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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 (U39G)	Application 13-12-012 (Filed December 19, 2013)
And Related Matter.	Investigation 14-06-016

APPLICATION FOR REHEARING OF DECISION NO. 16-06-056 BY COMMERCIAL ENERGY OF CALIFORNIA AND TIGER NATURAL GAS INC.

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In accordance with Rule 16.1 of the Commission's Rules of Practice and Procedure, Commercial Energy of California ("Commercial Energy") and Tiger Natural Gas Inc. ("Tiger") submit their application for rehearing of D.16-06-056 ("Decision").[1] The Commission's decision to adopt Pacific Gas and Electric Company's ("PG&E") proposed seasonal capacity allocation factor is not supported by adequate findings or substantial evidence in light of the whole record and contravenes longstanding cost-causation principles of ratemaking. Rehearing is necessary to correct this legal error and to avoid shifting substantial and unwarranted costs onto Core Transport Agents ("CTAs") and their core customers.

I. INTRODUCTION AND SUMMARY OF ARGUMENT

The Commission's eleventh-hour adoption of PG&E's seasonal factor for allocating pipeline capacity is legal error. The Commission is obligated to proceed in the manner

[1] Decision 16-06-056 was issued July 1, 2016. July 30, the last day on which applications for rehearing of D.16-06-056 can be submitted under Rule 16.1(a), is a Saturday. This application is therefore submitted on the next business day after July 30. (Rule 1.15.)

required by law when issuing decisions.[2] Decisions appearing on the Commission's public voting agenda must be subject to review and comment by the parties before the Commission can vote on the decision.[3] The Proposed and Alternate Proposed Decisions concluded that PG&E's proposed seasonal capacity allocation factor was flawed and should not be adopted; the parties drafted their comments accordingly. The Decision reversed that conclusion and did so just before the Commission vote on the Decision; the parties were not given notice of the reversal, let alone an opportunity to review and comment.

Commission decisions must also be supported by adequate findings,[4] which, in turn, must be supported by substantial evidence in light of the whole record;[5] failure to meet this requirement is reversible error.[6] The Decision adopts PG&E's proposed seasonal capacity factor ("Seasonal Factor") for allocating transmission pipeline costs and abandons the January peak use-based factor ("January Factor") that the Commission adopted and re-approved in multiple successive Gas Accord proceedings.[7] The Decision's findings in support of adopting the Seasonal Factor, however, are not supported by substantial evidence in light of the whole record;

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[2] Pub. Util. Code, § 1757(a)(2).
[3] Pub. Util. Code, § 311(e).
[4] Pub. Util. Code, §§ 1705, 1757(a)(3).
[5] *Id.* at § 1757(a)(4).
[6] *California Manufacturers Association v. Public Utilities Commission* (1979) 24 Cal.3d 251; *California Motor Transport Co. v. Public Utilities Commission* (1963) 59 Cal.2d 270; *The Utility Reform Network/Independent Energy Producers Association v. Public Utilities Commission* (2014) 223 Cal.App.4th 945 ("*TURN II*").
[7] D.97-08-055 (adopting first Gas Accord settlement), p. *198 (1997 Cal. PUC LEXIS 763) (stating that local transmission costs are allocated based on the LRMC methodology adopted in D.95-12-053, PG&E's Biennial Cost Allocation Proceeding); D.95-12-053, p. *52, fn. 14 (1995 Cal. PUC LEXIS 1014) (stating that the Commission adopted a cold year coincident peak month as the demand measure for PG&E's local transmission); D.02-08-070 (Gas Accord II settlement) (2002 Cal. PUC LEXIS 518) (extending the existing Gas Accord market structure, rates, tariffs, and terms and conditions of service for one year); D.03-12-061 (Gas Accord II amendment) (2001 Cal. PUC LEXIS 1279) (extending existing Gas Accord provisions through 2004); D.04-12-050 (Gas Accord III settlement) (2004 Cal. PUC LEXIS 579), p. *51 (providing that local transmission cost of service continues to be allocated based on Cold Year January demand); D.07-09-045 (Gas Accord IV settlement) (2007 Cal. PUC LEXIS 449) (continuing Gas Accord market structure and allocation methodologies for three years); D.11-04-031 (Gas Accord V settlement), p. 30 (continuing the Gas Accord peak month allocation methodology for local transmission rates).

the Decision's determination that the Seasonal Factor is consistent with cost-causation principles is supported by no findings at all. In addition, the Decision adopts PG&E's highly flawed reasoning and concludes that because the CTAs' relatively flat load utilizes a greater *percentage*—but not greater throughput *volume*—of existing pipeline capacity in the summer months *relative to* the bundled core's load, cost-causation principles demand that CTAs be allocated a higher percentage of pipeline capacity.[8] Neither conclusion is supported by substantial evidence.

The record shows that CTAs' summer throughput is lower than the throughput of the bundled core.[9] The bundled core's load shrinks substantially in the summer, which allowed PG&E to calculate that CTA load is a higher *percentage* of overall core load during the summer months.[10] However, such a relative change in off-peak usage is not related to the concept of cost causation in gas rate design and does not reflect actual throughput volumes. The record confirms that PG&E designs its system to meet periods of extreme high usage—in other words, peak demand[11]—and confirms that the Commission does not use off-peak usage to allocate costs.[12] The adoption of PG&E's Seasonal Factor is not supported by the record and warrants rehearing.

II. <u>SPECIFICATIONS OF LEGAL ERROR</u>

1. Adoption of the Seasonal Factor in D.16-06-056 is a reversal of the Commission's conclusion in the Proposed and Alternate Proposed Decisions that the Seasonal Factor was flawed and should not be adopted. This significant substantive change was made days before the Decision was approved by the Commission; the parties were not notified and were not able

[8] D.16-06-056, pp. 356–357.
[9] Commercial Energy Opening Brief, pp. 42, 44–46; Exh. CE-1, Monsen, p. 8, Figure 1.
[10] *Ibid.*
[11] Commercial Energy Opening Brief, pp. 39–40.
[12] Commercial Energy Opening Brief, pp. 43–44; see also discussion at pp. 6–9, *infra*.

to review or comment on the substantially revised Decision, and were therefore prejudiced. The Commission therefore failed to proceed in the manner required by law. (Pub. Util. Code, § 1757(a)(2).)

2. Finding of Fact No. 212, which states that CTAs are not currently allocated the capacity and associated costs for those periods when they utilize a greater percentage of pipeline capacity, is not supported by substantial evidence in light of the whole record. (Pub. Util. Code, § 1757(a)(4).)
3. Finding of Fact No. 214, which states that PG&E's transmission system is designed to optimize annual flow based on an annual demand criterion, is not supported by substantial evidence in light of the whole record. (Pub. Util. Code, § 1757(a)(4).)
4. Conclusion of Law No. 270, which provides that an annual allocation factor based on a single month of use does not appropriately reflect customer use throughout the year, is not supported by substantial evidence in light of the whole record. (Pub. Util. Code, § 1757(a)(4).)
5. Conclusion of Law No. 271, which provides that the Seasonal Factor better reflects the way in which pipeline capacity is actually utilized since the transmission system is designed to optimize annual flow based on an annual demand criterion, is not supported by substantial evidence in light of the whole record. (Pub. Util. Code, § 1757(a)(4).)
6. Conclusion of Law No. 272, which provides that PG&E's proposal to change the pipeline capacity allocation methodology from a January Factor to a

Seasonal Factor should be adopted, is not supported by substantial evidence in light of the whole record. (Pub. Util. Code, § 1757(a)(4).)

7. The Decision's determination that the January Factor is contrary to principles of cost causation is not supported by any findings or conclusions. (D.16-06-056, pp. 356–357.)

III. THE COMMISSION FAILED TO PROCEED IN THE MANNER REQUIRED BY LAW WHEN IT ADOPTED THE SEASONAL FACTOR AT THE ELEVENTH HOUR

Substantive revisions that change the outcome of a proposed decision must be presented to the parties for review and comment.[13] The Commission's failure to notify the parties that the Proposed ("PD") and Alternate Proposed Decisions ("APD") had been significantly revised to reverse the conclusion that the Seasonal Factor should not be adopted and to include new discussion of cost-causation principles that changed the outcome of the PD and APD was legal error. The parties did not have the opportunity to review and comment on the substantive revisions; the significant errors and lack of support in the record for the Decision's new conclusions would have been addressed in comments. Because the parties were denied the ability to alert the Commission to the errors in the Decision and because the adoption of the Seasonal Factor shifts substantial costs onto the CTAs and their core customers, the CTAs have been prejudiced by the Decision.[14]

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[13] *Application of the Coastal Alliance on Plant Expansion and City of Morro Bay for Rehearing of Resolution E-3929, etc.*, D.06-05-043, p. *13 (2006 Cal. PUC LEXIS 197); see also *TURN II*, *supra*, Cal.App.4th at p. 951 (citing *The Utility Reform Network v. Public Utilities Commission* (2012) 2012 Cal. App. Unpub. Lexis 2049, pp. *42–44 ("*TURN I*"), which held that the Commission's substantive changes to an APD that substantially changed the procedural mechanism to achieve the outcome of the final decision violated.

[14] *TURN II*, *supra*, 223 Cal.App.4th at p. 951 ("We concluded [in *TURN I*] the Commission's failure to proceed in the manner required by law had prejudiced the parties to the proceeding, and we therefore set aside the Commission's decisions.").

The Commission failed to proceed in the manner required by law when it quietly adopted the Seasonal Factor. This failure prejudiced the CTAs and their customers. Rehearing of the Decision is warranted.

IV. THE DECISION'S ADOPTION OF PG&E'S SEASONAL CAPACITY FACTOR IS NOT SUPPORTED BY THE RECORD

A. The Seasonal Capacity Factor is Not Consistent with Cost-Causation Principles

1. Peak Usage Has Always Been the Metric for System Design and Cost Allocation

The bedrock principles of cost causation dictate that the customers that cause a utility to incur certain costs should pay for those costs.[15] The Commission has adhered to these principles in gas rate design for decades and memorialized its commitment to cost-based ratemaking in D.92-12-058, known as the Long Run Marginal Cost ("LRMC") Decision. The LRMC Decision determined that marginal cost principles should be used to allocate costs and that individual cost elements should be allocated to best match the incremental costs of new facilities or services with the customers that caused the need for those services or facilities.[16] For each function of a utility's gas system, the Commission concluded that the demand measure used to calculate marginal costs should reflect the cause of those costs.[17] PG&E's pipeline system was built to accommodate the winter peak volume required by the bundled core: "Any given system's capacity is sized using the design day that yields the highest peak load."[18] So under

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[15] See, e.g., *OIR to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs, etc.*, D.14-12-024, p. *69 ("The Commission has clearly stated that the principle of cost causation means that costs should be borne by those customers who cause the utility to incur the expense, not necessarily by those who benefit from the expense."); *In re Revenue Adjustment Proceeding Application of SDG&E*, *etc.*, D.99-06-058 ("Our policy has consistently been that costs should be allocated to customers who impose them.").
[16] D.92-12-058, pp. 20–21.
[17] *Id.* at p. 20.
[18] Exh. PG&E-2 (Christopher), p. 10-9 (lines 1–2); see also *id.* at pp. 10-8 (line 21) to 10-10 (line 25) (PG&E uses Abnormal Peak Day or Cold Winter Day as predominant system design criteria). Finding of

cost-causation principles, the core must be allocated the share of the peak capacity costs that must be built to serve its peak load. The Decision erred when it adopted the Seasonal Factor, which relies on off-peak usage to allocate capacity costs,[19] and concluded that the previous January peak usage capacity factor was "contrary to the principles of cost causation."[20]

The Decision's findings and conclusions stating that "PG&E's transmission system is designed to optimize annual flow based on an annual demand criterion" cannot be reconciled with the record.[21] Peak usage—in one form or another—has always been the metric used to design system capacity and allocate pipeline capacity costs. PG&E's design criteria for its backbone system is 1-in-10 cold and dry year throughput, which resulted in a flow rate of 2300 million cubic feet per day in 2015.[22] The capacity of PG&E's local transmission system subdivisions are designed using either an Abnormal Peak Day or Cold Winter Day throughput standard, depending on which measure creates the largest need for capacity in the individual local transmission sector.[23] None of these allocation criteria are intended to "optimize" annual flow through PG&E's pipes; they are designed to ensure PG&E's system is large enough to supply core customers during the daily period of peak demand that always occurs during the coldest period of the year.

Fact No. 214 and Conclusion of Law No. 271, which claim PG&E's transmission system is designed to "optimize annual flow based on an annual demand criterion," are contradicted by PG&E's own testimony and significant additional evidence.

[19] The Seasonal Factor is based on an aggregation of the most recent historical loads for each customer for the four months in the capacity offering period (March–June, July–October, November–February), which is divided by the most recent historical load for all core customers for the same period. (Exh. PG&E-2 (Elmore), p. 19-17 (lines 12–18).) This results in using significant periods of off-peak throughput to allocate capacity costs.

[20] D.16-06-056, p. 357.

[21] *Id.*, Finding of Fact No. 214, Conclusion of Law No. 271.

[22] Commercial Energy Opening Brief, p. 39 and fn. 137. The design criterion throughput is much higher than average throughput, as its name demonstrates: 1-in-10 means the highest demand year in 10 years; cold year means colder than normal (which increases heating demand); and dry year means that electric generation (EG) load is greater than normal due to dry hydro conditions (and reduced availability of out-of-state hydropower imports).

[23] Commercial Energy Opening Brief, p. 39.

Moreover, it is unclear what the Decision means when it concludes PG&E's transmission system "is designed to optimize annual flow based on an annual demand criterion."[24] Optimization suggests designing capacity or rates in a way that will encourage customers to reduce their gas usage. In this sense, optimization is irrelevant to the question of how PG&E designs its gas system to accommodate peak winter throughput, how the Commission has traditionally allocated those capacity costs, or which customers caused PG&E to incur the capacity costs in the first place. Neither the January Factor nor the Seasonal Factor affect a customer's "flow" in any way, let alone to "optimize" it. The Decision does not provide any clues that would allow for an alternative reading. The meaning of "annual demand criterion" is equally opaque. The record is clear that PG&E designs its gas system to meet peak winter demand; the amount of gas a customer uses annually is irrelevant. The Decision's perplexing declaration regarding PG&E's transmission system design, added hastily after comments on the PD and APD were submitted, is further proof that the Decision's findings and conclusions are not based on the record evidence.

The record supports the conclusion that costs related to PG&E's system capacity are allocated using a different set of demand measures, but those measures are still based on peak usage and cost causation. The LRMC Decision adopted cold year peak season as the demand measure for PG&E's backbone system because it was the "best estimat[e] of cost causation"[25] and a cold year coincident peak month demand measure for the local transmission system.[26] Costs on PG&E's distribution system were most appropriately allocated using a peak day demand measure.[27] The first Gas Accord decision adopted a cold year coincident peak month

[24] D.16-06-056, Finding of Fact No. 214, Conclusion of Law No. 271.
[25] D.92-12-058, p. *26.
[26] *Id.* at p. *29.
[27] *Id.* at pp. *29, 34–37.

(i.e., January) marginal demand measure methodology for PG&E's local transmission rates.[28] This standard has never changed for PG&E's local transmission costs,[29] and has been preserved in subsequent Gas Accord settlements.[30] While intervening Gas Accord settlements adopted different measures for allocating other costs on PG&E's gas system,[31] the allocation metric for pipeline capacity has always adhered to peak usage and cost causation.

Regardless of the specific cost or capacity allocation measure—abnormal peak day, cold winter day, peak winter month, 1-in-10 cold dry year—peak usage is always the fundamental factor. The Commission's long-held cost-causation principles require that the customers driving that peak usage bear their proportional costs.

2. The Seasonal Factor Improperly Allocates Costs Based on Relative Percentage of Core Volume

PG&E itself has recognized that rates should be based on cost causation on multiple occasions, including:

[28] D.97-08-055, p. 61; D.03-12-061 (Gas Accord II amendment), p. *363.
[29] Direct Testimony of Thomas Beach on behalf of Calpine/Indicated Shippers ("Beach Testimony"), Exh. Calpine/Indicated Shippers-1, p. 11 (lines 3–4).
[30] D.97-08-055, p. *198 (stating that local transmission costs are allocated based on the LRMC methodology adopted in D.95-12-053, PG&E's Biennial Cost Allocation Proceeding); D.95-12-053, p. *52, fn. 14 (stating that the Commission adopted a cold year coincident peak month as the demand measure for PG&E's local transmission); D.02-08-070 (extending the existing Gas Accord market structure, rates, tariffs, and terms and conditions of service for one year); D.03-12-061, p. *543 (holding that PG&E should use the existing cost allocation methodology and rate design in the Gas Accord for local transmission rates in 2004); D.04-12-050, p. *51 (providing that local transmission cost of service continues to be allocated based on Cold Year January demand); D.07-09-045 (continuing Gas Accord market structure and allocation methodologies for three years); D.11-04-031, p. 30 (continuing the Gas Accord allocation methodology for local transmission rates).
[31] See, e.g., D.03-12-061, p. *352 (noting that the Gas Accord allocated costs for the backbone service paths using embedded costs of the facilities or based on a pro rata share of the firm design capacities of each path); D.04-12-050, p. *41 (holding that Core Vintage Redwood capacity would be allocated using average-year January demand).

- In Application 13-06-011, PG&E acknowledged that having "customers pay the costs they cause the utility to incur" is a fundamental ratemaking principle.[32]
- In Application 10-03-014, PG&E proposed that the Commission adopt its marginal cost proposals "to foster equitable and economically efficient ratemaking by ensuring that rates are substantially aligned with cost causation, so that customers bear the costs that they cause."[33]
- In a proceeding addressing its electric rates 20 years ago, PG&E stated that it assigned costs to various system functions according to cost causation, consistent with Commission policy.[34]
- In a case against the Federal Energy Regulatory Commission before the U.S. Court of Appeals, PG&E state that "[i]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[35]

PG&E departed from these fundamental cost-causation principles, however, when it proposed the Seasonal Factor. Instead of allocating capacity costs according to peak January usage (as has been done since the LRMC Decision in 1992),[36] the Seasonal Factor allocates costs based on the core's and CTAs' respective ratios of their load to total core load during three

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[32] Supplemental Testimony of Pacific Gas and Electric Company, served in Docket No. A.13-06-011 (October 15, 2013), p. 2-7.
[33] Update to Prepared Testimony of Pacific Gas and Electric Company Exhibit (PG&E-15) Marginal Cost, served in Docket No. A.10-03-014 (January 7, 2011), p. 7-22.
[34] *Application of PG&E to Identify and Separate Components of Electric Rates, etc.*, D.97-08-056, p. *17.
[35] U.S. Court of Appeals, On Petition for Review of Orders of the Federal Energy Regulatory Commission, Docket No. 03-1025 (July 9, 2004), pp. 8–9.
[36] See also D.97-08-055 (Gas Accord I); Exh. PG&E-2 (Elmore), p. 19-16 (lines 15–21) (describing the January Factor).

seasonal periods in the previous year, two of which are primarily off-peak.[37] A ratio based on a core customer's load relative to total core throughput during an entire year (even if segregated into three seasons) is not an appropriate allocation method because it does not accurately reflect the use of PG&E's gas system during peak periods, which is what causes PG&E to incur costs, but only reflects the usage levels of the bundled core and CTA customers *relative to each other*. CTA load decreases in the summer, which means CTAs do not impose a greater demand for capacity on PG&E's system. CTAs' *percentage* of total core load grows in the summer only because the bundled core load drops significantly from its extremely high winter peak. This increase in the CTAs' relative use of off-peak capacity, however, does not cause PG&E to incur additional costs because all core pipeline usage is far below full capacity during the off-peak period. Allocating costs between the bundled core and CTAs based on their relative usage percentages misrepresents the actual demand on system capacity attributable to CTAs; relative percentages of off-peak usage are not indicative of cost causation. Figure 1, below, shows the actual throughput volumes for the bundled core and CTAs from January 2013 to February 2014:[38]

[37] The peak winter period is December to March, which creates some overlap with PG&E's proposed allocation seasons of November–February, March–June, and July–October. (See Figure 19-2.)
[38] The record evidence shows that the bundled core is responsible for the capacity required to meet winter peak demand. The record also shows that CTA load does not create a greater demand for capacity in the summer than does the bundled core.

Figure 1: PG&E Core and CTA Throughput[39]

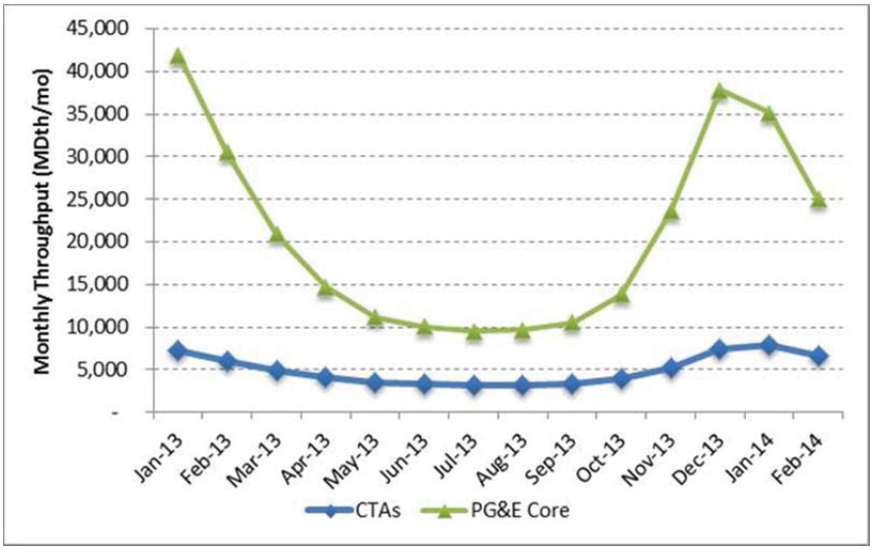

Figure 1 makes it clear that the only reason CTAs' percentage of total core load increases during off-peak months is because the load of the bundled core plummets from its winter peak. The CTAs still use substantially *less* pipeline *capacity* in the summer months than the bundled core. Both PG&E and the Decision disregard the *actual capacity used by CTAs and the bundled core* and mistakenly focus on the *ratio of total core capacity* throughout the year as the measure of the extent to which each group makes use of PG&E's system.[40] PG&E did not design its system based on what percentage of capacity its customer classes would need relative to total capacity throughout the year. PG&E designed its system, and its acquisition of interstate transmission capacity, to accommodate the winter peak volumes for the core, and primarily the bundled core.

3. Customers Must Bear the Costs They Cause PG&E to Incur

The Decision's determination that "CTAs are not currently allocated the capacity and associated costs for those periods when they utilize a greater percentage of pipeline

[39] Exh. Commercial Energy-1 (Monsen), p. 8.
[40] D.16-06-056, pp. 356–357.

capacity,"[41] and that "[t]his result is contrary to the principles of cost causation,"[42] is not supported the record evidence of actual customer class usage as shown by Figure 1, the remainder of the record in this proceeding, or the substantial Commission precedent holding that costs must be allocated to the customers that cause them.

In the LRMC Decision, the Commission rejected ORA's proposal to use non-coincident peak month (i.e., a customer's peak usage during a month other than the system-wide peak month) as a demand measure for cost allocation because the non-coincident peak measure "does not reflect system planning, and it certainly does not reflect cost causation."[43] In Gas Accord II and in *this proceeding*, PG&E took the position that the cold year coincident peak month allocation measure (i.e., the January Factor) continued to be the appropriate marginal demand measure for local transmission cost allocation between core and noncore customers; the Commission did not disagree.[44] When adopting SDG&E and SoCalGas's proposal to integrate their transmission system costs, the Commission agreed with the utilities that the proposed integrated rate should be based on an LRMC allocation methodology.[45] The Commission also agreed that a cold year throughput allocator for backbone transmission costs was appropriate because it was the "Commission-adopted allocator."[46] When setting SoCalGas's rates for firm peaking service, the Commission noted that the utility designs its transmission and distribution systems to meet abnormal peak day demand, and that in designing rates, the utility's costs are allocated using marginal demand measures of coincident peak month demand (distribution) and

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[41] D.16-06-056, Finding of Fact No. 212; *id.* at pp. 356–357.
[42] *Id.* at pp. 356–357.
[43] D.92-12-058, pp. *36–37.
[44] *Application of PG&E Proposing a Market Structure and Rules for the Northern California Natural Gas Industry, etc.*, D.03-12-061 (2001 Cal. PUC LEXIS 1279), p. *534; D.16-06-056, pp. 311–312.
[45] *Application of SDG&E and SoCalGas for Authority to Integrate Their Transmission Rates, etc.*, D.06-04-033 (2006 Cal. PUC LEXIS 292), pp. *83–86.
[46] *Id.* at pp. *83, 85.

cold year throughput (transmission).[47] The Commission went on to state that the peaking rate should reflect the cost the customer imposes on the system when the customer takes peaking service.[48] And in SDG&E's 1994 Biennial Cost Allocation Proceeding, the Commission determined that the utility's transmission demand measure should be the highest coincident cold-year peak month during the BCAP period.[49]

The Commission routinely follows similar cost-causation principles when allocating costs for electric service, as well. The Commission recently concluded that adopting a flexible resource adequacy requirement allocation methodology based on load serving entities' contributions to the CAISO's monthly net-load ramps to determine the overall flexible resource adequacy requirement followed cost-causation principles.[50] The Commission also recently rejected PG&E's argument that cost causation supported allocating demand response program costs to all customers, instead of to its bundled customers alone, because demand response programs provide grid reliability, which benefits all customers.[51] This argument was rejected because "[t]he Commission has clearly stated that the principle of cost causation means that costs should be borne by those customers who cause the utility to incur the expense, not necessarily by those who benefit from the expense."[52] In an earlier proceeding overseeing resource adequacy requirements, the Commission adopted an allocation methodology specific to load-serving entities based on their individual loads and rejected the previous methodology that used an

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[47] *Application of SoCalGas for Authority to Implement a Rate for Peaking Service, etc.*, D.01-08-020 (2001 Cal. PUC LEXIS 572), pp. *34–35.
[48] *Id.* at p. *35.
[49] *Application of SDG&E, etc.*, D.94-12-052 (1994 Cal. PUC LEXIS 1059), Finding of Fact No. 123.
[50] *OIR to Oversee the Resource Adequacy Program*, D.15-06-063, pp. *61–63 (2015 Cal. PUC LEXIS 368).
[51] *OIR to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs, etc.*, D.14-12-024, pp. *68–69 (2014 Cal. PUC LEXIS 591).
[52] *Id*. at p. 69.

averaged factor that pooled all customer classes together.[53] In support of this decision, the Commission cited precedent that "[a]ll customer classes should be aware of the 'peakiness' of that particular customer class, and all LSEs should face costs consistent with cost causation. An average coincidence factor across all customer classes hides certain cost differences among classes and LSEs."[54] And, in the wake of the energy crisis, the Commission held that cost allocation principles adopted to address the revenue requirement associated with the exorbitantly priced power purchases the Department of Water Resources had been forced to make should reflect the cost that the customer imposes on the system.[55]

The Decision's faulty reasoning is further undermined by Resolution G-3512, issued in January 2016, which arose out of the canon of San Bruno decisions (to which the Decision arguably belongs). The Commission rejected PG&E's proposal to allocate $400 million in San Bruno-related refunds to customers based on their actual annual throughput and instead ordered PG&E to issue refunds based on a monthly average of December 2015 and January 2016 throughput as an allocator "because those months represent a period with high total gas throughput."[56] This peak month allocation method for refunds is consistent with cost causation and adheres to Commission ratemaking practice. Resolution G-3512 is persuasive evidence that, as recently as this year, the Commission has reiterated that peak period consumption is the correct way to allocate gas system cost responsibility. The Resolution adopted by the Commission treated the refund as simply a negative cost, and accordingly allocated the refunds in the same manner as costs have consistently been allocated for decades.

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[53] *OIR to Oversee the Resource Adequacy Program, etc.*, D.12-06-025, pp. *35–38 (2012 Cal. PUC LEXIS 313).
[54] *Id.* at p. *36 (quoting D.11-06-022, p. 17).
[55] *Emergency Application of PG&E to Adopt a Rate Stabilization Plan, etc.*, D.02-02-052, p. 58; see also D.00-06-034, pp. *83–84 ("Further, allocation of costs based on energy consumption is consistent with our long-standing principles of allocation by cost causation.").
[56] CPUC Resolution G-3512, p. 12.

The Decision further commits legal error by concluding that an allocation factor based on a single month or day of peak use does not appropriately reflect customer use throughout the year.[57] This statement misinterprets the factors relevant to cost-causation principles and is flatly contrary to established Commission precedent. Peak use—whether peak day, peak month, or winter season—is not intended to measure customer use throughout the year; it is intended to identify the customer class that has the greatest peak load, which dictates the amount of capacity PG&E must build for its system to accommodate that peak load. The customer class whose peak volume usage drives PG&E's system capacity requirements has the greatest share of responsibility for causing PG&E to incur the costs of building and maintaining that capacity. That customer class must bear the costs its causes. Some form of peak use, therefore, is the *only* appropriate metric for allocating capacity costs under the cost-causation principles D.16-06-056 purports to espouse.[58]

Additional evidence was submitted in this proceeding that supports the conclusion that cost-causation principles require assigning more backbone capacity costs to the bundled core. PG&E's testimony in A.13-06-011, the interstate gas capacity planning proceeding, states that PG&E purchases interstate capacity to meet the winter peak demands of the bundled core.[59] Because suppliers are often unwilling to offer PG&E anything other than annual constant contract volumes, these contracts result in excess off-peak capacity from May to September.[60] The costs of this excess capacity are borne by core customers if PG&E cannot otherwise recover them.[61] The Decision endorsed PG&E's argument that its intrastate pipeline capacity holdings

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[57] D.16-06-056, Conclusion of Law No. 270; *id.* at p. 356.
[58] See D.92-12-058, pp. 25–41.
[59] Exh. CTAC-6, *PG&E Core Gas Capacity Planning Range Testimony* (Lang), pp. 4–5.
[60] *Id.* at p. 5.
[61] *Ibid.*

must match its interstate capacity;[62] if the capacity must be the same, the cost allocation principles should also be the same. Bundled core customers, not CTAs, are responsible for by far the largest portion of the peak load that PG&E must ensure it is able to meet every winter. CTAs should therefore not bear a larger portion of the costs PG&E incurs on behalf of the bundled core.

Finally, the Decision contains no findings of fact or conclusions of law that support its conclusion that the January Factor is inconsistent with cost-causation principles.[63] Neither does the Decision contain any findings or conclusions that support the corollary determination that the Seasonal Factor *is* consistent with cost-causation principles, which is never stated in the Decision but can be inferred. A Commission decision must be supported by adequate findings, which must themselves be supported by substantial evidence.[64] The Decision does not meet these basic criteria. Rehearing is necessary.

B. PG&E's Seasonal Capacity Factor is Based on a Misleading Exhibit that Fails to Support a Shift of Costs to CTA Customers

The Decision relies on PG&E's Figure 19-2 as justification for the conclusion that CTAs use more off-peak pipeline capacity and therefore must be allocated a significantly larger portion of the capacity costs.[65] The Decision also relies on Figure 19-2 to conclude that CTAs were under-allocated capacity by 2.3% using the January Factor, which justifies allocating them more capacity using the new Seasonal Factor.[66] What neither PG&E nor the Decision acknowledge, however, is that alleged under-allocation is merely the result of representing CTAs' load as a percentage of total core load, not as a straight representation of actual annual

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[62] D.16-06-056, p. 372.
[63] D.16-06-056, pp. 356–357.
[64] Pub. Util. Code, §§ 1757(a)(3)–(4).
[65] D.16-06-056, p. 356.
[66] *Ibid.*

throughput volumes. As Figure 1 shows, CTAs have a significantly lower throughput than the bundled core throughout the entire year, and CTA load *decreases* slightly in the summer[67]—it does not increase dramatically, as Figure 19-2 hopes to convince the viewer. The apparent increase in CTA off-peak load in Figure 19-2 is the result of changes in the volatile bundled core load; CTA load is relatively flat throughout the year. The alleged increase in CTA capacity usage during the summer months is an optical illusion.

The misleading impact of Figure 19-2 was confirmed by PG&E's own witness. In response to a hypothetical question that assumed the CTA load was completely flat with a 100% load factor for the entire year—meaning the CTAs used the same amount of throughput capacity year-round—Mr. Elmore conceded that under the PG&E Seasonal Factor, the CTAs would still experience an increase in the costs allocated to them during the summer even though *CTA usage did not increase at all*.[68] The Commission's determination that PG&E's Seasonal Factor is nevertheless reasonable and consistent with cost causation is not only not supported by the record, it cannot be reconciled with the testimony of PG&E's witness on this topic.

While the Commission's justification based on CTAs' increased use of off-peak pipeline capacity has no basis in reality, adoption of the Seasonal Factor has serious real-world consequences for the CTAs. The Seasonal Factor will increase CTAs' allocated capacity costs by 42%,[69] despite the fact that their actual throughput remains well below that of the bundled core and their throughput volume decreases in the summer. Even if CTAs had been historically under-allocated capacity by 2.3%, which is not accurate, increasing their allocation by 42% is a staggering overcorrection that fails to conform to cost-causation principles.[70] The record

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[67] See Figure 1, *supra*.
[68] TR 4747 (line 12)–4748 (line 12) (PG&E/Elmore); Commercial Energy Opening Brief, p. 45.
[69] Commercial Energy Reply Brief, pp. 13–14.
[70] Cf. D.16-06-056, p. 357.

contains no evidence to justify this dramatic cost shift: PG&E presented no testimony to illustrate the cost impacts of its proposed Seasonal Factor, nor did PG&E attempt to calculate the effects of its proposal on the CTA customer class.[71] The Seasonal Factor shifts $10 million in capacity costs onto the CTAs despite the fact that the CTAs are not responsible for the vast majority of the peak load that PG&E's system is designed to meet and use less capacity than the bundled core at all times of the year.[72] PG&E had the burden of proof to justify its Seasonal Factor as reasonable, which it failed to do. The Decision compounds that failure by adopting the proposal anyway and declaring it reasonable.[73]

In contrast, Commercial Energy presented uncontroverted evidence of the extraordinary cost increase that CTAs would face, using PG&E's own forecast information.[74] The substantial rate increase caused by the Decision's last-minute adoption of PG&E's Seasonal Factor proposal will impact **core customers** served by CTAs. If the Commission sought to reduce the burden of the overall GT&S rate increase on core customers due to a concern about affordability, the Decision fails to do so, as all of the CTAs' customers are themselves core customers, including hundreds of thousands of both single family and multi-unit residential customers.

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[71] TR 4769 (line 23)–4771 (line 16) (PG&E/Elmore); Commercial Energy Reply Brief, p. 51. PG&E's attempts to introduce gas costs and other CTA costs as a means of diminishing the impact of the 42% capacity cost increase is a red herring. (PG&E Opening Brief, p. 18-11.) CTAs' gas costs are irrelevant to a determination of transmission rates and pipeline cost allocation. (Commercial Energy Reply Brief, p. 18.) CTAs' total costs are also irrelevant to the reasonableness of a specific 42% cost increase. The increase in capacity costs alone can erode a CTA's gross profit margin and slash its net revenues dramatically. (*Ibid.*)
[72] Exh. Commercial Energy-23.
[73] D.16-06-056, p. 356.
[74] Exh. Commercial Energy-23; Commercial Energy Reply Brief, p. 17.

V. THE JANUARY CAPACITY FACTOR SHOULD BE REINSTATED UNTIL PG&E SATISFIES ITS OBLIGATION TO MEET AND CONFER WITH THE CTAs

A. The Decision Unreasonably Treats the Backbone and Local Transmission Cost Allocation Proposals Differently

The Proposed and Alternate Proposed Decisions properly determined that PG&E had not met its burden of proof to support the Seasonal Factor and left the January Factor in place until PG&E and the CTAs were able to discuss and present a new proposed allocation factor.[75] The final Decision adopted a similar solution with respect to potentially changing the allocation factor for PG&E's local transmission: the Decision determined that the proposed Cold Winter Day allocator would not appropriately reflect marginal costs and ordered the existing peak month allocator to remain in place pending further studies on the efficacy of a different allocation factor.[76] This is the same outcome ordered by the PD and APD regarding the proposed changes to the January Factor for backbone and interstate capacity. The Decision's unexpected about-face to adopt the Seasonal Factor, which necessitated a hasty post-comment period rewrite, and which cannot be supported by findings or the record, is an unnecessary and irresponsible departure from the reasonable conclusion reached by the PD and APD. The Decision's legal error in abruptly reversing its position on the Seasonal Factor and failing to justify the choice is even less reasonable in light of the concurrent decision to retain the January Factor as PG&E's local transmission cost allocator. The January Factor should remain in place as the allocator for interstate and intrastate pipeline capacity costs until a reasonable alternative can be identified.

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[75] Proposed Decision, pp. 346–347; Alternate Proposed Decision, pp. 349–350. The Proposed and Alternate Proposed Decisions also noted that the Commission recently determined the PG&E should reduce the amount of interstate pipeline capacity it holds to meet core demand, and that reduction "could impact how the allocation of capacity (and thus costs) should be changed." (*Ibid.*)

[76] D.16-06-056, pp. 315–316.

B. The January Factor Remains In Place Under the CTA Settlement

The CTA Settlement adopted in connection with Gas Accord V[77] provided that January Factor must remain in place unless changed by the Commission in a future settlement or decision.[78] However, the Decision has not properly adopted PG&E's seasonal capacity factor due to the lack of adequate findings and conclusions, and the presence of legal error in the cost-causation analysis. In the absence of a validly adopted alternative, the January Factor must therefore remain in place until a reasonable alternative can be designed and presented to the Commission.

VI. CONCLUSION

The Commission's adoption of PG&E's Seasonal Factor in D.16-06-056 is not supported by adequate findings, conclusions, or substantial evidence in light of the whole record and is therefore reversible error. The Seasonal Factor is contrary to the Commission's well-established principles of cost causation; the decision's determination to the contrary cannot be justified by either the record or decades of precedent. The decision's rejection of peak usage as a valid allocator for capacity costs is also belied by PG&E's own system design, the record, and Commission practice. Rehearing is necessary to correct the legal error D.16-06-056 committed in adopting the Seasonal Factor at the eleventh hour and shifting millions of dollars in unwarranted costs onto the CTAs.

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[77] D.11-04-031, Appendix B.
[78] *Id.*, Appendix B, section A.1.

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