BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015-2017 (U 39 G).	Application No. 13-12-012 (Filed December 19, 2013)
Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Services and Facilities of Pacific Gas and Electric Company.	Investigation 14-06-016 (Filed June 26, 2014)

Prepared Direct Testimony of R. Thomas Beach on behalf of Calpine Corporation and the Indicated Shippers

R. Thomas Beach
Crossborder Energy
2560 Ninth Street, Suite 213A
Berkeley, California 94710
Telephone: 510-549-6922
E-mail: tomb@crossborderenergy.com

August 11, 2014

<u>Executive Summary</u>

This testimony presents the position of Calpine Corporation (Calpine) and the Indicated Shippers on the proposal of Pacific Gas and Electric (PG&E) to implement new gas transmission and storage (GT&S) transportation rates to be effective in 2015-2017. Calpine and the Indicated Shippers are major noncore customers of PG&E, and transport large volumes of natural gas over the PG&E system to gas-fired power plants, industrial facilities, and other gas consumers in northern California. Calpine and Indicated Shippers are concerned with the extraordinarily large noncore rate increases which PG&E has proposed, including increases which, by 2017, would more than double the cost of transporting natural gas to price-sensitive power plants and industrial users in PG&E's territory.

The primary driver of PG&E's proposed rate increases is the utility's planned expenses and investments to improve the safety of its gas transmission system in the wake of the tragic pipeline explosion of a PG&E local transmission pipeline in San Bruno, California, in September 2010. Calpine and the Indicated Shippers support the new emphasis of PG&E, the Commission, and the state of California on improving pipeline safety, and recognize that all PG&E customers will pay higher transportation rates to support needed safety improvements. However, PG&E's proposal would result in increases in its transportation revenue requirement that average 23% per year from 2012-2017. Accordingly, the Commission should ensure that PG&E's proposed safety-related spending strikes a reasonable balance between improving safety and keeping gas and electric service affordable for energy consumers in northern California. The Commission should review the allocation of PG&E's costs between core and noncore ratepayers, in order to ensure that the burdens of any approved cost increases are fairly apportioned among PG&E's customer classes. The Commission also needs to modify PG&E's proposed policy changes governing gas system operations and the cost recovery for its GT&S revenue requirement, to ensure that the utility has adequate incentives both to improve safety and to provide reliable service to gas shippers and consumers at reasonable and cost-competitive rates. This testimony makes recommendations in these areas, and suggests a number of ways in which the Commission can mitigate these extraordinary rate increases.

For example, based on a 1992 decision, PG&E currently allocates its local transmission costs on the basis of January throughput in a cold year, which is not the basis on which PG&E designs and incurs costs for its local transmission facilities. PG&E's actual design criteria is the higher of its total throughput on a Cold Winter Day (CWD) or core loads on an Abnormal Peak Day (APD). This testimony explains why PG&E should change its allocation of local transmission costs to use the CWD design basis for this capacity, and presents a revised allocation of local transmission costs which more accurately reflects cost causation.

Calpine and the Indicated Shippers also are concerned with PG&E's proposal to increase the amount of storage resources allocated to the load balancing function, thus doubling load balancing costs. PG&E justifies this proposal with an assertion that the hourly variability of its use of storage for load balancing is increasing. This testimony reviews not only the 2010-2012 data which PG&E used to justify its proposal, but also data for another three-year period (2005-2007) that enables a view of PG&E's load balancing requirements over a longer time period. This data shows that PG&E's use of storage for load balancing has not changed significantly over the last decade, and thus there is no need to allocate additional storage resources to the existing 75 MMcf/d of injection and withdrawal that have been used for load balancing since 2004. This conclusion is supported by a review of the trend in the frequency and severity of PG&E's operational and emergency flow orders (OFOs/EFOs), which also have not increased over the last 10 years.

Finally, this testimony comments on PG&E's cost recovery proposal. PG&E asks to modify the Gas Accord market structure to remove all risk of revenue recovery for GT&S costs. Calpine and Indicated Shippers oppose this proposal, and this testimony discusses how PG&E's proposal will not necessarily improve safety, and may act at cross purposes to enhancing safety by focusing management attention on cutting costs to improve financial performance. Placing PG&E at a moderate risk for recovery of GT&S revenues in the noncore market also is not inconsistent with state policy goals to use energy efficiently and reduce carbon emissions. Placing PG&E at moderate risk for its revenues for contestable backbone and storage services will align the utility's incentives with the goal of providing transportation services that support the most efficient and cost-effective use of clean-burning natural gas. PG&E should be placed 50% at risk for noncore backbone revenues and 100% at risk for market storage revenues. There are some instances in which a balancing account would be appropriate; for example, a one-way balancing account should be used to ensure that PG&E spends approved safety-related costs. The Commission also should continue to adopt rate "adders" for large new transmission projects, such as PG&E's proposed Line 407 serving the Sacramento Valley, which may be delayed if expected load growth does not materialize. The Line 407 adder should not be included in local transmission rates unless this project is built.

<u>Table of Contents</u>

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Service for the Period 2015 - 2017. (U39G)	)))))	A. 13-12-012 (Filed December 19, 2013)

Prepared Direct Testimony of R. Thomas Beach on behalf of Calpine Corporation and the Indicated Shippers

I. INTRODUCTION

Q: Please state for the record your name, position, and business address.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae* (CV), which is **Attachment RTB-1** to this testimony.

Q: Have you testified previously before this Commission?

A: Yes, I have. A current list of the testimony that I have filed before this Commission is included in my CV.

Q: On whose behalf are you testifying today?

A: I am appearing on behalf of Calpine Corporation (Calpine) and the Indicated Shippers.

Calpine develops, builds, and operates electric generating plants in California and throughout the United States. Calpine owns and operates 4,500 megawatts (MW) of gas-fired power plants in northern California that receive noncore gas transportation services from PG&E. Calpine is one of the largest noncore gas transportation customers on the PG&E system, and its plants receive service both from PG&E's local transmission system as well as directly from the utility's backbone pipelines.

The Indicated Shippers, for the purposes of this proceeding, include Aera Energy LLC, Chevron U.S.A. Inc., Phillips 66 Company, Shell Oil Products US, Tesoro Refining & Marketing Company LLC and Occidental Energy Marketing Inc. Each of these companies transports natural gas on PG&E's transmission system, as end-use customers and/or natural gas marketers.

Both Calpine and the Indicated Shippers have participated actively in prior PG&E Gas Transmission & Storage (GT&S) rate cases.

II. BACKGROUND

Q: Please discuss the origin and purposes of this proceeding.

A: Since 1998, the PG&E gas transmission and storage system has operated under the "Gas Accord" market structure. The Commission and parties have reviewed the Gas Accord structure repeatedly in GT&S rate cases since 1998. The market structure generally has received positive reviews from end use customers, shippers, PG&E, and the Commission.[1] This application is PG&E's GT&S rate case that will set PG&E's gas transmission and storage rates for the years 2015-2017.

[1] The Commission has approved or extended the Gas Accord six times in PG&E GT&S rate cases: three times as a result of all-party settlements, twice (in 1987 and 2011) after partially contested settlements, and once (in 2003) by Commission decision after a fully litigated rate case. *See* CPUC Decisions (D.) 11-04-031, D. 07-09-045, D. 04-12-

Q: Are there circumstances unique to this PG&E GT&S rate case?

A: Yes. This is the first PG&E GT&S rate case to be conducted after the tragic gas pipeline explosion on the PG&E system on September 9, 2010 in San Bruno, California.

After the San Bruno incident, the Commission initiated a rulemaking (R. 11-02-019) as "a forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines." On June 9, 2011, the Commission issued D. 11-06-017 in this rulemaking, directing each of the state's regulated gas utilities, including PG&E, to file an Implementation Plan describing how the utility will "achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested." The Commission's goal was that, once the plans are implemented, the gas transmission lines of each gas utility will have been pressure tested, will have "traceable, complete, and verifiable records readily available," and if appropriate will be able to be inspected using in-line techniques.[2] Decision (D.) 11-06-017 emphasized that a "key question" was how the plans were to be funded, in other words, whether and how the costs would be recovered in rates. The Commission stressed that "obtaining the greatest amount of safety value, i.e. reducing safety risk, for ratepayer expenditures will be an overarching Commission goal in reviewing the plans."[3]

Similarly, the Independent Review Panel (IRP) on the San Bruno incident also emphasized the importance of considering tradeoffs that include ratepayer costs:

> We assume PG&E wants regulators to agree to hundreds of millions or billions of dollars in improvements to its system to assure public safety. The Panel believes for ratepayers to be responsible in the future for investments (some of which, arguably, should have been made already),

050, D. 03-12-061, D. 02-08-070, and D. 97-08-055. D. 03-12-061 resolved the one fully-litigated Gas Accord proceeding.

[2] D. 11-06-017, at 19-20.

[3] *Ibid.,*at 22.

> PG&E must be prepared to support its request for rate recovery with a thorough delineation of its long-term capital program, including the specification of the alternatives considered and an appraisal of the tradeoffs among safety, effectiveness, and cost for each alternative approach.[4]

PG&E filed its Implementation Plan (Plan) on August 26, 2011. After extensive Commission proceedings on PG&E's Plan, the Commission issued D. 12-12-030 on December 20, 2012. This order adopted a safety implementation plan for PG&E, authorizing increases in PG&E's revenue requirements to be recovered in rates totaling $299 million in 2012-2014, about 39% of what the utility had requested in its original plan.[5] In terms of the costs and rate treatment for the plan, the focus of D. 12-12-030 was on the allocation of cost responsibility between ratepayers and shareholders and on the overall level and pace of ratepayer funding for PG&E's Plan. With respect to the allocation of Plan costs among PG&E's ratepayer classes, the utility proposed to follow the cost allocation and rate design principles adopted in the 2011 GT&S Rate Case (Gas Accord V) settlement, which the Commission approved in D.11-04-031. Other parties proposed alternative allocations of Plan costs. The Commission determined that such allocation issues were best addressed in GT&S rate case proceedings, like this one:

> We find that PG&E has justified its proposal to retain the currently adopted cost allocation and rate design. <u>Such issues are better handled in general rate cases, not a proceeding of limited ratemaking review, such as this one</u>. Accordingly, we are not reopening the rate case adopted cost allocation and rate design and will follow the existing structure. PG&E's proposal comports with existing cost allocation and rate design and we, therefore, approve PG&E's proposed cost allocation and rate design.[6]

The California Legislature has also taken action to prioritize gas pipeline safety. In 2011, the Legislature enacted Senate Bill (SB) 705, which declared for the first time that "[i]t is the policy of the state that the commission and each gas corporation place safety of the

4 "Report of the Independent Review Panel" (IRP Report) on the San Bruno incident, released June 9, 2011, at page 14. Available at http://www.cpuc.ca.gov/PUC/events/110609_sbpanel.htm .

5 D. 12-12-030, at 3.

6 *Ibid.*, at 106 (emphasis added).

public and gas corporation employees as the top priority."[7] Notably, SB 705 did not call for safety at any cost, but affirmed the traditional standard that rates must be just, reasonable, and based on costs:

> The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates.[8]

Q: Did the approval of PG&E's Plan in D. 12-12-030 result in significant rate increases for PG&E ratepayers?

A: Yes, it did. For example, in 2014 the Plan's safety surcharge increased rates for electric generators on the local transmission system by 44% and for electric generators on the backbone system by 25%. The rate increase for core customers was more modest, with transportation charges for residential customers increasing by just 4%.[9]

Q: Please describe the GT&S rate increases which PG&E is proposing in this rate case.

A: PG&E again is proposing very substantial new costs in this GT&S rate case, largely (but not completely) due to safety-related improvements.

Table 16-1 of PG&E's testimony shows that PG&E's proposed annual revenue requirement is $1.29 billion in 2015, rising to $1.35 billion in 2016 and $1.52 billion in 2017, compared to the 2014 GT&S revenue requirement of $582 million approved in D. 11-04-031 plus the 2014 PSEP revenue requirement of $181 million for 2014 adopted in D. 12-12-030 for a total 2014 revenue requirement of $763 million. Thus, compared to current rates, PG&E is asking to increase its GT&S rates by $530 million (70%) in 2015, $590 million (78%) in 2016, and $760 million (100%) in 2017. The result is that, under the utility's proposal, by 2017 noncore local transmission rates for electric generation (EG) customers would more than triple, from $0.33 per Dth to $1.01 per Dth, and the

---

[7] P.U. Code Section 963[b][3].
[8] P.U. Code Section 963[b][4].
[9] Based on the 2014 PSEP surcharges and 2014 GT&S rates shown in PG&E Testimony, at Table 17-C.

noncore backbone rates paid by EG customers would roughly double, from $0.30 - $0.34 per Dth to $0.61 per Dth.[10] Noncore industrial customers would see similarly large percentage increases in their gas transportation costs. Core residential customers would see 18% increases in their transportation charges immediately in 2015, with further increases in 2016-2017.

Q: Are Calpine and the Indicated Shippers concerned about the very large noncore rate increases which PG&E has proposed in this rate case?

A: Yes. In the aftermath of the tragic San Bruno incident, the Commission's efforts to ensure pipeline safety are justified, and PG&E's new emphasis on safety is welcome. At the same time, in both its Implementation Plan and now in this rate case, PG&E is taking the opportunity to propose to add substantial rate base and to increase its noncore transportation rates dramatically in a short period of time. Rate increases of this magnitude, in such a short period of time, would have adverse economic impacts on energy consumers, both gas and electric.

To put PG&E's request in perspective, these new GT&S costs are two to four times greater than PG&E's new costs, which began in 2013, to purchase greenhouse gas (GHG) emission allowances under the state's AB 32 program to regulate GHG emissions.[11] Importantly, concerns about GHG price increases and the resulting trade exposure of the California economy have caused the California Air Resources Board (CARB) to designate a number of California industries as energy-intensive, trade-exposed (EITE) industries. As such, CARB has expressed concerns that significant California-specific rate increases for EITE entities as a result of its GHG regulations could lead to a significant loss (known as "leakage") in economic activity to competitors outside of the

[10] See PG&E Testimony, at Tables 17-1 and 17-2.
[11] The public E3 GHG calculator projects PG&E's 2015 GHG obligations to be about 16 million metric tonnes under a scenario of a 33% RPS and aggressive energy efficiency goals. The most recent version 3c of the E3 GHG calculator is available at http://www.ethree.com/public_projects/cpuc2.php . Assuming a current allowance price of $12 per tonne for 2015, PG&E would spend less than $200 million in 2014 on GHG allowances.

state. To forestall such leakage, CARB will allocate free emission allowances to certain EITE industries.[12] In addition, the Commission has mitigated GHG costs for retail electricity consumers, by allocating to consumers at least a portion of the revenues from the electric utilities' auction of free GHG allowances associated with retail electricity. No such allowances are available to mitigate the impacts of these even larger gas transportation rate increases.

Accordingly, the Commission should ensure that PG&E's proposed safety-related spending strikes a reasonable balance between improving safety and keeping gas and electric service affordable for energy consumers in northern California. The Commission should review the allocation of PG&E's costs between core and noncore ratepayers, in order to ensure that the burdens of any approved cost increases are fairly apportioned among PG&E's customer classes. The Commission also needs to modify PG&E's proposed policy changes governing gas system operations and the cost recovery for its GT&S revenue requirement. These changes are needed to ensure that the utility has adequate incentives both to improve safety and to provide reliable service to gas shippers and consumers at reasonable, cost-competitive rates. This testimony makes recommendations in all of these areas, and suggests a number of ways in which the Commission can mitigate these extraordinary rate increases.

III. THE ALLOCATION OF LOCAL TRANSMISSION COSTS

Q: What component of PG&E's transmission rates is most impacted by PG&E's proposed spending on safety-related aspects of its gas transmission infrastructure?

[12] In fact, PG&E and the other electric utilities have stated that mitigating the costs of GHG regulation for electricity consumers is a "critical" policy goal, while preventing economic leakage is a "very important" objective. "Joint Proposal Of Pacific Gas And Electric Company, Southern California Edison Company, and San Diego Gas &Electric Company on the Appropriate Use of Allowance Auction Revenues," filed October 5, 2011 in R. 11-03-012, at 8-14.

A: Much of PG&E's proposed spending is on its local transmission system. This can be seen in its proposed increases for noncore local transmission rates, which would increase from $0.33 per Dth in 2014 (including PSEP costs) to $1.06 per Dth in 2017. When the first Gas Accord case rates were implemented in 1998, the noncore local transmission rate was just $0.135 per Dth, just 53% of the noncore Redwood backbone rate of $0.253 per Dth. Since then, local transmission rates have been lower than or (as today) roughly the same as backbone rates. However, this would change with PG&E's proposed safety-related spending on its local transmission system.

Q: How are PG&E's local transmission costs allocated to customer classes?

A: Local transmission costs are allocated on the basis of each customer class's peak month (December or January) throughput in a cold year. This allocation was set 22 years ago, in 1992 in D. 92-12-058. As discussed below, this allocation does not reflect the cost drivers for PG&E's local transmission system, and dates from a time when the rate design structure and methodology for PG&E's gas transportation rates were very different than today. The magnitude of the increases in the local transmission costs which PG&E is proposing, particularly for noncore customers, also justifies a new look at the allocation of these costs. This allocation should reflect cost causation as accurately as possible, should be based directly on PG&E's design criteria for these facilities, and should capture how the respective customer classes benefit from safe and reliable local transmission facilities.

Q: What are the criteria that PG&E uses to design its local transmission facilities?

A: As PG&E notes in its testimony, the utility designs its local transmission facilities to meet the higher of either (1) core and noncore demand on a Cold Winter Day (CWD), or (2) core demand on an Abnormal Peak Day (APD). On an APD, PG&E plans to provide service only to core customers, with no service for noncore customers.[13] Peak month

[13] PG&E Testimony, at 10-8 to 10-10.

throughput, the current allocator for local transmission costs, is not a design criterion for local transmission. As a result, a change to a new allocation of local transmission costs based on PG&E's actual design criteria would result in an allocation between the core and noncore classes that more accurately represents the gas usage by both core and noncore customers that drives PG&E to incur local transmission costs.

Q: What are the options for a new allocation of local transmission costs based on the design criteria?

A: The two options are either (1) the use of an allocator based on CWD throughput for both core and noncore or (2) an allocation that uses APD throughput for the core and CWD throughput for the noncore. **Table 1** below shows how these new allocations would compare to the existing allocation of local transmission costs between the core and noncore.

Table 1: *Possible Allocators for Local Transmission Costs*

Throughput / Allocator	Core	Noncore[14]
Cold-year peak-month	58%	42%
Cold winter day (CWD)	65%	35%
Core-APD / Noncore – CWD	72%	28%

Q: Which allocation do you recommend for local transmission costs?

A: I recommend the use of CWD throughput as the allocator for local transmission costs.

Q: Why would a change to the use of CWD throughput as the allocator for local transmission costs be reasonable?

A: This change is reasonable because it would more accurately align the allocation of these costs with how PG&E designs its system and with the core and noncore usage that determines the need for local transmission capacity. Today's allocator, peak-month cold-year throughput, is not based on PG&E's design criteria for local transmission, and

[14] Noncore includes wholesale loads.

allocates a too-large share of local transmission costs to noncore customers, forcing them to subsidize the core. The need to address this subsidy is magnified by the magnitude of the possible increases in PG&E's local transmission costs in this proceeding.

Q: Would such a change be fair to core customers?

A: Yes, it would. Even with the change to the use of a CWD allocator, the overall allocation of local transmission costs would remain favorable for core customers, for two reasons.

First, some local transmission facilities are designed to meet core APD demands that are even higher than core CWD demand. As a result, arguably the core could be allocated local transmission costs based on its APD throughput, because the core will be the beneficiary of the facilities that are designed to meet the higher core APD loads. Noncore customers receive no benefit from these local transmission facilities during an APD event, because they will be curtailed. Thus, the most accurate allocation would be the alternative of APD throughput for the core and CWD demand for the noncore. However, to be conservative, we do not propose this alternative.

Second, PG&E reports that more than one million citizens live or work within the Potential Impact Radius of its gas transmission pipelines.[15] These core ratepayers who live and work in proximity to transmission pipelines will be the direct beneficiaries of the safety improvements to the local transmission system, as they will bear fewer risks from pipeline failures. These considerations mean that the use of a CWD allocation of local transmission costs is reasonable based both on PG&E's design criteria and on the benefits, including the safety benefits, which core ratepayers will receive from improvements to the local transmission system.

[15] See PG&E Testimony, at 2-23 to 2-25, especially footnote 15, and PG&E response to CUE Data Request (DR) No. 1, Question (Q) No. 3, which is included in **Attachment RTB-2**.

Q: Has the Commission revisited and revised the allocation between the core and noncore of other GT&S costs since D. 92-12-058?

A: Yes, it has. In fact, the allocation of local transmission costs is the only allocation of gas transmission and storage costs adopted in D. 92-12-058 which has <u>not</u> been changed. The allocators adopted in D. 92-12-058 were chosen for a cost allocation based on long-run marginal costs at a time when all gas transportation and storage services – including backbone transmission, local transmission, storage, distribution, and customer-related services – were provided together on a completely bundled basis. Since that time, GT&S services for transmission and storage have been unbundled from gas distribution and the rates for these services are now based on embedded costs. Importantly, in the Gas Accord rate structure, the allocation of backbone transmission and storage costs has changed from the allocations adopted in D. 92-12-058. Today, these allocations are based on the respective backbone and storage capacities used by the core and noncore classes.

Q: Would a CWD allocation of local transmission costs be more consistent with the capacity-based allocation of other GT&S costs for backbone transmission and storage?

A: Yes, it would, because CWD throughput is one of the design criteria which PG&E uses to determine how much local transmission capacity is needed to serve the capacity-related demands of each class for service under peak demand conditions. This would be consistent with the current capacity-based allocation of backbone transmission and storage costs.

Q: Please present your calculation of PG&E's proposed local transmission rates using the CWD cost allocation that you recommend.

A: **Table 2** shows PG&E's proposed local transmission rates using a CWD cost allocation, and compares the resulting rates to the use of the current cost allocation.[16]

Table 2: *Local Transmission Rates ($/Dth)*

Line No.	Customer Groups	2013	2014	2015	2016	2017
1	**PG&E Proposed Rates:**					
2	Core Retail	$0.629	$0.680	$1.959	$2.109	$2.371
3	Noncore Retail and Wholesale	$0.295	$0.332	$0.875	$0.919	$1.057
4	Noncore Retail G-EG D&T			$0.849	$0.849	$1.009
5	**Calpine / Indicated Shippers Proposed (CWD Allocation):**					
6	Core Retail			$2.149	$2.290	$2.576
7	Noncore Retail and Wholesale			$0.701	$0.748	$0.861
8	Noncore Retail G-EG D&T			$0.674	$0.685	$0.815
9	**System Design (Core APD / Noncore CWD Allocation):**					
10	Core Retail			$2.316	$2.469	$2.777
11	Noncore Retail and Wholesale			$0.547	$0.580	$0.668
12	Noncore Retail G-EG D&T			$0.520	$0.525	$0.625

IV. ALLOCATION OF STORAGE CAPACITY TO LOAD BALANCING

Q: PG&E proposes to increase the allocation of storage capacity, and costs, to the load balancing service that it provides to backbone shippers. The injection capacity allocated to load balancing would increase from 75 MMcf/d to 130 MMcf/d; the allocated withdrawal capacity would increase from 75 MMcf/d to 200 MMcf/d. These costs are included in backbone rates. What would be the impact of this proposal on backbone rates?

A: PG&E's proposal would roughly double the costs allocated to load balancing, raising backbone rates by about $0.02 per Dth.[17]

[16] PG&E provided its CWD forecast in response to GTN DR 2, Q21, which is included in **Attachment RTB-2**. PG&E forecasts CWD throughput for the core and noncore as a whole, but states that it does not break this forecast down for each customer class within the core and noncore. To perform this step, I have used the relative January peak month throughput forecasts for the customer classes within the core and noncore. See PG&E response to Calpine DR 1, Q1, which is included in **Attachment RTB-2**.

Q: How does PG&E support this proposal?

A: PG&E justifies this proposal as follows:

> Records from 2010-2012 indicate that to manage pipeline inventory, storage injection and withdrawal capacity dedicated to balancing exceeded 75 MMcf/d (76 MDth/d) for injections approximately 37 percent of the days, and for withdrawals approximately 40 percent of the days. The incremental capacity above 75 MMcf/d was available for load balancing only because it happened to be unused on those days by those who were otherwise contractually entitled to it. As a corollary, using this capacity for balancing foreclosed PG&E's opportunity to market it on an as-available basis to recover a portion of its revenue requirement. These empirical observations indicate that there is no assurance that the balancing capacity will be available when necessitated by customer nomination and usage activity, especially if hourly variability continues to increase, placing the pipeline at significant operational risk and elevating the risk of increased OFOs and Emergency Flow Orders (EFO).[18]

PG&E states that, unless more storage is allocated to load balancing, ultimately it may have to move to daily or hourly load balancing.[19] PG&E's workpapers include the study that the utility used to choose the new amounts of injection and withdrawal capacity to allocate to load balancing.[20] In this analysis, PG&E focused on the difference on each day of a three-year period (2010-2012) between its hourly maximum use of injection and withdrawal and its daily average use of these resources. PG&E observes that "[h]ourly fluctuations of storage flows are used as a proxy to determine the required balancing capacities needed to maintain pipeline integrity throughout the day."[21] This study shows that PG&E selected 130 MMcf/d of injection and 200 MMcf/d of withdrawal based on the averages over a three-year period of the ratios of (1) the maximum hourly injection or withdrawal capacity used on each day to (2) the average daily quantity used on

---

[17] See PG&E response to ORA DR 63, Q2.

[18] PG&E Testimony, at 10-49.

[19] *Ibid.*, at 10-49.

[20] See PG&E Chapter 10 Workpapers, WP 54 to WP 79.

[21] *Ibid.*, at WP 54.

that day. PG&E then applied these "hourly variability ratios" (1.75 for injection and 2.61 for withdrawal) to the existing 75 MMcf/d of injection and withdrawal capacity for load balancing to determine its recommended higher amounts of storage resources to allocate to load balancing.[22]

Importantly, from a shipper perspective, PG&E is not proposing to change the criteria that it will use to call periodic operational or emergency flow orders (OFOs / EFOs) that impose gradually more restrictive daily balancing limits on shippers.[23] PG&E would continue to assume 75 MMcf/d of storage balancing resources in determining whether to call an OFO / EFO. Thus, the additional storage resources that PG&E would allocate to load balancing would double shippers' costs for load balancing without reducing the frequency with which OFOs or EFOs are called.[24]

Q: Do you agree with PG&E that a key function of load balancing storage resources is to maintain system integrity by serving the difference between maximum hourly and daily average demands?

A: Yes, I do. Natural gas supplies are scheduled on a daily basis under an assumption that they will flow at a constant hourly rate over the 24-hour period. However, the end-use demand for natural gas is not constant on an hourly basis. I agree that a key role for load balancing storage is to meet these hourly fluctuations in demand.

Q: Please critique PG&E's approach to justifying an increase in storage resources for load balancing.

---

[22] In other words, 75 MMcf/d x 1.75 = 130 MMcf/d and 75 MMcf/d x 2.61 = 200 MMcf/d. This calculation is shown on Chapter 10 WP 54, which is included in **Attachment RTB-2**.
[23] PG&E Testimony, at 10-49, lines 19-24.
[24] See PG&E response to Calpine DR 3, Q1, which is included in **Attachment RTB-2**.

A: First, I agree that the hourly variability ratios which PG&E examined in its analysis – the ratios of (1) the maximum hourly injection or withdrawal capacity used on each day to (2) the average daily quantity used on that day – are a key measure of the hourly variability of storage use for load balancing. However, there is no clear reason, and PG&E has provided none, why the average of this metric over a three-year period (2010-2012) represents the amount by which the current 75 MMcf/d of load balancing injection or withdrawal should be increased. Instead, PG&E should look at the trend in this metric over time – if these ratios are increasing over time, then the variability of hourly gas demand that must be served using storage is rising and an increase in storage resources for load balancing could be appropriate. Unfortunately, PG&E's analysis considered only a three-year period, which is too short for a clear trend to emerge. The current 75 MMcf/d each of injection and withdrawal capacity allocated to load balancing was adopted in the Gas Accord III decision, D. 03-12-061,[25] and was implemented in 2004. To see if load balancing resources need to be increased, one should compare the hourly variability of storage use on PG&E's system a decade ago, when the 75 MMcf/d of load balancing storage was first implemented, to the hourly variability of storage use today.

Q: Did you do such a longer-term analysis?

A: Yes. I obtained another three-year set of data from PG&E for 2005-2007, comparable to the three-year set of data from 2010-2012 which PG&E used in its analysis. The annual averages of the hourly variability ratios for each three-year period are shown in **Table 3**.[26]

[25] D. 03-12-061, at 184-186.

[26] The hourly variability ratios shown in Table 4 for 2010-2012 are slightly lower than the ratios which PG&E reported in its analysis. This is because PG&E used ratios from all days in which the daily average injection or withdrawal was at least 0.1 MMcf/d. However, PG&E's comparable data for 2005-2007 used only days in which the daily average injection or withdrawal was at least 1.0 MMcf/d. It makes sense to me only to use days on which there was at least a minimal use of storage – 1 MMcf/d or higher. As a result, I corrected PG&E's 2010-2012 analysis to use only days with at least an average of 1 MMcf/d of storage use.

Table 3: *Hourly Storage Variability Ratios (2005-2007 and 2010-2012)*

Year	**Hourly Variability Ratios: Hourly Max / Daily Average Storage Use**	
	Injection	**Withdrawal**
2005	1.85	2.79
2006	1.89	2.02
2007	1.67	2.31
Average: 2005-2007	**1.80**	**2.38**
2010	1.61	2.40
2011	1.80	2.30
2012	1.78	2.71
Average: 2010-2012	**1.73**	**2.46**
Change: 2005-2007 to 2010-2012	**-4%**	**+3%**

This data shows no clear trend in the hourly variability in PG&E's use of storage over the last ten years, since the adoption of 75 MMcf/d of load balancing storage resources. The hourly variability in injection use has dropped 4% while the comparable metric for withdrawal has increased by 3%. These are not major changes and do not show any trend that would justify increasing the amount of load balancing storage resources.

Q: Have you done any other analysis that would indicate changes in the adequacy of PG&E's load balancing resources over time?

A: Yes. If hourly variability were increasing, one would expect PG&E to call more OFOs and EFOs over time. PG&E's testimony, quoted above, justifying its proposed increase in load balancing resources makes the same observation. PG&E's Pipe Ranger website provides a log of OFOs and EFOs on the PG&E system since 1998 when the Gas Accord was first implemented. **Figures 1 and 2** below show the history of PG&E OFOs and EFOs since the present 75 MMcf/d of load balancing injection and withdrawal were adopted in 2004. Figure 1 presents the annual number of OFOs / EFOs; Figure 2 weights the data on the number of OFOs and EFOs by their severity, using the non-compliance penalty as the weight. The figures also show trend lines for the frequency and severity of OFOs/EFOs since the load balancing storage quantities were last revised in 2004; as explained in more detail below, the figures and associated trend lines omit data from certain months in the year 2011. The trend lines over the past decade show that both the number and severity of OFOs has declined.

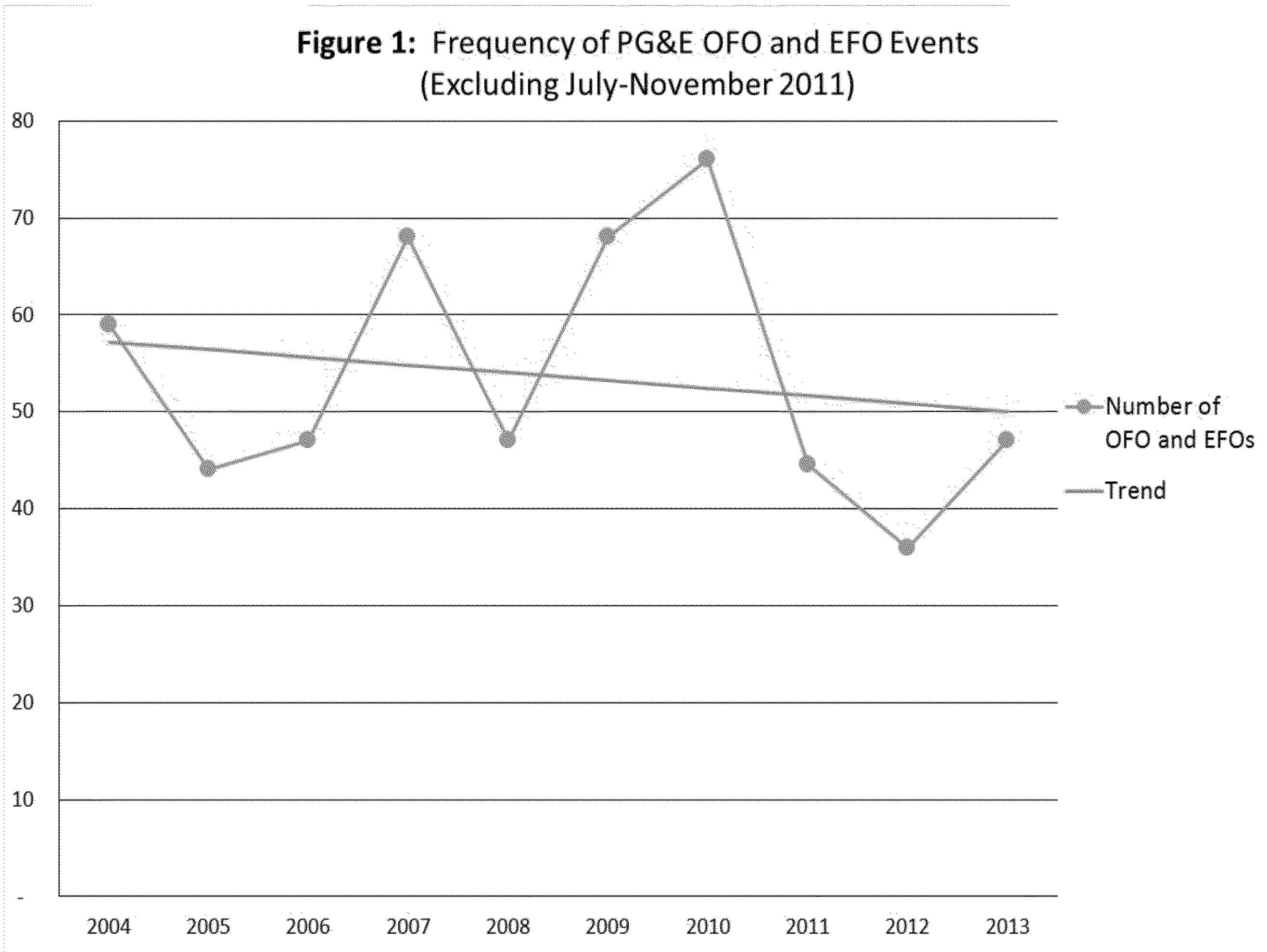
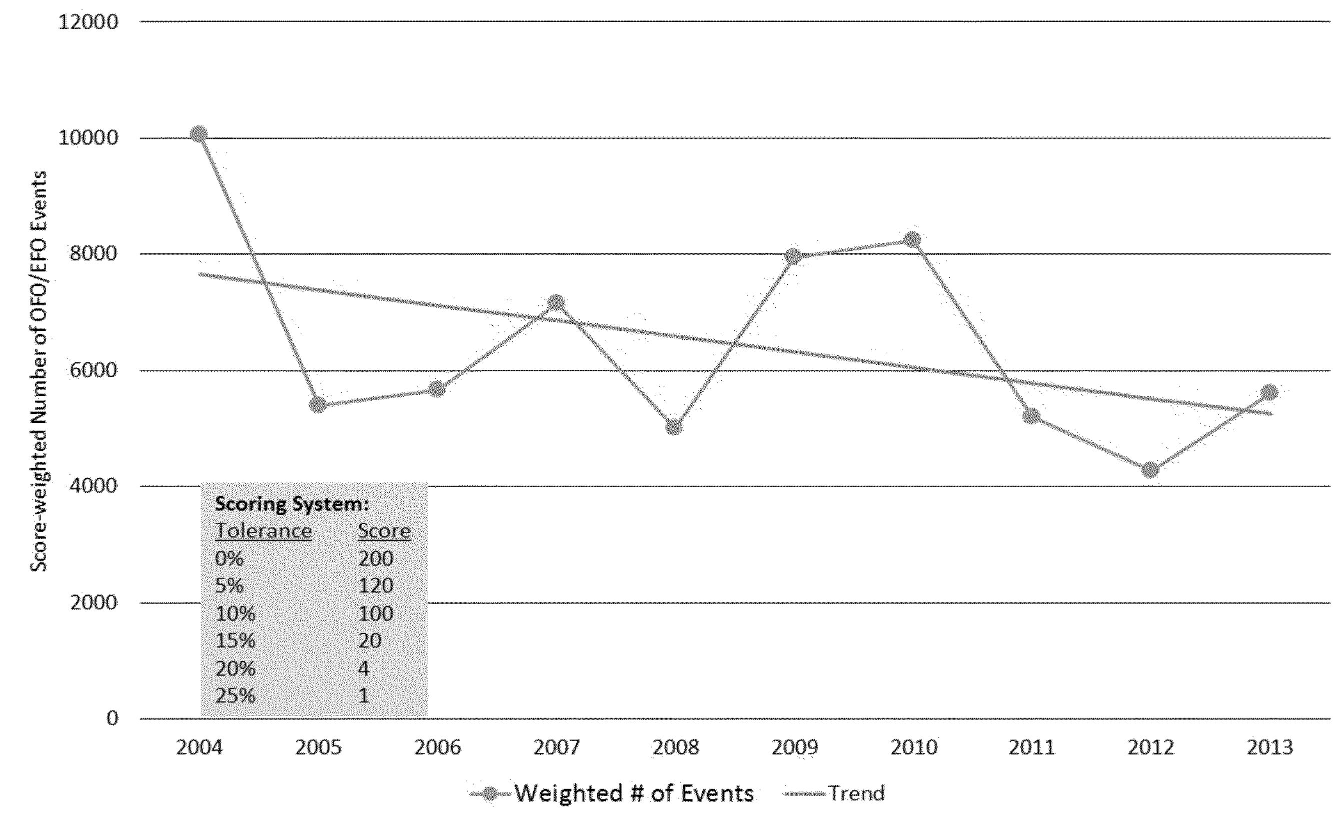


Figure 2: Number of OFO/EFO Events weighted by Severity (Excluding July-November 2011)



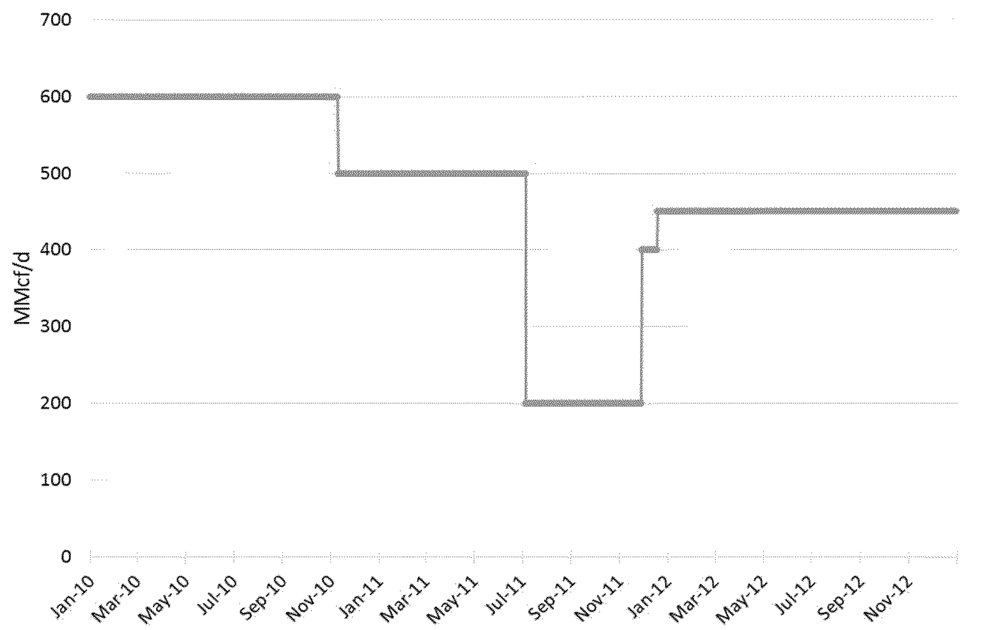
Q: You noted that the trend lines presented in Figures 1 and 2 exclude data for certain months in 2011. Why?

A: Gas utilities such as PG&E also use "line pack," the gas volumes "packed" into their transmission lines at any point in time (also known as "system inventory"), to meet hourly load fluctuations.[27] The line pack available for load balancing is a function of the pressure in the system at any point in time. Prior to 2011, PG&E typically used about 600 MMcf/d of system inventory to contribute to its balancing resources. Beginning in July 2011, the first summer after the San Bruno incident, PG&E implemented a significant reduction in its backbone

[27] See PG&E response to Calpine DR 2, Q1, which is included in **Attachment RTB-2**.

system pressure which reduced the available system inventory from 600 MMcf/d to 200 MMcf/d. This reduction lasted until the end of November 2011, at which time PG&E was able to restore available system inventory to 400 MMcf/d and then 450 MMcf/d. These changes in available system inventory in 2010-2012 are shown in **Figure 3**.

Figure 3: Pipeline Inventory Total Swing Capacity



During the July – November 2011 reduction in system inventory, PG&E called a low system OFO every day of this period.[28] As a result, 2011 saw an exceptional increase in the number of OFOs compared to other years. For this reason, data from July – November 2011 are excluded from the data used in Figures 1 and 2.[29] Figures 1 and 2 show that there has been a trend toward less frequent and less severe OFOs / EFOs over time. This trend has continued in 2012-2013 even though PG&E has reduced its system inventory in 2012 and 2013 to 450 MMcf/d, 25% below the pre-2011 system inventory of 600 MMcf/d.

[28] Documentation of this reduction in system inventory is provided in the Pipe Ranger notices included in **Attachment RTB-3**.
[29] In Figures 1 and 2, the frequency and severity of OFOs and EFOs in July – November 2011 is assumed to be the same as in the other months in 2011.

Q: Based on the analyses you have described above, has PG&E adequately justified its proposal to increase the storage resources, and associated costs, for load balancing?

A: No, it has not. PG&E's storage resources for load balancing should remain at 75 MMcf/d each for injection and withdrawal until PG&E can establish that there is a clear trend toward increased hourly variability in its use of storage for load balancing.

V. COST RECOVERY ISSUES

A. Revenue Balancing Accounts

Q: PG&E is proposing 100% balancing account protection for its GT&S revenues, with the sole exception of PG&E's interest in the Gill Ranch storage field. This would be a significant change from current policy adopted in the last Gas Accord settlement agreement, which places PG&E 25% at risk for noncore local transmission revenues, 50% at risk for noncore backbone revenues, and 100% at risk for undercollections of market storage revenues. How does PG&E justify changing this new policy?

A: PG&E argues that full balancing account protection for its GT&S revenues would be, in the words of PG&E's policy witness, "consistent with state policy of making safety the top priority."[30] PG&E also contends that this change in policy will eliminate any "conflict of interest" between increasing sales and promoting the efficient use of energy. Finally, PG&E cites the full revenue balancing accounts which the Commission has approved for other gas utilities.[31]

[30] PG&E Testimony, at 1-12.
[31] PG&E Testimony, at 10-18 to 10-19.

Q: Please discuss the implications of full balancing account protection for GT&S revenues for safety on the PG&E system.

A: It is important to recognize that PG&E is proposing 100% balancing account protection for its GT&S revenues. This change in policy would guarantee that PG&E will be able to recover 100% of its approved GT&S revenues. However, the activities involved in a utility making safety a top priority are not directly related to collecting revenues; instead, they are a matter of spending money – i.e. a matter of expenses and capital investment. In particular, safety is a matter focused attention on identifying the most serious risks and spending money to mitigate them. As the Interstate Natural Gas Aassociation of America's pipeline safety website states, "[c]ontinued investment is the key to maintaining a long-lived investment such as a pipeline."[32] PG&E's massive safety-related spending program proposed in this case is clearly PG&E's response to prioritizing safety.

If safety is a top priority, or even is the top priority, it will not be the utility's only priority. Financial performance will remain important for the utility, as it is for any business. A business has two ways to improve financial performance – increase revenues or reduce expenses. Importantly, providing balancing account protection to gas utility revenues does nothing to change the utility's incentive to increase financial performance by underspending its authorized expenses or capital additions. PG&E conceded this point in discovery in this case, and argued that its ability to improve financial performance through underspending provides an incentive to operate "efficiently."[33] It is this underspending or underinvestment that is most problematic for safety – for example, if the utility chooses to reduce spending on integrity management or to cut back on pipeline replacement or other safety-related investments. Underspending and

---

[32] See http://www.ingaa.org/Topics/Safety/4921.aspx .

[33] See PG&E response to Calpine DR 1, Q7, which is included in **Attachment RTB-2**.

underinvestment over time appear to have been principal concerns with PG&E's past safety-related practices.

The only nexus between revenues and safety is the possibility that the utility might seek to push its system to operate at pressures above safe levels in order to achieve higher throughput and higher revenues. PG&E has asserted that "PG&E does not plan to take any action to increase revenues that would compromise safety."[34] Even if PG&E were to take such actions to increase revenues, however, the real problem would be that the utility has not spent enough to increase system capacity to accommodate the higher throughput. Again, the real issue would be underspending on the expense side, not overcollecting on the revenue side.

In sum, if the Commission were to remove PG&E's ability to increase revenues, through 100% revenue balancing account protection, the utilities' only ability improve financial performance would be by reducing spending below authorized levels. This could be deleterious to safety as it might increase the temptation for management to cut safety-related spending. Assuming that utility management is going to spend some of its time and attention on financial performance, it would be better for the utility to seek to increase revenues, rather than focusing only on cutting expenses, which could jeopardize safety. Thus, providing PG&E with 100% balancing account protection for its revenues may act at cross purposes to improving safety.

Another key to ensuring safety is making certain that the utility spends on safety improvements the money which has been authorized for safety improvements. This can be done through one-way balancing accounts for safety-related spending, which I discuss further below.

---

[34] *Ibid.*

Q: Please discuss the argument that placing PG&E at some risk for its GT&S revenues in the noncore market would be inconsistent with the state's goals to improve energy efficiency and reduce GHG emissions.

A: Obviously, PG&E is correct that promoting energy efficiency and reducing carbon emissions are central to the state's energy and environmental policy goals. However, placing PG&E at some risk for noncore revenues will not jeopardize those goals – instead, it will advance them.

First, it is simply not credible to suggest that, if PG&E is at risk for noncore revenues, the utility will reduce its efforts to promote energy efficiency. That has not been the experience for the past 16 years under the Gas Accord's "at risk" revenue recovery policy. First of all, most reductions in gas usage from energy efficiency programs affect core loads. For many years, PG&E has had 100% balancing account protection for the recovery of core fixed costs, and this testimony does not propose to change that policy. Moreover, pursuant to D. 07-10-021, PG&E has an affirmative shareholder incentive to produce savings from its energy efficiency programs. Thus, it strains credulity to think that placing PG&E at risk for noncore throughput will impede its delivery of energy efficiency programs.

Second, there are a variety of substantial ways in which PG&E can advance the state's energy efficiency, environmental, and electric reliability goals, while also increasing noncore gas throughput:

- **Promote combined heat & power.** Combined heat and power (CHP) plants produce two useful products, typically electricity and steam, with much greater efficiency than the separate production of both products. Both this Commission and the California Air Resources Board (CARB) have identified expanded CHP as an important element in the state's scoping plan for meeting AB 32's ambitious goals. When a customer with an existing thermal load installs CHP, the gas consumption on the site increases as a result of the new power production. The CHP unit's electric production will displace power produced elsewhere, but much of the power displaced will be off the PG&E system. CHP already represents

27% of PG&E's expected EG throughput,[35] and the potential growth in CHP represents a continuing market opportunity for the gas utilities. Thus, PG&E can increase noncore throughput by taking more aggressive actions to promote CHP.

- **Continue to back out coal.** California utilities have reduced their direct reliance on imported coal generation, but coal-fired power still constitutes a portion of the state's power imports. In-state gas-fired generation, if its fuel is competitively priced, can continue to gain market share from imported coal-fired power, with a net reduction in carbon emissions.

- **Attract new gas-fired generation.** New gas-fired plants sited in northern California are likely to be more efficient than the units they displace, which, on a societal basis, increases energy efficiency and reduces GHG emissions. Even though the new plants may reduce gas use overall, they will increase throughput on the PG&E system, because many of the plants displaced will be located elsewhere. As shown in PG&E's Chapter 10 testimony, in recent years PG&E has attracted, and expects to continue to attract, a number of new gas-fired generating units on its system.[36]

- **Compete with interstate pipelines.** PG&E can increase throughput by competing successfully against the Kern River and Mojave interstate pipelines, which compete directly with PG&E to serve large customers in the Bakersfield area. PG&E also competes with the interstate pipelines in transporting natural gas to the southern California market, where gas-fired generation has increased markedly since 2012 as a result of the closure of the San Onofre nuclear plant.

If PG&E's revenue balancing account is approved, the utility would bear <u>no</u> risk if it loses throughput to competing pipelines or fails to retain existing loads or attract new loads to its system.

Significantly, under the Gas Accord structure, PG&E asks its GT&S customers to make long-term commitments to firm service and to pay fixed demand charges based on the amount of service contracted, which places the customer at risk if its throughput is less than anticipated. Yet PG&E is not willing to take risks comparable to those that it is asking its customers to bear – PG&E wants zero risk if its throughput declines. As I have

[35] PG&E Testimony, at Table 14-1 and pages 14-9 to 14-10, discussing PG&E's throughput forecast of 178 MDth per day in "non-market-responsive" CHP gas throughput.

noted above, this is not a circumstance in which utility shareholders can only lose, because there are market opportunities for PG&E to increase throughput in ways that could both reward shareholders and advance the state's energy policy goals.

Q: Under the Gas Accord V settlement approved in D. 11-04-031, PG&E has been subject to revenue sharing provisions which place it at risk for 50% of its noncore backbone revenues and 25% of its local transmission revenues. For market storage, PG&E shareholders receive 25% of any overcollections, and are 100% at-risk for undercollections. PG&E also has funded the revenue sharing with $30 million per year, in view of the utility's historical overcollection of Gas Accord revenues, particularly from market storage.[37] Do you recommend the continuation of these provisions of Gas Accord V in 2015-2017?

A: For the reasons explained above, PG&E should continue to have a measured incentive to earn its forecasted revenues, by offering gas transportation services that meet its customers' needs and that allow customers to compete in the markets in which they operate. This is particularly true with respect to backbone transmission and market storage, services where PG&E is operating in contestable markets against other operators who provide similar services. I recommend that PG&E should be at risk in 2015-2017 for 50% of its backbone revenues and 100% of its market storage revenues. This risk should be symmetric, both upside and downside. As a result of the decline in market storage revenues, there is no longer a need for the $30 million annual "seed" amount in the revenue sharing calculations, or for ratepayers to have a 75% share in upside market storage revenues.

PG&E should receive assured recovery through a revenue balancing account for 100% of its local transmission costs. This recognizes that PG&E rarely competes to provide local transmission service.

---

[36] See 10-22 to 10-23, plus 10-26.
[37] See D. 11-04-031, at 32-33.

Q: How should PG&E recover the balances in the revenue-sharing accounts?

A: PG&E should continue to recover these balances through the Customer Class charge for end-use customers, as it does today. This will have the benefit of continuing the longstanding Gas Accord feature of backbone rates which are fixed for the three-year GT&S rate case period (2015-2017), providing a measure of rate certainty and predictability for backbone shippers moving gas from the California border to the PG&E City-gate market. I discuss in the next section the need for additional, more timely information on expected changes in the revenue-sharing balances collected through the Customer Class charge.

B. Forecast of Year-end Rate Changes

Q: PG&E currently files an advice letter with its expected year-end natural gas rate changes in the fall of each year, including changes to GT&S transportation rates. For example, in 2013, PG&E filed Advice Letter No. 3430-G on November 4, 2013. Do you have a recommendation related to this annual filing?

A: Yes. One of the significant benefits of the Gas Accord structure has been the rate certainty that it has provided to noncore gas customers. Typically, Gas Accord transportation and storage rates have been established in advance for three-to-five-year periods. Until the 2011-2014 Gas Accord V period, PG&E was 100% at risk for its recovery of GT&S revenues. As a result, GT&S rates for noncore customers were not subject to changes at the end of each year due to balancing account true-ups related to differences between PG&E's expected and actual recovery of GT&S costs. This provided significant and beneficial rate certainty for gas customers.

This rate certainty began to erode with Gas Accord V, which, as noted above, implemented provisions to share GT&S noncore revenues between ratepayers and shareholders. This required year-end true-ups of balancing accounts for GT&S revenues and introduced uncertainty into year-end changes in the GT&S components of end-use rates for noncore customers. The problem is that most noncore customers are businesses of significant size for whom natural gas is a major expense, and most operate on an annual budgeting cycle under which budgets for the coming calendar year, including projections of gas transportation costs, need to be in place by the end of the third quarter of each year. An advice letter proposing year-end GT&S rate changes for noncore customers on or about November 1, which is PG&E's current practice, is too late to allow inclusion of this significant new information in the annual budget cycle.

Q: How do you propose to address this issue?

A: Calpine and Indicated Shippers recommend that PG&E file an informational advice letter on or about August 1 of each year which includes its forecast at that time of the year-end true-ups of the noncore balancing accounts for GT&S revenues, of the expected year-end changes in GT&S revenue requirements that impact noncore customers, and of the resulting noncore GT&S rate changes expected at the end of the year. This would be an informational filing that could be limited only to those balancing accounts and revenue requirements changes that impact noncore customers. This filing would be an important and beneficial service to PG&E's noncore customers that would help them to adapt to what is likely to be the increasing uncertainty and complexity in how PG&E's noncore transportation rates are set.

C. One-way Balancing Account for TIMP

Q: PG&E proposes a two-way balancing account for its Transmission Integrity Management Program (TIMP). This would replace the one-way balancing accounts adopted in the Gas Accord V settlement[38] and for the PSEP program.[39] Please comment.

[38] D. 11-04-031, at Finding of Fact 47.
[39] D. 12-12-030, at 107-108.

A: The one-way TIMP balancing account is designed to remove the incentive for the utility to improve financial performance by underspending its approved budget for safety-related expenses and capital additions. Under a "one-way" account, if approved TIMP-related expenses and capital are not spent, the money is returned to ratepayers. As PG&E notes, the Legislature has added Section §969 to the Public Utilities Code requiring the use of a one-way balancing account for TIMP costs, but also providing the discretion for the Commission to approve a two-way account that would enable the utility to recover TIMP spending that exceeds approved levels. PG&E has requested a two-way account, with the restriction that increases in TIMP budgets would be approved by the Commission through Tier 3 advice letters. Given the major cost and rate impacts of this spending, it is important that PG&E have a strong incentive to complete TIMP-related projects at or below the approved budgets and not to seek to reduce the scope of TIMP-related work if it experiences cost overruns. Accordingly, the Commission should continue for TIMP the one-way balancing account for PSEP that was adopted in D. 12-12-030, including the limitations on recovery if the scope of TIMP work completed in 2015-2017 is less than approved in this case.

D. Line 407 Adder Project

Q: PG&E is seeking authorization to build Line 407, a major new 30" local transmission line to serve the Sacramento Valley. This expensive project was an "adder project" in last two Gas Accord settlements, covering the years 2008-2014, but the project has never been built as a result of slower-than-expected load growth in this region. The cost estimates for this project have more than quadrupled, from $37.3 million in the Gas Accord IV settlement to $157 million today. PG&E now wants to complete this project by the end of 2017, and argues that it experienced system constraints in this region during cold weather in December 2013. Although PG&E is not proposing treatment of Line 407 as an "adder" project, the utility is

willing to return the moneys collected for this large project if it is not completed in 2017.[40] What is the position of Calpine and Indicated Shippers on Line 407?

A: Line 407 should remain an "adder" project, with PG&E receiving cost recovery as an adder to local transmission rates only in the year after the project is finished. If the project is not completed until 2017, then PG&E should request cost recovery in the next GT&S rate case, for rates to take effect January 1, 2018. Obviously, this project has been often-delayed over the last decade, and there still is only limited evidence that load growth in the Sacramento Valley is returning to the levels that would justify this project. PG&E has justified building this project based on an assumption that new connections in the area would reach and remain at a level of above 10,000 per year over the next 20 years.[41] PG&E's forecast expects new connections to increase sharply from the existing level of about 4,000 per year in 2012-2013 to almost 10,000 in 2015 and to over 12,000 in 2016. The increase in connections in 2013 over 2012, however, was only about 1,000 connections, from about 3,500 to 4,500 connections.[42] This remains a long way from the 10,000 to 12,000 annual connections that PG&E expects in its justification for this project's need. As a result, it is far from clear that new demand will reach the levels that PG&E has cited in support of this project.

In addition, it is important to put into context the December 2013 noncore curtailments experienced in the Sacramento Valley, on which PG&E also relies to justify this project. In discovery, PG&E provided its forecast for the December 2013 temperatures in the region that were the basis for its curtailment orders.[43] The forecasted temperatures for the upcoming five-day period were in the range of 32.0 to 34.5 degrees F, below the CWD design temperature of 36.1 degrees F for full service to noncore customers in the area. Thus, it is not surprising that PG&E had to initiate curtailments given that the weather was colder than the design criteria for full noncore service. This episode thus

[40] PG&E Testimony, at 10-28 to 10-30.
[41] PG&E Chapter 10 workpapers, at WP-29.
[42] See the chart included in PG&E Response to ORA DR 37, Q3(a), included in **Attachment RTB-2**.

does not necessarily indicate that the local transmission system in this area needs to be expanded, unless PG&E is proposing for some reason to change its design criteria for service to noncore customers.

Accordingly, given both the history and uncertain need for this project, Line 407 remains a classic candidate for "adder project" treatment. Treatment as an adder will eliminate the need to remove Line 407 costs from rates in 2018 and to refund the resulting overcollections if the project is not built. As with other past adder projects, PG&E's cost estimate for Line 407 should be the cost cap for recovery of this project's costs in rates.

VI. DESIGN OF GT&S RATES FOR NONCORE END-USERS

Q: PG&E is proposing no changes in the structure of the GT&S transportation rates applicable to noncore end-use customers. Do you support the continuation of the existing structure for noncore end-use rates?

A Yes.

Q: Does this complete your prepared direct testimony in this case?

A: Yes, it does.

[43] See PG&E response to Calpine DR 4, Q5(b), which is included in **Attachment RTB-2.**

Attachment RTB-1

Curriculum Vitae of R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has participated actively in most of the major energy policy debates in California, including renewable energy development, the restructuring of the state's gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning California's large independent power community. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of PURPA.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning California's Renewable Portfolio Standard program, including the calculation of the state's Market Price Referent for new renewable generation. He has also worked for the solar industry on the creation of the California Solar Initiative (the Million Solar Roofs), as well as on a wide range of solar issues in other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, electric transmission and interconnection issues, property tax matters, standby rates, QF efficiency standards, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CPUC

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

- *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

- *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

- *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

- *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

- *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

- *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

- *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

- *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

- *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

    - *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

    - *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony ofR. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

    - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

    - *Development of a community solar program for Xcel Energy.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

   - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

   - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

   - *Standby rates for net-metered solar customers, and the cost-effectiveness of net energy metering.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of Geronimo Energy, LLC. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Attachment RTB-2

PG&E Data Responses

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	CUE_001-03		
PG&E File Name:	GTS-RateCase2015_DR_CUE_001-Q03		
Request Date:	February 3, 2014	Requester DR No.:	001
Date Sent:	February 14, 2014	Requesting Party:	Coalition of California Utility Employees
PG&E Witness:	Jesus Soto	Requester:	Jamie L. Mauldin/ David Marcus

QUESTION 3

p. 2-24, fn. 15. Please confirm that this footnote means that, according to PG&E's estimates, there are more than a million people living close enough to a PG&E gas pipeline that they are at risk of a "significant" impact from a pipeline break, as defined by 49 CFR 192.203 (per p. 2-22 and fn. 13). If PG&E cannot so confirm, please indicate the correct meaning of the number in fn. 15.

ANSWER 3

Yes, it is true that using the estimating process to develop the total occupancy count (TOC), PG&E estimates there are more than a million people living or working near PG&E's transmission pipeline that could be adversely impacted by a rupture of one of PG&E's transmission lines. This does not mean that there are over a million people who would be adversely affected in the event of an actual pipeline failure. Only those people living or working within the potential impact radius (PIR) for that particular segment are likely to be directly adversely impacted by such a failure.

A potential impact radius is defined in 49 CFR 192.903 as stated on p. 2-22, footnote 13.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	GTN_002-21		
PG&E File Name:	GTS-RateCase2015_DR_GTN_002-Q21		
Request Date:	May 2, 2014	Requester DR No.:	002
Date Sent:	May 16, 2014	Requesting Party:	Gas Transmission Northwest Corporation
PG&E Witness:	Mel Christopher	Requester:	F. Jackson Stoddard/David Huard/R. Thomas Beach

QUESTION 21

Please provide PG&E's current 2015 forecast of core, noncore, industrial, noncore EG, and wholesale gas demand (in MDth/day) on an Abnormal Peak Day ("APD") and on a Cold Winter Day ("CWD"). Please show the percentage of the gas demand for each of these customer classes that PG&E plans to serve on an APD and a CWD.

ANSWER 21

PG&E's forecasts for core gas demand on Abnormal Peak Day ("APD") and Cold Winter Day ("CWD") are applicable per winter, rather than calendar year. APD is core load only. CWD includes all load core and noncore; PG&E has calculated core CWD in the table below. PG&E does not maintain a system-wide forecast for noncore CWD demand. However, PG&E does forecast average daily noncore load per month. The noncore load from the highest noncore load month (January) is provided as a proxy for CWD noncore demand.

Below is PG&E's estimate of APD and CWD gas demand for the next two winters:

Demand Forecast for APD and CWD (MDth/d)					
Design Day	**Customer Set**	**2014-2015**	**% of Total Demand Served**	**2015-2016**	**% of Total Demand Served**
APD	**Core**	3,232	100%	3,180	100%
	Electric Generation	0	0%	0	0%
	Industrial	0	0%	0	0%
	Total APD	***3,232***	***100***	***3,180***	***100%***
CWD	**Core**	2,314	65%	2,262	66%
	Electric Generation	762	21%	671	20%
	Industrial	474	13%	471	14%
	Total CWD	***3,550***	***99% *****	***3,404***	***100%***

* Daily averages for January are used to represent typical winter demands

**Total does not equal 100% due to independent rounding.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	Calpine_001-01		
PG&E File Name:	GTS-RateCase2015_DR_Calpine_001-Q01		
Request Date:	July 3, 2014	Requester DR No.:	001
Date Sent:	July 16, 2014	Requesting Party:	Calpine Corporation
PG&E Witness:	Mel Christopher	Requester:	R. Thomas Beach/ Joseph M. Karp

SUBJECT: FOLLOW-UP QUESTIONS TO PG&E RESPONSES TO GTN'S FIRST DATA REQUEST

QUESTION 1

a. In response to GTN DR1, Question 21, PG&E provided its current 2015 forecast of core, noncore, industrial, noncore EG, and wholesale gas demand (in MDth/day) on an Abnormal Peak Day (APD) and on a Cold Winter Day (CWD). Please show the core demand on a CWD and an APD by each core customer class (i.e. residential, small commercial, large commercial, interdepartmental, NGV, etc.).

b. PG&E's response to GTN DR1, Question 21, did not appear to include wholesale CWD or APD loads. Please clarify the response – are wholesale loads included in the core?

c. Please explain the difference in the CWD forecast for the core and the 1-in-35 year Cold Year Peak Month forecast for the core which PG&E filed in this case. Why is the CWD forecast for the core higher than the daily average of the 1-in-35 year Cold Year Peak Month forecast for the core?

ANSWER 1

a. PG&E does not forecast the individual rate class Abnormal Peak Day (APD) loads or cold winter day (CWD), only the total core demand for APD and CWD load.

b. No, the core APD and CWD forecast do not include gas wholesale customers.

c. The Cold Winter Day forecast for core is higher than the daily average of the 1-in-35 year Cold Year Peak Month forecast for the core because the average temperature throughout the month, even in a 1-in-35 year Cold Year Peak Month, is higher than the temperature for a CWD.

Determination of Storage Injection and Withdrawal Capacities Required to Support Hourly Peak Balancing of the Backbone Gas Transmission System

This workpaper provides the derivation and supporting data in determining the proposed changes of storage capacity dedicated to gas transmission pipeline balancing.

Problem Statement

What quantity of storage injection and withdrawal needs to be set aside needed to balance peak hourly demands of PG&E's natural gas Backbone Transmission?

Solution

The peak hourly demand and supply on the backbone gas transmission system must be in balance to maintain integrity of transmission operations. Storage injection is used to create pipeline demand when customer's hourly demand is low and withdrawal provides supply to the pipeline when hourly demand is high. Highly reliable storage capacity in sufficient quantity must be reserved to balance the hourly peaks of supply and demand.

Hourly fluctuations of storage flows are used as a proxy to determine the required balancing capacities needed to maintain pipeline integrity throughout the day. Historic data for the period 2010 through 2012 provides the basis for this empirical determination. A ratio of the maximum hourly flow during the day to the average hourly flow for the entire day is used to compare their relative difference. This comparison is made for injection and withdrawal flows for each day. The average of all non-zero daily ratios is determined and is then multiplied by the daily balancing quantities to determine the proposed storage capacities to be set aside to accommodate hourly pipeline fluctuations. The average injection ratio is 1.75 and the average withdrawal ratio is 2.61.

The calculations below determine the proposed storage capacities to be set aside to accommodate hourly pipeline fluctuations.

<u>Injection:</u>

75 (mmscf/d) X 1.75 = 131.25 (mmscf/d); (Propose 130 mmscf/d)

<u>Withdrawal:</u>

75 (mmscf/d) X 2.61 = 195.75 (mmscf/d); (Propose 200 mmscf/d)

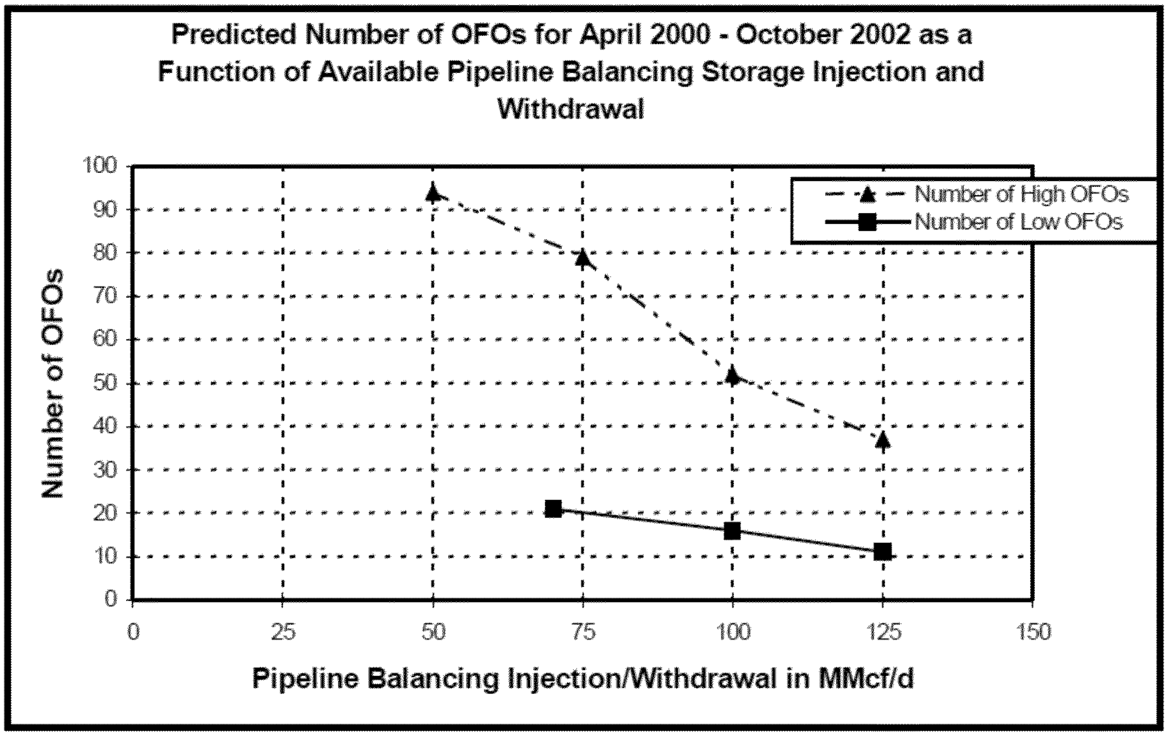
PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	Calpine_003-01		
PG&E File Name:	GTS-RateCase2015_DR_Calpine_003-Q01		
Request Date:	July 11, 2014	Requester DR No.:	Third Data Request
Date Sent:	July 24, 2014	Requesting Party:	Calpine Corporation
PG&E Witness:	Mel Christopher	Requester:	R. Thomas Beach/ Joseph M. Karp

SUBJECT: IMPACT OF ADDITIONAL PIPELINE BALANCING INJECTION/WITHDRAWAL ON NUMBER OF OFOS (CHAPTER 10 – GAS OPERATIONS)

QUESTION 1

a. Please update for 2015-2017 the following Figure 8-1 from PG&E's Gas Accord II Testimony (A. 01-10-011, Chapter 8 – see copy attached to the email transmitting this Third Data Request), in which PG&E predicted the number of High OFOs and Low OFOs as a function of available pipeline injection and withdrawal capacity.



b In its Gas Accord II testimony, PG&E indicated that the addition of 25 MMcfd of storage injection capacity could result in a 20% reduction in high inventory OFOs, as shown by the top line in the above figure. What is PG&E's forecast of the reduction in high inventory OFOs that will occur in 2015-2017 as a result of increasing balancing injection capacity from 75 MMcfd to 130 MMcfd?

SB_GT&S_0346030

c. What is PG&E's expected reduction in low inventory OFOs that will occur in 2015-2017 as a result of increasing balancing withdrawal capacity from 75 MMcfd to 200 MMcfd?

ANSWER 1

a. PG&E has not updated the study that was used to prepare the Figure 8-1 above.

b. PG&E does not expect to see a change in the number of high inventory Operations Flow Orders (OFOs) or low inventory OFOs. PG&E's proposal is to continue to use the current 75 million cubic feet per day (MMcf/d) of injection and withdrawal when doing the calculation to determine if an OFO is needed.

c. See response to (b) above.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	Calpine_002-01		
PG&E File Name:	GTS-RateCase2015_DR_Calpine_002-Q01		
Request Date:	July 8, 2014	Requester DR No.:	002
Date Sent:	July 25, 2014	Requesting Party:	Calpine Corporation
PG&E Witness:	Mel Christopher	Requester:	Thomas Beach/Joseph Karp/Avis Kowalewski

SUBJECT: FOLLOW-UP QUESTION TO CALPINE'S FIRST DATA REQUEST, REGARDING PG&E LOAD BALANCING

QUESTION 1

In SoCalGas Application (A.) 14-06-021, in the prepared direct testimony of Steve Watson, at page 2, which is posted at http://www.socalgas.com/regulatory/documents/a-14-06-021/FINAL%20Watson%20Testimony.pdf, Mr. Watson indicates that the assets PG&E has dedicated to the balancing function include 75 MMcfd of storage withdrawal plus several hundred MMcf of pipeline draft.

a. Is it an accurate statement that PG&E can use 75 MMcfd of storage withdrawal plus several hundred MMcf of pipeline draft for load balancing?

b. Please provide PG&E's 2010-2012 daily forecasts of pipeline line pack amounts that PG&E expects to be available for load balancing. This should include two numbers per day, both how much can be drawn from line pack and how much can be added to line pack for load balancing purposes.

c. Please provide PG&E's daily 2010-2012 line pack inventory amounts that were used to balance load.

d. Please provide PG&E's daily 2010-2012 additions to line pack that were added to balance load.

ANSWER 1

a. Yes. PG&E currently has about 350 million cubic feet (MMcf) of pipeline inventory swing under most conditions.

b. Attachment GTS-RateCase2015_DR_Calpine_002-Q01Atch01 has hourly inventory levels as well as the target maximum and minimum inventory level for the start of each gas day (7:00 am Pacific Time). At the start of each gas day, PG&E could have drafted the system down to the minimum inventory level or packed the system up to the maximum inventory level.

c. All the inventory variations were for the balancing function.

d. See the attachment for response (b) above which shows the daily line pack available for balancing load as well as the storage injections and withdrawals.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	Calpine_001-07		
PG&E File Name:	GTS-RateCase2015_DR_Calpine_001-Q07		
Request Date:	July 3, 2014	Requester DR No.:	001
Date Sent:	July 22, 2014	Requesting Party:	Calpine Corporation
PG&E Witness:	Mel Christopher	Requester:	R. Thomas Beach/ Joseph M. Karp

SUBJECT: CHAPTER 10 – GAS SYSTEM OPERATIONS

QUESTION 7

At page 10-18, lines 9-10, PG&E proposes a 100% "two-way" balancing account to recover GT&S revenues.

a. Please confirm that this is a revenue balancing account only. In other words, PG&E is only proposing to recover 100% of its authorized GT&S revenues. Please confirm that PG&E is not requesting to recover whatever its actual expenses or capital additions are to provide GT&S service, if those expenses or capital additions differ from those authorized in the Commission's decision in this case. Please explain if this understanding is not correct.

b. Please confirm that, under PG&E's proposal, PG&E will continue to have an incentive to spend less than its authorized GT&S expenses, because such cost efficiencies would result in increased net revenue for the utility (because its revenues would be guaranteed by the 100% balancing account). Please confirm that the only exception to this is the balancing account for TIMP expenses which PG&E proposes in Chapter 18 (pages 18-3 to 18-5). Please explain if this understanding is not correct.

c. If PG&E confirms the incentive described in Question (b), please explain how an incentive to cut costs and defer capital additions aligns with PG&E's safety-related goals.

d. Please explain the types of actions that PG&E might take to <u>increase revenues</u>, i.e. to recover more money from selling more gas services to customers, which might compromise safety. "Increase revenues" refers only to the revenue side of PG&E's business; it does not include the expense side (i.e. it does not include decisions about operating and maintenance expenses or capital additions).

e. PG&E describes both the balancing account for noncore revenues and the TIMP balancing account as "two-way" balancing accounts (pages 10-18 and 18-3). Explain what PG&E means by "two-way" in each of these contexts.

ANSWER 7

a. Yes, this understanding is correct that PG&E is requesting a two-way revenue balancing account.

b. PG&E's proposal for revenue balancing accounts does not alter any incentives PG&E may have on expenditures. Executing work as efficiently as possible is an important goal, and provides the opportunity to offset cost overruns that may occur for other reasons or to complete additional activities to mitigate more risk for the same level of spend. In addition, PG&E will be held accountable for its investment decisions through the reporting structure to be developed, as proposed in Chapter 13.

   In addition to the Transmission Integrity Management Program (TIMP) two-way cost balancing account proposed in this case, PG&E has the Gas Operations Balancing Account.

c. Based on the reporting proposal described in subpart b), PG&E does not believe that it will have the incentive to defer spend below authorized levels, and views cost efficiencies as a way to reduce risk at a faster pace. As indicated throughout its application, PG&E's goal is to reduce risk as quickly and effectively as possible utilizing the funds authorized by the Commission in this proceeding.

d. PG&E does not plan to take any action to increase revenues that would compromise safety.

e. As described in lines 8-11 on page WP 10-18 of PG&E's 2015 Gas Transmission and Storage (GT&S) Rate Case Testimony, a two-way balancing account means any overcollections (from adopted) would be returned to ratepayers and any undercollections (from adopted) would be paid by ratepayers. For a description of PG&E's proposed operation of the two-way TIMP balancing account (TIMPBA), please refer to lines 23-31 on page WP 18-4 and lines 1-6 of page WP 18-5 of PG&E's 2015 GT&S Rate Case Testimony.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	ORA_037-03		
PG&E File Name:	GTS-RateCase2015_DR_ORA_037-Q03		
Request Date:	May 14, 2014	Requester DR No.:	ORA-GT&S-37
Date Sent:	May 29, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Mel Christopher (a-d,f-h) Teresa Hoglund (e)	Requester:	Pearlie Sabino/ Nathaniel Skinner

SUBJECT: CHAPTER 10, GAS SYSTEM OPERATIONS

QUESTION 3

On page 10-28 of the above subject, PG&E states the construction of a major transmission line to expand the Sacramento Valley local transmission (SVLT) system was agreed upon in both the Gas Accord IV and Gas Accord V settlements as an adder project. However, PG&E explains that in each instance construction was deferred due to the failure of demand growth to materialize as forecast, driven by the lingering effects of the economic crisis of 2008-2009. In PG&E's Response shown in GTS-RateCase2015_DR_ORA_021-Q03 dated March 27, 2014, PG&E states that PG&E proposes Line 407 because the Sacramento Valley local transmission system is already constrained and cites to the "protracted cold weather event in December 2013" and that "PG&E was required to initiate and maintain fifteen significant manual operations on the SVLT system, issue curtailment orders to 59 noncore customers, and rely on operational cooperation from a third-party storage provider to maintain pressures, all at temperatures warmer than would have been the case just two years ago. According to PG&E, if Line 407 were operational today, the manual operations, noncore curtailments, and close coordinations with the third-party storage provider would not have been required." Further, PG&E also identified the alternative to installing Line 407 by winter 2017-2018 as requiring 54 more miles of pipeline construction than Line 407 and cost $132 million more to build compared to the PG&E proposal.[1] PG&E requests a funding for Line 407 of $157 million (nominal dollars) in this rate case which is an increase from the previously estimated cost of $103 million in the 2011 GT&S rate case. For the details regarding the Line 407 project, PG&E refers to its workpapers for Chapter 10 on pages WP 10-29 through WP 10-36. A confidential attachment discussing the Line 407 expansion project business case was included in the PG&E Response to ORA_021-Q03.

a) In the document marked "confidential," PG&E discusses a justification on pages 3-4 of 17. PG&E there describes the same forecast demand growth as it had indicated on page 10-29 of PG&E's public Testimony. Please provide verifiable evidence that the forecast demand growth in the area proposed to be served by the SVLT is in

1 PG&E Response GTS-Ratecase2015_DR_ORA_021-Q02 states that thepreviously stated figure of $142 million was incorrect and that the workpaper will be corrected.

fact on track to meet the forecast presented in the confidential document that is included in the 2015 GT&S rate case. Please provide actual annual demand levels on the line for the period 2004-present. In the confidential document, PG&E identifies on page 3 of 17 the high level issues and risks relating to Line 407. Please provide verifiable evidence showing that the high-level issues and risks discussed on page 3 of 17 of the confidential document are no longer a concern for implementation of Line 407.

b) In the confidential document, PG&E provides a summary of the current status of implementation. Please provide the Line 407 project status with respect to these high level issues and risks.

c) Please explain whether the PG&E assertion that the SVLT is already constrained is attributable solely to the occurrence of the purported extreme weather event in December 2013. Under normal weather conditions, please explain whether the SVLT system would be considered constrained by PG&E.

d) If the forecast demand growth in the SVLT system area does not materialize, is it possible that PG&E will consider, and possibly institute, another deferral, as it has done in the past two rate case periods? Please explain.

e) In this GT&S rate case, please explain whether PG&E proposes the Line 407 project as another "Adder" project (similar to its treatment during the Gas Accord IV and V settlements) which means it could be subject to a capital expenditure cap for ratemaking purposes and where the capital costs will be included in rates only if the project is actually built and only starting on the January 1 following the project's in-service date.[2] If not, please explain how PG&E proposes to recover the costs of Line 407 in the GT&S rate case and indicate the expected first year for such recovery in rates.

f) Please show how the costs increased from \$103 million to \$157 million in this rate case by providing the details to explain the significant increase in project cost for Line 407. On page WP 10-30, PG&E only provides a general discussion of the cost assumptions while the charts on pages WP 10-31 and 10-32 only show the project cost components add up to a total of \$157.0 million. There is no document showing how the costs increased from \$103 million to \$157 million. In addition, please provide the active excel spreadsheets corresponding to the charts presented in the workpapers.

g) Please clarify whether the \$157 million for Line 407 consists of capital expenditures only, and if so, whether there are any proposed expense amounts for Line 407.

h) Please explain whether the amount of \$157 million includes any contingency amounts, and if so, please identify and describe what those contingency amounts will cover.

i) Assume that the Line 407 project is approved at the proposed cost of \$157 million, and assuming no changes in project scope but the actual project costs exceed the authorized amount. Please describe PG&E's proposed treatment for cost recovery of the amounts that exceed the authorized amounts.

---

2 Refer to Section 7.4 of the PG&E Gas Accord V Settlement Agreement on page 8 for the "Adder" project definition.

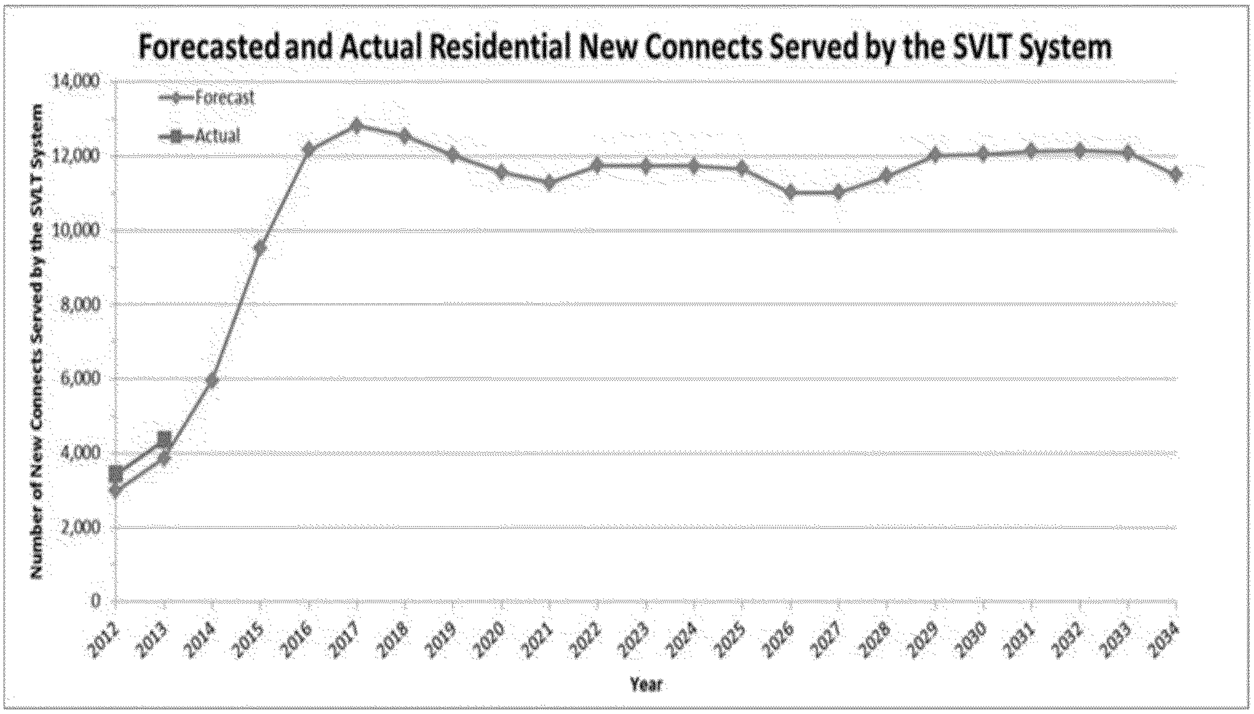
ANSWER 3

a) **Growth:**

The confidential attachment provided in GTS-RateCase2015_DR_ORA_021_Q03Atch01CONF states on page 3: "The Utility expects an average annual increase of 9,800 new residential and 700 new commercial gas customers per year over the next 20 years in this area."

The latest growth forecast (completed in May 2014) used updated information from the Sacramento Area Council of Governments and other sources to arrive at 10,000 new residential and 1,000 new commercial gas customers per year over the next 20 years. This is an increase of 200 residential and 100 commercial customers above those stated in the confidential document.

The chart below displays the annual number of new residential connects forecasted to be served by the Sacramento Valley Local Transmission (SVLT) Systemin 2012 through 2034. It also displays the actual number of new connects for 2012 and 2013 provided by PG&E's Regulatory Analysis and Forecasting Department. As can be seen on the graph, the actual number of new connects over the past two years was higher than forecasted (15% in 2012, 12% in 2013). Also, the rate of increase from 2012 to 2013 is consistent with what was forecasted.



Actual demand levels from 2004-present:

PG&E objects to this request as unduly burdensome. Subject to and without waiving the foregoing objection, PG&E responds as follows:

PG&E does not track actual demand at the local transmission level. The data could be approximated using Supervisory Control and Data Acquisition data and significant analysis, but would not provide meaningful information because actual demand data does not readily translate to the design criteria PG&E uses to fulfill its obligation to serve on an Abnormal Peak Day (APD). By definition, APD occurs once in 90 years. Pressure, a key factor in pipeline capacity, becomes increasingly nonlinear as APD temperatures are approached. Also, capacity constraints tend to be particularized to certain locations within the pipeline network. Actual flows at moderate temperatures at locations that may not correspond to the constraint locations cannot be extrapolated to arrive at any meaningful insight into the adequacy of pipeline capacity.

High level issues and risks:

The high level issues and risks on page 3 of attachment GTS-RateCase2015_DR_ORA_021_Q03Atch01CONF are typical of any pipeline project. They are ongoing and dynamic and cannot be disposed of as discrete tasks. Rather, they will require continual management throughout the project. They are replicated below for convenience:

- Land rights acquisition
- Future material cost increases
- Constrained resources (both internal and external)
- High water table risk of delay and higher costs during construction
- Nesting birds risk of delay and higher costs during construction

b) The current status of implementation for the Line 407 project is as shown in the table in attachment GTS-RateCase2015_DR_ORA_021_Q03Atch01CONF on page 5, Section 3 part B "Detailed Scope", with the exception of Land Rights Acquisition. This item has changed from 34% complete to 41% complete. Note that the items with 0% complete have start dates after the date of this data request response.

c) PG&E objects to ORA's characterization of the December 2013 cold weather event as "purported," and ORA's substitution of the word "extreme" for the word "protracted" as stated in the 2015 Gas Transmission and Storage (GT&S) rate case testimony for Chapter 10 on page 10-28. The duration and cold weather of that event is evidenced by the temperatures of the time period, which PG&E can provided if requested.

The fact that Sacramento Valley Local Transmission System (SVLT) is already constrained is based on hydraulic modeling and analysis that preceded the December 2013 cold event. The cold weather event of December 2013 confirmed the validity of the model and analysis.

The SVLT becomes constrained near Cold Winter Day conditions, when the average daily temperature in the region drops below approximately 36 degrees Fahrenheit. Above that temperature, the SVLT is not constrained. System behavior under "normal weather conditions" is not a valid way to measure constraint on a gas system. The term "normal weather conditions" fails to recognize monthly differences in climate. Per PG&E's obligation to serve, gas systems must be designed to provide continuous service even under the historically cold conditions of APD. The cold conditions in December 2013 that caused constraints in the SVLT, which had to be relieved by vigorous manual intervention and extensive region-wide noncore customer curtailments, were significantly short of the APD temperature for the SVLT area, which is 27 degrees Fahrenheit.

d) PG&E has no plans to defer the Line 407 project because the constraints discussed in response to part (a) above have already manifested.

e) No, PG&E does not propose Line 407 as an adder project. As discussed in the 2015 GT&S Rate Case testimony, Chapter 18, Cost Recovery and Post Test-Year Ratemaking Proposals, on page 18-6 to 18-7, PG&E anticipates that the Line 407 project will become operational in 2017. As such, PG&E has included the related revenue requirement forecast in 2017 (See 2015 GT&S Rate Case testimony on page 16-22, lines 22 to 25 , page 16-27, Table 16-7 and page 16-28, Table 16-8). If the Line 407 project is not constructed and placed into service in 2017, PG&E will refund the 2017 revenue requirement to customers as part of the 2018 Annual Gas True-Up .advice letter filing.

f) The response to ORA 037-03 f will be provided at a later date.

g) The $157 million for Line 407 consists of capital expenditures only. There are no proposed expense amounts for Line 407.

h) The workpapers supporting Chapter 10 on pages WP 10-19 through WP 10-36, which show the costs for Line 407, do not identify any contingency amounts. The costs in the workpapers are based on an earlier, October 2013 draft of the confidential attachment provided in GTS-RateCase2015_DR_ORA_021_Q03Atch01CONF, because this was the best information available as the 2015 GT&S Rate Case application was being prepared. This earlier draft contained less detail than the February 2014 final confidential document.

On page 9 of attachment GTS-RateCase2015_DR_ORA_021_Q03Atch01CONF, Section 4 “Financials” contains a table entitled “A) Costs Forecasts.” In the table section “Capital (Expected Case),” there is a line labeled “Contingency.” This line reflects an expected expenditure of $15.6 million that could not be exclusively ascribed to any of the listed major cost categories (Labor, Material, Contract, Other, or AFUDC).

The “Contingency” expenditure shown in “A) Costs Forecast” is an identified cost resulting from a probabilistic risk analysis that is shown in Section 3 “Implementation,” in “E) Risk Assessment Table.” This cost is expected to be incurred. It does not represent unexpected costs.

The table “B) Cost Assumptions” in Section 4 “Financials” lists the Major Scope Items and their expected costs. The costs for Major Scope Items apply to one, several, or all of the categories in table “A) Costs Forecast, Expected Case” except “Contingencies.” For each Major Scope Item, a cost is shown for the “Expected Case.” In the subsequent column, labeled “Best Case,” certain costs are backed out of the Expected Case. These Best Case savings will occur if the risk-based costs in "E) Risk Assessment Table" do not materialize as expected.

The Best Case savings in "B) Cost Assumptions" total $16.3 million. This amount is offset by $0.7 million driven by a change in AFUDC treatment if the entire Best Case scenario transpires. After the offset, the resulting Contingency figure is $15.6 million, as shown in "A) Costs Forecast." The Best Case is not the basis of the workpapers. PG&E is unlikely to capture these savings, but accounts for the 20 percent possibility that some of the savings may be realized.

To summarize, the amount labeled "Contingency" is an integral part of the Expected Case whose impact spans one or more of Labor, Material, Contract, Other, or AFUDC. The use of the term "contingency" may cause confusion; an alternate term is "Expected Risk-Based Costs."

i) In this proceeding, the Line 407 Project is just one of many projects for which PG&E is requesting recovery of revenue requirements associated with forecasted project costs. PG&E is not proposing cost caps for particular projects. PG&E expects that it will ultimately be allowed to recover the revenue requirements associated with the total adopted costs of all approved projects. While actual costs will be less-than-forecasted for some projects and higher-than-forecasted for other projects, PG&E will only be able to recover its adopted revenue requirements based on the forecasted costs, no more and no less.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	Calpine_004-05		
PG&E File Name:	GTS-RateCase2015_DR_Calpine_004-Q05		
Request Date:	July 18, 2014	Requester DR No.:	004
Date Sent:	August 4, 2014	Requesting Party:	Calpine Corporation
PG&E Witness:	Mel Christopher	Requester:	R. Thomas Beach/ Joseph M. Karp/ Avis Kowalewski

SUBJECT: CHAPTER 10 – GAS SYSTEM OPERATIONS

QUESTION 5

PG&E states on pages 10-28 to 10-29 that "[d]uring the protracted cold weather event in December 2013, in which PG&E experienced several record daily gas sendouts exceeding 4.6 billion cubic feet, PG&E was required to initiate and maintain fifteen significant manual operations on the SVLT system, issue curtailment orders to 59 noncore customers, and rely on operational cooperation from a third-party storage provider to maintain pressures, all at temperatures warmer than would have been the case just two years ago."

a. Please describe and provide the costs which PG&E incurred for the "fifteen significant manual operations on the SVLT system" and for the "operational cooperation from a third-party storage provider."

b. Please explain how the temperatures which PG&E experienced in the December 2013 cold weather event compared to the CWD design standards for the SVLT system.

c. PG&E states that it was forced to "issue curtailment orders to 59 noncore customers." Were these customers actually curtailed? Please provide the number of noncore customers actually curtailed, the amount of gas not served, and the length of the curtailments.

ANSWER 5

a. PG&E does not track the costs it incurs for specific, individual manual operations. This cost could be estimated, but not within the time before intervenor testimony is due. PG&E incurred no significant cost for the operational cooperation it obtained from the third-party storage provider.

b. Curtailments are called prospectively, based on the prior day's forecast. The table below shows PG&E's forecast of average daily temperature for Sacramento for the five-day period when curtailments occurred on the Sacramento Valley Local Transmission System.

Sacramento Temperatures					
CWD*	Forecast for Curtailment Order, December 2013				
	5-Dec	*6-Dec*	*8-Dec*	*9-Dec*	*10-Dec*
36.1	33.2	34.5	32.1	33.5	32.0

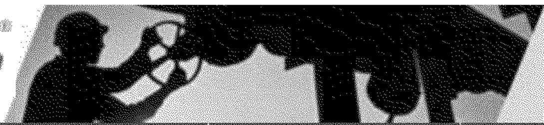
* CWD= Cold Winter Day

c. Curtailment orders rely on voluntary compliance, enforced by financial penalties for failure to comply, per Gas Rule 14[1]. During the curtailments of December 2013, compliance with the curtailment orders was incomplete. Please refer to PG&E's response to GTS-RateCase2015_DR_CommercialEnergy-CA_006-Q06 for a complete discussion of compliance data from the December 2013 curtailments.

1 http://www.pge.com/nots/rates/tariffs/tm2/pdf/GAS_RULES_14.pdf

Attachment RTB-3

Piperanger Notice of Inventory Reduction



News

Pressure Reductions on CGT's System

Wednesday, July 06, 2011

PG&E recently has reduced pressure on several segments of its pipeline system, throughout the service area, to ensure the segments are operating at appropriate pressures. Some of these pressure reductions are likely to be temporary, with pressure being restored once we are able to ensure the operating pressure is appropriate. Other pressure reductions may last throughout the summer if we need to do additional work on the pipeline.

The reduced pressures will mean that, throughout any gas day, California Gas Transmission (CGT) will have less pipeline system inventory to meet hourly and daily fluctuations in demand and supply:
- Normal operating conditions - 600 MMcf
- Current operating conditions with reduced pressure - 200 Mmcf

As a result, suppliers and customers will need to more closely match gas supply and usage. Noncore customers under a Noncore Balancing Aggregation Agreement (NBAA) can look to their NBAA holder to manage this process, as can core customers managed as part of a Core Transportation Aggregation (CTA)group.

Starting this week, as early as Thursday, July 7 for gas day, Friday July 8, CGT will begin calling simultaneous high and low inventory Operational Flow Orders (OFO's). That is, an OFO with a high inventory tolerance band and a low inventory tolerance band at the same time. Visitors to this web page will see this posted as a "High/Low Inventory OFO". This will be a system-wide OFO, and will require suppliers and large customers to balance supply within a specified tolerance range, which will be announced daily.

CGT will call a High/Low Inventory OFO each day for the foreseeable future, throughout the period of pressure reductions.

We appreciate your patience and understanding during these unique circumstances. Please call your CGT Sales, Services, or Scheduling Representative with questions.

For additional information, please see this article posted on PGE.com.

For a more in-depth explanation of OFO rules, please see Gas Rule 14, Sheets 14 and 15.

News

Increase in Inventory Swing on December 1st

Tuesday, November 29, 2011

PG&E's California Gas Transmission is pleased to announce that, effective December 1, 2011, the available inventory swing to absorb fluctuations in supply and demand will increase from 200 MMcf to 450 MMcf. As was reported in early November, this increase is a result of CGT's ability to restore pressure on several critical backbone segments.

The increase in inventory swing is reflected on the "System Inventory Status" chart. The gray bands that represent "within operating limits" will now be between 3900 MMcf to 4300 MMcf on a day of lower system send-out and between 4000 MMcf to 4400 MMcf on a day of higher system send-out. Please note that CGT is in the process of modifying this chart to show increments of 50 MMcf, rather than 100 MMcf. As of December 1st, the true inventory bands used to determine if an OFO is necessary will be 3900 MMcf to 4350 MMcf and 4000 MMcf to 4450 MMcf, even though the chart is currently reflecting a slightly tighter set of bands.

With this increase in available inventory swing, we are also pleased to announce that we will cease calling high/low inventory OFOs as of gas day December 1st and return to our normal balancing provisions. We may still need to call the more traditional one-sided OFOs on any gas day, so please stay tuned to INSIDE*tracc* and Pipe Ranger for those notices.

CGT again thanks you for your great efforts in maintaining supply and demand balances during the five months of high/low inventory OFOs.

Please contact your CGT Account Services Representative with any questions.