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Exhibit Number	:	ORA-20
Commissioner	:	C. Peterman
ALJ	:	J. Wong
Witness	:	P. Sabino

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Report on the Results of Operations for Pacific Gas and Electric Company Test Year 2015 Gas Transmission and Storage Rate Case

Rebuttal on Cost Allocation and Rate Design

San Francisco, California
September 15, 2014

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I. INTRODUCTION

The Office of Ratepayer Advocates (ORA) submits this Rebuttal Testimony on Cost Allocation and Rate Design issues pursuant to the Administrative Law Judge John Wong's Ruling dated April 17, 2014 setting forth the scoping memo and the procedural schedule for filing of rebuttal testimonies in the Pacific Gas and Electric Company's (PG&E's) 2015 Gas Transmission and Storage rate case A.13-12-012.

ORA rebuts the Prepared Direct Testimony of Mr. R. Thomas Beach ("Beach Testimony") submitted on behalf of Calpine Corporation and the Indicated Shippers ("IS")[1] in A.13-12-012 with respect to Mr. Beach's proposal to change the allocator for local transmission costs between core and noncore customers from cold-year peak month to cold winter day (CWD) and substantially increase the allocation of local transmission costs to core customers from a 58%/42% core-noncore ratio to 65%/35%.[2] Mr. Beach's recommendation is transparently motivated by the desire of noncore customers on the local transmission system to avoid paying the increased "safety-related" spending[3] requested by PG&E in this proceeding under the current allocation, justified in part by asserting that safety improvements proposed in this

[1] The Indicated Shippers are 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. These same companies were initially known in this proceeding as Indicated Producers, and filed a motion to change their name on June 30, 2014.

Mr. Beach filed separate testimony in this proceeding on other rate issues on behalf of Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest, and the City of Palo Alto. This rebuttal testimony only addresses Mr. Beach's testimony on behalf of Calpine and the Indicated Shippers.

[2] Beach Testimony, Table 1, p. 9.

[3] Id., pp. i, 5, 7 lines 8 & 28; see also p. 21, p. 22 lines 2 and 25. That PG&E's basis for almost the entirety of its requested increased spending is "safety-related" is not in dispute. PG&E has received revenue requirement increases of approximately 3.5% in the previous three GT&S rate proceedings, and roughly a 6% annual revenue requirement increase from 2011 to 2014, but has requested an 80% increase in 2015 revenue requirement in this case over authorized levels, with ORA recommending a 48% increase.

proceeding only directly benefit the specific core customers living and working near transmission pipelines.[4]

The impact on local transmission[5] core customers solely due to adopting Mr. Beach's proposed changed core/noncore allocation of 65%/35% core/noncore instead of the current 58%/42% allocation is huge by itself, a 12.1% increase of costs allocable to core, and a 16.7% decrease in costs allocable to noncore customers.[6] Although Mr. Beach is "concerned about the very large noncore rate increases which PG&E has proposed in this rate case,"[7] and testifies that "[t]he 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,"[8] the rate increases for core customers for local transmission service are much bigger than the increases for noncore for local transmission service, on a percentage and absolute basis **even if PG&E's proposal to maintain the current allocation is adopted**, as Mr. Beach's own numbers in Table 2[9] clearly show. PG&E's proposed 2015 core retail rate of $1.959/Dth, compared with the 2014 rate

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[4] "PG&E reports that more than one million citizens live or work within the Potential Impact Radius of its gas transmission pipelines. **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." Beach Testimony, p. 10 (Emphasis added). As will be explained in more detail below this particular language and argument to justify it bears a striking resemblance to the language and argument in Mr. Beach's testimony in A.11-11-002, the Southern California Gas TCAP proceeding, on behalf of Watson Cogeneration and Indicated Producers of Southern California to justify allocating 93% of PSEP safety-related costs to core customers, an argument to justify an increased cost allocation to core customers the Commission rejected in D.14-06-007. See Finding of Fact No. 12, Conclusion of Law No. 30, and Ordering Paragraph No. 9 in D.14-06-007.

[5] Unless otherwise specified, all subsequent references to "core" and "non-core" are in reference to local transmission customers only.

[6] Core increase = [(65-58)/58]; Noncore Decrease = [(42-35)/42].

[7] Beach Testimony, p. 6.

[8] Id., p. 8 (emphasis added).

[9] Id., p. 12.

of $0.680/Dth, is a **188% increase** or $1.279/Dth, whereas the proposed noncore 2015 rate of $0.875/Dth, compared with the 2014 rate of $0.332/dth is a **164% increase** or $0.543/Dth. Mr. Beach's allocation proposal then greatly increases the different size rate increases in favor of noncore customers. Under Mr. Beach's allocation proposal, the 2015 core retail rate of $2.149/Dth is a **216% increase**, or $1.469/Dth over the 2014 rate, while the 2015 noncore rate of $0.701 is a **111% increase**, or $0.369/Dth, over the 2014 rate, almost twice as much a percentage rate increase in 2015 for the core than noncore. The rate impact on 2015 core rates solely due to Mr. Beach's proposal compared to PG&E's would be a **9.7% increase** or $0.190/Dth, while the impact of Mr. Beach's proposal on 2015 noncore rates would be a **19.9% <u>decrease</u>** or $0.174/Dth. The referenced Table 2 from Mr. Beach's Testimony is reproduced below with the four rightmost columns added by ORA to show the numbers discussed in the foregoing.

Table 2: Local Transmission Rates ($/Dth)

Line No.	Customer Groups	2013	2014	2015	2016	2017	Rate Increase from 2014 to 2015 (in $/Dth)	Annual Percentage Rate Increase from 2014 to 2015 (in %)	Rate Increase of Mr. Beach Proposal Over PG&E's in 2015 (in $/Dth)	Annual Percentage Rate Increase of Mr. Beach Proposal Over PG&E's in 2015 (in %)
1	**PG&W Proposed Rates:**									
2	Core Retail	$0.629	$0.680	$1.959	$2.109	$2.371	$1.279	188%		
3	Noncore Retail and Wholesale	$0.295	$0.332	$0.875	$0.919	$1.057	$0.543	164%		
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	$1.469	216%	$0.190	9.7%
7	Noncore Retail and Wholesale			$0.701	$0.748	$0.861	$0.369	111%	$ (0.174)	-19.9%
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	$1.636	241%	$0.357	18%
11	Noncore Retail and Wholesale			$0.547	$0.580	$0.668	$0.215	65%	$ (0.328)	-37%
12	Noncore Retail G-EG D&T			$0.520	$0.525	$0.625				

Source: Table 2, Prepared Direct Testimony of R.Thomas Beach on behalf of Calpine Corporation and the Indicated Shippers in A.13-12-012 dated August 11, 2015, p.12.

Note: Table 2 as shown in Mr. Beach's Testimony does not include 2013 & 2014 rates for Line 4.

It is noteworthy that Mr. Beach fails even to mention the Commission's June 12, 2014 decision in San Diego Gas and Electric Company's ("SDG&E's") and Southern California Gas Company's (SCG's) Triennial Cost Allocation Proceeding (TCAP), D. 14-06-007,[10] in which the Commission explicitly rejected a portion of a contested settlement that proposed changing current allocation factors for gas Pipeline Safety Enhancement Program (PSEP) costs and dramatically increasing the allocation assigned to core customers on the basis that the new safety expenditures benefitted core customers in a higher proportion than other gas spending. The Commission determined in Conclusion of Law 30 that "[t]he existing cost allocation methodology is reasonable for the costs of Safety Enhancement **because these costs are necessary to safely and reliably supply natural gas to existing customers in the same manner as the existing system serves customers**."[11] The Commission rejected the proposed modifications to existing cost allocation methodology on SCG's and SDG&E's system that were specifically directed at Safety Enhancement Costs and ordered that "Safety Enhancement costs will be allocated consistent with the existing cost allocation and rate design for the companies."[12]

The Commission's reasoning and ruling on allocation of gas pipeline safety spending in D.14-06-007 in SCG's/SDG&E's TCAP is applicable to Mr. Beach's proposal in the current proceeding to increase the allocation of local transmission costs to core customers over PG&E's proposal to retain the currently authorized allocation in the proceeding in which the great majority of increased costs are "safety-related." As noted above, Mr. Beach justifies his proposal in part because

[10] D.14-06-007, *Decision Implementing a Safety Enhancement Plan and Approval Process for San Diego Gas and Electric Company and Southern California Gas Company; Denying the Proposed Cost Allocation for Safety Enhancement Costs; and Adopting a Ratemaking Settlement*, (June 12, 2014), in A.11-11-002. (TCAP Decision.) Attachment A.

[11] Id., Conclusion of Law. No. 30, p. 59 (emphasis added).

[12] Id., Ordering Paragraph No. 9, p. 61. The Commission applied SDG&E's/SCG's core/non-core/backbone allocation factor of 53.9/43.8/2.3 to PSEP spending. See ORA Reply Brief in A.11-11-002, p. 1. Attachment B.

the allocation would allegedly more accurately reflect that the "direct beneficiaries of the safety improvements"[13] are core customers living in proximity to the local gas transmission system, an argument rejected and discredited by D.14-06-007 as a proper factor to consider in gas transmission cost allocation. Mr. Beach fails to justify his proposal that allocation be based on Cold Winter Day rather than coincident peak winter on the basis of "design criteria." Mr. Beach does not show that his proposed rates are "just and reasonable" due to the much different sized rate increases of the core and noncore resulting from his allocation, which would impose rate increases of almost twice the size on a percentage basis on core customers in 2015 than noncore customers. ORA discusses the implications of Mr. Beach's proposal and safety arguments, and the impact of the Commission's views in D.14-06-007 in greater detail below.

II. REBUTTAL TO MR. BEACH'S TESTIMONY ON LOCAL TRANSMISSION ALLOCATION

A. A.14-06-007 Ruled That Safety-Related Costs Should Be Allocated Consistent With Current Allocation, and Not Increased to Core on the Basis That Benefits Accrue More to Core

The proposal of Mr. Beach to increase the allocation of local transmission costs to core customers appears primarily motivated by the desire of noncore customers to pay less than the amount under the current allocation of the increased safety costs proposed by PG&E in this proceeding rather than to properly align all local transmission costs to cost causation based solely on "actual design criteria."[14] Consistent with D.14-06-007, the Commission should reject Mr. Beach's proposals for changing existing cost allocation on the basis that safety costs benefit core customers more than noncore customers, and for other reasons discussed below.

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[13] Beach Testimony, p. 10.

[14] Id., p. 9.

The Commission provided guidelines for interpreting the relative allocation of safety costs compared with other costs in Decision 14-06-007, which adopted a plan for Pipeline Safety Enhancement for San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas), approved a proposed settlement in the Triennial Cost Allocation proceeding, and rejected "a specific cost allocation modification proposed to allocate the costs of Safety Enhancement based on human exposure to risk rather than the cost of providing service to all customer classes."[15] This cost allocation modification proposed that PSEP costs be allocated on the basis of "Equal Percentage of Authorized Margin," and Mr. Beach, represented by the same counsel but testifying on behalf of Watson Cogeneration Company and a coalition of mostly different non-core shippers than in this proceeding,[16] argued why an allocation of 93% of PSEP costs to core customers was reasonable:

> **Q: Are there other reasons an EPAM methodology should be used to allocate pipeline safety costs?**
>
> A: Yes. First, data from SDG&E / SoCalGas clarify that 97% of the premises structures found within the Potential Impact Radius (PIR) of their transmission pipelines are typically those associated with core residential and commercial customers. [fn omitted] **Obviously, customers who live or work within the PIR of a gas transmission line will receive the direct benefits of enhanced safety, in terms of reducing their own risk of harm from a catastrophic pipeline incident. This data demonstrates that almost all of the direct safety benefits of the utilities' plans will accrue to core customers**. The EPAM methodology would allocate 93%[17] of PSEP costs to core customers;[fn omitted] thus, the customer classes which receive most (97%) of the direct safety benefits from the PSEP would also pay the bulk (93%) of PSEP costs.[18]

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[15] D.14-06-007, pp. 1-2.

[16] The Southern California Indicated Producers: ConocoPhillips Company, Chevron U.S.A. Inc., and Exxon Mobil Gas Corporation. Chevron U.S.A. Inc. is also one of the Indicated Shippers in the current proceeding.

[17] ORA's Opening Brief in. A.11-11-002, p. 4, calculated the allocation of PSEP costs to core under the EPAM-based calculation at 95%. Attachment C. The existing allocation adopted in D.14-06-007 was approximately 53.9% core, 43.8% noncore, and 2.3% backbone. ORA Reply Brief in A.11-11-002, p. 1, Attachment B.

[18] Prepared Direct Testimony of R. Thomas Beach on Behalf of the Southern California

(continued on next page)

The Commission explained the context and decision as follows:

> This application began as a conventional “phase 2” application to address rate design and cost allocation issues in a proceeding trailing the triennial general rate cases. As already noted Safety Enhancement issues were added to the scope of the proceeding and in addition, parties litigated the question of whether the Safety Enhancement costs required any variance to the existing cost allocation methodology – that is, not allocating the eventual new and higher costs of repaired or replaced pipeline components on the same methodology of the existing pipeline components but perhaps allocating them differently.
>
> This section finds that parties reasonably entered into a settlement of the conventional issues and we therefore adopt it. However we are not persuaded that there is any merit to reallocating the costs of Safety Enhancement. Some parties suggest that safety is somehow a severable service from gas delivery: arguing in essence that the only reason we want the system to be safe is to not kill people if there is an explosion. We do of course want it to be safe and not kill people: but that is a prerequisite of having any pipeline. **We therefore reject all proposed changes and find that the new costs of a safe system should be allocated exactly the same way the existing components to be repaired or replaced are allocated**. [19]

The Commission summarized its decision as follows:

> Several parties suggest that the Safety Enhancement costs do not contribute to gas delivery service; the costs only reduce the risk of death and injury to people who live or work adjacent to a pipeline should that pipeline rupture or fail. We observe that a ruptured pipeline delivers no gas – to anyone, business or individual – and as we discuss in the Safety Enhancement portion of this decision enhanced safety is also, equally, enhanced reliability. An un-ruptured pipeline (properly constructed and tested) can usually be expected to deliver gas in a reliable fashion to businesses or individuals. We therefore decline to modify any cost allocation to shift Safety Enhancement costs from one customer class to another. The cost of the new safe component should be allocated just as its predecessor was allocated; SDG&E and SoCalGas have shown no persuasive justification to deviate from the existing cost allocation and rate design principles.[20]

(continued from previous page)
Indicated Producers and Watson Cogeneration Company, pp. 14-15, Ex. SCIP-100 in A.11-11-002, Attachment D (emphasis added).

[19] D.14-06-007, p. 40.

[20] D.14-06-007, p. 47.

The Commission concluded:

> We disagree with the Coalition's assumption that Safety Enhancement is somehow a one-time cost. As required by Pub. Util. Code § 451, safe operation of a natural gas system is the operator's long-standing and continuing responsibility, not a one-time event. Moreover, an unreliable or ruptured pipeline delivers no gas to any class of customer. No persuasive justification has been presented to apply different cost allocation or rate design principles to Safety Enhancement costs and we decline to adopt a different approach. The cost of these new facilities that replace existing pipeline facilities should be allocated in the same manner as the old facilities were allocated.[21]

The Commission issued the following Findings of Fact under "Cost Allocation For Safety Enhancement":

> 23. The proposed allocation of costs of the new pipeline, which replaces the existing pipeline, would reallocate costs between customer classes with no change in service.
>
> 24. The existing cost allocation, as settled, allocates costs to customer classes based upon the costs incurred to serve those customers.
>
> 25. Safety Enhancement does not change the service provided to customers although it does likely improve reliability by replacing existing pipelines with new pipelines that meet industry and Commission required safety standards.
>
> 26. The ratepayers will be served by a safe and reliable system with new components that will operate for decades.[22]

The Commission issued the following Conclusion of Law under "Cost Allocation For Safety Enhancement":

> 30. The existing cost allocation methodology is reasonable for the costs of Safety Enhancement because these costs are necessary to safely and reliably supply natural gas to existing customers in the same manner as the existing system serves customers.[23]

The Commission ordered:

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[21] Id., p. 50.

[22] Id., pp. 54-55, Findings of Fact Nos. 23 – 26.

[23] D.14-06-007, p. 59, Conclusion of Law No. 30.

> 9. We reject all proposed modifications to the existing cost allocation methodology proposed by San Diego Gas & Electric Company and Southern California Gas Company and the parties for Safety Enhancement costs. Safety Enhancement costs will be allocated consistent with the existing cost allocation and rate design for the companies.[24]

Similarly, in the PG&E PSEP proceeding, R. 11-02-019, Mr. Beach, on behalf of another coalition of mostly different non-core shippers, the Northern California Indicated Producers,[25] and represented by the same counsel, recommended that the Commission adopt the same EPAM methodology for PG&E as the methodology recommended by SDG&E/SoCalGas in the TCAP.[26] Mr. Beach referred to the SDGE&/SoCalGas PIR study, and stated:

> PG&E's response to a comparable data request states that it does not record building types when surveying the PIRs surrounding its pipelines. [fn. omitted] **Nonetheless, I see no reason why the SoCalGas/SDG&E data should not be comparable to the circumstances on the PG&E system. This data demonstrates that almost all of the direct safety benefits of the utilities' plans will accrue to core customers.**[27]

In the PSEP Phase 1 proceeding, PG&E proposed to follow the cost allocation and rate design principles adopted in the GA V Settlement Agreement adopted in D.11-04-031.[28] The Commission found that PG&E has justified its proposal to retain the GA V principles and methodology and rejected the recommendations of the noncore parties, including the Northern California Indicated Producers, to abandon the cost allocation and rate design principles in the GA V and

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[24] Id., p. 61, Ordering Paragraph No. 9.

[25] ConocoPhillips Company, Chevron U.S.A. Inc., Aera Energy LLC Inc., and Equilon Enterprises, LLC dba Shell Oil Product U.S. Chevron U.S.A. Inc. is part of all three coalitions in A.11-11-002, R.11-02-019 and A.13-12-012 for which Mr. Beach submitted cost allocation recommendations.

[26] Prepared Direct Testimony of R. Thomas Beach on Behalf of the Northern California Indicated Producers, R.11-02-019, p. 14. (Ex. 123, R.11-02-019).

[27] Id., p. 15 (emphasis added).

[28] D.12-12-030, p. 105.

instead use the EPAM methodology.[29] The Commission later decided in the PSEP to defer any consideration of allocation issues for safety expenditures to this GT&S proceeding.[30]

Mr. Beach explicitly justifies his changed proposed rate allocation increasing the burden on core customers in this GT&S proceeding on the basis that the safety expenditures would provide direct benefits to core customers. He does so using very similar language about direct benefits to core customers in the Potential Impact Radius as he did in the TCAP and PSEP proceedings, even though the Commission rejected this argument in D.14-06-007:

> **Q: Would such a change [of allocator to CWD from cold-winter peak-month] 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….
>
> Second, PG&E reports that more than one million citizens live or work within the Potential Impact Radius of its gas transmission pipelines. [fn omitted] **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.[31]

As ORA discusses below, the use of CWD is not reasonable just because it is based on "design criteria," but regardless, the discussion of safety benefits as justifying the allocation is one of many indications in testimony of Mr. Beach's true

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[29] Id., p. 106.

[30] Id., p. 106.

[31] Beach Testimony, p. 10.

intent in proposing a new allocation. Mr. Beach states correctly that "[t]he 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."[32] Mr. Beach specifically notes as the only "circumstances unique" to this case that it is the first GT&S to be conducted since the accident.[33] Mr. Beach explicitly references the increased "safety-related" spending as the reason why the Commission should review and adopt his proposal to allocate more costs to core customers:

> Accordingly, the Commission should ensure that PG&E's proposed **safety-related spending**[34] 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.[35]

Even when Mr. Beach attempts to explain why the Commission should adopt his proposed rate design he still references the size of the rate increase and not just the fairness of his proposed allocator: the "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"[36] which he elsewhere correctly notes are primarily driven by the safety costs.[37] Mr. Beach mentions no other changes in PG&E's local transmission operations in this proceeding that justify a reallocation.

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[32] Beach Testimony, p. i.

[33] Beach Testimony, p. 3.

[34] The Beach testimony uses the term "safety-related" to refer to "costs" and "spending" numerous times in reference to allocation (pp. i, 5, 7 lines 8 and 28), and other issues (pp, 21, 22 lines 2 and 25).

[35] Beach Testimony, p. 7.

[36] Beach Testimony, p. 10.

[37] Beach Testimony, Executive Summary, p. i; p. 8 lines 1-8.

B. Mr. Beach's Fails to Show that His Proposed Allocator, Based Solely on "Actual Design Criteria," Results in Just and Reasonable Rate Increases to Core Customers

Other than arguing that noncore customers should pay a lower share of increased safety costs, Mr. Beach's primary explanation for why a move to cold winter day as an allocator instead of cold year peak month throughput for local transmission is reasonable is that PG&E "designs its local transmission facilities to meet the higher of" two different measures, one of which is core and noncore demand on a cold winter day, and the other core demand on an abnormal peak day, but "[p]eak month throughput, the current allocator for local transmission costs, is <u>not a design criterion</u>."[38] Mr. Beach asserts that:

> 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.[39]

Mr. Beach does not cite any Commission decisions, nor provide any other supporting data for his assertion that the Commission only considers "actual design criteria" rather than a much broader potential range of factors to determine "more accurate" cost allocation, or that PG&E only incurs local transmission costs primarily on such criteria. Mr. Beach does not note any changes in PG&E's "design" of its local transmission facilities since the previous rate proceeding attributable to its use of CWD as a design criteria to warrant a change in allocators.

Mr. Beach also never discusses the actual and dramatic rate impact his allocation proposal would have on core and noncore customers, raising core rates by almost 10% and reducing noncore rates by almost 20% over the PG&E proposal.

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[38] Beach Testimony, pp. 8-9 (emphasis in original).

[39] Beach Testimony, p. 9.

Nor does Mr. Beach acknowledge that even retaining PG&E's current allocation increases rates to core customers more than noncore customers.

The only other supporting argument Mr. Beach offers is that because core/noncore allocation of other GT&S costs such as storage and backbone have changed since the adoption of the gas accord, after such costs were unbundled from local transmission, to allocations "based on the respective backbone and storage capacities used by the core and noncore,"[40] a move to a CWD would "be consistent with the current capacity-based allocation of backbone transmission and storage 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."[41] The history of the Gas Accord's adoption of a process to allocate capacity itself to backbone and storage allocation customers backed up by contracts, and the difference between those factors (based on the ratio of firm contracted capacity between core and noncore at specific points in the system) and the Cold Winter Day factor proposed by Mr. Beach shows that Mr. Beach's argument of consistency is strained.

After the Commission initially approved Cold Year Winter Season as the allocation factor in D. 92-12-058 for both storage and backbone services,[42] the parties in the initial Gas Accord approved agreed that PG&E should provide such services on an unbundled basis and via a process to allocate the actual capacity (not just the costs of such capacity based on an allocation factor) between noncore and core customers on the basis of their relative usage.[43] The Gas Accord parties also maintained the allocation methodology for local transmission adopted in

[40] Beach Testimony, p. 11.

[41] Beach Testimony, p. 11.

[42] D.92-12-058, p. 31.

[43] See, e.g., D.97-08-055, Appendix A, Gas Accord, Section E, pp. 15-30, Section I, pp. 36-44.

PG&E's BCAP decision, D.95-12-053,[44] which itself had rejected changes to the cold peak winter month allocation factor adopted in D.92-12-058.[45]

First, Mr. Beach's argument that CWD must be adopted because it is more consistent with the backbone and storage allocators than cold peak winter month, as shown by the Gas Accord's change of backbone and storage allocators from D.92-12-058 while cold peak winter month remains as the local transmission allocator, is contradicted by the parties' and Commission's actions in the Gas Accord and subsequent proceedings. The cold peak winter month has remained as the local transmission allocator for the entire 17 year period since the Gas Accord was adopted, and had been in place for five years prior. Had the cold winter peak measure been so fundamentally inconsistent with the backbone and storage allocator, parties and the Commission would have rejected it in the Gas Accord and subsequent proceedings and negotiations.

Mr. Beach implies that the use of cold winter peak month as an allocator was somehow only determined as reasonable in 1992,[46] rather than repeatedly agreed upon by the parties and upheld as reasonable by the Commission repeatedly since.[47] PG&E's local transmission costs are allocated to core and noncore customers based on cold year forecast coincident peak month demands.[48] This cost allocation methodology for local transmission was first approved by the Commission in D.92-12-058.[49] The Commission states in D.92-12-058:

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[44] D.97-08-055, Appendix A, Gas Accord, Section I.8, pp. 40-41.

[45] D.95-12-053, p. 72, Finding of Fact No. 13. See below for a further discussion of this decision and review of the Local Transmission allocator throughout the Gas Accord.

[46] See Beach Testimony, p. 8.

[47] See, e.g., D.11-04-031, p. 29: " For local transmission rates, the settlement parties agreed to design the rates in the same manner as in the past Gas Accord decisions, as updated by the Gas Accord V Settlement revenue requirement, the on-system demand forecast, and the Cold-Year-January-Demand allocators."

[48] PG&E Prepared Testimony, Volume 2 (Niemi), p. 17-6.

[49] Finding of Fact No. 22, Conclusion of Law No. 2, and Ordering Paragraph No. 1, D.92-12-058, pp.66-75.

> 22. Use of a cold year coincident peak month measure for local transmission on SDG&E and PG&E systems best reflects the cost responsibility of customers using the system.[50]

In Conclusion of Law No. 2, the Commission decision adopted different marginal demand measures for the different functional parts of the utility's gas system. The decision states:

> 2. We should adopt the following marginal demand measures for computing and allocating marginal cost revenues:
>
> a. Backbone Transmission: Cold Year Peak Season for PG&E and Cold Year for SoCal.
>
> b. Local Transmission: Cold Year Coincident Peak Month for PG&E and SDG&E.
>
> c. High-pressure Distribution: Cold Year Coincident Peak Month for SoCal.
>
> c. Storage: Cold year Winter Season for PG&E, SoCal, and SDG&E.
>
> d. Distribution: Peak Day for PG&E and SoCal, and Cool Year Peak Day for SDG&E.[51]

In Ordering Paragraph No. 1, the Commission decision states:

> 1. The Long-run Marginal Cost (LRMC) methodology as set forth in the discussion, findings, and conclusions of this decision is hereby adopted.[52]

Even back in 1992, the Commission already considered the possibility of the CWD for purposes of the local transmission cost allocation. In D.92-12-058, the Commission had considered both CWD and peak-month cold year throughput as possible allocators for local transmission costs of PG&E.[53] However, the Commission decided to adopt peak-month cold year throughput over CWD. The Commission states in D.92-12-058:

> PG&E argues that the estimated demand on a cold winter day should be used as a demand measure for its local transmission system. As a

[50] Finding of Fact No. 22, D.92-12-058, p. 66.

[51] Conclusion of Law No. 2, D.92-12-058, pp. 72-73.

[52] Ordering Paragraph No. 1, D.92-12-058, p. 75.

[53] Section 2.3.3, D.92-12-058, pp. 22-24.

> secondary position, it argues for cold year coincident peak month demand as the MDM for this function. SDG&E argues that the estimated demand on the coldest day in 35 years should be used because that measure corresponds with the results of its reliability study. DRA supports a cold year coincident peak month measure for PG&E, and extends that recommendation to SDG&E.
>
> And also:
>
> All of the parties argue that local transmission is the bridge between transmission and distribution. **Logically, local transmission would be taking gas from both flowing supplies and storage withdrawal, and transporting that gas to local areas. Essentially, the MDM should be somewhere between transmission and distribution**. [Emphasis added] As will be explained more fully below, a peak day measure should be used for distribution. We will use a coincident peak month measure for local transmission on both the PG&E and the SDG&E systems.[54]

The 1992 Commission decision explains in Finding of Fact No. 22:

> 22. Use of a cold year coincident peak month measure for local transmission on SDG&E and PG&E systems best reflects the cost responsibility of customers using the system.[55]

A review of D.92-12-058 as well as the Commission decisions immediately following this 1992 decision on the LRMC methodology cost allocator will reveal that the Commission has considered more than system design criteria. In the discussion section on Cost Responsibilities, the Commission gives an insight into its thinking:

> The purpose of marginal costing methods is to reflect the costs incurred over the long run caused by serving an additional unit of demand. For each function of a utility's gas system, the demand measure used to calculate that function's marginal cost should be the one that reflects cost causation for that function.
>
> The controlling planning criteria used by the utilities reflect the manner in which the utilities will incur costs in response to changes in demand for specific functional elements of their respective systems. Thus, parties' requests that we deviate from the utilities' planning criteria in favor of "flatter" allocation factors could result in adopting measures of cost responsibility which depart from accurate marginal costs.

[54] Id, pp.22-23.

[55] Id., p. 66.

> In issuing Decision 92-11-052, we recognized that uneconomic bypass is an imminent threat presented by several pipeline projects which could attract large noncore customers of PG&E and SoCal. We permitted PG&E and SoCal to submit long-term contracts subject to an expedited review process. Our desire to facilitate long-term transportation contracts is based in part on our policy to prevent unnecessary duplication of facilities and the consequent customer costs.
>
> It is our belief that accurate marginal cost methods will lead to clearer signals when marginal cost-based prices are implemented, thereby providing the opportunity for customers to purchase economically efficient levels of service. The decisions on the chosen measures of cost responsibility described below are based upon accurate cost causation and recognize the interrelated nature of utility operations.[56]

Based on the above, it is clear that the Commission decisions on the chosen measures of cost responsibility were focused on both accurate cost causation and recognition of the interrelated nature of utility operations. Regarding the latter, the Commission's 1992 decision D.92-12-058 states the importance of considering the different portions of utility systems that serve multiple functions:

> Utility system planners examine various types of peak demand to insure that their system provides adequate service. PG&E, SoCal, and SDG&E all indicate that a number of different objectives are examined in planning for the capacity of their systems' transmission, storage and distribution facilities. For example, SoCal examined peak-day demand, summer-day demand and cold-year demand in trying to determine which load was the cause of capacity expansion on the system.
>
> While some parties have tried to designate a single type of load as the cause of capacity costs, the different portions of utility systems serve multiple functions. For instance, both PG&E and SoCal agree that storage provides protection for peak-day demand, daily load balancing, and seasonal demand on their systems.
>
> Parties disagreed about the importance of particular functions, but all admit that multiple services are provided. PG&E describes its transmission capacity as providing service on an adverse peak-day, and insuring that noncore curtailments occur no more than once in 5 years. SDG&E contends that its transmission system is designed to meet peak-day gas requirements of core customers, natural gas vehicle (NGV) refueling stations and 20% of noncore load. SoCal uses transmission to

[56] Section 2.3.1 on Cost Responsibilities discussion, D.92-12-058, p. 20.

> provide peak-day gas to core customers, but assumes a certain level of noncompliance during curtailment, and also designs the system to meet a peak summer load. Further, Toward Utility Rate Normalization (TURN) contends that intrastate transmission investments are actually being made to enhance gas-on-gas competition, not to enhance system reliability. No party has challenged the Commission's assumption in D.90-07-055 that there is a tradeoff between transmission and storage facilities. This again confirms that multiple functions are served by these facilities.[57]

Moreover, at that time, the Commission also cites to issues concerning whether the utilities' core customers value peak service sufficiently to be willing to bear the costs of providing it. Quoting TURN's Opening Brief, the Commission states:

> "First of all, PG&E and SoCal have not presented any evidence that would indicate that their core customers actually value extreme peak day service highly enough that they would be willing to pay what it costs to provide it, if given the choice. Both of these companies assertedly design their systems such that full core service could be maintained even under the most extreme cold weather conditions ever experienced. SDG&E, on the other hand, has undertaken an extensive study, called the recurrence interval study, which compares the costs of the additional facility investments required to maintain service under various weather conditions against the tangible and intangible costs of not serving the load. Based upon this study, SDG&E has concluded that it should plan its system based on a coldest day in 35 years standard, which does not represent the coldest day that has ever occurred in the service area (SDG&E/Roskowski: Tr. 70/8849-51). TURN does not necessarily endorse all of the details of that analysis, but submits that SDG&E should certainly be commended for making the effort, which its larger sister utilities have not."

> "Absent such a study, PG&E and SoCal do not really know whether their core customers value peak service sufficiently to be willing to bear the costs of providing it. Further, those core customers have no options for avoiding the cost of peak service if they do not in fact value it that highly. A customer that willingly foregoes gas usage on a peak day saves only the tariffed per therm rate, not the much higher cost of providing extreme peak service. Neither PG&E nor SoCal offers any demand-side management programs designed to reduce extreme peak usage in particular, or to reward those customers who do (PG&E/Heffner: Tr. 77/9656; SoCal/Van Lierop: Tr. 69/8785-86). While one can probably

[57] Section 2.1.1 on Utility Planning Criteria in D.92-12-058, pp. 10-11.

> assume that many, if not most, core customers would want to maintain full service on an extreme peak day regardless of cost, there may very well be customers, perhaps many of them, who would be willing to endure a certain amount of disruption to their normal activities in order save the additional cost that extreme peak service may entail. If there are enough such customers, there could be a significant impact on the utilities' planning and total cost of service." (TURN O.B. pp. 34-36.)[58]

The Commission reflected the above discussion in Finding of Fact #5:

> 5. PG&E and SoCal have not presented any evidence that would indicate that their core customers actually value extreme peak day service highly enough that they would be willing to pay what it costs to provide it.[59]

As a result, the Commission required that the utility resource plans contain explicit system design reliability objectives for both core and noncore customers and that reflect the findings of service reliability studies documenting the value core customers place on peak service reliability.[60] The 1992 Commission order also states that the LRMC methodology shall be updated in each utility's cost allocation proceeding.[61] Subsequently, in November 1994, PG&E filed its first cost allocation update application (A.94-11-015) where the Commission's LRMC-based prices and methodologies adopted in D.92-12-058 were examined and resulted in D.95-12-053.[62]

In A.94-11-015, PG&E incorporated in its resource plan the results of its core customer survey to address the Commission's concerns in D.92-12-058.[63] The Commission states in D.95-12-053:

[58] Section 2.1.2 Least Cost Resource Planning discussion in D.92-12-058, pp. 13-14.

[59] Finding of Fact No. 5, D.92-12-058, p. 64.

[60] Section 2.1.2 Least Cost Planning Criteria discussion, D.92-12-058, pp.14-15.

[61] Ordering Paragraph No. 3, D.92-12-058, p. 76.

[62] D.95-12-053, p. 1.

[63] As ordered in D.92-12-058, PG&E's resource plan should reflect the findings of service reliability studies documenting the value core customers place on peak service reliability.

> 12. PG&E incorporates in its resource plan the results of its core customer survey: a lowering of core reliability standards from a once in 90 years outage to a once in 40 years outage that has a price impact of increasing core rates .6% (with continued higher rates through 2007) and decreasing noncore rates by 7.5%.
>
> 13. We find there is little change in investment planned in the next two years attributable to the proposed change in APD, therefore we will retain the current standard until a more credible study is performed.[64]

The Commission did not adopt PG&E's proposal to change the APD criteria because it produced what the Commission described as "perverse results."[65] In Conclusion of Law No. 3, the Commission directs PG&E to describe how it proposes to correct the problem noted above:

> PG&E should, in its next BCAP filing, identify how its LRMC methodology produced such a perverse result in incorporating the rate impact of its APD change, and what it has done, or proposes to do, to correct the problem.[66]

In addition to the issue regarding the proposed change to the APD criteria, the Commission also ordered PG&E in D.95-12-053 to present an analysis of the weather sensitivity of its industrial load for its next BCAP filing.[67]

An attempt was made by SDG&E and SoCalGas in A.96-04-030 to change the local transmission cost allocator.[68] In D.97-04-082, the Commission rejected the proposed change as it states:

> 98. SDG&E provides no new evidence to support its proposal to change its local transmission MDM and its proposal to change the allocator for SoCalGas' system costs is not persuasive. Therefore, we should retain the existing cost allocators.[69]

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[64] Findings of Fact Nos. 12 and 13, D.95-12-053, p. 72.

[65] D.95-12-053, p. 28.

[66] Conclusion of Law No. 3, D.95-12-053, p. 79.

[67] Conclusion of Law No. 19, D.95-12-053, p. 81.

[68] The proposal was to change the local transmission cost allocator from Cold Year Coincident Peak Month to Normal Peak Day.

In D.98-06-073 (in A.97-03-022), the Commission describes in footnote 2 that PG&E filed A.96-08-043, together with a motion in many of its pending proceedings, which sought Commission approval of a broad settlement known as Gas Accord.[70]

In D.97-08-055, the Commission adopted PG&E's first Gas Accord. The first Gas Accord Settlement Agreement, which is Appendix 1 to D.97-08-055, states in Section II.I. item 8.c. that the "Local transmission costs are allocated to core and noncore based on LRMC methodology from PG&E's BCAP decision 95-12-053."[71] In every PG&E Gas Accord since then, including the most recent one in Gas Accord V, PG&E has always proposed to keep the existing cost allocation methodology for local transmission, and the Commission has approved and adopted the Settlement Agreements for the Gas Accords. Although PG&E tried unsuccessfully to change the cost allocation methodology for its backbone transmission costs in the 2011 GT&S that resulted in Gas Accord V, PG&E has never tried to change its local transmission cost allocation methodology. In the 2011 GT&S rate case, PG&E proposed to retain the existing local transmission cost allocation methodology adopted in D.97-08-055, which is also the same one adopted in D.92-12-058 and D.95-12-053, and updated the cold winter January cost allocator and its throughput forecast. While proposing to retain the cost allocation methodology, PG&E also updated its throughput forecast. In this 2015 GT&S rate case, PG&E proposes to continue the existing cost allocation and rate design for its local transmission system.[72]

Second, the allocations of capacity and then costs resulting from unbundling of storage and backbone are not themselves not based on "design criteria" but on contracted-for capacity, a much different measure of "capacity" than the CWD forecast as represented by a pipeline's design. The backbone/storage allocations

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(continued from previous page)
[69] Finding of Fact No. 98, D.97-04-082.

[70] D.98-06-073, p. 3.

[71] Appendix 1 to D.97-08-055, PG&E Gas Accord Settlement Agreement, p. 41.

[72] PG&E Prepared Testimony, Volume 2 (Niemi), p. 17-6.

do not support use of any one specific design criteria as an allocator. The Commission has never constrained itself to the use of any one factor such as "design criteria" in determining a reasonable allocation or even cost causation. As ORA has also argued in its opening brief in A.11-11-002,[73] "the Commission's guiding principles for allocation of natural gas pipeline transportation costs focus costs on cost causation, economic efficiency, and equity."[74] Cost allocation is primarily, but not only, based on the determination of what is driving the costs. Many factors drive local transmission costs including design capacity for a Cold Winter Day, but that is far from the only factor.

Moreover, in A. 11-11-002, Watson/SCIP, the party sponsoring Mr. Beach's testimony, as part of its argument to adopt an EPAM-based allocator for safety-related costs rather than the then-current allocation based on a functional approach, argued in its final brief with respect to SDG&E's and SCG's PSEP costs that safety-costs were **not** caused by design criteria such as traditional demand measures:

> PSEP costs, however, are not being caused by nor will they vary by the traditional cost drivers or demand measures. Traditional demand drivers that cause the incurrence of natural gas pipeline costs include customer usage, as measured by cold year peak throughput, cold year peak month throughput, average daily demand or peak demand, or number of customers. **These demand measures gauge customers' peak requirements for purposes of designing, building and operating the utilities' systems.** The primary driver of PSEP costs, however, is not these traditional cost drivers or demand measures but safety: PSEP costs are being incurred "to address safety concerns arising from missing records in providing safe and reliable gas transportation service."[75]

Now that the Commission has rejected use of a separate allocator for safety costs than the allocator used for other gas transmission activities in D.14-06-007, Mr.

[73] ORA Opening Brief, A. 11-11-002, p. 3. Attachment C.

[74] See, e.g., *Order Instituting Investigation on the Commission's own Motion into Implementing a Rate Design for Unbundling Gas Utility Services Consistent with Policies Adopted in D.86-03-057* (1992*)* D.92-12-058, Conclusion of Law No. 2. ORA discusses allocation policy further below.

[75] SCIP/Watson Cogeneration Opening Brief, A.11-11-002, pp. 6-7.

Beach is recommending that the predominately safety-related costs for PG&E are indeed caused and best measured by a traditional demand cost driver – just a different cost driver that is more favorable to the noncore than the current allocator that has been in place for over two decades.

When considering cost allocation issues and appropriate cost allocators, the Commission should consider many factors such as the fact that the system provides various services to customers such as meeting cold year, average daily and peak demands throughout the year and various months for all customer classes. When adopting the appropriate cost allocators, the Commission must consider many factors including the equity to all ratepayer classes of the allocation factors in conjunction with the various services provided by the system, and not merely rely upon one factor such as design criteria. The current method, proposed by PG&E and previously adopted and used by the Commission for more than two decades, has balanced the various factors to result in reasonable rates. Mr. Beach's proposal would result in rate increases almost twice as big for core customers than noncore customers on a percentage basis, and he believes it is fair because core customers will benefit more from safety improvements than noncore customers. The Commission should reject Mr. Beach's proposal, as it did in D.14-06-007.

III. CONCLUSION

ORA respectfully requests that the Commission retain the current local gas transmission allocation methodology that has been effect since 1992 as proposed by PG&E, and reject the allocation recommendations of Mr. Beach.