can take storage from the utility, but must contract and directly pay for this service.

[24] D.86-12-010, pp. 2-3

Q. Did the Commission make any distinction between Core and Noncore market in D.86-12-010?

A. Yes. The Commission made a distinction between the Core market and the Noncore market. The Commission stated in its Adopted Rules:

> The "Core market" shall be comprised of all customers with end-use Priorities 1, 2A, and 2B. Those large Core customers with usage in excess of 250,000 therms/yr may choose transmission-only service and may purchase gas from any of the portfolios available to Noncore customers.
>
> The "Noncore market" shall be comprised of all customers with end-use Priority 3 and below. Customers in the Noncore market are eligible, regardless of size, to select among a variety of transmission and procurement options. Default service levels will be provided to customers which have not themselves made an affirmative choice among the options.
>
> The Core and Noncore markets are established by definition, and no switching between these two markets will be allowed.[25]

Q. Did the Commission present a rationale for restricting eligibility in procuring natural gas independently from the utility?

A. Yes. The Commission stated, "[c]ustomers who, because of larger size and/or alternative fuel capabilities, are likely best equipped to participate in a competitive marketplace and make well-reasoned decisions regarding natural gas service for themselves." The secondary reason for this distinction was a reduction of administrative burden on the utility.[26]

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[25] D.86-12-010, pp. 17-18
[26] D.86-12-010, p. 15

Q. Did the Commission allude to allowing future examination of its restrictions on eligibility in procuring natural gas independently from the utility?

A. Yes. The Commission clearly signaled its openness to reexamining the Noncore definition in the future. It stated, "As the marketplace develops, both of these factors may become less important, and we may reconsider whether the restrictions should be reduced or eliminated." The "factors" mentioned by the Commission are the size of the customer and the ability of a customer to procure alternative fuel capabilities.[27]

Q. Do you believe that the marketplace has changed since the time of this decision in 1986?

A. Yes. In 1991 the Commission started a Core gas procurement aggregation pilot program, which was later adopted in 1995 on a permanent basis.[28] This allowed competition with the utilities in California for Core customers' gas procurement. Today, aggregators, including Commercial Energy, serve approximately 20% of PG&E's Core market.[29] Additionally, the options for customers to transport natural gas both to California and within California have changed significantly since 1986. There have also been significant changes in the market for storage in California. Smart-Meters have allowed customers to better understand their energy usage and make sophisticated decisions to control their energy costs. Finally, the Internet has created visibility for gas prices as well as the

[27] D.86-12-010, p. 15

[28] D.91-02-040

[29] PG&E Response to Tiger Natural Gas Data Request, Set 2, Question 2, Attachment 1. See Attachment D.

ability to quickly reach end users to advise of curtailments, creating the opportunity for more efficient real time gas management by both the utility and its customers.

Q. Has the marketplace developed in a manner such that the Commission should revisit the qualifications for Noncore service?

A. Yes. The natural gas marketplace has changed dramatically since 1986 allowing customers to have more information to make better decisions about how to control their energy usage and costs than ever before. The 250,000 therms/yr eligibility level that the Commission imposed in 1986 does not fit the sophisticated nature of the decision making of customers in PG&E's territory.

Q. Have Core gas customers become more sophisticated and knowledgeable about energy markets since 1986?

A. This seems very likely. Since 1986, many customers have had options to install behind-the-meter generation and have done so. For example, many customers decided to install combined heat and power projects. The decision to make such an investment is far from simple, since it involves understanding the nature of their demands for both heat and electricity, forecasting future power and gas prices, understanding regulatory risk, and evaluating technology options.

~~Currently~~Also, PG&E has thousands of customers that have analyzed and opted to install solar PV systems. This decision involves weighing specific unknowns such as changes in rate design, Net Energy Metering policy, and the relative value of leasing versus buying a

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project. These examples demonstrate the greater level of understanding of power and fuel markets than existed in 1986.

Q. Has the Commission addressed how the marketplace for natural gas storage on PG&E's system has developed?

A. Yes. In 1993, the Commission adopted a "let the market decide" policy for gas storage.[30] This policy sought to increase efficiency of allocation of gas supplies, access diverse gas supplies, and lower costs through gas-on-gas competition.[31] As it relates to this proceeding, maintaining the previous arbitrary level for dividing Core and Noncore customers is inhibiting the market from making efficient decisions on gas procurement.

Q. Has the Commission's view on competition for energy services evolved since 1986?

A. Yes. In the mid-1990s, the Commission expanded retail competition in the electric sector.[32] After Direct Access was suspended in 2001, the Commission has continued to evaluate where and when to expand retail competition for electric customers. Ultimately, in October 2009, Senate Bill (SB) 695 added Section 365.1 (b) to the Public Utilities Code, which states in pertinent part:

> The commission shall allow individual retail nonresidential end-use customers to acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total ~~kilowatt hours~~kilowatt-hours annual limit.[33]

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[30] D.93-02-013, p. 2
[31] D.93-02-013, p. 8
[32] D.95-12-063, modified by D.96-01-009.
[33] D.10-03-022, p. 4.

SB 695 provides clear legislative policy guidance for the Commission that competition in the energy markets must be encouraged and promoted. The addition of Section 365.1(b) makes this legislative policy into a statutory mandate. The Commission has adopted this policy, and implemented it to protect competition in the Direct Access market.

When determining whether Direct Access providers should be required to pay a reentry fee for involuntarily returned customers, the Commission expressly declined to impose a large reentry fee on residential and small commercial DA providers because a large fee could harm the DA market.[34] The Commission instead imposed a small administrative fee for Electric Service Providers (who are similar to CTAs) in order to preserve their ability to remain competitive in the DA market.[35] "The provisions we adopt advance the principles of promoting competitive choice for electric procurement," the Commission declared.[36]

Q. Why are there additional restrictions provided in SB 695?

A. The SB 695 cap limits any potential risk associated with reopening of Direct Access by eliminating uncertainty associated with unrestricted load migration. This "go slow" approach ensures that the Commission can control the pace at which new customers can take Direct Access service.

[34] D.11-12-018, pp. 57-58.
[35] D.11-12-018, pp. 58-62.
[36] D.11-12-018, p 4.

Q. What do you propose?

A. I propose that the Commission reduce the floor for becoming a Noncore customer to 100,000 therms/yr for a single meter. To ensure that this change does not trigger a "gold rush" of customers migrating to Noncore service, I propose that the Commission adopt the 100,000 therms/yr floor to limit the amount of Core load that can migrate to Noncore service over the next three years. Such a limitation on load migration is consistent with the re-opening of the electric Direct Access as a result of SB 695.

After the end of the trial period, PG&E should provide a report to the Commission regarding the successes and challenges associated with allowing these new customers opt to take Noncore service. For customers to migrate to Noncore service, they would be required to have either alternate fuel capability prior to switching or a certified statement that firm capacity was not needed to run their business. This will ensure that the customer has sufficient secondary resources if the customer is curtailed by PG&E. If a customer shifts from Core to Noncore, the customer would have to remain a Noncore customer for at least five years.

Q. Why do you propose the 100,000 therms/yr usage level?

A. I believe that customers at this usage level and above are sophisticated energy consumers and can understand and evaluate the opportunities and risks associated with becoming a Noncore customer. It is my understanding that customers with this level of usage may include hospitals, food processors, and large apartment complexes~~,~~ and office buildings. These types of customers have engaged in other energy management activities, including investing in energy efficiency, renewable resources, and demand response. Some of these customers even purchase electricity from third-party direct access suppliers.

Q. Why don't you recommend that all customers should have the option to become Noncore customers?

A. I am aware that a gradual movement toward customer choice would mitigate risks. Thus, I recommended the 100,000 therms/yr lower bound as a first step. This level is somewhat arbitrary, just like the current 250,000 therms/yr limit.

Q. How might the Commission get a better understanding of the actual demand for Noncore service?

A. In order to understand the demand for Noncore status at lower levels, the Commission should order PG&E to study customer demand at lower annual usage levels and to report back in the next Gas Accord. One possible means to understand the demand for Noncore service at levels less than my proposed threshold is to allow PG&E to have an open season at incremental levels between 0 therms and 100,000 therms/yr. PG&E's report on the demand for Noncore status could include the results of such an open season.

Q. Based on information PG&E has provided to date, can you develop estimates of the number of customers and the amount of load that could possibly migrate?

A. PG&E provided counts for the number of customers in various usage bands for 2011, 2012 and 2013.[37] The following table presents the 2013 data:

Table 1: Customers Potentially Eligible to Become Noncore

Range of Usage (therms/yr)	Number of Customers	Total Usage within Range (MDth/yr)
100,000-150,000	394	4,925
150,000-200,000	170	2,975
200,000-250,000	98	2,205
Total	6~~7~~62	10,105

In this table, I assumed that the average usage per customer in each bin is the mid-point of the usage range for the bin.[38]

Q. What might be the impact on PG&E's forecast of Core demand if the Commission were to allow customers down to 100,000 therms/yr to opt for Noncore service?

A. It is unlikely that all customers would opt for Noncore service. Assuming that 50% of the approximately 660~~750~~ eligible customers opted for Noncore service, Core gas demand would be reduced by approximately 2%.[39]

Q. Is this level of shift to Noncore significant?

[37] PG&E Response to Commercial Energy Data Request Set 3, Question 3 and Attachment 1~~s 3~~, Question 4 and Attachment 1 and Question 5 and Attachment 1.~~and 5~~. See Attachment C.

[38] Some customers may have more than one meter, thus the data in this table is an approximation of the potential size of the number of meters that might migrate to Noncore status.

[39] 2% = (10,105 / 2) / 280,014. Gas load for 2015 from PG&E Testimony, p. 19-4, Table 19-2.

A. While this is not a major increase in demand relative to Noncore load, it is important to note that PG&E generally bases its determination of capacity investments in local transmission on the type of load being served. PG&E states that:

> Systems that contain mostly core load are more likely to require capacity investments due to the APD design standard. Systems with higher levels of non-core loads are more likely to require investments due to the CWD design standard. This is only a general guideline, as each system is unique.[40]

Thus, moving Core customers to Noncore would reduce APD, which might result in a reduction in the need for additional local capacity. For the purpose of this testimony, I have not tried to quantify the local capacity requirements that would be avoided as a result of this proposal.

Q. What are some of the benefits of reducing the minimum load for Noncore customer class eligibility?

A. This would reduce the demand for interstate pipeline capacity, storage capacity, and intrastate backbone capacity needed by PG&E for Core customers. It would provide the system with additional "demand response" capacity in the form of an increased amount of curtailable load, which would reduce the need for incremental facilities that are driven by peak demand, such as pipeline capacity, storage inventory, and withdrawal capacity. This additional flexibility could be valuable especially as gas demand for electric generators becomes more volatile as a result of the increased levels of intermittent renewable resources serving electric load.

[40] PG&E Response to Calpine Data Request 1, Question 3. See Attachment L.

Q. Why would this result in a reduction in the demand for interstate pipeline capacity, storage capacity, and intrastate backbone capacity for PG&E's Core customers?

A. By moving customers from the Core to the Noncore, the required capacity to serve Core customers would be reduced.

Q. How would this reduction in Core demand affect the requirements for future increases in interstate pipeline capacity, storage, and intrastate backbone capacity for Core customers?

A. PG&E designs its system to meet APD requirements. This assumes that in a 1-in-90 year cold day, all Core customers are served and all Noncore customers are curtailed. By moving some Core customers to Noncore, there is less need for additional pipeline and storage to meet this design criterion.

Q. Is gas "demand response" something that PG&E has examined in the past?

A. Yes. PG&E has considered various demand response programs for natural gas.[41] One was targeted at reducing the risk of curtailment of EG loads.[42] PG&E ultimately did not pursue this gas demand response program because PG&E did not believe that it was cost-effective.[43] Moving some Core load (which is only curtailable in extreme emergency

[41] PG&E Response to Commercial Energy Data Request Set 7, Question 6. See Attachment C.
[42] PG&E Response to Commercial Energy Data Request Set 7, Question 7, CONFIDENTIAL Attachments 1 and 2; Question 7, Attachment 3. See Attachment C.
[43] PG&E Response to Commercial Energy Data Request Set 7, Question 6. See Attachment C.

conditions) to the Noncore (which is curtailable under PG&E's rules) would provide additional operational flexibility.

Q. What amount of gas "demand response" capacity would your proposed change bring to the system?

A. When customers opt to become Noncore customers, they accept the risk that they might be curtailed. While this risk is relatively low, this curtailable capacity could be critical at times of extreme gas demand or gas system congestion. Conservatively assuming that the migrating gas customers have high load factors (e.g., 75%), this would bring about 17 MDth/day of incremental curtailable load.

Q. What is the cost of your proposal?

A. There would be little or no costs to ratepayers. This is inexpensive capacity relative to expansion of PG&E's system. It is also inexpensive relative to the gas demand response program that PG&E considered in the past.[44] Also, the Commission should recognize that even a 0.9% load reduction,[45] achieved by simply redefining the lower limit for Noncore customers, would be very cost-effective. For comparison, the demand response target for the California electric IOUs is about 5% of peak load, and the Commission has authorized substantial sums of ratepayer funds to try to achieve this target. For example, the Commission has authorized PG&E to spend approximately $706 million for electric

[44] PG&E Response to Commercial Energy Data Request Set 7, Question 7, CONFIDENTIAL Attachment 1, p. 23. See Attachment C.

[45] 0.9% = (10,105 / 2 / 0.75) / 365 / 2,014. Cold year gas demand from PG&E Testimony, p. 14-9, Table 14-2.

demand response since 2006, of which about $229 million has been authorized since 2012.[46]

IV. CTAs Should Have Ability to Procure Storage and Backbone Capacity at Market Prices

Q. What is the purpose of this section of your testimony?

A. To present a program for allowing CTAs to obtain storage and backbone transmission at market-based rates. After I discuss the current Core portfolio, I discuss storage and backbone transmission in turn below.

A. PG&E Core Procurement Has Excess Capacity

Q. How much Transmission and Storage capacity does PG&E currently hold for its Core customers?

A. PG&E currently has 1,278 MDth/day of Intrastate Capacity and 1,312 MDth/day of storage withdrawal capacity for a total of 2,590 MDth/day of capacity.[47]

Q. How did PG&E meet its Core load when the system hit its 1-in 10-year Peak Day on December 9, 2013?

A. On December 9, 2013, which was the System Peak Day for 2013, the total volume of gas delivered on the system that day was 4,900 MDth.[48] Of that, Core gas demand was 2,283

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[46] Opening Testimony of Pacific Gas and Electric Company in the 2013 Demand Response Rulemaking Phase 2 and 3, served in Docket No. in R.13-09-011, Table 8-1, p. 8-3. See Attachment M.

[47] PG&E Testimony, p. 19-14, Table 19-5.

[48] PG&E Response to Commercial Energy Data Request Set 3, Question 25(j). See Attachment C.

MDth, Noncore Industrial demand on that day was 1,016 MDth, and Electric Generation demand was 1,308 MDth.[49] Thus, Core had approximately 307 MDth of excess capacity under contract on the Peak Day.

Q. How was all overall load met on that day?

A. To meet the load of 4,900 MDth on the Peak Day, a total of 3,600 MDth was delivered on that day from a combination of PG&E and third party storage providers.[50] Effectively, storage withdrawals met over 75% of the Peak Day demand on the System Peak Day. Noncore load curtailment added an estimated 1.6 MDth of capacity from about 40 users.[51] The balance of approximately 1,300 MDth was from flowing volumes either produced in-state or procured through interstate transmission capacity.

Q. Was Core load at risk of curtailment on December 9, 2013?

A. That is unlikely. PG&E only curtailed 40 of its eligible Noncore accounts, amounting to about 1.6 MDth. However, in theory, all Noncore load (i.e., 1,016 MDth) could have been curtailed that day. Also, in theory, some or all of Electric Generation load (i.e., 1,308 MDth) could have been curtailed. Thus, even if California production and/or imports from interstate capacity was zero (instead of the approximate 1,300 MDth that

[49] PG&E Response to Commercial Energy Data Request Set 3, Question 25(f). See Attachment C.

[50] PG&E Response to Commercial Energy Data Request Set 3, Question 25(j) 1,364 MDth came from PG&E's storage fields and (k) 2,236 came from independent providers comprised of Lodi Gas, Wild Goose, Central Valley, and Gill Ranch. See Attachment C.

[51] PG&E Response to Commercial Energy Data Request Set 3, Question 25(l). See Attachment C.

was flowing), there was still about 1,026 MDth of capacity available on the coldest day in ten (10) years.

Q. What do you conclude from this?

A. It appears that Core customers were at no risk of curtailment on the peak day of 2013. In addition, PG&E Core Procurement likely has excess capacity in its portfolio. Currently, the costs of that excess capacity is allocated, in part, to CTAs.

B. Storage

Q. Please explain how CTAs currently are allocated stranded costs associated with storage.

A. PG&E Tariff Schedule G-CT describes the allocation of Core firm storage capacity. In summary, PG&E determines an Initial Storage Allocation in February for the following storage year (i.e., April 1 through the following March 31). This allocation is then assigned to each CTA based on the CTA's winter season usage relative to PG&E's total Core winter season forecast throughput. Using this fraction, storage from PG&E's total Core storage capacity reservation is offered to each CTA. A CTA has an option to accept or reject some or all of the offered capacity. If the CTA rejects some or all of the offered capacity, the CTA must certify that it has alternative storage resources (Alternate Resources) equivalent to the rejected capacity. PG&E will attempt to broker the rejected capacity. However, the CTA is responsible for the difference in cost between the offered capacity and the amount PG&E receives for sale of the rejected capacity on the open market. By having to pay for the rejected storage capacity, the CTA is being forced to pay stranded costs of PG&E's storage system.

Q. What are the potential Alternate Resources that CTAs might use?

A. Alternate Resources may consist of any combination of the following:

a. Contracted firm storage services from PG&E or from an on-system CPUC-certified independent storage provider; and/or

b. Contracted firm PG&E Backbone capacity matched with an equivalent volume of contracted upstream gas supply, plus any necessary firm upstream pipeline capacity (upstream gas supply may include a gas producer contract, or a contract with an off-system CPUC-certified, gas utility or independent storage provider); and/or

c. Third-party peaking supply arrangements, where that supply is backed up by contracts, as specified in (a) or (b), above.

Q. Does PG&E procure storage for its Core customers from multiple storage providers?

A. Yes. PG&E has one third-party storage contract. This third-party storage contract allows PG&E to have withdrawal rights on 15 days of 100 MDth/d from December to February.[52]

[52] PG&E Response to Commercial Energy Data Request Set 3, Question 15. See Attachment C.

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Q. What is the approximate magnitude of the CTAs' stranded storage costs?

A. They are substantial. For example, in April 2014, CTAs paid stranded costs for 84% of the PG&E Core storage capacity PG&E had assigned to them because the released capacity for that month sold at about 16% of the tariff rate.[53]

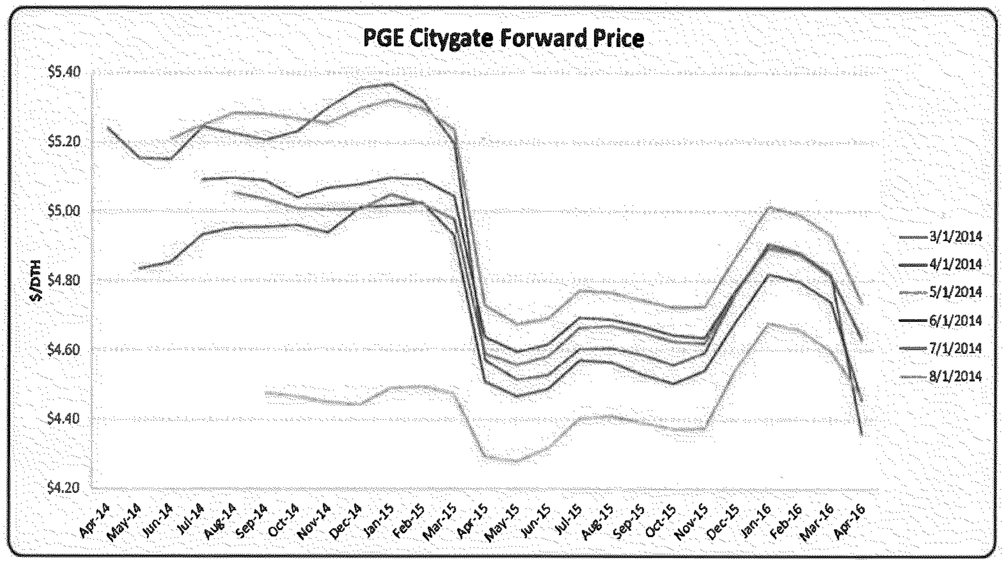
Q. Why was PG&E only able to sell the storage capacity that was released by CTAs for 16% of the tariffed rate?

A. First, with the growth of natural gas as the primary fuel for summer electric generation needed to meet cooling requirements,[54] the California market has evolved into a double peaking market with peaks in both the summer and the winter. This has diminished the price spread between the summer season and the winter season. Based on PG&E Citygate forward prices from 2014, that price differential has been below $0.30/MMBtu all year. The following figure summarizes the forward price data for the period from March through August.

[53] PG&E Response to CTAC Data Request 2 Question 1, Attachment 1. See Attachment N.

[54] California Independent System Operator, *2013 Annual Report on Market Issues and Performance*, April 2014, p. 39. See Attachment O.

Figure 5: PG&E Citygate Forward Prices from March-August 2014



Since a large part of the value of storage is this differential in price between summer and winter, it creates a market value of about $0.30 per MMBtu, which I assume was reflected in the bidding. Second, over the past twenty years, alternative storage providers such as Wild Goose, Gill Ranch, and Lodi have developed third party, market competitive storage services that cost considerably less than PG&E's own storage capacity.

Q. What are your concerns regarding PG&E's current approach for allocating stranded storage costs to CTAs?

A. Different CTAs likely have different business models for serving their customers. The current approach leaves very little room for individual CTAs to pursue those options. Also, under the current approach, PG&E has little incentive to make its storage facilities cost competitive with other storage service providers. In fact, the current program provides little or no incentives for PG&E to limit incremental investments in its storage facilities, even though those investments would almost certainly result in additional stranded costs.

Q. Is PG&E proposing incremental investments in its storage facilities in this proceeding?

A. Yes. It appears from my review of PG&E storage costs as described in Chapter 5 of PG&E's testimony, that the company is proposing very large investments in its existing storage system. Since it appears that PG&E's storage costs are ~~out-of~~above market, it seems likely that such investments would be stranded since the investments would not reduce the cost of PG&E's storage relative to alternative independent storage options.

Q. How should the Commission view these proposed investments in PG&E's storage system?

A. The Commission should carefully examine PG&E's proposed investments in MacDonald Island and other storage facilities to determine if the proposed investments are cost effective in light of storage capacity available from less expensive, more modern, storage facilities. Given the desire of CTAs to cap stranded storage costs imposed by PG&E, the Commission should not permit excessive or unreasonable additional investment in PG&E storage that may only add to the stranded costs of storage.

Q. What do you propose regarding the stranded costs on PG&E's storage system?

A. PG&E's stranded costs for storage should not be permanent. If PG&E continues to impose stranded storage costs on CTAs year after year, the Commission could conclude that PG&E has contacted for more storage than it needs for the Core, and PG&E should reduce its investment in such storage over time. Therefore, I propose to calculate stranded costs and to pay down those stranded costs over time. In this way the CTAs would be permitted to transition to a regulatory environment where they have no responsibility for PG&E's stranded storage costs. I discuss my proposal for stranded cost recovery below.

C. Backbone Transmission

Q. Please explain how CTAs are currently allocated stranded costs associated with backbone transmission.

A. CTAs must meet a firm Winter Capacity Requirement pursuant to Schedule G-CT. CTAs can meet this requirement either by accepting allocated firm backbone capacity from PG&E or by obtaining firm capacity on their own. PG&E determines the volume needed by a CTA to serve the aggregate of its customers under contract for the month of January. PG&E simply adds together all of those customers' meter reads for the prior January and divides that amount by 31 days to come up with a daily average peak capacity. All CTAs' January volumes are then aggregated and that total is compared to total Core load for the month of January. This percentage is applied to the total costs for backbone transmission and applied to the CTA group as a whole. Each CTA is given the option to accept or reject some or all of its *pro rata* allocation of backbone capacity. If the CTA rejects some or all of the offered capacity, the CTA must certify that it has alternate firm backbone capacity equivalent to the rejected capacity. PG&E will attempt to broker the rejected capacity. However, the CTA is responsible for the difference in cost between the offered capacity and the amount PG&E receives for sale of the rejected capacity on the open market. By having to pay for the rejected backbone transmission capacity, the CTA is being forced to pay the stranded costs of PG&E's backbone transmission system.

Q. What are the potential alternate providers of backbone capacity that CTAs might use?

A. A CTA has two alternatives for achieving compliance with its Firm Winter Capacity Requirement:

1. Under the terms of Schedules G-SFT or G-AFT, contract with PG&E for all or part of the CTA's path-specific proportionate share of firm Backbone pipeline capacity PG&E has reserved for Core End-Use Customers.

2. Contract with a party other than PG&E for guaranteed use of that party's firm Backbone pipeline capacity or for guaranteed use of that party's firm PG&E storage capacity and withdrawal rights in conjunction with Mission Path capacity under Schedules G-AA or G-NAA.[55]

Q. What is the level of January throughput adopted by PG&E and how has the CTA level of rejected PG&E pipeline capacity changed?

A. PG&E Core Procurement had 43,699,915 MMBtu of pipeline capacity reserved for Core end-use customers effective January 4, 2014.[56] CTAs rejected approximately 56.6% of

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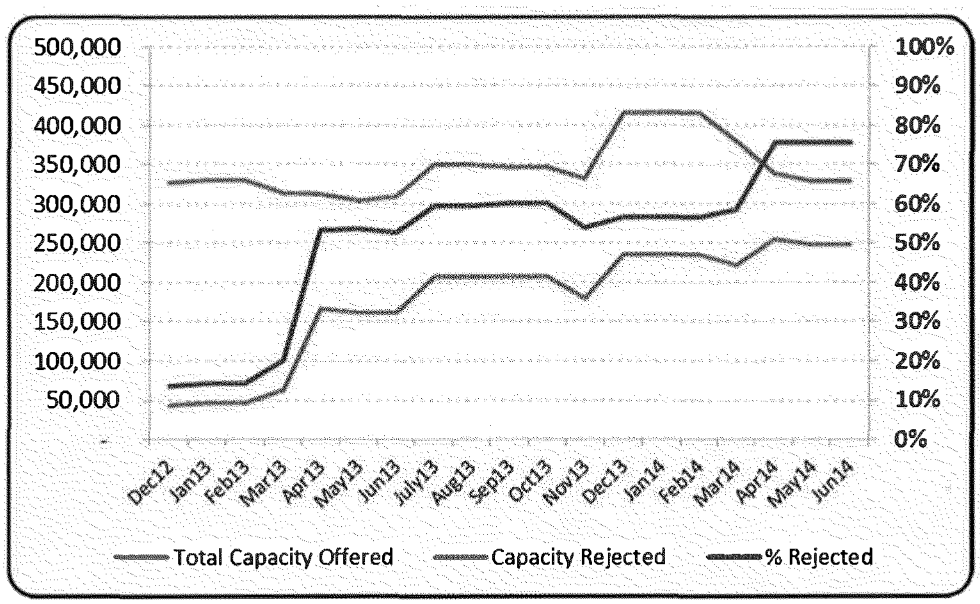
[55] PG&E Gas Schedule G-CT, January 4, 2014, Sheet 9. See Attachment B.

[56] PG&E Gas Schedule G-CT, January 4, 2014, Sheet 7. See Attachment B.

the pipeline capacity that was allocated to them in January 2014.[57] As the following figure demonstrates, rejected pipeline capacity has steadily grown to 75% in the most recent quarter.[58]

Figure 6: Pipeline Capacity Rejected By CTAs (Dths/day)



Q. Does PG&E sell the rejected/released pipeline capacity to market participants?

A. Yes. PG&E resells the rejected/released pipeline capacity. The resell price is based on the price the market is willing to bear for such capacity.

Q. Why has the proportion of CTA rejected/released capacity reached a level of 75% in the most recent quarter-?

A. As discussed above, many CTAs have a generally flatter load shape than the Core load as a whole. CTAs like Commercial Energy that serve almost entirely business clients do not

[57] PG&E Response to CTAC Data Request Set 2, Question 1, Attachment 1~~, and CTAC Data Request Set 1, Question 5 and Attachment 1~~. See Attachment N.

[58] PG&E Response to CTAC Data Request Set 2, Question 1, Attachment 1. See Attachment N.

have loads that are as weather sensitive as the Core portfolio. Therefore, the CTA needs less pipeline capacity to meet winter peak because of its inherently less volatile backbone transportation requirements.

Q. What are your concerns regarding the current approach for allocating stranded costs to CTAs?

A. Different CTAs have customer bases with different load profiles than PG&E's overall Core customer load, which means that they likely need different quantities of backbone transmission capacity to serve their customers during periods of peak demand. The current approach forces each CTA to pay for a quantity of backbone transmission capacity that may not be consistent with its needs, and often well in excess of its peak demand requirements. For example, those CTAs that serve commercial customers generally impose a relatively flat load on the PG&E backbone transmission system, as opposed to residential customers who have lower load factors because of their high space heating loads during periods of cold weather.

In addition, by continuing to require CTAs to pay stranded backbone transmission capacity charges, the Commission provides little incentive to PG&E to control the backbone transmission costs that Core customers bear. This results in higher backbone transmission costs for all customers.

Q. How should PG&E's backbone transmission costs be allocated?

A. PG&E should allocate transmission costs in a manner that matches the peak demand that each customer class imposes on the backbone transmission system during Peak Day circumstances. Such an approach is consistent with the design standard to which the backbone system must be built.

Q. What do you propose regarding handling stranded backbone transmission costs?

A. As with storage, I propose a period for PG&E to recover its stranded backbone transmission costs. After that period, CTAs would no longer be responsible for those stranded costs. My proposal is discussed in more detail below.

D. Proposal for Mitigation of Stranded Costs to CTAs

Q. -What do you propose regarding allocation of storage and backbone transmission capacity to CTAs?

A. While it might not be unreasonable to deny PG&E cost recovery of all rejected capacity of the CTAs for both storage and transmission, such an approach would be very disruptive. Therefore, I propose that any storage and backbone capacity in excess of what is required for PG&E Core Procurement would be offered to market participants (including CTAs) at market-based rates. The CTAs would have the option to purchase this capacity from PG&E. CTAs would also have the option to purchase firm capacity from third parties. If a CTA does not fulfill its winter firm capacity requirements with capacity purchased from PG&E, the CTA should be required to acquire Alternate Resources, as currently is currently the case. In this event, CTAs will need to certify such acquisition to the Energy Division or to PG&E.

Q. Wouldn't this result in significant under-collection of costs by PG&E?

A. Yes. As a result, in exchange for receiving this flexibility to procure their firm storage and backbone capacity, CTAs would be responsible for paying a declining amount of such stranded costs over a reasonable transition period. Such a transition mechanism would give PG&E an incentive to align its storage and backbone transmission holdings with the amount required to reliably serve its remaining Core customers on a system Peak Day.

Q. How would you establish the magnitude of PG&E's stranded costs?

A. PG&E's stranded costs for CTAs would be based on the difference between full revenue requirements for storage and backbone transmission capacity currently allocated to CTAs and the value of that capacity based on market-based prices for storage and backbone transmission, To determine the stranded costs, I recommend setting an initial estimate of stranded costs based on the discount for market-based capacity over the last 3 years. For example, if market-based backbone transmission capacity has sold at a 40% discount to firm rates, then that rate would establish the level of stranded backbone transmission capacity. Thus, if the present value of the CTA's portion of the backbone contracts that serve Core customers ~~is~~were $50 ~~million,~~million then stranded costs would equal $20 million. Similarly, if market-based storage has sold at a 60% discount to firm storage costs and the present value of the CTA's portion of the storage contracts that serve Core customers is $60 million, then stranded costs for storage capacity would be $36 million.

These initial estimates of stranded costs would be entered into tracking accounts. In the future, the amounts in the tracking accounts would be adjusted based on (1) payments of stranded costs by CTAs and (2) changes in the market value of storage and firm backbone capacity. The amounts in the tracking accounts would also be reduced as PG&E reduces its storage and backbone transmission capacity holdings to more closely reflect the Peak Day needs of those customers for which PG&E Core Procurement serves. This would not include CTA customers.

Q. **How would changes to the market value of storage and firm backbone capacity be reflected in the tracking account?**

A. The value in the tracking account must reflect payments made into the tracking account less the actual market value of capacity over the transition period. If market value increases over time, then the value of stranded costs should decline. Similarly, if the market value of capacity decreases over time, then stranded cost should increase. The stranded cost payments should ensure that stranded costs are paid off by the end of the transition period.

Q. **What amortization period do you recommend?**

A. I recommend an amortization period of nine (9) years. This is gradual enough that it would not impose rate shock on customers of CTAs and would not have a material effect on PG&E or its Core customers.

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Q. What rate of return would PG&E earn on these stranded costs?

A. PG&E would earn its embedded cost of debt as return on these ~~assets~~stranded costs.

Q. What if PG&E were to write off some of these stranded costs?

A. If PG&E were to accelerate the amortization of the stranded costs through write-offs, then PG&E should receive a higher rate of return on the tracking account. If PG&E were to write off 25% of the tracking account, it should receive a rate of return equal to 75% of its authorized return on ratebase on the remaining balance. Greater levels of write-offs should result in higher rate of return on the remaining tracking account balances.

Q. PG&E has proposed New Business, Customer Demand Growth and other capital additions in this proceeding that would add to the stranded costs. How would those costs be allocated to CTAs?

A. PG&E should be required in the next Gas Accord proceeding to show that CTAs and/or CTA customers have caused the capital expenditures that PG&E is proposing in this proceeding. The concept of cost causation should be the basis for allocations to CTAs and PG&E should have the burden to show that CTAs and/or CTA customers are the underlying reason for capital expenditures on both the transmission and storage facilities. If PG&E is unable to meet that burden, then those costs should not be included in CTA rates in the next Gas Accord proceeding.

Q. How would you determine the magnitude of the stranded cost charges?

A. Stranded cost charges would equal the amount of the stranded cost accounts divided by the remaining amortization period. The annual portion of stranded costs to be recovered would be divided by CTA throughput to determine the stranded cost rate. CTA customers would pay stranded costs on a per-therm basis.

Q. Why is your proposal reasonable?

A. The proposal would ultimately allow CTAs to obtain storage and backbone transmission services at market-based rates. This would benefit CTA customers, who are the fastest-growing segment of the customers currently defined as Core customers. At the same time, it would allow PG&E to recover much of its stranded costs with a modest rate of return. The proposed carrying charge is reasonable because PG&E would bear little or no risk of recovery of these stranded costs and it would give PG&E a strong incentive to move quickly toward market-based rates for storage and backbone transmission.

V. Operational Issues Related to CTAs

Q. What are the operational issues that you wish to address in your testimony?

A. There are three broad classes of operational issues related to CTAs that I address in this section. First, I discuss problems faced by CTAs related to payment plans authorized by PG&E's customer service staff. Second, I address problems with PG&E's Core load forecasting model and how it should be revised. Third, I discuss a proposed revision to the schedule for PG&E to provide data to CTAs. I discuss each of these issues in turn below.

A. Payment Plan Issues

Q. Please provide some background about the billing and payment practices for CTAs.

A. CTAs provide commodity gas service to their customers via PG&E's gas transmission and distribution system. Thus, bills for CTA customers represent payment requirements for both PG&E and CTAs. PG&E is the billing and collection agent for many CTAs. Thus, when customers have payment issues (such as non-payment), customers interact with PG&E's customer services staff. This interaction may be initiated by the customer or by PG&E.

Q. How is revenue collected from a CTA's customer allocated between PG&E and the CTA?

A. Under Rule 23,[59] revenue collected from customers is first allocated to pay PG&E's portion of the bill and then is allocated to pay the CTA's portion of the bill. For example, assume a CTA customer has a bill of $1,000, consisting of $300 for PG&E's services and $700 for the CTA's services. If the customer pays $1,000, then the first $300 collected goes to PG&E and the remaining $700 goes to the CTA. However, if the customer only pays $300 of their total bill of $1,000, then PG&E still receives $300 and the CTA is issued an IOU by PG&E. The CTA is only paid when the customer makes a payment in excess of the PG&E portion of the bill.

Q. What is PG&E's current practice when customers are behind on their payments?

[59] Gas Rule No. 23, Gas Aggregation Service for Core Transport Customers, January 4, 2014. See Attachment P.

A. Often, customers that are in arrears will call PG&E and PG&E's customer services representatives will try to work to get the customer to pay at least a portion of the outstanding balance in the form of a payment plan.

Q. Are PG&E's customer service representatives instructed to determine whether the customer has a CTA agreement before granting a payment plan?

A. No. There are no such requirements for PG&E's customer services representatives.[60]

Q. Are PG&E's customer services representatives instructed to offer alternative bill payment arrangements to customers of CTAs prior to offering a bill payment extension?

A. No. According to PG&E, their customer services representatives are not instructed to offer any different types of payment plans to customers with CTA agreements.[61]

Q. Do the PG&E customer services representatives contact the CTA prior to establishing a payment plan with customers that are in arrears?

A. No. PG&E's customer services representatives unilaterally decide the appropriate level for the payment plan. PG&E provides their customer service representatives with guidelines[62] on how to negotiate a payment ~~pan~~ plan as well as a Pay Plan Assessment

[60] PG&E Response to Commercial Energy Data Request Set 3A, Question 23. See Attachment C.
[61] PG&E Response to Commercial Energy Data Request Set 3A, Question 23. See Attachment C.
[62] PG&E Response to Commercial Energy Data Request Set 3A, Question 23, Attachments 1 and 2. See Attachment C.

tool to determine the customer's risk level when negotiating the plan.[63] However, the guidelines make no mention of how to deal with customers with CTA agreements.

Q. Does PG&E instruct its customer services representatives to use the standard Pay Plan Assessment except in certain special situations in which that tool is not appropriate?

A. Yes. Customer service representatives are explicitly told to always use the Pay Plan Assessment tool except in cases where a "special situation" exists. Special situations include the following:

- Agency Pledges
- CIA account
- CC&B is down
- Medical
- Solar
- Special Handle situation exists
- Unbilled Deposits

It is important to note that customers being served by CTAs are not included in these "special situations."[64]

Q. Are PG&E's customer services representatives instructed how to address issues related to customers of CTAs?

A. No. PG&E provides no training of its customer services representative related to CTA-related issues.[65]

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[63] PG&E Response to Commercial Energy Data Request Set 3A, Question 23, Attachments 1 and 2. See Attachment C.

[64] PG&E Response to Commercial Energy Data Request Set 3A, Question 23, Attachments 4. See Attachment C.

Q. Why is this a problem for the CTA?

A. Since the customer in arrears is making payments, PG&E cannot turn off the customer's service. As a result, the customer continues to receive gas service from the CTA but the CTA might be receiving little or no revenue from the customer. In addition, the CTA may be unaware that the customer has obtained PG&E's agreement to a payment plan, or that the customer is making partial payments.

Q. How is that possible?

A. If the PG&E representative and the customer agree to a payment plan that only covers the PG&E portion of the customer's bill, then the CTA receives no revenue since the payments from the customer first go to PG&E and only once PG&E is paid for its service does revenue flow to the CTA.

Q. What do you recommend?

A. I have two recommendations. First, I recommend that PG&E's customer services staff should be prohibited from making payment plan arrangements with CTA customers without getting permission from the CTA. Second, I recommend that any revenues collected from customers should be allocated on a *pro rata* basis between PG&E and the CTA.

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[65] PG&E Response to Commercial Energy Data Request Set 3A, Questions 8 and 23, Attachments 1, 2, 3, and 4. See Attachment C.

Q. Why are your recommendations reasonable?

A. My first recommendation is reasonable because the PG&E customer services representative effectively must represent both PG&E and the CTA in establishing a payment plan. Without getting input from the CTA about the potential terms of a payment plan, the PG&E customer services representative cannot adequately represent the CTA's interests. In addition, PG&E's current practice of agreeing to such payment plans without notifying the affected CTA means that the CTA is unable to represent its own interests because it doesn't even know that it should contact the customer regarding payment issues.

My second recommendation is reasonable because it gives PG&Es customer services representatives an incentive to negotiate payment plans that would meet the legitimate revenue needs of both PG&E and the CTA. Without this requirement, PG&E's customer services representatives have no incentive to negotiate a payment plan for any amount greater than PG&E's outstanding amount. In cases where PG&E has contracted to perform consolidated billing for the CTA, my recommendations would have PG&E act in a fair and reasonable manner consistent with the obligations imposed on PG&E by the billing and payment provisions of PG&E Gas Rule 23.C. At the very least this should include informing the CTA of the customer's request for a payment plan, and attempting to obtain partial payments for the CTA proportional to the payments PG&E will receive under any payment plan.

B. Core Load Forecasting Model

Q. What is the purpose of the Core Load Forecasting (CLF) model?

A. PG&E states that "The mission of the Core Load Forecasting Model (CLF Model) is to predict (or determine) how much gas will (or has been) consumed during a given Gas Day by a Core Transport Agent's (CTA) Core Procurement Group (CPG) in PG&E's retail service territory."[66] Thus, PG&E recognizes the importance of the CLF model to CTAs. The CLF model is also used to specify each CTA with individualized estimates of its customers' aggregate daily usage.

Q. Why are Core load forecasting issues important for CTAs?

A. Under PG&E Gas Rule 23.B.4a-b,[67] CTAs are eligible for a significant discount on credit requirements if they agree to nominate their gas supplies based on PG&E's forecast of Core gas demands. The discount is significant: 80 percent, which is equal to reduction of about $70 million in credit requirements, if all CTAs used this option. However, if the PG&E Core load forecast is faulty, then CTAs may meet their daily nomination requirements based on the results of the CLF model but find that their customers' total gas usage is outside of an acceptable band, which can result in additional charges or lost opportunities for the CTA. In addition, Core Load Forecasting errors frequently have the effect of requiring CTAs to pay overpay to establish credit with PG&E.

[66] CONFIDENTIAL PG&E Operator's Manual for "Core Load Forecasting and Load Determination Service," p. 4. See Attachment Q.

[67] Gas Rule No. 23, Gas Aggregation Service for Core Transport Customers, January 4, 2014. See Attachment P.

Q. What are the problems with PG&E's ~~Core Load Forecasting~~CLF model?

A. In summary, the CLF model treats each CTA as if their client group is identical with similar weather variances, which is not correct. Second, it does not use real-time information, such as SmartMeter data, to back-test its daily forecasts for accuracy for each CTA. Third, PG&E does not provide each CTA with a list of all the meters that are being used each month to derive the load that each CTA must nominate and balance to. I describe each issue in detail below.

Q. Does PG&E's CLF model rely on SmartMeter data at the present time?

A. No. PG&E states in Chapter 10 of its testimony that it investigated using data from gas SmartMeters in its CLF model, and determined that the data is not yet practical for daily gas use forecasts. PG&E has indicated that devising systems to gather SmartMeter data and transform it for forecasting purposes may be a future improvement to its CLF model identified through ongoing research and testing.[68]

Presently, rather than using SmartMeter data, PG&E has proposed to modify its C~~ore load forecasting~~LF model to use an average of 24 hourly temperature forecasts, rather than a simple average of the daily high and low forecast.[69] PG&E believes this methodology will yield greater accuracy for determining customer usage.

[68] PG&E Testimony, p. 10-44
[69] PG&E Testimony, p. 10-43

Q. Has PG&E indicated when this improvement to its model might occur?

A. No. PG&E did not have a timeframe for this improvement to occur.[70] In its testimony, PG&E notes that investigating possible improvements to its C~~ore load forecasting~~LF model would require "construction of a robust test environment, significant data manipulation, and ongoing test cycles."[71] Presumably, such improvements would take a significant amount of time.

Q. Do you believe that PG&E's proposed enhancement to its CLF model will be very helpful?

A. It might make a small difference. However, the larger problem is not what the temperature is but how the gas consumption of each customer of each CTA varies when the weather changes. PG&E does not appear to be planning to address this issue.

Q. Does PG&E have an active gas load research program that might help to improve the CLF model?

A. According to PG&E, it does not.[72] This is unfortunate since load research would at least be a stop-gap measure until PG&E is able to more fully utilize its SmartMeter data for load forecasting.

Q. Does PG&E rely on other tools to improve its CLF model?

[70] PG&E Testimony, p. 10-44
[71] PG&E Testimony, p. 10-44
[72] PG&E Response to Commercial Energy Data Request Set 7, Question 8 (c). See Attachment C.

A. It is unclear. PG&E states that it is not using the Core Gas Asset Model (CGAM) to calculate peak demands by Residential or Commercial classes, even though in Docket A.13-06-011 PG&E claimed to use it for system planning.[73] Since system planning is driven by peak day gas demand, it seems plausible that the CGAM might prove useful in improving the CLF model.

Q. How should PG&E revise the ~~Core load forecasting~~CLF model?

A. PG&E should pull random samples monthly of the daily data that it receives from Smart Meters and compare that to their forecast. The random samples should provide a statistically valid view of Core load. I understand that PG&E has the North American Industry Classification System (NAICS) codes for almost all of its client's meters, so polling from each of the predominant codes starts to build a relevant database without the burden of analyzing too large a dataset.

Q. Are there other issues related to the CLF model and the data being used in the model that you would like to comment upon?

A. Yes. PG&E should provide a list of all the meters that PG&E is using in the CLF model for the upcoming month. PG&E already has a file of the meters for each CTA since it uses this file to create the monthly credit request with each CTA. Thus, providing this list

[73] PG&E Response to Commercial Energy Data Request Set 3, Question 25 (Attachment C); PG&E Response to Commercial Energy Data Request Set 7, Question 8 (Attachment C); PG&E Testimony p. 10-43; and PG&E Prepared Testimony of Karen Lang served in Docket No. A.13-06-011, June 13, 2013, p. 14 (Attachment R).

of meters to the CTA should not create a burden on PG&E.[74] PG&E should also provide the prior year's monthly volume used by those meters to verify the accuracy of the data used by PG&E to create individual CTA's load forecasts. The individual CTA should be given three (3) business days to notify PG&E of errors in the file and to provide corrected information. Given the financial impacts of the CLF modeling, Commercial Energy requests that there be ~~a~~ collaboration between CTAs and PG&E on the inputs used in the CLF model.

C. Information Provided to CTAs by PG&E

Q. What kinds of information does PG&E provide to CTAs related to their customers' usage to meet their CLF obligations and balancing requirements?

A. For purposes of balancing and scheduling, PG&E currently provides CTAs with a file containing the ~~monthly metered~~monthly-metered loads of each of their customers. PG&E provides this file to the CTA 75 days after the close of each calendar month, which means that for a customer with a meter read on the 15th, the CTA gets the volume for the first half of the month fully ninety (90) days after the read. Thus, CTAs have little or no understanding about the specific loads that their aggregate of customers incurs until so far after the fact that they can do nothing to remedy the situation.

Q. Does PG&E agree that its SmartMeter data can provide daily load data to CTAs?

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[74] Providing this file to the CTA has an additional benefit: it would ensure that PG&E has the correct list of meters for the credit request.

A. No. PG&E contends that its SmartMeters only send out meter readings after the meter has recorded a certain amount of gas flow: 100 cubic feet for residential, small commercial, and residential master-metered accounts. As a result, PG&E contends that their SmartMeters might not send usage information out for several days during periods with low gas flow through the meter.[75]

Q. Is 100 cubic feet a significant amount of gas usage for a commercial or master-metered residential customer?

A. No. The heat content of 100 cubic feet of natural gas is about one therm. If a customer uses one therm per day, that is equivalent to 365 therms per year. This is quite a bit less than the annual usage for master-metered residential or small commercial customers, which might use up to 250,000 therms per year as Core customers.

Q. What do you conclude from this?

A. It seems unlikely that PG&E's SmartMeters would not register usage for several days at a time for small commercial or master-metered residential customers. As a result, PG&E should have daily SmartMeter data for CTAs that serve commercial or master-metered residential accounts.

[75] PG&E response to Commercial Energy Data Request 9, Question 1. See Attachment C.

Q. Why is it important for CTAs to receive information about their customers' gas usage more frequently than once per month and more promptly than 75 days after the close of the calendar month?

A. When CTAs are not able to obtain data about their customers' usage in a timely manner, CTAs must purchase and sell supplies for their customers in the dark with no reliable knowledge of their actual client loads until it is far too late to do anything about it. This puts the CTA at risk, which ultimately increases the cost of service to its customers.

Q. What do you recommend?

A. PG&E receives some amount of data on daily gas loads from its SmartMeters. These data could and should be used to provide at least some information to CTAs about their customers' usage. Even a timely report that shows only a subset of a CTA's loads would be more useful than a complete report up to 75 days after the calendar month is closed. Therefore, I recommend that PG&E should be required to provide daily usage by meter to CTAs via EDI (as they are currently doing for less than 1% of current Core meters.)

Q. What if the Commission finds it is impractical for PG&E to provide EDI data for all of a CTA's customers that have SmartMeters?

A. If the Commission believes that PG&E is unable to provide those data via EDI, then the Commission should order PG&E to provide each CTA with a single login to PG&E's MyEnergy portal and to have that login linked to data for all meters served by that CTA. This would be a vast improvement over the current system that requires a CTA to login separately to each and every customer. By using next day SmartMeter data each CTA can truly assess the relative accuracy of the CLF model and its execution.

VI. Conclusion

Q. Does this conclude your opening testimony?

A. Yes.