**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms	R.11-02-019 (Filed February 24, 2009)

COMMENTS OF THE NORTHERN CALIFORNIA INDICATED PRODUCERS ON THE PROPOSED DECISION

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Pursuant to Rule 14.3 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, the Northern California Indicated Producers (NCIP)[1] submit these comments on Commissioner Bushey's Proposed Decision (PD) implementing, with significant modifications, Pacific Gas and Electric Company's (PG&E's) Pipeline Safety Implementation Plan (PSEP).

I. INTRODUCTION AND SUMMARY

The PD generally strikes a reasonable balance of responsibility between shareholders and ratepayers for the PSEP costs identified by PG&E. The PD would allow PG&E to recover a PSEP revenue requirement of $277.8 million from 2012 through 2014, or roughly 36% of the $768.8 million requested revenue requirement.[2] Going forward, however, the PD would allow PG&E to recover $1.389 billion, or roughly 63%, of the $2.2 billion of the total PSEP Phase I

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1 Member companies include Aera Energy LLC, ConocoPhillips Company, Shell Oil Products and Chevron U.S.A. Inc.

2 PD at 3.

expenses and capital.[3] While the record no doubt provides sufficient grounds to further limit cost recovery, NCIP recognizes the PD's effort to balance equity between shareholders and ratepayers with the need to maintain a stable financial condition for PG&E.

The PD reaches its conclusion relying primarily on four principles – principles that are easily justified in light of the record. The PD would:

- Deny the request to include the costs of pressure testing post-1955 pipelines where PG&E's record retention failures led to re-testing these pipelines.[4]

- Deny the request to include the costs of integrating gas system records on grounds that PG&E has long had the obligation to create and maintain these records and has, in fact, sought and obtained ratepayer funding for these functions.[5]

- Assign the risk of cost overruns to shareholders, creating "*powerful incentives for PG&E to manage this program efficiently and to aggressively identify and capture cost savings*."[6]

- Reduce the return on equity (ROE) on PG&E's PSEP capital investments to the incremental cost of debt for five years to address "*inefficient or ineffective management*."

NCIP steadfastly supports each of these principles and the resulting adjustment to PG&E's proposed PSEP revenue requirement, capital costs and expenses.

While the PD reasonably resolves the issues related to the PSEP investments and revenue requirement, it fails to recognize the importance of two additional positions proffered by NCIP and others. First, with little consideration, the PD proposes to use the Gas Accord V cost allocation factors to allocate the

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3 *Id.*, Table E-4.
4 *Id.* at 57, 60.
5 *Id.* at 57, 89.
6 *Id.* at 57, 101.

PSEP costs to ratepayers. NCIP submits that, instead, using an equal percent of authorized margin methodology (EPAM) makes more sense as an interim approach pending the next Gas Accord or cost allocation proceeding. Moreover, EPAM would avoid a material disruption of the delicate balance struck by the parties in settling the numerous issues in Gas Accord V and would reduce the incentive for noncore customers to pursue bypass alternatives.

Second, the PD entirely overlooks important issues of record associated with the operational impacts of the PSEP on gas customers, such as NCIP's proposal to ensure that PG&E provides reasonable notice and credit to customers that will be materially affected by service disruptions resulting from pipeline testing and replacement.[7]

Each of these issues is discussed in these comments.

II. THE COMMISSION SHOULD REQUIRE PG&E TO MITIGATE OPERATIONAL AND FINANCIAL IMPACTS OF SERVICE DISRUPTIONS WITH ADEQUATE NOTICE AND CREDITS

The PD overlooks entirely an important issue raised by NCIP. The PSEP, as PG&E acknowledges, can result in service disruptions that will have operational and financial implications for large-volume noncore industrial and electric generation customers.[8] To mitigate these impacts, NCIP requested that the Commission require a minimum amount of notice, ranging from 30 days to six months.[9] In addition, NCIP identified the need for PG&E to continue and expand

[7] This is clearly a material issue in this case, one which was addressed by many parties in their testimony and briefs. Public Utilities Code Section 1705 requires Commission decisions to include separately stated, findings of fact and conclusions of law on all issues material to the decision; the PD must be modified to address this deficiency.

[8] 14 Tr. 1895 (PG&E/Berkovitz).

[9] Opening Brief of the Northern California Indicated Producers at 47-49.

rate credits that heighten PG&E's awareness of its customers' circumstances as it implements the PSEP. In particular, NCIP proposed the continued application of the Gas Accord V backbone transmission credit. It further proposed a 25¢ per therm credit mechanism through which shareholders would compensate noncore customers for local transmission disruptions when PG&E fails to provide the required notice of service disruptions that can be very costly for customers of this essential fuel.

The Commission should adopt the proposed notice requirement and service disruption credit. PG&E has a detailed implementation plan and should be able to provide reasonable notice to affected customers when it will likely disrupt their service. A failure to do so would represent "*inefficient or ineffective*" utility management. The PD places the burden on shareholders for utility mis-management in other areas; NCIP is simply asking for the Commission to extend the principle to service disruptions.

A. Service Disruptions Will Have Financial and Operational Impacts on Noncore Customers

Service disruptions will prevent noncore customers from using firm transportation rights.[10] Thus, these disruptions may prevent these customers from meeting contractual obligations to deliver electricity or other energy-intensive products and may increase operating costs.[11] Importantly, even if service reductions and disruptions take place over the weekend, they will still have financial and operational impacts on customers, including electric

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10 Exhibit 123, at 28 (NCIP/Beach).
11 *Id.*

generators and refineries that must operate continuously in order to meet the state's energy needs.[12] While PG&E is aware of the impact a disruption can have on a noncore customer – *e.g.,* critical energy infrastructure such as a refinery[13] -- it has not committed to a minimum notice period for these customers.[14]

PG&E's customers, including NCIP, are interested in facilitating the modification of PG&E's system to ensure safe and reliable natural gas transportation. The scope of work contemplated by the PSEP, however, dramatically increases the magnitude of the risk to customers of financial and operational impacts.[15] Adequate notice will be one of the only tools available for customers to manage these impacts.

B. PG&E Currently Has No Protocols in Place To Ensure Large Noncore Customers Will Receive Notice of Disruptions

PG&E acknowledges that it is important to provide notice of service disruptions to its customers, but it has not committed to provide a reliable notice period. In its testimony, PG&E states that it "*will conduct extensive customer and community outreach to notify and educate affected customers of any field activities that may impact them, respond to safety concerns, and [ ] inform the public and local government officials of PG&E's schedule and progress*."[16] Rule 14(A) also provides that PG&E "*shall give Customers reasonable notice as circumstances will permit, and PG&E shall complete repairs or improvements as*

12 *Id.*
13 14 Tr. 1895 (PG&E/Berkovitz).
14 14 Tr. 1893 (PG&E/Berkovitz).
15 *Id.*
16 Exhibit 2, at 1-6.

soon as practicable and with minimal inconvenience to Customers."[17] However, in hearings PG&E's witness testified that if NCIP's notice recommendation is not adopted, the amount of notice PG&E would provide to customers would "*vary depending on the circumstances of the situation*."[18] Stated differently, PG&E has not committed to any minimum notice period.[19]

C. Adequate Notice and Credit Would Partly Mitigate the Financial Impact of Service Disruption

To mitigate the impacts of service disruptions on customers, the Commission should specify the notice requirements that must be met by PG&E in advance of such disruptions. Where adequate notice cannot be provided, the Commission should direct PG&E to provide service disruption credits, both to backbone transmission and end-use transportation customers.[20]

NCIP has proposed a two-part notice requirement. First, PG&E would (except in an emergency) provide all customers with a minimum 30 days' notice prior to scheduled pipeline enhancement activities that may result in pressure reductions or minor service reductions and disruptions.[21] Where a complete service curtailment is required, PG&E should provide much more notice -- at least six months' notice -- to large noncore customers operating critical energy infrastructure such as a refinery or electric generator. This notice period is

[17] PG&E Rule 14. *See also* Exhibit 123 (NCIP/Beach), at 27.
[18] 14 Tr. 1893-1894 (PG&E/Berkovitz).
[19] 14 Tr. 1894 (PG&E/Berkovitz).
[20] Under NCIP's proposal, provision of notice would obviate payment of any credit.
[21] Exhibit 123 (NCIP/Beach), at 28.

required for large noncore customers operating energy infrastructure to ensure they have sufficient time to safely wind down or change operations.[22]

The Commission should base the service disruption credits for backbone transmission service on the Gas Accord V methodology. Since June 2011, PG&E has provided its firm backbone transportation customers with credits to reservation charges to make such customers whole when they have been unable to use their full firm capacity due to pressure reductions or related safety-related work.[23] To mitigate financial impacts on backbone customers, the Commission should require PG&E to continue providing reservation charge credits to firm backbone customers when they are unable to use their contracted firm capacity as a result of pipeline safety work.[24] Under the Gas Accord V settlement, 50% of these credits are funded by shareholders, the other 50% by backbone ratepayers.[25] This credit is not currently memorialized in PG&E's tariffs.[26]

To compensate local transmission customers for the financial and operational impacts associated with local transmission disruptions, the Commission should adopt a service disruption credit structured like SoCalGas' Rule 23 credit.[27] Under SoCalGas' Rule 23, customers with qualifying service interruptions, not noticed by at least 30 days' prior notice, are entitled to a flat 25¢ per therm of gas curtailed or diverted.[28] The same credit should apply to customers not receiving 30 days' notice or six months' notice, where applicable.

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22 *Id.*, at 28.
23 *Id.*
24 *Id.*, at 29.
25 *Id.*
26 14 Tr. 1899 (PG&E/Berkovitz).
27 Exhibit 123, at 29-30 (NCIP/Beach).
28 SoCalGas Rule 23(K). *See also* Exhibit 123 (NCIP/Beach), at 29.

III. THE COMMISSION SHOULD REJECT THE PD'S PROPOSED ALLOCATION METHODOLOGY IN FAVOR OF EPAM

The Commission should reject the PD's proposal to allocate the PSEP costs using Gas Accord V principles adopted by the Commission in D.11-04-031. The PD's four-paragraph review of cost allocation proposals gives short shrift to this important issue. As NCIP and others pointed out, using Gas Accord V allocation factors for this unintended purpose will materially disturb the balance struck by Gas Accord V settlement parties. The PD's approach also risks additional bypass by large noncore customers, to the detriment of all ratepayers. Instead, the Commission should adopt the EPAM method, proposed by NCIP, Northern California Generation Coalition and Dynegy, which more fairly balances the allocation of PSEP costs.

A. Using the Gas Accord V Transmission Cost Allocation Methodology to Allocate PSEP Costs Materially Disturbs the Balance Struck in the Gas Accord V Settlement

The PD would allocate the PSEP revenue requirement through a surcharge developed using the Gas Accord V transmission cost allocation methodology. The PD observes that *"[s]uch issues are better handled in general rate cases, not a proceeding of limited ratemaking review…."*[29] It further states that "*we are not reopening the rate case adopted cost allocation and rate design and will follow the existing structure.*"[30] To the contrary, the PD's approach ***would*** reopen the Gas Accord V adopted cost allocation, with potentially detrimental consequences to all electric and gas ratepayers. Adopting NCIP's

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29 *Id.* at 110.
30 *Id.*

EPAM cost allocation proposal instead -- a more typical mid-rate case allocation methodology -- would better align core and noncore increases with their existing cost burdens.

The Gas Accord V allocation methodology, on which the PD relies, is not based solely on cost causation principles; it is the product of settlement encompassing a wide range of issues. PSEP costs obviously were not considered by Gas Accord V settling parties at the time that the agreement was completed on August 20, 2010 – 20 days before the San Bruno explosion. Moreover, PG&E has acknowledged that the Gas Accord V allocation methodology was selected because it was equitable, not because it was based on cost causation principles.[31] Had the parties anticipated that the Gas Accord V allocation principles would be used to allocate an enormous increase in PG&E's revenue requirement such as the PSEP, the settlement package certainly would have been balanced differently. Consequently, the use of the Gas Accord V methodology would disturb the balance of a settlement negotiated carefully by the parties.

[31] 14 Tr. 2025 (PG&E/Blatter).

B. Using the Gas Accord V Transmission Cost Allocation Methodology Magnifies the Risk of Bypass by Noncore Customers and Rate Increases to Remaining Customers

Selecting the wrong cost allocation method can have significant adverse impacts for all natural gas ratepayers. The PD's proposed methodology would bring major increases in noncore natural gas transportation rates. Even with the major reductions in PG&E's PSEP revenue requirement which the PD proposes, transportation rates for electric generation customers served at the local transmission level would increase an eye-popping 55% by 2014, and rates for industrial customers at the local transmission level would increase 22%. By comparison, transportation rates for retail core customers (excluding CARE) would increase only 4.6% by 2014. The noncore rate increases heighten the risk of industrial and electric generator (EG) bypass of PG&E's system, which would be detrimental in the long run to all ratepayers, core and noncore alike.

History suggests that bypass can be material and should be taken into account in the Commission's decision. Notably about 4,300 MW of efficient gas-fired combined-cycle power plants have been connected to interstate pipelines or California production in the last ten years.[32] In addition the percentage of gas use served from non-utility pipelines has increased from 29.7% in 1999 to 34.3% in 2009.[33] It is in the interest of all ratepayers to adopt an allocation methodology that does not invite further bypass.

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32 Exhibit 123, at 16 (NCIP/Beach).

33 *Id.*, at 16.

C. Using the Gas Accord V Transmission Cost Allocation Methodology Will Result in a Greater Increase to Electric Rates

Reliance on the Gas Accord V cost allocation methodology can also lead to significant increases in electric rates because of its impact on gas costs for gas-fired electric generators. The PD would increase the transportation rate for EG customers on the local transmission system by roughly 9¢ per MMBtu in 2012 and 18¢ per MMBtu in 2014.[34] This amounts to a 55% increase in this EG transportation rate by 2014.[35] While NCIP will not repeat the arguments, its Opening Brief identifies three ways in which these significant EG transportation rate increases would increase wholesale and retail electric rates.[36]

The effect of gas rate increases is multiplied in electric rates; electric rate increases can be 2.4 times higher than the increase in gas transportation costs.[37] NCIP's witness Mr. Beach notes that an increase of 19¢ per MMBtu in the cost of marginal electric generation with a market heat rate of 8,000 Btu per kWh will raise electric market prices by $1.50 per MWh.[38] Assuming that such an increase will impact the cost for electric ratepayers of (1) in-state gas-fired generation (109,000 GWh), (2) 50% of electricity imports (36,000 GWh), and (3) SRAC-priced renewable generation (15,000 GWh), the increase in electricity costs would be $1.50 per MWh times 160,000 GWh per year, or $240 million per

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[34] *Id.*, at 17. Importantly the EG rate increase will also impact the ability of these customers to compete. PG&E's proposed surcharges would increase the total burnertip gas costs of EG customers by about 4%. This could shift generation to facilities outside the state or to generators served by interstate pipelines or California production. *Id.*

[35] *Id.*

[36] NCIP Opening Brief at 43-45.

[37] *Id.*, at 17.

[38] *Id.*, at 18-19.

year.[39] This amounts to 2.4 times the direct increase in gas costs for electric generators, which would be reflected in the wholesale markets and ultimately in retail electric rates.

D. EPAM Leads to a More Equitable Result

Using EPAM will not exempt noncore customers from paying PSEP costs, but will more equitably distribute the increases among core and noncore customers. Under either the PD or NCIP allocation methodologies, noncore customers will see a more significant percent increase in transport-only rates than will core customers. The table below demonstrates how core transport-only rate increases would compare to the rise in noncore transport-only rates under the PD cost allocation.[40] For the purposes of this comparison, core retail residential transport-only rates are compared to noncore transport-only rates.[41]

Transport-Only Rate Increases: PD + Gas Accord Cost Allocation

Customer Class	April 2012 Rates ($/Dth)	Apr-12 w/ 2014 Adder ($/Dth)	Percent Increase in 2014
Core Retail-Residential Non-CARE (Transport Only)	6.97	7.29	4.6%
Industrial Distribution	1.89	2.07	9.3%
Industrial Transmission	0.79	0.97	22.2%
Industrial Backbone	0.52	0.57	9.5%
Electric Generation-Transmission	0.32	0.50	54.8%
Electric Generation-Backbone	0.12	0.17	41.0%

[39] *Id.*

[40] This table and the succeeding table in this section are based on the PD revenue requirement as shown in the workpapers for the PD that were circulated to the parties on November 2, 2012.

[41] A comparison of transport-only rates is more appropriate than a comparison of bundled rates because noncore customers do not secure natural gas commodity from the utility. *Id.* at 12. A transport-only rate comparison not only allows an apples-to-apples comparison of rates, it also better focuses on the services actually secured from the utility.

The table reveals that using the PD's proposed revenue requirement and the PD's cost allocation proposal, the core residential transport-only rate increases by just 4.6% by 2014 while noncore transport–only rates increase by 9.3% to 54.8%.

If an EPAM allocation is used, the following table shows that the percentage increases in transportation rates will be more uniform across customer classes, although residential customers would still see a much smaller percent increase in their transportation rates than noncore customers.

Transport-Only Rate Increases: PD + EPAM Cost Allocation

Customer Class	**April 2012 Rates ($/Dth)**	**Apr-12 w/ 2014 Adder ($/Dth)**	**Percent Increase in 2014**
Core Retail-Residential Non-CARE (Transport Only)	6.97	7.39	**6.1%**
Industrial Distribution	1.89	2.11	11.6%
Industrial Transmission	0.79	0.89	12.1%
Industrial Backbone	0.52	0.57	9.5%
Electric Generation-Transmission	0.32	0.41	**28.7%**
Electric Generation-Backbone	0.12	0.17	41.0%

With EPAM, core residential rates will increase by 6.1% in 2014 (versus 4.6% under the PD), while noncore transmission-level industrial rates would increase by 12.1% (compared to 22.2% under the PD) and noncore transmission-level electric generation rates would grow by roughly 29% (versus 55% under the PD). While noncore customers will still pay more in proportion to their existing rates, the EPAM method softens the disparity that would be created by using the Gas Accord V allocation methodology.

IV. A CORRECTION TO THE PD'S REFERENCE TO NCIP POSITIONS IS REQUIRED

In its recitation of party positions, the PD mentions NCIP's cost allocation proposal. It states "*NCIP also put forward a cost allocation proposal which would allocate more costs to noncore customers than the current allocation methodology*…." [42] As discussed in Section III of these comments, the NCIP proposal would *reduce* the allocation to noncore customers relative to the Gas Accord V methodology. Moreover, it is debatable whether the Gas Accord V methodology is, in fact, the "current methodology." Gas Accord V contains no provision for allocation of additional rate increases using its adopted transmission allocation factors. The Commission should correct the PD to read: "*NCIP also put forward a cost allocation proposal which would allocate fewer costs to noncore customers than the Gas Accord V methodology proposed by PG&E*…."

V. CONCLUSION

For all of the foregoing reasons, NCIP urges the Commission to adopt the PD with two key changes necessary to protect California's large noncore customers from disproportionate impacts. First, the Commission should reject the PD's proposed use of Gas Accord V allocation factors, relying instead on an EPAM methodology. Second, the Commission should adopt a minimum notice

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42 PD at 40.

requirement for service disruptions resulting from the PSEP and a credit for customers when PG&E fails to meet those requirements.

Respectfully submitted,

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