STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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TO PARTIES OF RECORD IN A.13-12-012 AND I.14-06-016:

This is the proposed decision of Administrative Law Judge Kevin Dudney. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's December 1, 2016 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

/s/ DARWIN E. FARRAR for
Karen V. Clopton, Chief
Administrative Law Judge

KVC: ge1

Attachment

Decision **PROPOSED DECISION OF ALJ DUDNEY (Mailed 11/1/16)**

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

DECISION REGARDING $850 MILLION PENALTY ALLOCATION FOR PACIFIC GAS AND ELECTRIC COMPANY FOR GAS PIPELINE SAFETY ENHANCEMENTS

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DECISION REGARDING $850 MILLION PENALTY ALLOCATION FOR PACIFIC GAS AND ELECTRIC COMPANY FOR GAS PIPELINE SAFETY ENHANCEMENTS

Summary

This decision finalizes the ratemaking treatment relating to the $850 million penalty assessed in Decision (D.) 15-04-024[1] for violations by Pacific Gas and Electric Company (PG&E) associated with the September 9, 2010 gas transmission pipeline explosion and subsequent fire in San Bruno, California. We previously required that the $850 million penalty must be used to fund approved gas transmission pipeline safety enhancements, but we deferred a final determination as to the amount to be used for capital investments versus for current expenses. As determined below, we direct PG&E to allocate 81percent of the $850 million to fund capital expenditures, with the remaining 19 percent to fund expenses. In this decision, we also adopt a finalized list of approved gas transmission pipeline projects and programs which meet the California Public Utilities Commission's definition of "safety related," the costs of which are to be funded through the $850 million penalty.

To reflect our determinations regarding allocation of the $850 million penalty between capital and expense, we make adjustments to finalize PG&E's Gas Transmission and Storage (GT&S) revenue requirement as previously adopted on an interim basis in D.16-06-056 for test year 2015 and for post-test-year 2016-2018. We also correct a minor technical error included in

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1 *See* D.15-04-024, issued April 9, 2015, re: *Decision on Fines and Remedies to be Imposed on Pacific Gas and Electric Company for Specific Violations in Connection with the Operation and Practices of its Natural Gas Transmission System Pipelines*.

D.16-06-056. As explained in D.16-06-056, the interim GT&S revenue requirement adopted therein was reduced by the incremental amount of 2015 revenues that would be amortized over a five-month period associated with the delay caused by PG&E's violation of the *ex parte* rules.[2] The effects of today's decision on the adopted revenue requirement for 2015, 2016, 2017 and 2018 are summarized below. The 2015 amounts are shown after applying the *ex parte* disallowance. We set forth the applicable revised revenue requirement and rate tables in the Appendices C-J to this decision to reflect the changes in rates that result from the findings of this decision.

Year	2015	2016	2017	2018
Base Revenue Requirement,[3] Pipeline Safety Enhancement Plan Included (1000s of $)	$815,207	$1,061,436	$1,125,292	$1,230,110

1. Background

This decision finalizes Pacific Gas and Electric Company's (PG&E's) Gas Transmission and Storage (GT&S) revenue requirements through 2018, as adopted on an interim basis in Decision (D.) 16-06-056. Pursuant to D.16-06-056, interim GT&S revenue requirements were adopted subject to the results of today's decision.[4] The finalized rates adopted herein reflect our adopted ratemaking treatment of the $850 million penalty that was imposed for violations

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[2] *See* also D.14-11-041.

[3] Excludes carrying costs on working gas and load balancing gas.

[4] The adopted revenue requirement was reduced by the incremental amount of 2015 revenues that would be amortized over a five-month period associated with the delay caused by PG&E's violation of the *ex parte* rules. Until a final revenue requirement is adopted, a placeholder disallowance of $137.840 million was used to establish interim rates.

associated with the September 9, 2010 gas transmission pipeline explosion and subsequent fire in San Bruno, California.

In D.16-06-056, Ordering Paragraph (OP) 63, we directed that the ratemaking issues relating to the $850 million penalty would be finalized by subsequent order. Pursuant to OP 63 in D.16-06-056, we allowed parties to comment as to the appropriate list of safety-related programs and projects to be used in tracking PG&E's actual expenditures relating to the $850 million penalty. Parties could also address how the $850 million should be allocated to pay for shareholder-funded gas transmission pipeline safety improvements as ordered in D.15-04-024.

PG&E, The Utility Reform Network (TURN), Indicated Shippers (IS), and the California Manufacturers & Technology Association (CMTA) filed opening briefs on July 7, 2016. On July 26, 2016, Dynegy, TURN, CMTA with The California League of Food Processors (CLFP), and IS provided supplemental opening briefs based on additional information provided by PG&E. Reply briefs were filed on August 2, 2016, by PG&E, Office of Ratepayer Advocates (ORA), IS, CMTA and CLFP, and Northern California Generation Coalition (NCGC).

On September 6, 2016, the Administrative Law Judge (ALJ) issued a ruling setting a workshop to discuss Results of Operations (RO) modelling issues. In the ruling, the ALJ noted that certain assumptions underlying the RO model may or may not be appropriate in the circumstances of implementing this penalty. The ALJ permitted the Energy Division to circulate illustrative RO modelling results to the parties in advance of the workshop, and the Energy Division provided illustrative results to the service list by e-mail on September 9, 2016. During the workshop on September 26, 2016, parties examined the issue and provided comments.

2. Framework for the Ratemaking Treatment of the $850 Million Penalty

In the interests of making PG&E's gas transmission system as safe as possible for the public, ratepayers, utility workers, and the environment, in D.15-04-024, we required, among other things, that PG&E shareholders pay an $850 million penalty. The $850 million penalty was one of the sanctions assessed against PG&E in reference to the September 9, 2010 gas transmission pipeline explosion and subsequent fire in San Bruno, California. We further required in D.15-04-024 that the $850 million penalty be spent exclusively on approved gas transmission safety-related projects or programs, most of which was to be spent on capital investments.

Since the $850 million penalty was to be funded exclusively by shareholders, we thus required that any safety-related costs associated with the $850 million penalty be excluded from PG&E's GT&S revenue requirements adopted in A.13-12-012. Accordingly, any expenses funded through the $850 million penalty were to be excluded from the revenue requirement. Likewise, capitalized expenditures funded through the $850 million penalty were to be permanently excluded from PG&E'S rate base. PG&E was not permitted to add such expenditures to rate base or to earn a profit on them.[5] By excluding these capital expenditures from rate base via the Capital Sub-Account, ratepayers will never pay for depreciation or a return on the excluded plant in future general rate cases.[6]

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[5] *See* OP 7 of D.15-04-024.

[6] If the total penalty amount was not exhausted by designated safety-related projects or programs authorized in this proceeding, a determination of additional capital projects or programs to be funded by shareholders would be made in future proceedings, as necessary to

Footnote continued on next page

Only costs for which PG&E would have been granted rate recovery in the GT&S proceeding count towards the $850 million penalty. Work that PG&E chose to do at shareholder expense (i.e., not approved in the GT&S proceeding or a similar subsequent proceeding) does not count towards the $850 million total.

In D.15-04-024, we adopted a tracking process to ensure that the amounts spent on safety-related projects funded through the $850 million penalty are paid by shareholders, not recovered from ratepayers. Safety-related expenses and capital expenditures were to be tracked in a "Shareholder-Funded Gas Transmission Safety Account," consisting of two subaccounts – one for expense and one for capital expenditures.[7] PG&E was authorized to record costs incurred on or after January 1, 2015, for approved safety-related programs and projects into these accounts.

We also provided guidance in D.15-04-024 as to how the $850 million was to be allocated between expense versus capital expenditures. As a framework for this purpose, we looked to the budgets adopted in the Pipeline Safety Enhancement Plan (PSEP) proceeding (D.12-12-030). As authorized therein, capital expenditures for 2013 and 2014 totaled $696.2 million, and approved expenses totaled $162.5 million. The sum of $696.2 million and $162.5 million total $858.7 million, reflecting 81 percent as capital expenditures (i.e., $696.2/$858.7) and 19 percent as expenses (i.e., $162.5/858.7 million).

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ensure that PG&E ultimately spends the full $850 million designated for safety-related projects and programs.

[7] *See* D.15-04-024 at 96 (slip op.). On May 20, 2015, PG&E filed Advice Letter 3596-G to establish the "Shareholder Gas Transmission Safety Account" and two subaccounts. Resolution G-3509, issued December 17, 2015, directed PG&E to make certain revisions through a supplemental advice letter, filed on December 31, 2015, and approved on March 7, 2016.

Applying a similar pattern to the $850 million penalty, we specified that up to $161.5 million (19 percent of the $850 million) was to apply to current expenses, and a minimum of $688.5 million (81 percent of the $850 million) was to apply to capital expenditures.[8]

We directed PG&E to cap the amount in the Expense Sub-Account at the lesser of $161.5 million or the amount of "safety-related" costs so designated. If the total was less than $161.5 million, the limit included in the Capital Sub-Account was to be adjusted above $688.5 million by a corresponding amount, so that the two sub-accounts would total $850 million. For items included in the Expense Sub-Account, we adopted a forecast in D.16-06-056 of when those expenses will be incurred. Those expenses must be excluded in calculating the ratepayer-funded revenue requirements for each applicable year.

On June 1, 2015, PG&E identified safety-related gas transmission projects and programs in the GT&S rate case forecast that it claimed should be recorded in the Shareholder-Funded Gas Transmission Safety Account (SFGTSA) and its two subaccounts. These authorized expenses and capital expenditures for safety-related gas transmission projects or programs were to be funded by shareholders, subject to adopted expense and capital expenditure spending limits. If the total funded by shareholders was not exhausted by designated safety-related projects or programs authorized in the GT&S proceeding, we would make a determination of additional capital projects or programs to be funded by shareholders in future proceedings, as necessary to ensure that PG&E

[8] D.15-04-024 at 94-95.

ultimately spends the full $850 million designated for safety-related projects and programs.[9]

As noted in the Second Amended Scoping Memo, however, certain parties asserted that prioritization of programs and projects cannot be made until a final decision on authorized GT&S revenue requirement was issued. TURN, ORA and IS, in particular, argued that D.15-04-024 contemplated two separate tasks in this regard: (1) determining PG&E's revenue requirement for safety-related programs and projects and (2) determining which of the authorized programs and projects costs would be offset by the $850 million penalty. ORA contended that a discrete list of disallowances for capital projects is needed that can be tracked from year to year to ensure that these projects do not creep into rate base.

In view of parties' concerns, we deferred the final identification of safety-related projects for use in tracking spending relating to the $850 million penalty. In D.16-06-056, we adopted PG&E's proposed listing on an interim basis for purposes of identifying the safety-related projects used to track and verify that PG&E spends the $850 million penalty on approved projects only. We solicited comments on whether, in light of the revenue requirements adopted in D.16-06-056, any revisions in the adopted list were warranted.

As a related matter, we also solicited comments to consider further how the $850 million should be allocated between expenses versus capital expenditures as reflected in the GT&S revenue requirement in this proceeding.

Parties filed an opening and reply round of briefs addressing the prioritization of safety-related programs and projects. Further, we invited

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[9] D.15-04-024 at 95.

parties to address whether the expense-versus-capital allocation of the $850 million as specified in D.15-04-024 should be changed. We also asked parties to identify the specific authorized safety-related programs and projects that meet the California Public Utilities Commission's (Commission) definition of being "safety-related" for purposes of tracking actual spending to be funded by the $850 million penalty.

In finalizing the GT&S revenue requirements in this proceeding, we finalize our determination of the respective limits on expenses and capital expenditures that apply for safety-related gas transmission projects or programs as necessary to exhaust the $850 million penalty to be funded by shareholders.

3. Approved Safety Programs and Projects to Offset the $850 Million Penalty

3.1. Position of PG&E

PG&E previously identified both the capital-related and expense-related programs and projects in its June 1, 2015 pleading[10] to be applied against the $850 million penalty. In its July 7, 2016 opening brief, PG&E asserts that these previous listings are still appropriate to apply to the $850 million penalty offset, with two exceptions. These two exceptions are the capital and expense associated with PG&E's Routine Spending for Compression and Processing (Asset Family – Facilities). PG&E had originally believed that these costs met the Commission's definition of "safety related" because they include work to repair or replace valves and other transmission pipeline equipment. PG&E states,

[10] In its June 1, 2015 Response to an ALJ ruling calling for information to implement D.15-04-025, PG&E identified capital and expense projects and programs to meet the Commission's definition of "safety related," the costs of which should be offset by the $850 million penalty.

however, that based on closer examination, it has determined that the vast majority of the work relates to compressor equipment rather than pipeline equipment. PG&E now believes that this work should not be categorized as "safety-related" for purposes of determining costs to be offset by the $850 million penalty.

In its July 2016 brief, PG&E identified the projects and programs that it believes to be "safety-related," designated as capital expenditures (in Appendix A to the brief) versus expense (in Appendix B). These appendices agree with PG&E's June 1, 2015 filing, other than for classification of the Routine Spending for Compression and Processing noted above. PG&E reflected this change in redlining.

PG&E thus requests authority to record to the SFGTSA the safety-related costs it incurs or has incurred since January 1, 2015 in these categories up to the amounts the Commission adopted in D.16-06-056 through 2018 or until such earlier time as PG&E has recorded the full $850 million to the SFGTSA.

3.2. Position of Other Parties

TURN was the only party to respond on the issue of PG&E's updated listing of the approved safety-related programs and project costs as an offset by the $850 million penalty. TURN accepts PG&E's modified designation of programs and projects that meet the definition of "safety-related," as set forth in PG&E's opening brief. TURN recommends that costs be allocated to those designated projects and programs as identified by PG&E.

3.3. PG&E's Proposed List of Safety-Related Programs and Projects is Adopted

Particularly in view of the fact that there is no opposition on this issue, we conclude that PG&E's proposed list of safety-related programs and projects that qualify as "safety-related", as identified in its July 7, 2016 comments, is reasonable and should be adopted.

Accordingly, we adopt modified list of programs and projects incorporated in PG&E's Appendix A and B, respectively, for purposes of identifying and tracking expenses and capital expenditures incurred by PG&E relating the $850 million penalty offset. This modified list supersedes Appendix G of D.16-06-056, which previously set forth 2015 expenses and capital expenditures, and 2016 and 2017 expenses and capital additions based on post-test-year escalation rates for safety-related capital expenditures and expenses as originally identified in PG&E's June 1, 2015 filing.

4. Allocation of $850 Million Penalty to Expense versus Capital Expenditure and Sequence of the Penalty versus *Ex Parte* Disallowance

This section addresses two interconnected disputes: (1) the allocation of the penalty between expense and capital expenditure and (2) the sequencing of the five month *ex parte* disallowance adopted in D.14-11-041 in relation to the penalty. We conclude that it is appropriate to apply the penalty 81 percent to capital expenditure and 19 percent to expense and that there shall be no change to the sequencing of the *ex parte* disallowance, i.e., the penalty is applied before calculation of the *ex parte* disallowance as previously decided in D.16-06-056. Our decision on each of these issues is consistent with prior decisions.

As noted above, in D.15-04-024, we determined that up to 19 percent of the penalty could be applied to expense, with the remaining 81 percent or more applied to capital expenditure.

As adopted in D.16-06-056 and D.14-11-041, PG&E's revenue requirement was reduced by the incremental amount of 2015 revenues that would be amortized over a five-month period associated with the delay caused by PG&E's

violation of *ex parte* rules. Any revenue requirement effects due to the $850 million penalty were to be subtracted first to derive the *ex parte* disallowance. As a result of this sequencing, the *ex parte* disallowance varies depending on how much of the $850 million penalty is applied to reduce the amount of current expenses versus capital expenditures.

4.1. Position of PG&E

PG&E takes no position regarding the relative percentage allocation of the $850 million penalty offset between capital expenditures versus expense items. PG&E, however, does dispute arguments advanced by other parties that the Commission mitigate two "unintended consequences" of the allocation by: (1) reconsidering the decision to sequence the calculation of the *ex parte* disallowance after the application of the $850 million penalty and (2) altering PG&E's RO model to lower the revenue requirement that would result if 100 percent of the $850 million penalty were applied to expense.

PG&E argues that such changes are simply a function of the calculation of a revenue requirement using the ratemaking principles adopted by the Commission. PG&E argues, however, that irrespective of how the $850 million is allocated between expense and capital items, the Commission's previously adopted approach of sequencing the calculation of the *ex parte* disallowance should not be changed. PG&E believes that the Commission correctly determined that the $850 million penalty must be applied before calculating the *ex parte* disallowance in order to carry out the Commission's intent to treat the *ex parte* disallowance as a ratepayer reparation, not a penalty. PG&E argues that that determination should not be disturbed. PG&E disputes characterizations of the calculation of the *ex parte* disallowance as a shareholder "windfall."

4.2. Positions of ORA and TURN

TURN recommends that the Commission's previously determined allocation of 81 percent capital and 19 percent expense should continue to apply for purposes of spending authorizations relating to the $850 million penalty. ORA agrees with TURN.

As a way to mitigate the magnitude of rate increases adopted in D.16-06-056, TURN acknowledges that allocating more of the $850 million penalty as an offset to expenses would reduce the current GT&S revenue requirement and thus produce lower rate levels during the current rate cycle. TURN also believes, however, that using more of the penalty amount as an offset to expenses would run counter to the apparent intent of D.15-04-024 to apply most of the offset to capital expenditures, and thereby, provide longer-term benefits to ratepayers. TURN also argues that the best balance of short- and long-term benefits would result from the allocation that maximizes net present value benefits to ratepayers. In this regard, TURN expects that the 81percent capital/19 percent expense allocation would offer higher net present value benefits to ratepayers than would a 100 percent expense approach. TURN observes that a 100 percent allocation to expense produces only slightly lower rates in 2017 and 2018 than the 81percent/19 percent capital-to-expense ratio.

Based on rate tables provided by PG&E in response to the ALJ's e-mail ruling, TURN states that rates in 2017 and 2018 would be "slightly lower" (with the difference shrinking in 2018) under a 100 percent expense allocation. TURN expects the effect of lower rate base from the 81 percent capital/19 percent expense allocation would yield lower rates than would a 100 percent expense allocation in subsequent years, however, and continuing into the future. The length of time that future rate levels will be lower depends on the depreciation lives of the affected assets.

TURN also argues that the choice between a 100 percent expense allocation versus an 81 percent capital/19 percent expense allocation for the $850 million is unduly complicated by the sequence that applies in calculating the disallowance for the delay due to PG&E's improper *ex parte* communications.

TURN disagrees with the Commission's decision[11] to calculate the *ex parte* penalty by first deducting the $850 million penalty from the revenue requirement. If the *ex parte* disallowance were calculated on a revenue requirement before deducting the penalty, PG&E would be subject to a $138 million delay disallowance. This amount assumes no $850 million penalty. Based on calculations from PG&E, if the *ex parte* disallowance is calculated after the $850 million offset, there would be a $75 million reduction in the disallowance under the 81 percent capital/19 percent expense scenario. Allocating 100 percent of the $850 million to expenses would negate virtually all of the 2015 revenue requirement increase and, therefore, reduce the delay disallowance nearly to zero. TURN characterizes this result as a "windfall" to PG&E's shareholders.

TURN argues that maximizing the penalty allocation to capital costs would thus preserve more of the *ex parte* delay disallowance, thereby minimizing what TURN characterizes as a "windfall" to PG&E shareholders and muting the $850 million penalty.

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[11] D.16-06-056 and D.14-11-041.

By applying the *ex parte* disallowance after the penalty offset, the impact of the $850 million penalty is, therefore, to reduce the *ex parte* disallowance by $63 million under the 81 percent/19 percent approach and to negate the full $138 million under a 100 percent expense allocation.

TURN believes that allowing the $850 million penalty to moderate the adverse financial impacts to PG&E under either scenario is contrary to the Commission's punitive intent in D.15-04-024. TURN states that it intends to seek rehearing of the sequencing determination. TURN recommends the 81 percent capital/19 percent expense approach even assuming the sequencing changed, but believes the choice becomes a closer call.

TURN also expresses concerns about tax benefits relating to the $850 million penalty expenditures inappropriately flowing to PG&E's shareholders. PG&E believes these concerns apply whether the penalty is applied to expenses or to capital expenditures and thus are not a distinguishing factor in the choice of allocations. TURN recommends that if any of the $850 million is allocated to capital spending, PG&E shareholders should not gain any net present value benefit from the short-term tax deductions from which ratepayers do not benefit under PG&E's results of operations model because of the rate base offset. TURN believes that ratepayers should ultimately be made whole for lost tax benefits that result from allocating penalty amounts to capital costs. TURN believes this requirement should be enforced by an independent audit subject to review and comment by the parties to this proceeding.

4.3. Positions of Industrial Customer Groups

Parties representing PG&E's large industrial customers propose that the $850 million penalty should be allocated 100 percent to expenses of the current rate cycle. IS, in particular, believes the expense-versus -capital expenditure allocations adopted in D.15-04-054 should be changed to apply 100 percent of the $850 million penalty to rate case period expense, arguing that ratepayer benefits are maximized under this approach. CMTA, CLFP, and NCGC make similar arguments as discussed below.

The large industrial customers favor allocation 100 percent of the $850 million penalty to offset 2015-2017 expenses to mitigate "rate shock" resulting from D.16-06-056. They argue that allocation of 81 percent of the $850 million penalty to offset capital expenditures and only 19 percent to offset expense would do little to mitigate this rate shock. For example, NCGC contends that certain electric generation customers face a 202 percent increase in cost for gas transmission and recommends that we allocate the penalty to expense in order to mitigate this increase. An approximation of rate impacts can be drawn from comparisons between Table J-1A and Table G-15A (revised) of PG&E's May 26, 2016 Revised Rate Appendices. These rate schedules differ only in the application of the $850 million penalty using the 81 percent capital/19 percent expense allocation. Based on this data, IS states that application using these percentages will reduce the industrial rate increase by roughly $0.13/Dth (Dekatherm) in 2016 in the face of an increase of more than $1/Dth.

IS concedes that, in theory, allocating more of the penalty to capital might yield a greater net present value, but claims that nothing in the record illuminates the long-term benefits.

IS also argues that, under TURN's proposal, the reduction benefits--in the form of reduced depreciation expense, taxes and return--would be realized over asset lives of up to 60 years. Given the extended period required to recapture the penalty value long term, IS argues that the annual impacts of the 81 percent/19 percent may be limited.

CMTA argues that it is impossible to predict future rate changes and rate impacts of capital reduction benefits stretching years into the future. CMTA/CLFP members express concern over the magnitude of the rates authorized for 2016, 2017 and 2018 and not with long-term minor rate impacts. CMTA/CLFP argue that their members need immediate and maximum rate relief to deal with the near-term financial impacts of annual bill increases of $500,000 or more and are willing to forego the loss of what they characterize as "uncertain small capital reduction benefits that may or may not show up as noticeable rate impacts many years in the future."

IS argues that noncore customers face an unprecedented doubling or tripling of transportation rates as a result of the increases approved in D.16-06-056. Absent other Commission action, the only further mitigation of these increases will come from allocation of the $850 million penalty to rates, which carries the potential to significantly reduce the level of rate increases at least for this rate cycle.

IS agrees with TURN that the $850 million penalty should be applied after the *ex parte* disallowance to avoid entirely eliminating the reductions otherwise passed through to ratepayers and the deterrent effect on PG&E. IS argues that any other resolution will reduce benefits to ratepayers by undermining the penalty and the deterrence effect of the disallowance. IS and other industrial customer parties believe that by calculating the *ex parte* disallowance after deducting the $850 million penalty serves to dilute the ratepayer benefits and PG&E punishment intended by the Commission in approving the San Bruno Penalty and five-month *ex parte* disallowance.

Although IS favors the 100 percent expense allocation, IS characterizes such an allocation as resulting in a "windfall" to PG&E investors. PG&E's

Results of Operation model shows a return that is $157 million greater over the 2015-18 period under the 100 percent allocation compared to the 81 percent/19 percent allocation method. While the 81 percent/19 percent allocation provides a shareholder return of $971 million, the 100 percent expense method provides a $1.13 billion return over the rate period. IS characterizes this $157 increment as a "shareholder windfall." To prevent this claimed shareholder "windfall," IS proposes an incremental ratemaking disallowance to mitigate this result under the 100 percent expense method.

4.4. Penalty Shall Be Applied First and Allocated 81 Percent to Capital

We conclude that the allocation of the $850 million penalty between expense (19 percent) versus capital expenditures (81 percent), as previously adopted in D.15-04-024, is reasonable for purposes of finalizing the 2015 - 2018 GT&S revenue requirements. Further, we conclude that the sequencing of the $850 million penalty before the five-month *ex parte* disallowance, as previously adopted in D.16-06-056, is appropriate. The resulting revenue requirements and rate impacts are appended to this decision.

Allocating the penalty 81 percent to capital and 19 percent to expense provides the greatest long-term benefit to ratepayers, as noted by TURN and ORA. This higher net present value of ratepayer benefits is a key factor in our analysis. Some parties correctly observe that the net present value benefit is not quantified in the record of this proceeding. Different assumptions could be made for various relevant factors to do this calculation (e.g., PG&E's future costs of capital, ratepayers' risk-adjusted discount rates). However, any reasonable assessment of these values would lead to a conclusion that ratepayers receive a net present value benefit from this allocation relative to a 100 percent expense allocation. Thus, we agree with TURN and ORA.

We decline to adopt proposals to apply 100 percent of the $850 million penalty as an offset to expenses. Applying a 100 percent expense allocation would not be consistent with D.15-04-024 in which we stated that the majority of the funds to be spent on pipeline safety were to be capital expenditures.[12] By simply allocating 100 percent of the $850 million penalty to current expense, there would be no continuing benefits to ratepayers in subsequent years. By contrast, an investment in long-term capital spending will provide benefits to ratepayers for years to come, continuing through the useful lives of the resulting facilities.

Instead of framing their proposals within a long-term perspective, the arguments of the industrial customers advocating a 100 percent expense allocation focus on temporary mitigation of what they characterize as rate shock. We recognize the concerns expressed with the level of rate increases adopted in D.16-06-056. We also note that the percentage increases faced by non-core customers for gas transportation cost is relatively higher than the levels faced by core customer classes and that the percentage increase varies considerably across customer categories. However, Tables J-2 and J-3 of D.16-06-056 show that, factoring in an estimate of the gas commodity cost, the magnitude of rate shock is smaller.

We conclude, however, that the proposal to apply 100 percent of the penalty to offset safety-related expenses is not an appropriate remedy when

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[12] D. 15-04-024 at 94.

viewed in the larger context of all ratepayers' welfare over the long run. Under the industrial customers' position, current rate levels would be temporarily lowered by allocating 100 percent of the penalty to offset expenses. Yet, by exhausting 100 percent of the penalty funds during the current rate cycle, effects of rate increases from D.16-06-056 are not eliminated, but are merely shifted to a later cycle. The impact of future "rate shock" is not obviously and significantly preferable to current rate increases.

IS also argues that any long-term benefits would accrue to future ratepayers who do not experience the substantial rate increases resulting from this GT&S rate cycle. While it is correct that future ratepayers do not experience rate levels borne by current customers, such an observation offers no basis as to how to allocate the $850 million across time periods. Both current and future customers bear their own respective share of costs based on factual conditions, ratemaking principles and costs of service that apply at each respective time. The level of rates facing current ratepayers does not give them an inherently stronger claim to the benefits of the $850 million penalty offset as compared to future ratepayers. Determinations of how to allocate the $850 million penalty across rate cycles is not a function simply of the rate levels that otherwise rightfully apply across rate cycles.

We conclude that over the long term, moreover, ratepayers as a whole are more likely to realize lower rates on a net present value basis under the 19 percent/81 percent allocation rather than by exhausting 100 percent of the penalty during the current rate cycle. The method that maximizes ratepayer benefits over the long term is preferable to one focusing solely on short-term advantages. In assessing net present value benefits to ratepayers relating to these future savings, their value would depend on the discount rate available to the average ratepayer. The discount rate faced by individual ratepayers no doubt varies, and in particular, residential ratepayers may face different discount rates than do industrial customers, for example. Even though no party has precisely calculated the net present value benefits, however, we conclude that ratepayers generally benefit from a capital cost offset by avoiding future revenue requirements to cover the related depreciation charges as well as the cost of capital and related tax obligations for equity portion of the investment.

We find no error in the sequence adopted in D.16-06-056 for calculating the *ex parte* disallowance. As explained in D.16-06-056, while a lower revenue requirement would result in a lower *ex parte* disallowance, the $850 million penalty must be applied first. The incremental revenues that PG&E is authorized to collect over the five-month delay period cannot be determined until the safety-related programs and projects costs are deducted from the otherwise authorized revenue requirement. The applicable offset for the $850 million penalty must, therefore, be determined to calculate what 5/12 of that incremental revenue requirement is.

Assuming the $850 million were allocated 100 percent to expense, the reduction for 2015 would result in no incremental revenues in 2015. In that case, ratepayers would thus not be exposed to higher rates as a result of the delay, and there would be no need for an *ex parte* disallowance to compensate customers for the delay. Since we are adopting an 81 percent/19 percent allocation, however, there will be a positive *ex parte* disallowance.

The adopted revenue requirement must first be reduced by the $850 million penalty to determine what is to be collected from ratepayers. The amount to be collected is then allocated so that five months of the incremental

2015 revenue requirement would be absorbed by shareholders and only seven months' worth would be collected from ratepayers.

As explained in D. 16-06-056:

> "The ex parte disallowance simply reduces the amount of the authorized revenue requirement to be collected from ratepayers. This is true whether the $850 million San Bruno penalty is allocated as part of this Decision or in a separate decision. More importantly, a final decision in this case cannot be rendered until after the $850 San Bruno penalty is applied. Thus, applying the ex parte disallowance prior to applying the San Bruno penalty would be contrary to the Ex Parte Sanctions Decision.
>
> Based on the above, the proper sequence for applying the penalties is to first reduce the adopted revenue requirement by the $850 million San Bruno penalty to determine the final revenue requirement to be collected from ratepayers. The ex parte disallowance would then be applied so that five-twelfths of the 2015 incremental increase is collected from PG&E shareholders. In this Decision, we have included a placeholder for the ex parte disallowance. However, as the revenue requirement adopted in this Decision will be reduced with the allocation of the $850 million San Bruno penalty, the ex parte disallowance will be adjusted at the time that final decision issued."[13]

As noted by PG&E, the *ex parte* disallowance is a ratemaking reparation to compensate ratepayers for any negative impacts resulting from the delay in this proceeding caused by PG&E's improper *ex parte* communications. The *ex parte* disallowance was intended to hold ratepayers harmless for five months of the delay attributable to PG&E's conduct. The disallowance, therefore, was "to be calculated based on the maximum of all authorized revenues that would have

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[13] D.16-06-056 at 405-406.

been amortized (collected from) ratepayers during the period of delay (currently believed to be five months.)"[14]

As described in D.15-04-024, PG&E shall track both the expense and capital components of the $850 million penalty in sub-accounts of the SFGTSA. As we noted, PG&E shall track its expense and capital expenditures as debits in this account, up to the lesser of (i) the amount authorized (including any contingency) or (ii) the amount actually expended.

5. Correcting a Technical Error in D.16-06-056

In D.16-06-056, we discussed hydrostatic station testing. Our discussion clearly and correctly indicated our intent to defer consideration of the entire program to a later reasonableness review. Accordingly, we held that the entire program would be excluded from rates and tracked in a memorandum account.[15] However, in the appendices to the decision, one component of the program, Compression and Processing ($455,000, 2015$), was incorrectly included in rates for 2015 and tracked in a balancing account. As an expense item, this amount was escalated for 2016, 2017, and 2018.[16] PG&E has implemented the Hydrostatic Station Testing Memorandum Account (HSTMA) in Advice Letter 3733-G, filed July 8, 2016, and included the $455,000 and associated escalated amounts in rates.

In order to correct this error, PG&E shall revise the HSTMA to remove the Hydrostatic Station Testing Compression and Processing (HSTCP) amounts from rates and include the entire Hydrostatic Station Testing program in the HSTMA.

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[14] D.15-06-035 at 10.

[15] D.16-06-056 at 135-136.

[16] D.16-06-056, Appendix I, Table 3.

6. Results of Operations (RO) Modeling

We adopt revised GT&S revenue requirements and related tariff rate revisions as set forth in the appendices to incorporate the adopted penalty offset approach as discussed above. The adopted revenue requirements reflect RO modeling adjustments to ensure that the reduction to rate base excludes the appropriate amounts consistent with the intent of D.15-04-024. In view of the unusual nature of the penalty offset procedure that we adopt, a workshop was held on September 26, 2016 for parties to offer input on the appropriate RO modeling procedures to implement the necessary revenue requirements adjustments. The primary technical RO modeling issue discussed at the September 26, 2016 workshop was how or if certain ratemaking items (e.g., retirements, working cash, deferred tax, depreciation expense, and net salvage) are related to the capital portion of the penalty. However, a related material policy issue arose at the workshop. Parties disagreed about the intent of the Commission in D.15-04-024 about how the capital portion of the penalty should be applied. Workshop participants acknowledged that the situation of a penalty applied to capital expenditures is unusual.

The illustrative results provided by the Energy Division apply the $688.5 million capital penalty as a reduction to gross additions to plant in service. Other factors that change as a function of plant in service (e.g., depreciation expense, working cash, etc.) are calculated dynamically in the RO model. For example, a change in the amount of plant in service automatically changes the calculated amount of plant-related elements such as depreciation expense. The RO model calculation of depreciation includes a provision for salvage value net of removal costs, estimated to be incurred once the plant in service is retired. As a result, by changing the plant in service amount, the RO model dynamically calculates resulting changes in depreciation, including net salvage. Notably, Energy Division calculates a $54.5 million increase in net salvage (an element of the depreciation reserve) as a result of this application of the penalty. Generally, net salvage is negative because cost of removal exceeds gross proceeds from salvage. The increase in net salvage can be thought of as lower future costs of removal because for ratemaking purposes, "a project" is not implemented. Energy Division's illustrative results show a $676.5 million reduction in rate base due to the application of the capital penalty. The $12 million difference between the rate base reduction and the penalty amount is calculated as follows:

Rate Base Changes Net of Gross Additions:	
59,820	Negative Line 3 (Retirements)
(59,820)	Negative Line 23 (Retirements)
(7,092)	Positive Line 9 (Working Cash)
60,994	Negative Line 20 (Deferred Tax)
12,689	Negative Line 22 (Dep. Exp.)
(54,544)	Negative Line 24 (Net Salvage)
12,048	Sum of above

PG&E contends that the penalty should be applied to capital expenditures, which PG&E interprets as a combination of gross additions and net salvage. Based on this interpretation, PG&E argues that the Energy Division's illustrative results inappropriately lead to a total capital penalty of $743.0 million (= $688.5 million of gross additions + $54.5 million of net salvage). PG&E proposes two alternative approaches to implement its position. In PG&E's first approach, PG&E applied 4.62 percent[17] of the $688.5 million penalty as net

[17] Based on workpapers indicating that this is a typical ratio.

salvage[18] and the remainder as gross additions. Using this approach, PG&E calculates a rate base reduction of $628.1 million. In PG&E's second approach, PG&E applied the entire $688.5 million as a reduction to gross additions. Under the second approach, PG&E calculates a rate base reduction of $637.0 million. In each of PG&E's approaches, the remaining factors were not calculated dynamically by the RO model, but were instead approximated. Some factors (e.g., depreciation expense) were approximated using typical ratios; other factors (e.g., working cash) were taken directly from Energy Division's illustrative results.

TURN contends that the intent of the Commission in D.15-04-024 is that the entire amount of the capital penalty be removed from rate base. Accordingly, TURN presented illustrative numbers showing adjustments for return, depreciation, and taxes so that the full $688.5 million is deducted from rate base. Like PG&E, TURN's adjustments are approximated using a combination of ratios and copying from Energy Division's illustrative results. According to TURN's estimate, the revenue requirement difference relative to Energy Division's illustrative results is less than $2 million per year.

As stated by parties at the workshop, this is a novel situation. It appears that few, if any, parties clearly considered or understood the fine details of the application of the capital penalty in the RO model prior to our decision setting the penalty in D.15-04-024. As a result, we must now clarify our intent in D.15-04-024. In that decision, we repeatedly framed the penalty in terms of

[18] In the workshop transcript, PG&E refers to cost of removal rather than net salvage. These terms only differ by the gross salvage amount, which may be small relative to the cost of removal. In workshop discussion, parties generally used the terms interchangeably. In order to be consistent, we refer to net salvage in our discussion in this decision.

"capital expenditures" without defining that term.[19] However, we also discussed the penalty in terms of "rate base"[20] and as "plant,"[21] again, without defining these terms. Further, we clearly stated our intent that PG&E would not earn depreciation or rate of return on the capital penalty.[22]

We find TURN's interpretation is most consistent with our discussion of the penalty in terms of rate base. The language of D.15-04-024 indicates our expectation that the entire penalty amount would be removed from rate base, particularly: "the amounts of capital expenditures to be funded by shareholders shall be excluded from PG&E'S rate base to be determined in A.13-12-012 and in all PG&E proceedings thereafter."[23] We find that by simply relying on the default RO model dynamic calculations and the underlying assumptions, the result would be to lessen the impact of capital penalty on rate base and future revenue requirements relative to our intent in D.15-04-024. Therefore, as a policy matter, we require that the rate base reduction due to application of the penalty equal $688.5 million. Energy Division's illustrative results indicate that this can be achieved by the end of 2016. This leaves the technical matter of how to accomplish this goal.

TURN's approach applies the difference between the rate base adjustment and the capital penalty demonstrated in Energy Division's illustrative results as a further adjustment to rate base. Thus, TURN implicitly relies on the dynamic

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[19] *See*, e.g. D.15-04-024 at 95, 97, 98, and 222.

[20] *See*, e.g. D.15-04-024 at 95, 98, and 99.

[21] *See*, e.g. D.15-04-024 at 97, 98, 99, and 223.

[22] *See*, e.g. D.15-04-024 at 98, 99, and 222.

[23] D.15-04-024 at 95.

calculations of the RO model. TURN makes the adjustment to Energy Division's results on a prorated basis according to the amount of the penalty applied in 2015 and 2016. TURN acknowledges that its approach relies on certain simplifications (e.g., assuming an imputed depreciation expense rate).

However, in another circumstance, we have made an adjustment to rate base as a direct line-item adjustment independent of other factors.[24] This simple approach is consistent with our intent in D.15-04-024 and is appropriate here. We will adopt rate base adjustments applied in 2015 and 2016, prorated based on the Energy Division's illustrative results. D.15-04-024 adopted detailed accounting and tracking requirements relating to the capital portion of the $850 million penalty. Those requirements apply in tracking the implementation of the revenue requirements adjustments made pursuant to this decision. These adjustments will be accounted for in accordance with those tracking requirements the assets funded through the capital portion of the penalty (*see* Appendix A). The weighted-average expected life of these assets is 58 years.[25] Revenue-dependent ratemaking items (e.g., income taxes, franchise fees) are calculated dynamically after the rate base offset is applied. However, rate base components (e.g., working cash) are calculated before the rate base offset is applied and are not impacted by the application of the rate base offset (i.e., they are not dynamically calculated). The applied rate base offsets are summarized below:

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[24] *See*, D.15-11-021 at 455.

[25] *See* Appendix G, Table 4.

Year Applied	2015	2016	Total
Rate Base Offset ($ millions, end of year)	$379.325	$309.177	$688.502
Year Depreciation is Complete	2073	2074	

7. Update Transmission Integrity Management Program (TIMP) Balancing Account

D.16-06-056 created a TIMP Balancing Account with spending caps for certain categories. Many of the categories in the TIMP Balancing Account are partially funded by the capital portion of the penalty implemented by this decision. Accordingly, it is necessary to update the spending caps in the TIMP Balancing Account based on the amounts funded by the penalty. We direct PG&E to include this update in the advice letter implementing this decision.

8. Comments on Proposed Decision

The proposed decision of ALJ Kevin Dudney in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ______________, and reply comments were filed on ______________ by ____________________.

9. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Kevin Dudney is the assigned ALJ in this proceeding.

Findings of Fact

1. The uncontested list of safety-related capital and expense items included in PG&E's July 7, 2016 Opening Brief is reasonable for allocating and tracking PG&E's spending of the $850 million penalty adopted in D.15-04-024. This list of safety-related programs and projects is set forth in Appendices A and B.

2. An allocation of the $850 million penalty adopted in D.15-04-024, 19 percent to expense and 81 percent to capital expenditures, offers a higher net

present value benefit to ratepayers than would be achieved by a larger allocation to expense.

3. An allocation of the $850 million penalty adopted in D.15-04-024, 19 percent to expense and 81 percent to capital expenditures, is consistent with the policy objectives of D.15-04-024.

4. An allocation of the $850 million penalty adopted in D.15-04-024, 19 percent to expense and 81 percent to capital expenditures, is reasonable.

5. In the appendices to D.16-06-056, one component of the hydrostatic testing program, Compression and Processing ($455,000, 2015$), was incorrectly included in rates for 2015 and tracked in a balancing account. As an expense item, this amount was escalated for 2016, 2017, and 2018. PG&E has implemented the HSTMA in Advice Letter 3733-G, filed July 8, 2016, and included the $455,000 and associated escalated amounts in rates. In order to correct the error, the HSTMA must be revised to remove this component.

6. Relying on the default RO model dynamic calculations and the underlying assumptions would lessen the impact of capital penalty on rate base and future revenue requirements relative to our intent in D.15-04-024.

7. For consistency with D.15-04-024, the rate base reduction due to application of the penalty should equal $688.5 million.

8. Many of the categories in the TIMP Balancing Account are partially funded by the capital portion of the penalty implemented by this decision. Accordingly, it is necessary to update the spending caps in the TIMP Balancing Account based on the amounts funded by the penalty.

Conclusions of Law

1. The list of safety-related programs and projects set forth in Appendices A and B should be adopted for purposes of identifying and tracking PG&E's expenditures relating to the $850 million adopted in D.15-04-024.

2. The $850 million penalty adopted in D.15-04-024 should be applied to the safety-related programs identified in Appendices A and B, 19 percent to expense and
81 percent to capital expenditures.

3. PG&E should be required to revise the HSTMA to remove the HSTCP amounts from rates and include the entire Hydrostatic Station Testing program in the HSTMA.

4. PG&E should be required to update the spending caps in the TIMP Balancing Account to account for the amounts of the spending categories funded by the penalty implemented in this decision.

5. Since this decision authorizes a rate decrease 30 day notice before the effective date of the advice letters implementing this decision is not required by General Order 96-B, rule 4.2.

6. In order to give prompt effect to the rate reductions adopted herein, this decision should be effective today.

7. Application 13-12-012 and Investigation I.14-06-016 should be closed

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company shall adjust its rates and authorized ratemaking accounting mechanisms, as previously authorized in Decision (D.) 16-06-056, to apply over the remainder of this gas transmission and

storage rate case cycle through December 31, 2018, based upon the amounts set forth in Appendices C-J. The revised rates adopted herein represent a true up of the interim rates adopted in D.16-06-056, to reflect the offset of the $850 million penalty adopted in D.15-04-024, to be funded solely by shareholders and allocated 81 percent to capital expenditures and 19 percent to expenses. These offsets shall be tracked in the Shareholder-Funded Gas Transmission Safety Account adopted in D.15-04-024.

2. Pacific Gas and Electric Company shall file a Tier 2 advice letter in compliance with General Order 96-B within 10 days of the effective date of this decision to revise its tariffs to implement the rate adjustments adopted in this order. The advice letter shall revise the Hydrostatic Station Testing Memorandum Account previously approved in Advice Letter 3733-G to include the entire Hydrostatic Station Testing Program. The advice letter shall also update the spending caps in the Transmission Integrity Management Program Balancing Account to account for the amounts of the spending categories funded by the penalty implemented in this decision. The protest period for the advice letter shall be reduced, with protests due 10 days after the advice letter filing. The revised tariff sheets will become effective on January 1, 2017, subject to the Commission's Energy Division determining that they are in compliance with this order. No additional customer notice need be provided pursuant to General Rule 4.2 of General Order 96-B for this advice letter filing.

3. The list of safety-related programs and projects for capital and expense, as set forth in Appendices A and B are hereby adopted for purposes of identifying and tracking expenditures by Pacific Gas and Electric Company relating to its obligations to use the $850 million penalty for purposes of gas transmission pipeline safety enhancements, as directed by Decision (D.) 15-04-024. These

Appendices supersedes Appendix G of D.16-06-056 (which previously set forth 2015 expenses and capital expenditures, and 2016 and 2017 expenses and capital additions for safety-related capital expenditures and expenses).

4. The Energy Division results of operations model and rates model, as well as the workpapers supporting the modeling used to produce the rates in the appendices of this Decision, are received into the record of this proceeding, and identified as Exhibit ALJ-3. Upon the issuance of this decision, the Energy Division will provide a copy of the models, as well as the workpapers supporting the modeling used to produce the rates to Pacific Gas and Electric Company (PG&E) and the Office of Ratepayer Advocates. Other parties to the proceeding seeking to obtain access to the models and workpapers must first enter into a non-disclosure agreement with PG&E, and then contact Energy Division to arrange to receive a copy.

5. Application 13-12-012 and Investigation 14-06-016 are closed.

This order is effective today.

Dated ____________________________, at San Francisco, California.

APPENDIX A

2015 GAS TRANSMISSION AND STORAGE RATE CASE SUMMARY OF CAPITAL PROGRAMS

PACIFIC GAS AND ELECTRIC COMPANY
2015 GAS TRANSMISSION AND STORAGE RATE CASE
SUMMARY OF CAPITAL PROGRAMS

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
1	4A	Transmission Pipe Integrity and Emergency Response Programs	ILI	Yes	Testing that assesses the integrity and safety of gas transmission pipelines.
2			Hydrostatic Testing	Yes	Testing that assesses the integrity and safety of gas transmission pipelines; also required to validate maximum allowable operating pressure of gas transmission pipelines.
3			Earthquake Fault Crossings	Yes	Fault Crossing Program mitigates the time independent threat of weather-related or outside forces for gas transmission pipelines. Mitigation includes pipe replacements, relocations, and other pipe enhancements.
4			Vintage Pipe Replacement	Yes	This program replaces transmission line pipe where the stable/resident threat associated with vintage fabrication and construction interacts with the threat of land movement.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
5			Geo-hazard Threat Identification	Yes	Geo-hazard identification and monitoring mitigates against the time independent threat of the weather-related outside forces for gas transmission pipelines. The program is intended to improve the accuracy of geo-hazard threat identification data needed for pipe replacement activities. It involves mitigation of geo-hazard threats through pipe replacements and/or relocations.
6			Valve Automation	Yes	Valve Automation program involves the installation of automated valves to address the risks associated with timely emergency response to pipeline ruptures. This results in enhancements to transmission lines to improve safety.
7			Inoperable and Hard to Operate Valves	Yes	The In-Operable and Hard-to-Operate Valves program mitigates the threat of inadequate emergency response by repairing or replacing valves on gas transmission pipelines.
8	4B	Transmission Pipe Engineering Programs	Class Location Program	Yes	The Class Location Program identifies locations on PG&E's pipelines that have changed class due to population density changes. Mitigation, including pipe replacement or hydrostatic testing, may be required to ensure safe operations.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
9			Water and Levee Crossing Program	Yes	The Water and Levee Crossing Program mitigates time independent threats and risks associated with transmission pipes in proximity of water and levee crossings. Mitigations such as pipe replacement or hydrostatic testing may be required to ensure safe operations.
10			Shallow Pipe Program	Yes	The Shallow Pipe Program identifies, prioritizes and mitigates locations where transmission pipeline has insufficient cover and is vulnerable to exposure from third parties. Mitigation may include pipe replacement, relocation, or addressing inadequate cover.
11			Gas Gathering Program	No	This program supports continued retirement of PG&E's gas gathering facilities. This was based on direction provided by the CPUC regarding concerns on reasonableness of the costs associated with gas gathering facilities. This program is focused on financial rather than safety considerations.
12			Work Requested by Others Program	No	The primary driver of WRO work is related to public improvement work (new construction for freeways, residential/commercial subdivisions) and not pipeline safety.
13	5	Asset Family - Storage	WELL- Storage Well Work	No	This program is focused on storage facilities, and has no direct impact on line pipe safety.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
14			WELL - Well Overflow Protection	No	This program is focused on storage facilities, and has no direct impact on line pipe safety.
15	6	Asset Family - Facilities	Burney K-2 Compressor Replacement	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
16			Los Medanos K-1 Compressor Replacement	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
17			Compressor Unit Control Replacements	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
18			Upgrade Station Controls	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
19			Emergency Shutdown System Upgrades	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
20			Rebuild Santa Rosa Compressor Station Electrical Substation	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
21			Upgrade Pleasant Creek Processing Equipment	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
22			GT Electrical Upgrades - Hinkley and Topock Compressor Stations	No	This program is focused on station facilities, and has no direct impact on line pipe safety.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
23			GT Electrical Upgrades - Compressor Stations (excludes Hinkley, Topock)	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
24			Physical Security	No	This program includes projects to enhance security measures at critical facilities that impact line pipe safety and protect employees, contractors and the public, but does not meet the safety-related definition.
25			Hinkley Compressor Unit Retrofit Project	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
26			Install Active Fire Suppression Systems	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
27			Routine Capital Spending - C&P	~~Yes~~ <u>No</u>	Typical projects include repair or replacement of failed or malfunctioning equipment and instrumentation including station valves and actuators and other components needed for transmission pipe overpressure protection to ensure the safe operation of transmission line pipe<u>, but primarily relate to compression assets</u>.
28			Perform Simple Station Rebuilds	No	This program is focused on station facilities, and has no direct impact on line pipe safety.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
29			Perform Complex Station Rebuilds	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
30			Perform Transmission Terminal Upgrades	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
31			Gas Transmission SCADA Visibility	Yes	This program provides for additional pressure and flow measurement sensors that will be connected to PG&E's Gas Transmission SCADA system. This results in enhancements to transmission lines to improve safety.
32			Replace Obsolete Bristol Controllers	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
33			Replace Obsolete Limitorque Valve Actuators	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
34			Electric Upgrades Program	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
35			Becker System Upgrades	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
36			Biomethane Interconnects	No	Assembly Bill 1900, chaptered into law on September 27, 2012 (Chapter 602, Statutes of 2012), establishes a process to promote and facilitate the injection and use of biomethane into common carrier pipelines. Limited impact to GT pipeline safety.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
37			Routine Capital Spending - M&C	Yes	Typical projects include repair or replacement of failed or malfunctioning equipment and instrumentation including station valves and actuators and other components needed for transmission pipe overpressure protection to ensure the safe operation of transmission line pipe.
38			Bethany Unit Replacement	No	No forecast in Rate Case period
39			Gill Ranch	No	No forecast in Rate Case period
40			McDonald Island Processing Equipment Replacement	No	No forecast in Rate Case period
41			Prior Compression Replacement	No	No forecast in Rate Case period
42			Topock Install Suction Separation	No	No forecast in Rate Case period
43			Hinkley Install Suction Separation	No	No forecast in Rate Case period

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
44	7	Corrosion Control Program	CP Systems - Replace	Yes	Over time, CP systems (comprised of anodes and rectifiers) need to be replaced. Anodes deplete to a point at which they no longer provide adequate levels of protection to the pipeline. Rectifiers also degrade over time from environmental exposure. These replacements result in enhancements to transmission lines to maintain safety.
45			CP Systems - New	Yes	PG&E plans to install new CP systems on transmission pipelines where CP levels are determined to be inadequate. Inadequate CP can be caused by a variety of factors including coating deterioration, new pipeline construction, or interference from other direct current sources such as other underground utilities utilizing CP or transit systems like BART and MUNI. These installations result in enhancements to transmission lines to improve safety.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
46			Coupon Test Stations	Yes	Coupon Test Stations perform electrical measurement to determine the adequacy of cathodic protection. PG&E plans to install coupon test stations to monitor cathodic protection at approximately every mile along the transmission system. These installations result in enhancements to CP monitoring and testing capability for transmission lines to improve safety.
47			AC Interference Mitigation	Yes	External corrosion can be exacerbated by the presence of electrical interference. This can occur with the presence of AC interference. The AC interference mitigation program involves addressing transmission pipelines where this interference exists. These mitigation activities address this corrosion threat to transmission lines to improve safety.
48			DC Interference Mitigation	Yes	External corrosion can be exacerbated by the presence of electrical interference. This can occur with the presence of DC interference. The DC interference mitigation program involves addressing transmission pipelines where this interference exists. These mitigation activities address this corrosion threat to transmission lines to improve safety.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
49			Casings	Yes	Casings require both annual routine monitoring (a form of inspections) and mitigation as appropriate. These mitigation activities address corrosion threats to transmission lines to improve safety.
50			Internal Corrosion	Yes	The Internal Corrosion program mitigates the risk of internal corrosion through site-specific Internal Metal Loss Action Plans that contain internal corrosion control monitoring, testing and inspection requirements. This program includes installation of chemical injection pumps, Electron Microscopy coupon mounting devices, and permanently mounted Ultrasonic Thickness sensors, all of which address threats to the safety of PG&E's gas transmission line pipe.
51	9	Program Management Office	Program Management Office	Yes	Program covers the management of pipeline safety projects.
52	10	Gas System Operations	New Business	No	This program is focused on serving new load, and does not meet the safety-related definition.
53			Meter Sets - Power Plant	No	This program is focused on serving new load, and does not meet the safety-related definition.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
54			Capacity (NOP Program)	Yes	In order to minimize instances of incidental over-pressurizations, PG&E is programmatically lowering its regulator and overpressure protection set points through the NOP program and must, in some cases, complete capacity additions in order to maintain the ability to serve firm customers during extreme weather events. This category only includes the NOP program, not other capacity programs.
55	11	Information Technology	Gas Transmission IT Projects	No	These IT projects have no direct impact on line pipe safety.
56	12	Other GT&S Support Plans	Tools and Equipment	No	This program includes costs related to purchasing tools and equipment. This program has no direct impact on line pipe safety.
57			Manage Buildings	No	This program includes office facilities and yards. This program has no direct impact on line pipe safety.

(END OF APPENDIX A)

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
33			Cathodic Protection Troubleshooting	Yes	Work in this program includes the identification and analysis of any deficiencies indicated by CP monitoring. Low reads are often caused by CP system failure or a pipeline coming in physical contact with foreign metallic objects, which can result in leaks in gas transmission pipelines.
34			CP Corrective Maintenance	Yes	Work in this program includes remedial action to correct any deficiencies indicated by CP monitoring. Low reads are often caused by CP system failure or a pipeline coming in physical contact with foreign metallic objects, which can result in leaks in gas transmission pipelines.
35			Corrosion Investigations	Yes	In addition to the routine CP Monitoring performed each year PG&E also performs non-routine testing. Examples of non-routine testing include pipe-to-soil reads conducted during transmission leak repairs and direct examinations.
36			Close Interval Survey	Yes	CIS is an inspection method for determining the adequacy of cathodic protection between the monitoring points on gas transmission pipelines.

APPENDIX B

PACIFIC GAS AND ELECTRIC COMPANY
2015 GAS TRANSMISSION AND STORAGE
RATE CASE SUMMARY OF EXPENSE PROGRAM

PACIFIC GAS AND ELECTRIC COMPANY
2015 GAS TRANSMISSION AND STORAGE RATE CASE
SUMMARY OF EXPENSE PROGRAMS

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
1	4A	Transmission Pipe Integrity and Emergency Response Programs	ILI	Yes	Testing that assesses the integrity and safety of gas transmission pipelines.
2			Direct Assessment	Yes	Testing that assesses the integrity and safety of gas transmission pipelines.
3			Hydrostatic Testing	Yes	Testing that assesses the integrity and safety of gas transmission pipelines; also required to validate maximum allowable operating pressure of gas transmission pipelines.
4			Earthquake Fault Crossings	Yes	Fault Crossing Program mitigates the time independent threat of weather-related or outside forces for gas transmission pipelines. Mitigation includes pipe replacements, relocations, and other pipe enhancements.
5			Geo-Hazard Threat Identification	Yes	Geo-hazard identification and monitoring mitigates against the time independent threat of the weather-related outside forces for gas transmission pipelines. The program is intended to improve the accuracy of geo-hazard threat identification data needed for pipe replacement activities.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
6			Programs to Enhance Integrity Management	Yes	Root Cause Analysis (RCA) and Risk Analysis support the analysis and mitigation determination of the ASME B31.8S threats related to gas transmission pipelines.
7			Public Awareness	No	The Public Awareness Program mitigates the threat of inadequate emergency response related to gas transmission pipelines but does not meet the definition of "safety-related."
8			Inoperable and Hard to Operate Valves	Yes	The In-Operable and Hard-to-Operate Valves program mitigates the threat of inadequate emergency response by repairing or replacing valves on gas transmission pipelines.
9	4B	Transmission Pipe Engineering Programs	Class Location Program	Yes	The Class Location Program identifies locations on PG&E's pipelines that have changed class due to population density changes. Mitigations such as pipe replacement or hydrostatic testing, may be required to ensure safe operations.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
10			Water and Levee Crossing	Yes	The Water and Levee Crossing Program mitigates time independent threats and risks associated with transmission pipes in proximity of water and levee crossings. Mitigation, such as pipe replacement or hydrostatic testing, may be required to ensure safe operations.
11			Shallow Pipe Program	Yes	The Shallow Pipe Program identifies, prioritizes and mitigates locations where transmission pipeline has insufficient cover and is vulnerable to exposure from third parties. Mitigation may include pipe replacement, relocation, or addressing inadequate cover.
12			Gas Gathering Program	No	This program supports continued retirement of PG&E's gas gathering facilities. This was based on direction provided by the CPUC regarding concerns on reasonableness of the costs associated with gas gathering facilities. This program is focused on financial rather than safety considerations.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
13			Work Requested by Others Program	No	The primary driver of WRO work is related to public improvement work (new construction for freeways, residential/commercial subdivisions) and not pipeline safety.
14	5	Asset Family - Storage	WELL - GRN Surveys	No	This program is focused on storage facilities, and has no direct impact on line pipe safety.
15			WELL - Noise/Temperature Surveys	No	This program is focused on storage facilities, and has no direct impact on line pipe safety.
16			WELL - Casing Inspection Surveys	No	This program is focused on storage facilities, and has no direct impact on line pipe safety.
17			WELL - Other	No	This program is focused on storage facilities, and has no direct impact on line pipe safety.
18	6	Asset Family - Facilities	Routine Spend C&P	~~Yes~~ <u>No</u>	Typical projects include repair or replacement of failed or malfunctioning equipment and instrumentation including station valves and actuators and other components needed for transmission pipe overpressure protection to ensure the safe operation of transmission line pipe<u>, but primarily relate to compression assets</u>.
19			Critical Documents	No	This program is focused on station facilities, and has no direct impact on line pipe safety.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
20			Physical Security	No	This program includes projects to enhance security measures at critical facilities that impact line pipe safety and protect employees, contractors and the public, but does not meet the safety-related definition.
21			Gill Ranch Operating and Maintenance Costs	No	This program provides funding for operating and maintenance expenses related to the operation of the Gill Ranch Storage Facility. No impact to gas transmission line pipe.
22			Hydrostatic Testing C&P	Yes	Program includes hydrostatic testing of compression and processing facility piping. Many of these facilities impact pressures on the transmission pipelines, and failures could potentially cause over pressure events.
23			Engineering Critical Assessment Phase 2	Yes	The ECA Phase 2 program includes non-destructive mitigation testing activities on station facilities including station piping to avoid or limit system outages, while providing the desired reduction of operational and safety risk.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
24			Routine Spend M&C	Yes	Typical projects include repair or replacement of failed or malfunctioning equipment and instrumentation including station valves and actuators and other components needed for transmission pipe overpressure protection to ensure the safe operation of transmission line pipe.
25			Data Acquisition and Metric Development	No	This program is focused on station facilities that have no direct impact on line pipe safety.
26			Gas Quality Practices Assessment	No	This program is primarily in place for odorization of gas and BTU control for billing. It also includes monitoring, analyzing, and preventing liquid intrusion and sulfur buildup in the pipeline system, but no significant safety impact to the gas transmission pipelines.
27			Hydrostatic Testing M&C	Yes	Program includes hydrotesting of station piping. Many of these stations are pressure limiting or regulating stations that are part of the transmission line and failures could potentially cause over pressure events in the transmission pipelines.
28			Engineering Critical Assessment Phase 1	Yes	Identification and assessment of discrepancies using records containing manufacturing data and operating specifications for the piping within C&P and M&C stations.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
29			Becker Upgrade	No	This program is focused on station facilities that have no direct impact on line pipe safety.
30	7	Corrosion Control	Cathodic Protection Rectifier	Yes	Program includes monitoring of CP rectifiers for transmission assets (a form of safety inspections), including backbone and local pipelines, to ensure they are providing adequate electrical current to prevent corrosion, which can ultimately lead to leaks.
31			Cathodic Protection Monitoring	Yes	Program involves CP monitoring of Transmission assets (a form of safety inspections), including transmission pipe, to evaluate the effectiveness of the CP system by conducting voltage readings which helps ensure adequate protection against corrosion related impacts to the assets.
32			Cathodic Protection Resurvey	Yes	Program includes an evaluation of leak history, field current measurement and documentation updates (a form of safety inspections) to ensure that CP systems are operating effectively, thereby protecting assets including gas transmission pipelines, from corrosion related threats.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
33			Cathodic Protection Troubleshooting	Yes	Work in this program includes the identification and analysis of any deficiencies indicated by CP monitoring. Low reads are often caused by CP system failure or a pipeline coming in physical contact with foreign metallic objects, which can result in leaks in gas transmission pipelines.
34			CP Corrective Maintenance	Yes	Work in this program includes remedial action to correct any deficiencies indicated by CP monitoring. Low reads are often caused by CP system failure or a pipeline coming in physical contact with foreign metallic objects, which can result in leaks in gas transmission pipelines.
35			Corrosion Investigations	Yes	In addition to the routine CP Monitoring performed each year PG&E also performs non-routine testing. Examples of non-routine testing include pipe-to-soil reads conducted during transmission leak repairs and direct examinations.
36			Close Interval Survey	Yes	CIS is an inspection method for determining the adequacy of cathodic protection between the monitoring points on gas transmission pipelines.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
37			AC Interference	Yes	External corrosion can be exacerbated by the presence of electrical interference. This can occur with the presence of AC interference. The AC interference program involves the inspection of transmission pipelines where this interference exists, and the identification of appropriate mitigation.
38			DC Interference	Yes	External corrosion can be exacerbated by the presence of electrical interference. This can occur with the presence of DC interference. The DC interference program involves the inspection of transmission pipelines where this interference exists, and the identification of appropriate mitigation.
39			Casings	Yes	Casings require both annual routine monitoring (a form of inspections) and mitigation as appropriate.
40			Internal Corrosion	Yes	The Internal Corrosion program mitigates the risk of internal corrosion through site-specific Internal Metal Loss Action Plans that contain internal corrosion control monitoring, testing and inspection requirements.
41			Atmospheric Corrosion Inspection and Remediation	Yes	The Atmospheric Corrosion Inspection and Remediation program includes both the inspection for and mitigation of atmospheric corrosion.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
42	8	Gas Transmission Systems Maintenance and Operations	Locate and Mark	Yes	Locate and Mark is required as part of the PG&E Damage Prevention Program. This program is intended to prevent excavation damage by third-party contractors, PG&E construction crews, or others from causing damage to the PG&E transmission pipeline assets.
43			Pipeline Maintenance	Yes	Includes Leak Survey, Leak Repairs, Leak Rechecks, Ground Patrols, Aerial Patrols, Vegetation Management, Pipeline Markers, and other inspection activities.
44			Station Maintenance	No	This program is focused on station facilities that have no direct impact on line pipe safety.
45			Expense Projects	Yes	Expense Projects include gas transmission pipeline repairs including leak, corrosion, weld repairs, right-of-way (erosion) and paint/coatings.
46			StanPac	No	This program is focused on Stanpac facilities, and has no direct impact on line pipe safety.
47	9	Program Management Office	Program Management Office	Yes	Program covers the management of pipeline safety repair/replacement projects.
48	10	Gas System Operations	Gas System Operations	No	This program is focused on gas operations staff, and does not meet the safety-related definition.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
49			Marketing/Sales Strategy	No	This program is focused on gas operations staff, and does not meet the safety-related definition.
50			Compressor Fuel and Power	No	This program is focused on station facilities, and has no direct impact on line pipe safety.
51			Greenhouse Gas Compliance Instruments	No	PG&E requests that it be authorized to recover the cost of compliance instruments (allowances and offsets) it procures to satisfy obligations incurred by any of its gas transmission and storage facilities under the cap-and-trade program instituted by AB 32, the California Global Warming Solutions Act of 2006 (AB 32). This program has no direct impact on line pipe safety.
52	11	Information Technology	Gas Transmission Information Technology Expense	No	These IT projects have no direct impact on line pipe safety.
53	12	Other GT&S Support Plans	Support	No	This program captures building expenses and the forecast for the Process Safety organization. This program has no direct impact on line pipe safety.
54			Environmental Operations	No	This program captures the costs to coordinate PG&E's management of hazardous materials, including remediation. This program has no direct impact on line pipe safety.

Line Item	Chapter	Chapter Name	Program Name	Safety Related	Safety Rationale
55			Read & Investigate Meters	No	This program has no direct impact on line pipe safety.
56			Habitat and Species Protection	No	This program captures the costs to comply with regulations that protect endangered species and sensitive habitats. This program has no direct impact on line pipe safety.
57			Hazardous Waste Disposal & Transportation	No	This program captures the costs of disposing hazardous waste, universal waste, and other materials regulated as industrial wastes. This program has no direct impact on line pipe safety.
58			Manage Various Customer Care Processes	No	This program has no direct impact on line pipe safety.
59			Research and Development	No	This is the cost for projects that are included in PG&E's R&D and Innovation Program that are directly relevant to the GT&S activities. This program has no direct impact on line pipe safety.
60			Change/Maintain Used Gas Meters	No	This program has no direct impact on line pipe safety.

(END OF APPENDIX B)

APPENDIX C

SUMMARY OF RESULTS OF OPERATIONS - TEST YEAR 2015

APPENDIX C

Pacific Gas and Electric Company

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Summary of Results of Operations - Test Year 2015

TABLE INDEX

APPENDIX C: Table 1 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S) - Position Summary
Results of Operations Summary of Adopted over Authorized Gas Accord V
Results of Operations - Test Year 2015
(Thousands of Dollars)

			PG&E Application Testimony Exhibit (PG&E-2)		Adopted		
Line No.	Description	2014 Authorized [1]	2015 Proposed [2]	Difference from Authorized	2015	Difference from Authorized	Line No.
		(a)	(b)	(c)=(b)-(a)	(d)	(e)=(d)-(a)	
	REVENUE:						
1	Revenue Collected in Rates	731,125	1,286,329	555,203	886,917	155,791	1
2	Plus Other Operating Revenue	2,698	2,871	173	2,871	173	2
3	Total Operating Revenue	733,823	1,289,200	555,377	889,788	155,965	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production	3,618	1,919	(1,699)	1,882	(1,736)	5
6	Storage	19,108	18,867	(242)	16,635	(2,474)	6
7	Transmission	169,766	582,904	413,137	451,283	281,517	7
8	Distribution	336	346	10	346	10	8
9	Customer Accounts	2,528	3,483	954	3,483	954	9
10	Uncollectibles	2,238	4,709	2,471	2,888	650	10
11	Customer Services	7,784	5,955	(1,829)	5,955	(1,829)	11
12	Administrative and General	41,273	70,243	28,970	66,612	25,339	12
13	Franchise Requirements	7,012	12,137	5,125	8,358	1,346	13
14	Amortization	-	-	-	-	-	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	10,611	-	(10,611)	(157,047)	(167,658)	17
18	Subtotal Expenses:	264,276	700,563	436,287	400,395	136,119	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	31,161	37,577	6,416	32,437	1,276	20
21	Payroll	5,327	12,333	7,006	10,906	5,579	21
22	Business	49	67	19	67	19	22
23	Other	212	162	(50)	162	(50)	23
24	State Corporation Franchise	9,789	4,477	(5,313)	3,452	(6,337)	24
25	Federal Income	74,433	96,141	21,708	77,896	3,463	25
26	Total Taxes	120,971	150,756	29,785	124,920	3,949	26
27	Depreciation	132,129	151,345	19,216	128,658	(3,470)	27
28	Fossil Decommissioning	-	-	-	-	-	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	517,376	1,002,664	485,288	653,974	136,598	30
31	Net for Return	216,490	286,536	70,047	235,814	19,325	31
	Adjustments to Revenue Requirement for Rate Design:						
32	Carrying Cost of Working Gas & Load Balancing Gas	3,584	566	(3,018)	566	(3,018)	32
33	Greenhouse Gas (GHG) Costs	4,268		(4,268)		(4,268)	33
34	Fractional first year Adder project not in rates	(1,462)		1,462		1,462	34
35	Adder projects not operative by EOY 2013	(22,136)		22,136		22,136	35
36	Subtotal Rate Design Adjustments:	(15,746)	566	16,311	566	16,311	36
37	Adjusted Revenue Requirement for Rate Design	715,380	1,286,895	571,515	887,482	172,103	37
37	Ex-parte penalty (5/12 of Difference in Column E)			-	(71,709)		37
38	Final adjusted Revenue Requirement for Rate Design	715,380	1,286,895	571,515	815,773	100,393	38
38	**Percentage Change From Authorized**			**79.9%**		**14.0%**	38

(1) Gas Accord V Decision 11-04-031 + PSEP Decision 12-12-030
(2) 2015 Gas Transmission & Storage Request + PSEP Update 13-10-017

APPENDIX C: Table 2 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Results of Operations Summary at Proposed (PG&E Brief) and Adopted - Test Year 2015
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	PG&E Brief (1)	D.16-06-056	Safety Program ($850 M Penalty) Adopted	Difference Adopted and D.16-06-056	Difference Adopted and PG&E Brief	Line No.
		(A)	(B)	(C)	(D)=(C)-(B)	(E)=(C)-(A)	
	REVENUE:						
1	Retail Revenue Collected in Rates	1,262,815	1,045,629	886,917	(158,713)	(375,899)	1
2	Plus Other Operating Revenue	2,871	2,871	2,871	0	0	2
3	Total Operating Revenue	1,265,687	1,048,501	889,788	(158,713)	(375,899)	3
	OPERATING EXPENSES:						
4	Energy Costs	0	0	0	0	0	4
5	Production / Procurement	1,919	1,882	1,882	(0)	(37)	5
6	Storage	18,640	16,687	16,635	(52)	(2,005)	6
7	Transmission	582,705	451,661	451,283	(378)	(131,421)	7
8	Distribution	346	346	346	0	0	8
9	Customer Accounts	3,483	3,483	3,483	0	0	9
10	Uncollectibles	4,681	3,403	2,888	(515)	(1,792)	10
11	Customer Services	5,955	5,955	5,955	0	0	11
12	Administrative and General	66,612	66,612	66,612	0	0	12
13	Franchise Requirements	11,883	9,849	8,358	(1,491)	(3,525)	13
14	Amortization	0	0	0	0	0	14
15	Wage Change Impacts	0	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	0	16
17	Other Adjustments	997	(777)	(157,047)	(156,269)	(158,044)	17
18	Subtotal Expenses:	697,220	559,101	400,395	(158,706)	(296,825)	18
	TAXES:						
19	Superfund	0	0	0	0	0	19
20	Property	37,672	32,437	32,437	0	(5,235)	20
21	Payroll	12,155	10,914	10,906	(8)	(1,249)	21
22	Business	67	67	67	0	0	22
23	Other	162	162	162	0	0	23
24	State Corporation Franchise	2,924	3,452	3,452	0	528	24
25	Federal Income	93,481	77,896	77,896	0	(15,585)	25
26	Total Taxes	146,461	124,928	124,920	(7)	(21,541)	26
27	Depreciation	143,665	128,658	128,658	0	(15,006)	27
28	Fossil Decommissioning	0	0	0	0	0	28
29	Nuclear Decommissioning	0	0	0	0	0	29
30	Total Operating Expenses	987,346	812,687	653,974	(158,713)	(333,372)	30
31	Net for Return	278,341	235,813	235,814	1	(42,526)	31
32	Rate Base	3,454,172	2,926,125	2,926,133	9	(528,039)	32
	RATE OF RETURN:						
33	On Rate Base	**8.06%**	**8.06%**	**8.06%**			33
34	On Equity	**10.40%**	**10.40%**	**10.40%**			34

(1) *PG&E Opening Brief* model at page 1-17. Further details shown in RO workpapers, Exhibit ALJ-1.

APPENDIX C: Table 3 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Income Taxes at Proposed and Adopted - Test Year 2015
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	PG&E Brief (1)	D.16-06-056	Safety Program ($850 M Penalty) Adopted	Difference Adopted and D.16-06-056	Difference Adopted and PG&E Brief	Line No.
		(A)	(B)	(C)	(D)=(C)-(B)	(E)=(C)-(A)	
1	Revenues	1,265,687	1,048,501	889,788	(158,713)	(375,899)	1
2	O&M Expenses	697,220	559,101	400,395	(158,706)	(296,825)	2
3	Nuclear Decommissioning Expense	0	0	0	0	0	3
4	Superfund Tax	0	0	0	0	0	4
5	Taxes Other Than Income	50,056	43,580	43,572	(8)	(6,484)	5
6	Subtotal	518,411	445,820	445,821	1	(72,590)	6
	DEDUCTIONS FROM TAXABLE INCOME:						
7	Interest Charges	89,615	75,915	75,916	0	(13,699)	7
8	Fiscal/Calendar Adjustment	1,753	196	196	0	(1,557)	8
9	Operating Expense Adjustments	(5,245)	(5,245)	(5,245)	0	0	9
10	Capitalized Interest Adjustment	0	0	0	0	0	10
11	Removal Costs	39,309	35,143	35,143	0	(4,166)	11
12	Vacation Accrual Reduction	(768)	(768)	(768)	0	0	12
13	Capitalized Other	8,725	8,725	8,725	0	0	13
14	Subtotal Deductions	133,389	113,966	113,966	0	(19,422)	14
	CCFT TAXES:						
15	State Operating Expense Adjustment	1,144	1,138	1,138	0	(7)	15
16	State Tax Depreciation - Declining Balance	0	0	0	0	0	16
17	State Tax Depreciation - Fixed Assets	289,454	236,675	236,675	0	(52,778)	17
18	State Tax Depreciation - Other	0	0	0	0	0	18
19	Capitalized Other	401	398	398	0	(2)	19
20	Repair Allowance	43,948	37,606	37,606	0	(6,342)	20
21	Subtotal Deductions	468,336	389,784	389,784	0	(78,551)	21
22	Taxable Income for CCFT	50,075	56,036	56,037	1	5,962	22
23	CCFT	4,427	4,954	4,954	0	527	23
24	State Tax Adjustment	0	0	0	0	0	24
25	Current CCFT	4,427	4,954	4,954	0	527	25
26	Deferred Taxes - Reg Asset	0	0	0	0	0	26
27	Deferred Taxes - Interest	101	101	101	0	(1)	27
28	Deferred Taxes - Vacation	(68)	(68)	(68)	0	0	28
29	Deferred Taxes - Other	0	0	0	0	0	29
30	Deferred Taxes - Fixed Assets	(1,536)	(1,534)	(1,534)	0	1	30
31	Total CCFT	2,924	3,452	3,452	0	528	31
	FEDERAL TAXES:						
32	CCFT - Prior Year	(31,832)	(24,085)	(24,085)	0	7,746	32
33	Federal Operating Expense Adjustment	397	393	393	0	(3)	33
34	Fed. Tax Depreciation - Declining Balance	0	0	0	0	0	34
35	Federal Tax Depreciation - SLRL	0	0	0	0	0	35
36	Federal Tax Depreciation - Fixed Assets	278,229	236,088	236,088	0	(42,141)	36
37	Federal Tax Depreciation - Other	0	0	0	0	0	37
38	Capitalized Other	401	398	398	0	(2)	38
39	Repair Allowance	43,948	37,606	37,606	0	(6,342)	39
40	Preferred Dividend Credit	49	49	49	0	(0)	40
41	Subtotal Deductions	424,581	364,416	364,416	0	(60,165)	41
42	Taxable Income for FIT	93,830	81,404	81,405	1	(12,425)	42
43	Federal Income Tax	32,841	28,492	28,492	0	(4,349)	43
44	Deferred Taxes - Reg Asset	0	0	0	0	0	44
45	Tax Effect of MTD & Prod Tax Credits	0	0	0	0	0	45
46	Deferred Taxes - Interest	139	138	138	0	(1)	46
47	Deferred Taxes - Vacation	(269)	(269)	(269)	0	0	47
48	Deferred Taxes - Other	0	0	0	0	0	48
49	Deferred Taxes - Fixed Assets	60,771	49,536	49,536	0	(11,235)	49
50	Total Federal Income Tax	93,481	77,896	77,896	0	(15,585)	50

(1) *PG&E Opening Brief* model at page 1-17. Further details shown in RO workpapers, Exhibit ALJ-1.

APPENDIX C: Table 4 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Ratebase at Proposed and Adopted - Test Year 2015
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	PG&E Brief (1)	D.16-06-056	Safety Program ($850 M Penalty) Adopted	Difference Adopted and D.16-06-056	Difference Adopted and PG&E Brief	Line No.
		(A)	(B)	(C)	(D)=(C)-(B)	(E)=(C)-(A)	
	WEIGHTED AVERAGE PLANT:						
1	Plant Beginning Of Year (BOY)	5,609,415	5,002,013	5,002,013	0	(607,402)	1
2	Net Additions	200,102	178,956	178,956	0	(21,146)	2
3	Total Weighted Average Plant	5,809,517	5,180,969	5,180,969	0	(628,548)	3
	WORKING CAPITAL:						
4	Material and Supplies - Fuel	0	0	0	0	0	4
5	Material and Supplies - Other	29,846	29,846	29,846	0	0	5
6	Working Cash	42,713	35,596	35,605	9	(7,108)	6
7	Total Working Capital	72,559	65,442	65,451	9	(7,108)	7
	ADJUSTMENTS FOR TAX REFORM ACT:						
8	Deferred Capitalized Interest	4,664	4,653	4,653	0	(11)	8
9	Deferred Vacation	11,535	11,533	11,533	0	(2)	9
10	Deferred CIAC Tax Effects	218	218	218	0	0	10
11	Total Adjustments	16,417	16,404	16,404	0	(13)	11
12	CUSTOMER ADVANCES	18,770	18,770	18,770	0	0	12
	DEFERRED TAXES						
13	Accumulated Regulatory Assets	0	0	0	0	0	13
14	Accumulated Fixed Assets	537,226	397,885	397,885	0	(139,341)	14
15	Accumulated Other	0	0	0	0	0	15
16	Deferred ITC	5,843	5,818	5,818	0	(25)	16
17	Deferred Tax - Other	0	0	0	0	0	17
18	Total Deferred Taxes	543,070	403,703	403,703	0	(139,366)	18
19	DEPRECIATION RESERVE	1,882,481	1,914,217	1,914,217	0	31,736	19
20	TOTAL Ratebase	3,454,172	2,926,125	2,926,133	9	(528,039)	20

(1) *PG&E Opening Brief* model at page 1-17. Further details shown in RO workpapers, Exhibit ALJ-1.

APPENDIX C: Table 5 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Results of Operations at Adopted by Unbundled Cost Category (UCC) - Test Year 2015
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	GT&S + PSEP Total Year 2015	Line No.
	REVENUE:														
1	Base Revenue Requirement	8,561	60,560	23,723	10,787	557,294	63,453	27,712	6,377	22,158	74,639	28,907	2,746	886,917	1
2	Plus Other Operating Revenue	0	0	0	0	763	777	0	0	0	1,332	0	0	2,871	2
3	Total Operating Revenue	8,561	60,560	23,723	10,787	558,056	64,230	27,712	6,377	22,158	75,971	28,907	2,746	889,788	3
	OPERATING EXPENSES:														
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	4
5	Gathering	110	111	52	19	1,238	21	58	4	29	212	28	0	1,882	5
6	Storage	137	8,075	3,230	230	3,984	66	186	12	95	528	92	0	16,635	6
7	Transmission	2,772	11,405	6,510	1,355	315,971	9,729	16,205	4,342	19,929	49,482	13,583	0	451,283	7
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	346	346	8
9	Customer Accounts	57	149	70	0	1,651	28	77	5	39	219	38	1,151	3,483	9
10	Uncollectibles	28	196	77	35	1,797	208	90	21	72	246	92	9	2,871	10
11	Customer Services	145	379	178	0	4,217	70	197	13	100	559	97	0	5,955	11
12	Administrative and General	1,629	4,242	1,990	0	47,176	785	2,196	145	1,117	6,248	1,085	0	66,612	12
13	Franchise Requirements	80	569	223	101	5,262	603	260	60	208	715	274	26	8,382	13
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	14
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0	16
17	Other Adjustments	(585)	(4,786)	(2,516)	0	(108,632)	(3,641)	(5,778)	(1,691)	(7,424)	(17,100)	(4,893)	0	(157,047)	17
18	Subtotal Expenses:	4,373	20,340	9,813	1,741	272,663	7,870	13,490	2,911	14,164	41,107	10,396	1,532	400,402	18
	TAXES:														
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0	19
20	Property	358	2,579	856	532	17,351	3,929	1,249	323	506	3,258	1,438	60	32,437	20
21	Payroll	105	329	229	27	6,362	212	441	132	747	1,640	629	52	10,906	21
22	Business	2	4	2	0	48	1	2	0	1	6	1	0	67	22
23	Other	4	10	5	0	114	2	5	0	3	15	3	0	162	23
24	State Corporation Franchise	(9)	1,079	305	346	732	2,217	(81)	2	(234)	(891)	(70)	54	3,451	24
25	Federal Income	357	6,599	2,313	1,769	53,050	8,742	1,336	384	233	619	2,542	(50)	77,894	25
26	Total Taxes	816	10,601	3,709	2,674	77,658	15,103	2,952	842	1,256	4,647	4,542	116	124,917	26
27	Depreciation	1,711	10,910	3,652	1,777	64,333	18,299	5,236	1,100	2,643	14,215	3,829	954	128,658	27
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	28
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	29
30	Total Operating Expenses	6,901	41,851	17,175	6,192	414,654	41,271	21,677	4,854	18,063	59,970	18,768	2,601	653,978	30
31	Net for Return	1,660	18,708	6,548	4,596	143,402	22,958	6,035	1,523	4,095	16,001	10,139	144	235,810	31
32	Rate Base	20,602	232,158	81,261	57,031	1,779,425	284,901	74,886	18,901	50,815	198,557	125,805	1,791	2,926,133	32
	RATE OF RETURN:														
33	On Rate Base	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	33
34	On Equity	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	34

APPENDIX C: Table 6 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Income Taxes Adopted by UCC - Test Year 2015
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	GT&S + PSEP Total Year 2015	
1	Revenues	8,561	60,560	23,723	10,787	558,056	64,230	27,712	6,377	22,158	75,971	28,907	2,746	889,788	1
2	O&M Expenses	4,373	20,340	9,813	1,741	272,663	7,870	13,490	2,911	14,164	41,107	10,396	1,532	400,402	2
3	Nuclear Decommissioning Expense	0	0	0	0	0	0	0	0	0	0	0	0	0	3
4	Superfund Tax	0	0	0	0	0	0	0	0	0	0	0	0	0	4
5	Taxes Other Than Income	469	2,922	1,092	558	23,876	4,144	1,697	456	1,257	4,919	2,071	112	43,572	5
6	Subtotal	3,719	37,297	12,818	8,488	261,518	52,216	12,525	3,010	6,737	29,944	16,440	1,102	445,814	6
	DEDUCTIONS FROM TAXABLE INCOME:														
7	Interest Charges	534	6,023	2,108	1,480	46,165	7,391	1,943	490	1,318	5,151	3,264	46	75,916	7
8	Fiscal/Calendar Adjustment	3	(15)	(8)	(6)	358	(87)	(19)	(3)	(5)	(33)	16	(5)	196	8
9	Operating Expense Adjustments	(98)	(272)	(125)	(4)	(2,839)	(1,262)	(131)	(9)	(67)	(374)	(65)	0	(5,245)	9
10	Capitalized Interest Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	10
11	Removal Costs	273	1,417	1,151	0	24,067	93	1,515	230	1,625	3,764	1,008	0	35,143	11
12	Vacation Accrual Reduction	(0)	(12)	(4)	(2)	(9)	(739)	(0)	(0)	(0)	(2)	(0)	0	(768)	12
13	Capitalized Other	213	556	261	0	6,179	103	288	19	146	818	142	0	8,725	13
14	Subtotal Deductions	925	7,698	3,383	1,468	73,922	5,499	3,595	728	3,018	9,325	4,365	42	113,966	14
	CCFT TAXES:														
15	State Operating Expense Adjustment	23	302	96	62	697	(481)	99	26	45	227	41	1	1,138	15
16	State Tax Depreciation - Declining Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	16
17	State Tax Depreciation - Fixed Assets	2,705	17,171	5,870	3,099	149,981	5,971	8,758	1,925	4,493	25,126	11,124	452	236,675	17
18	State Tax Depreciation - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	18
19	Capitalized Overhead	8	1	1	0	243	0	34	8	15	75	14	0	398	19
20	Repair Allowance	141	55	26	0	27,665	10	957	317	1,813	5,034	1,587	0	37,606	20
21	Subtotal Deductions	3,802	25,228	9,377	4,629	252,507	10,999	13,443	3,003	9,384	39,788	17,131	494	389,784	21
22	Taxable Income for CCFT	(82)	12,069	3,442	3,859	9,011	41,217	(918)	7	(2,647)	(9,844)	(691)	608	56,030	22
23	CCFT	(7)	1,067	304	341	797	3,644	(81)	1	(234)	(870)	(61)	54	4,953	23
24	State Tax Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	24
25	Current CCFT	(7)	1,067	304	341	797	3,644	(81)	1	(234)	(870)	(61)	54	4,953	25
26	Deferred Taxes - Reg Asset	0	0	0	0	0	0	0	0	0	0	0	0	0	26
27	Deferred Taxes - Interest	2	27	9	6	62	(43)	9	2	4	20	4	0	101	27
28	Deferred Taxes - Vacation	(0)	(1)	(0)	(0)	(1)	(65)	(0)	(0)	(0)	(0)	(0)	0	(68)	28
29	Deferred Taxes - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	29
30	Deferred Taxes - Fixed Assets	(4)	(13)	(7)	0	(125)	(1,319)	(8)	(0)	(4)	(40)	(13)	0	(1,534)	30
31	Total CCFT	(9)	1,079	305	346	732	2,217	(81)	2	(234)	(891)	(70)	54	3,451	31
	FEDERAL TAXES:														
32	CCFT - Prior Year	200	1,172	211	239	(34,037)	4,095	283	45	24	3,094	337	252	(24,085)	32
33	Federal Operating Expense Adjustment	12	234	74	49	353	(560)	52	15	24	121	22	0	393	33
34	Fed. Tax Depreciation - Declining Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	34
35	Federal Tax Depreciation - SLRL	0	0	0	0	0	0	0	0	0	0	0	0	0	35
36	Federal Tax Depreciation - Fixed Assets	1,861	12,704	5,034	1,727	156,434	8,244	6,389	1,569	5,753	24,045	12,011	318	236,088	36
37	Federal Tax Depreciation - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	37
38	Capitalized Overhead	8	1	1	0	243	0	34	8	15	75	14	0	398	38
39	Repair Allowance	141	55	26	0	27,665	10	957	317	1,813	5,034	1,587	0	37,606	39
40	Preferred Dividend Credit	1	1	0	0	29	0	4	1	2	9	2	0	49	40
41	Subtotal Deductions	3,148	21,865	8,729	3,483	224,608	17,288	11,313	2,682	10,648	41,704	18,338	612	364,416	41
42	Taxable Income for FIT	571	15,432	4,089	5,005	36,910	34,928	1,212	328	(3,911)	(11,759)	(1,898)	490	81,399	42
43	Federal Income Tax	200	5,401	1,431	1,752	12,918	12,225	424	115	(1,369)	(4,116)	(664)	172	28,489	43
44	Deferred Taxes - Reg Asset	0	0	0	0	0	0	0	0	0	0	0	0	0	44
45	Tax Effect of MTD & Prod Tax Credits	0	0	0	0	0	0	0	0	0	0	0	0	0	45
46	Deferred Taxes - Interest	4	82	26	17	124	(196)	18	5	8	42	8	0	138	46
47	Deferred Taxes - Vacation	(0)	(4)	(1)	(1)	(3)	(259)	(0)	(0)	(0)	(1)	(0)	0	(269)	47
48	Deferred Taxes - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	48
49	Deferred Taxes - Fixed Assets	153	1,120	857	1	40,011	(3,028)	893	264	1,594	4,693	3,198	(222)	49,536	49
50	Total Federal Income Tax	357	6,599	2,313	1,769	53,050	8,742	1,336	384	233	619	2,542	(50)	77,894	50

APPENDIX C: Table 7 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Rate Base Adopted by UCC - Test Year 2015
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	GT&S + PSEP Total Year 2015	Line No.
	WEIGHTED AVERAGE PLANT:														
1	Plant Beginning of Year	56,036	441,124	144,361	76,080	2,431,730	770,090	212,813	51,275	102,102	529,199	170,211	16,992	5,002,013	1
2	Net Additions	1,370	5,536	4,051	0	112,716	16,589	4,684	1,135	5,195	21,290	6,390	0	178,956	2
3	Total Weighted Average Plant	57,405	446,661	148,411	76,080	2,544,446	786,678	217,498	52,410	107,298	550,489	176,601	16,992	5,180,969	3
	WORKING CAPITAL:														
4	Material and Supplies - Fuel	0	0	0	0	0	0	0	0	0	0	0	0	0	4
5	Material and Supplies - Other	0	574	269	0	28,554	449	0	0	0	0	0	0	29,846	5
6	Working Cash	521	2,042	911	49	24,261	684	1,307	219	883	4,004	654	71	35,605	6
7	Total Working Capital	521	2,615	1,180	49	52,815	1,133	1,307	219	883	4,004	654	71	65,451	7
	ADJUSTMENTS FOR TAX REFORM ACT:														
8	Deferred Capitalized Interest	19	(33)	(10)	(6)	568	3,741	88	21	39	191	36	0	4,653	8
9	Deferred Vacation	4	173	57	33	130	11,098	6	0	3	25	3	0	11,533	9
10	Deferred CIAC Tax Effects	0	0	0	0	0	0	0	0	0	0	0	218	218	10
11	Total Adjustments	23	140	46	27	697	14,839	94	21	42	216	39	218	16,404	11
12	CUSTOMER ADVANCES	0	0	0	0	18,770	0	0	0	0	0	0	0	18,770	12
	DEFERRED TAXES														
13	Accumulated Regulatory Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	13
14	Accumulated Fixed Assets	6,112	33,838	9,943	8,292	159,628	94,398	22,224	5,202	4,406	41,979	11,455	409	397,885	14
15	Accumulated Other	0	0	0	0	0	0	0	0	0	0	0	0	0	15
16	Deferred ITC	97	656	219	126	2,993	10	381	84	171	889	157	35	5,818	16
17	Deferred Tax - Other	0	0	0	0	0	0	0	0	0	0	0	0	0	17
18	Total Deferred Taxes	6,210	34,494	10,162	8,417	162,621	94,408	22,605	5,287	4,576	42,868	11,612	444	403,703	18
19	DEPRECIATION RESERVE	31,138	182,764	58,215	10,708	637,143	423,342	121,407	28,462	52,831	313,284	39,877	15,046	1,914,217	19
20	TOTAL RATE BASE	20,602	232,158	81,261	57,031	1,779,425	284,901	74,886	18,901	50,815	198,557	125,805	1,791	2,926,133	20

APPENDIX C: Table 8 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Results of Operations at Adopted by UCC - Implementing Ex-parte Penalty Adjustment - Test Year 2015
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2015	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
	REVENUE:														
1	Base Revenue Requirement	7,869	55,663	21,805	9,915	512,235	58,322	25,471	5,861	20,366	68,605	26,569	2,524	815,207 (a)	1
2	Plus Other Operating Revenue	0	0	0	0	763	777	0	0	0	1,332	0	0	2,871	2
3	Total Operating Revenue	7,869	55,663	21,805	9,915	512,998	59,100	25,471	5,861	20,366	69,936	26,569	2,524	818,079	3
	OPERATING EXPENSES:														
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	4
5	Gathering	110	111	52	19	1,238	21	58	4	29	212	28	0	1,882	5
6	Storage	137	8,075	3,230	230	3,984	66	186	12	95	528	92	0	16,635	6
7	Transmission	2,772	11,405	6,510	1,355	315,971	9,729	16,205	4,342	19,929	49,482	13,583	0	451,283	7
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	346	346	8
9	Customer Accounts	57	149	70	0	1,651	28	77	5	39	219	38	1,151	3,483	9
10	Uncollectibles	26	180	71	32	1,651	192	83	19	66	226	84	8	2,638	10
11	Customer Services	145	379	178	0	4,217	70	197	13	100	559	97	0	5,955	11
12	Administrative and General	1,629	4,242	1,990	0	47,176	785	2,196	145	1,117	6,248	1,085	0	66,612	12
13	Franchise Requirements	74	523	205	93	4,838	555	239	55	191	658	252	24	7,708	13
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	14
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0	16
17	Other Adjustments	(1,269)	(9,621)	(4,409)	(861)	(153,119)	(8,706)	(7,990)	(2,200)	(9,193)	(23,058)	(7,201)	(219)	(227,846)	17
18	Subtotal Expenses:	3,681	15,444	7,895	868	227,606	2,740	11,250	2,396	12,373	35,073	8,059	1,310	328,696	18
	TAXES:														
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0	19
20	Property	358	2,579	856	532	17,351	3,929	1,249	323	506	3,258	1,438	60	32,437	20
21	Payroll	105	329	229	27	6,362	212	441	132	747	1,640	629	52	10,906	21
22	Business	2	4	2	0	48	1	2	0	1	6	1	0	67	22
23	Other	4	10	5	0	114	2	5	0	3	15	3	0	162	23
24	State Corporation Franchise	(9)	1,079	305	346	732	2,217	(81)	2	(234)	(891)	(70)	54	3,451	24
25	Federal Income	357	6,599	2,313	1,769	53,050	8,742	1,335	384	233	618	2,542	(50)	77,893	25
26	Total Taxes	816	10,601	3,709	2,674	77,658	15,103	2,952	842	1,256	4,647	4,542	116	124,916	26
27	Depreciation	1,711	10,910	3,652	1,777	64,333	18,299	5,236	1,100	2,643	14,215	3,829	954	128,658	27
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	28
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	29
30	Total Operating Expenses	6,209	36,955	15,257	5,319	369,597	36,141	19,437	4,338	16,271	53,935	16,431	2,379	582,270	30
31	Net for Return	1,660	18,708	6,548	4,596	143,401	22,958	6,035	1,523	4,095	16,001	10,139	144	235,808	31
32	Rate Base	20,601	232,156	81,260	57,031	1,779,408	284,899	74,885	18,901	50,814	198,555	125,804	1,791	2,926,106	32
	RATE OF RETURN:														
33	On Rate Base	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	33
34	On Equity	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	34

(a) Excludes Carrying Cost of Working Gas & Load Balancing Gas as shown on Appendix C: Table 1, Ln. 32.

(END OF APPENDIX C)

APPENDIX D

SUMMARY OF ADOPTED COSTS -
TEST YEAR 2015

APPENDIX D

Pacific Gas and Electric Company

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Summary of Adopted Costs - Test Year 2015

TABLE INDEX

APPENDIX D: Table 1 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Expenses Adopted by Program - Test Year 2015
(Thousands of Nominal Dollars)

Line	Exhibit (PG&E-1 & 2) Chapter	Chapter Name	Programs	Related MWC	2015 Forecast Exhibit PG&E-1	Stipulation and GRC Adj.	2015 Forecast PG&E Brief (1)	Adopted Adj.	2015 Adopted Forecast
1	4A	Transmission Pipe Integrity and Emergency Response Programs	ILI	HP, II, JT, KE, KF, 34	31,521		31,521	-	31,521
2			Direct Assessment (ECDA, ICDA and SCCDA)	HP, II	46,522		46,522	(21,540)	24,982
3			Hydrostatic Testing	HP, II, JT, KE, KF, 34	181,792		181,792	(80,865)	100,927
4			Earthquake Fault Crossings	JT	4,494		4,494	(1,904)	2,590
5			Geo-Hazard Threat Identification	HP, JT, 34	211		211	-	211
6			Programs to Enhance Integrity Management	HP, II, JT, KE, KF	7,315		7,315	-	7,315
7			Public Awareness	HP, KE	4,344		4,344	(786)	3,558
8			Inoperable and Hard to Operate Valves	KE, JT	242		242	-	242
9					276,443		276,443	(105,096)	171,347
10	4B	Transmission Pipe Engineering Programs	Class Location Program	HP, JT, KF, JO	6,411		6,411	(2,425)	3,985
11			Water and Levee Crossing	JT	1,372		1,372	-	1,372
12			Shallow Pipe Program	JT	3,073		3,073	-	3,073
13			Gas Gathering Program	JT	-		-	-	-
14			Work Required by Others Program	JT	739		739	-	739
15					11,593		11,593	(2,425)	9,168
16	5	Asset Family - Storage	WELL - GRN Surveys	JT	-		-	-	-
17			WELL - Noise/Temperature Surveys (PG&E/ORA Joint 3)	JT	342		342	-	342
18			WELL - Casing Inspection Surveys (PG&E/ORA Joint 3)	JT	295		295	-	295
19			WELL - Other	JT	-		-	-	-
20					638		638	-	638
21	6	Asset Family - Facilities	Routine Spend C&P	JT	8,440		8,440	-	8,440
22			Critical Documents	34, KF, JT	11,573		11,573	(11,573)	-
23			Physical Security	JT	1,055		1,055	-	1,055
24			Gill Ranch Operating and Maintenance Costs	JT, CX	2,306		2,306	-	2,306
25			Hydrostatic Testing C&P	JT	455		455	(455)	0
26			Engineering Critical Assessment Phase 2	JT, 34	8,682		8,682	-	8,682
27			Routine Spend M&C	34, JT, KE, KF	8,390		8,390	-	8,390
28			Data Acquisition and Metric Development	JT	1,583		1,583	-	1,583
29			Gas Quality Practices Assessment	JT	2,110		2,110	-	2,110
30			Hydrostatic Testing M&C	JT, 34	5,471		5,471	(5,471)	-
31			Engineering Critical Assessment Phase 1	JT, KF, 34	15,634		15,634	-	15,634
32			Becker Upgrade	JT	-		-	-	-
33					65,699		65,699	(17,499)	48,199
34	7	Corrosion Control	Cathodic Protection Rectifier	JO	450		450	-	450
35			Cathodic Protection Monitoring	JO	1,820		1,820	-	1,820
36			Cathodic Protection Resurvey	JO	177		177	-	177
37			Cathodic Protection Troubleshooting	JO	177		177	-	177
38			CP Corrective Maintenance	JO	1,340		1,340	-	1,340
39			CP Systems - Replace	HP	-		-	-	-
40			Coupon Test Stations	HP	-		-	-	-
41			Corrosion Investigations	HP, 34	5,455		5,455	-	5,455
42			Close Interval Survey	HP	8,759		8,759	-	8,759
43			AC Interference	HP, 34	528		528	-	528
44			DC Interference	HP, 34	2,552		2,552	-	2,552
45			Casings	HP, 34	48,504		48,504	(8,912)	39,592
46			Internal Corrosion	HP	8,784		8,784	-	8,784
47			Atmospheric Corrosion Inspection and Remediation	JO, JT, HP, 34	20,437		20,437	-	20,437
48			(Reference Information on Other Historical Work)	KF	-		-	-	-
49					98,982		98,982	(8,912)	90,070
50	8	Gas Transmission System Operations and Maintenance	Locate and Mark	DF	8,986		8,986	-	8,986
51			Pipeline Maintenance	JO, KE, KF	30,182		30,182	-	30,182
52			Station Maintenance	JP	27,310		27,310	-	27,310
53			Expense Projects	JT, KF	36,960		36,960	-	36,960
54			StanPac	34	652		652	-	652
55					104,090		104,090	-	104,090
56	9	Program Management Office	Program Management Office (PG&E/ORA Joint 3)	JT, KE, KF	6,330		6,330	-	6,330
57					6,330		6,330	-	6,330
58	10	Gas System Operations	Gas System Operations	CM	17,935		17,935	-	17,935
59			Marketing/Sales Strategy	CX	7,490		7,490	-	7,490
60			Compressor Fuel and Power (PG&E/ORA Joint 3)	CM	19,124	(883)	18,241	-	18,241
61			Greenhouse Gas Compliance Instruments (PG&E/ORA Joint 3)	JT	3,191	(103)	3,088	(3,088)	-
62					47,740	(986)	46,754	(3,088)	43,666
63	11	Information Technology	Gas Transmission Information Technology Expense (PG&E/ORA Joint 4)	JT, JV, KE, KF	16,342	(1,682)	14,660	-	14,660
64					16,342	(1,682)	14,660	-	14,660
65	12	Other GT&S Support Plans	Support (2014 GRC Decision Revised Building Allocation)	AB	4,642	838	5,480	-	5,480
66			Environmental Operations	AK	11,078		11,078	-	11,078
67			Read & Investigate Meters	AR	593		593	-	593
68			Habitat and Species Protection	AY	211		211	-	211
69			Hazardous Waste Disposal & Transportation	CR	211		211	-	211
70			Manage Various Customer Care Processes	EZ	866		866	-	866
71			Research and Development	GZ	2,216		2,216	-	2,216
72			Change/Maintain Used Gas Meters	HY	438		438	-	438
73			(Reference Information on Other Historical Work)	KF			-		-
74					20,254	838	21,091	-	21,091
75				Grand Total	648,110	(1,830)	646,280	(137,021)	509,259

Note (1) - *PG&E Opening Brief* model at page 1-17. Further details shown in RO workpapers, Exhibit ALJ-1.

APPENDIX D: Table 2
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Capital Expenditures Adopted by Program - Test Year 2015
(Thousands of Nominal Dollars)

Line	Exhibit (PG&E-1 & 2) Chapter	Chapter Name	Programs	Related MWC	2015 Forecast Exhibit PG&E-1	Stipulation and GRC Adj.	2015 Forecast PG&E Brief (1)	Adopted Adj.	2015 Adopted Forecast
1	4A	Transmission Pipe Integrity and Emergency Response Programs	ILI	44, 75, 98, 2H	74,259	-	74,259	(15,023)	59,236
2			Hydrostatic Testing	73, 75, 2H, 2J	24,316	-	24,316	-	24,316
3			Earthquake Fault Crossings	44, 75	5,442	-	5,442	(321)	5,121
4			Vintage Pipe Replacement	44, 75, 84, 2H, 2J	193,824	-	193,824	(50,146)	143,678
5			Geo-hazard Threat Identification	44, 75	8,007	-	8,007	(538)	7,469
6			Valve Automation	44, 75, 2H	52,502	-	52,502	-	52,502
7			Inoperable and Hard to Operate Valves	44, 75, 84, 98	7,067	-	7,067	-	7,067
8					365,416	-	365,416	(66,028)	299,388
9	4B	Transmission Pipe Engineering Programs	Class Location Program	44, 75, 84, 2J	17,056	-	17,056	-	17,056
10			Water and Levee Crossing Program	44, 75, 83, 84, 2H	13,360	-	13,360	-	13,360
11			Shallow Pipe Program	44, 75, 83	21,571	-	21,571	(4,344)	17,228
12			Gas Gathering Program	84	1,627	-	1,627	-	1,627
13			Work Required by Others Program	75, 83	24,610	-	24,610	(7,310)	17,300
14					78,224	-	78,224	(11,654)	66,570
15	5	Asset Family - Storage	WELL- Storage Well Work (PG&E/ORA Joint 3)	76, 89	9,781	-	9,781	-	9,781
16			WELL - Well Overflow Protection (PG&E/ORA Joint 3)	76	2,675	-	2,675	-	2,675
17					12,456	-	12,456	-	12,456
18	6	Asset Family - Facilities	Burney K-2 Compressor Replacement	76	26,750	-	26,750	-	26,750
19			Los Medanos K-1 Compressor Replacement	76	-	-	-	-	-
20			Compressor Unit Control Replacements	76	1,617	-	1,617	-	1,617
21			Upgrade Station Controls	76	-	-	-	-	-
22			Emergency Shutdown System Upgrades	76	2,675	-	2,675	-	2,675
23			Rebuild Santa Rosa Compressor Station Electrical Substation	76	3,745	-	3,745	-	3,745
24			Upgrade Pleasant Creek Processing Equipment	76	2,140	-	2,140	-	2,140
25			GT Electrical Upgrades - Hinkley and Topock Compressor Stations	76	-	-	-	-	-
26			GT Electrical Upgrades - Compressor Stations (excludes Hinkley, Topock)	76	-	-	-	-	-
27			Physical Security	76	2,706	-	2,706	-	2,706
28			Hinkley Compressor Unit Retrofit Project	76	-	-	-	-	-
29			Install Active Fire Suppression Systems	76	535	-	535	-	535
30			Routine Capital Spending - C&P	12, 44, 76, 84	32,867	-	32,867	-	32,867
31			Perform Simple Station Rebuilds	75, 76	19,660	-	19,660	-	19,660
32			Perform Complex Station Rebuilds	75, 76	8,186	-	8,186	-	8,186
33			Perform Transmission Terminal Upgrades	75, 76	2,140	-	2,140	-	2,140
34			Gas Transmission SCADA Visibility	76	5,671	-	5,671	-	5,671
35			Replace Obsolete Bristol Controllers	44, 75, 76	1,473	-	1,473	-	1,473
36			Replace Obsolete Limitorque Valve Actuators	44, 75, 76	1,311	-	1,311	-	1,311
37			Electric Upgrades Program	44, 76	1,064	-	1,064	-	1,064
38			Becker System Upgrades	76	3,437	-	3,437	-	3,437
39			Biomethane Interconnects	76	4,815	-	4,815	(4,815)	-
40			Routine Capital Spending - M&C	12, 44, 73, 75, 76, 84, 2J	20,505	-	20,505	-	20,505
41			Bethany Unit Replacement	76	-	-	-	-	-
42			Gill Ranch	76	-	-	-	-	-
43			McDonald Island Processing Equipment Replacement	76	-	-	-	-	-
44			Prior Compression Replacement	12, 76	-	-	-	-	-
45			Topock Install Suction Separation	76	-	-	-	-	-
46			Hinkley Install Suction Separation	76	-	-	-	-	-
47					141,296	-	141,296	(4,815)	136,481
48	7	Corrosion Control	CP Systems - Replace	75	3,253	-	3,253	-	3,253
49			CP Systems - New	75	8,186	-	8,186	-	8,186
50			Coupon Test Stations	75	5,136	-	5,136	(3,960)	1,176
51			AC Interference Mitigation	75	10,350	-	10,350	-	10,350
52			DC Interference Mitigation	44, 75	802	-	802	-	802
53			Casings	44,75	21,039	-	21,039	(4,048)	16,991
54			Internal Corrosion	75, 84	535	-	535	-	535
55			(Reference Information on Other Historical Work)	75	-	-	-	-	-
56					49,300	-	49,300	(8,008)	41,292
57	9	Program Management Office	Program Management Office (PG&E/ORA Joint 3)	75, 2H	6,420	-	6,420	-	6,420
58					6,420	-	6,420	-	6,420
59	10	Gas System Operations	New Business	26	8,560	-	8,560	-	8,560
60			Meter Sets - Power Plant	26	1,618	-	1,618	-	1,618
61			Capacity	26, 73, 75, 2J	66,993	-	66,993	-	66,993
62					77,171	-	77,171	-	77,171
63	11	Information Technology	Gas Transmission IT Projects (PG&E/ORA Joint 4)	75, 2H, 2F, 2J	24,473	(1,958)	22,515	-	22,515
64					24,473	(1,958)	22,515	-	22,515
65	12	Other GT&S Support Plans	Tools and Equipment (PG&E/ORA Joint 3)	05, 2H, 04	10,700	(1,709)	8,991	-	8,991
66			Manage Buildings (2014 GRC Decision Revised Building Allocation)	75, 78, 2H	13,537	4,956	18,493	-	18,493
67					24,237	3,247	27,484	-	27,484
68				Grand Total	778,993	1,289	780,282	(90,505)	689,777

Note (1) - *PG&E Opening Brief* model at page 1-17. Further details shown in RO workpapers, Exhibit ALJ-1.

APPENDIX D: Table 3 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Expenses Adopted by Major Work Category - Test Year 2015
(Thousands of Nominal Dollars)

Line	Exhibit (PG&E-1 & 2) Chapter	Chapter Name	MWC	MWC Description	2015 Forecast Exhibit PG&E-1	Stipulation and GRC Adj.	2015 Forecast PG&E Brief (1)	Adopted Adj.	2015 Adopted Forecast
1	4A	Transmission Pipe Integrity and Emergency Response Programs	34	StanPac Expense	15		15		15
2			HP	GT Integrity Management	89,899		89,899	(22,327)	67,573
3			II	GT Integrity Management			-		-
4			JT	GT Reliability & General Maintenance	186,529		186,529	(82,770)	103,759
5			KE	GT PL Safety Enhance Plan-Exp			-		-
6			KF	GT&D Impl Regulatory Change			-		-
7					276,443		276,443	(105,096)	171,347
8	4B	Transmission Pipe Engineering Programs	HP	GT Integrity Management	4,851		4,851	(2,425)	2,425
9			JO	GT Branch Pipeline Maintenance	399		399		399
10			JT	GT Reliability & General Maintenance	6,343		6,343		6,343
11			KE	GT PL Safety Enhance Plan-Exp			-		-
12			KF	GT&D Impl Regulatory Change			-		-
13					11,593		11,593	(2,425)	9,168
14	5	Asset Family - Storage	JT	GT Reliability & General Maintenance (PG&E/ORA Joint 3)	638		638		638
15					638		638	-	638
16	6	Asset Family - Facilities	CX	Gas Marketing, Sales&Strategy			-		-
17			34	StanPac Expense	1,237		1,237	(386)	851
18			JT	GT Reliability & General Maintenance	64,461		64,461	(17,113)	47,349
19			KE	GT PL Safety Enhance Plan-Exp			-		-
20			KF	GT&D Impl Regulatory Change			-		-
21					65,699		65,699	(17,499)	48,199
22	7	Corrosion Control	34	StanPac Expense	848		848		848
23			HP	GT Integrity Management	74,150		74,150	(8,912)	65,238
24			II	GT Integrity Management			-		-
25			JO	GT Branch Pipeline Maintenance	23,984		23,984		23,984
26			JT	GT Reliability & General Maintenance			-		-
27			KF	GT&D Impl Regulatory Change			-		-
28					98,982		98,982	(8,912)	90,070
29	8	Gas Transmission System Operations and Maintenance	DF	Mark & Locate - G&E	8,986		8,986		8,986
30			34	StanPac Expense	652		652		652
31			JO	GT Branch Pipeline Maintenance	30,182		30,182		30,182
32			JP	GT Station Maintenance	27,310		27,310		27,310
33			JT	GT Reliability & General Maintenance	36,960		36,960		36,960
34			KE	GT PL Safety Enhance Plan-Exp			-		-
35			KF	GT&D Impl Regulatory Change			-		-
36					104,090		104,090	-	104,090
37	9	Program Management Office	JT	GT Reliability & General Maintenance (PG&E/ORA Joint 3)	6,330		6,330		6,330
38			KE	GT PL Safety Enhance Plan-Exp			-		-
39			KF	GT&D Impl Regulatory Change			-		-
40					6,330		6,330	-	6,330
41	10	Gas System Operations	CM	Oper Gas Transmission Fac (PG&E/ORA Joint 3)	37,059	(883)	36,176		36,176
42			CX	Gas Marketing, Sales&Strategy	7,490		7,490		7,490
43			JT	GT Reliability & General Maintenance (PG&E/ORA Joint 3)	3,191	(103)	3,088	(3,088)	-
44				Total	47,740	(986)	46,754	(3,088)	43,666
45	11	Information Technology	JT	GT Reliability & General Maintenance			-		-
46			JV	Maintain IT Apps & Infra (PG&E/ORA Joint 4)	16,342	(1,682)	14,660		14,660
47			KE	GT PL Safety Enhance Plan-Exp			-		-
48			KF	GT&D Impl Regulatory Change			-		-
49					16,342	(1,682)	14,660	-	14,660
50	12	Other GT&S Support Plans	AB	Support (2014 GRC Decision Revised Building Allocation)	4,642	838	5,480		5,480
51			AK	Manage Environmental Oper	11,078		11,078		11,078
52			AR	Read & Investigate Meters	593		593		593
53			AY	Habitat and Species Protection	211		211		211
54			CR	Mnge Waste Disp & Transp	211		211		211
55			EZ	Manage Var Cust Care Processes	866		866		866
56			GZ	R&D Non-Balancing Account	2,216		2,216		2,216
57			HY	Change/Maint Used Gas Meters	438		438		438
58			KF	GT&D Impl Regulatory Change			-		-
59					20,254	838	21,091	-	21,091
60				Grand Total	648,110	(1,830)	646,280	(137,021)	509,259

Note (1) - *PG&E Opening Brief* model at page 1-17. Further details shown in RO workpapers, Exhibit ALJ-1.

APPENDIX D: Table 4
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Capital Expenditures Adopted by Major Work Category - Test Year 2015
(Thousands of Nominal Dollars)

Line	Exhibit (PG&E-1 & 2) Chapter	Chapter Name	MWC	MWC Description	2015 Forecast Exhibit PG&E-1	Stipulation and GRC Adj.	2015 Forecast PG&E Brief (1)	Adopted Adj.	2015 Adopted Forecast
1	4A	Transmission Pipe Integrity and Emergency Response Programs	44	Gas Capital:GasTrans-Sub	6,764		6,764	678	7,442
2			73	GT Pipeline Capacity	2,916		2,916		2,916
3			75	GT Pipeline Reliability	285,043		285,043	(51,683)	233,359
4			84	GT Gas Gathering System Manage	-		-		-
5			98	GT Integrity Management	70,694		70,694	(15,023)	55,671
6			2H	GT Implementation Plan Capital	-		-		-
7			2J	GT&D Impl Regulatory Change	-		-		-
8					365,416	-	365,416	(66,028)	299,388
9	4B	Transmission Pipe Engineering Programs	44	Gas Capital:GasTrans-Sub	1,556		1,556		1,556
10			45	Proceeds from the Sale of Prop	-		-		-
11			75	GT Pipeline Reliability	50,431		50,431	(4,344)	46,087
12			83	GT WRO	24,610		24,610	(7,310)	17,300
13			84	GT Gas Gathering System Manage	1,627		1,627		1,627
14			2H	GT Implementation Plan Capital	-		-		-
15			2J	GT&D Impl Regulatory Change	-		-		-
16					78,224	-	78,224	(11,654)	66,570
17	5	Asset Family - Storage	76	GT Station Reliability (PG&E/ORA Joint 3)	12,456		12,456		12,456
18			89	Other Balance Sheet	-		-		-
19					12,456	-	12,456	-	12,456
20	6	Asset Family - Facilities	12	Implement Environment Projects	-		-		-
21			44	Gas Capital:GasTrans-Sub	906		906		906
22			73	GT Pipeline Capacity	-		-		-
23			75	GT Pipeline Reliability	4,921		4,921		4,921
24			76	GT Station Reliability	135,469		135,469	(4,815)	130,654
25			84	GT Gas Gathering System Manage	-		-		-
26			2J	GT&D Impl Regulatory Change	-		-		-
27					141,296	-	141,296	(4,815)	136,481
28	7	Corrosion Control	44	Gas Capital:GasTrans-Sub	222		222	(31)	192
29			75	GT Pipeline Reliability	49,078		49,078	(7,977)	41,101
30			84	GT Gas Gathering System Manage	-		-		-
31					49,300	-	49,300	(8,008)	41,292
32	9	Program Management Office	75	GT Pipeline Reliability (PG&E/ORA Joint 3)	6,420		6,420		6,420
33			2H	GT Implementation Plan Capital	-		-		-
34					6,420	-	6,420	-	6,420
35	10	Gas System Operations	26	GT Customer Connects	10,178		10,178		10,178
36			73	GT Pipeline Capacity	66,993		66,993		66,993
37			75	GT Pipeline Reliability	-		-		-
38			2J	GT&D Impl Regulatory Change	-		-		-
39					77,171	-	77,171	-	77,171
40	11	Information Technology	75	GT Pipeline Reliability	-		-		-
41			2F	Build IT Apps & Infra (PG&E/ORA Joint 4)	24,473	(1,958)	22,515		22,515
42			2H	GT Implementation Plan Capital	-		-		-
43			2J	GT&D Impl Regulatory Change	-		-		-
44					24,473	(1,958)	22,515	-	22,515
45	12	Other GT&S Support Plans	04	Fleet / Auto Equip	-		-		-
46			05	Tools & Equipment (PG&E/ORA Joint 3)	10,700	(1,709)	8,991		8,991
47			75	GT Pipeline Reliability	-		-		-
48			78	Manage Buildings (2014 GRC Decision Revised Building Allocation)	13,537	4,956	18,493		18,493
49			2H	GT Implementation Plan Capital	-		-		-
50					24,237	3,247	27,484	-	27,484
51				Grand Total	778,993	1,289	780,282	(90,505)	689,777

Note (1) - *PG&E Opening Brief* model at page 1-17. Further details shown in RO workpapers, Exhibit ALJ-1.

APPENDIX E

SUMMARY OF RESULTS OF OPERATIONS - POST TEST-YEAR RATEMAKING (PTYR) (2016-2018)

APPENDIX E

Pacific Gas and Electric Company

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Summary of Results of Operations - Post Test-Year Ratemaking (PTYR) (2016-2018)

TABLE INDEX

APPENDIX E: Table 1 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Adopted PTYR Results of Operations at Proposed Rates (2015-2018)
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	Test Year 2015	Attrition Year 2016 Increase	Attrition Year 2016 Total	Attrition Year 2017 Increase	Attrition Year 2017 Total	Attrition Year 2018 Increase	Attrition Year 2018 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	
	REVENUE:								
1	Revenue Collected in Rates [(a)]	886,917	174,520	1,061,436	63,856	1,125,292	104,818	1,230,110	1
2	Plus Other Operating Revenue	2,871	-	2,871	-	2,871	-	2,871	2
3	Total Operating Revenue	889,788	174,520	1,064,308	63,856	1,128,164	104,818	1,232,981	3
	OPERATING EXPENSES:								
4	Energy Costs	-	-	-	-	-	-	-	4
5	Production	1,882	49	1,931	48	1,979	49	2,027	5
6	Storage	16,635	403	17,038	457	17,495	385	17,880	6
7	Transmission	451,283	14,521	465,805	41,221	507,026	11,518	518,544	7
8	Distribution	346	9	355	9	364	9	372	8
9	Customer Accounts	3,483	102	3,585	94	3,680	95	3,775	9
10	Uncollectibles	2,871	574	3,445	214	3,660	334	3,994	10
11	Customer Services	5,955	175	6,130	161	6,291	163	6,455	11
12	Administrative and General	66,612	2,038	68,650	2,071	70,721	2,134	72,855	12
13	Franchise Requirements	8,382	1,660	10,041	618	10,659	965	11,625	13
14	Amortization	-	-	-	-	-	-	-	14
15	Wage Change Impacts	-	-	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	-	-	16
17	Other Adjustments	(157,047)	107,292	(49,754)	(48,253)	(98,007)	4,022	(93,985)	17
18	Subtotal Expenses:	400,402	126,824	527,226	(3,359)	523,866	19,675	543,541	18
	TAXES:								
19	Superfund	-	-	-	-	-	-	-	19
20	Property	32,437	4,643	37,081	3,110	40,191	3,196	43,387	20
21	Payroll	10,906	324	11,230	292	11,522	300	11,822	21
22	Business	67	-	67	-	67	-	67	22
23	Other	162	-	162	-	162	-	162	23
24	State Corporation Franchise	3,451	1,306	4,757	2,996	7,753	4,180	11,933	24
25	Federal Income	77,894	(2,017)	75,877	14,741	90,618	18,948	109,566	25
26	Total Taxes	124,917	4,256	129,174	21,140	150,313	26,623	176,936	26
27	Depreciation	128,658	15,278	143,936	16,246	160,182	16,807	176,989	27
28	Fossil Decommissioning	-	-	-	-	-	-	-	28
29	Nuclear Decommissioning	-	-	-	-	-	-	-	29
30	Total Operating Expenses	653,978	146,358	800,336	34,026	834,362	63,105	897,467	30
31	Net for Return	235,810	28,162	263,972	29,829	293,802	41,767	335,569	31
32	Rate Base	2,926,133	349,478	3,275,611	370,171	3,645,782	518,309	4,164,091	32
	RATE OF RETURN:								
33	On Rate Base	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	33
34	On Equity	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	34

(a) Excludes Carrying Cost of Working Gas & Load Balancing Gas as shown in Exhibit (PG&E-2), p. 16-2, Table 16-1. 2018 amount same as 2017 ($2,841)

APPENDIX E: Table 2 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Adopted PTYR Income Taxes at Proposed Rates (2015-2018)
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	Test Year 2015	Attrition Year 2016 Increase	Attrition Year 2016 Total	Attrition Year 2017 Increase	Attrition Year 2017 Total	Attrition Year 2018 Increase	Attrition Year 2018 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	
1	Revenues	889,788	174,520	1,064,308	63,856	1,128,164	104,818	1,232,981	1
2	O&M Expenses	400,402	126,824	527,226	(3,359)	523,866	19,675	543,541	2
3	Nuclear Decommissioning Expense	-	-	-	-	-	-	-	3
4	Superfund Tax	-	-	-	-	-	-	-	4
5	Taxes Other Than Income	43,572	4,967	48,539	3,402	51,942	3,495	55,437	5
6	Subotal	445,814	42,729	488,543	63,812	552,355	81,648	634,003	6
	DEDUCTIONS FROM TAXABLE INCOME:								
7	Interest Charges	75,916	9,067	84,982	9,604	94,586	13,447	108,033	7
8	Fiscal/Calendar Adjustment	196	-	196	-	196	-	196	8
9	Operating Expense Adjustments	(5,245)	-	(5,245)	-	(5,245)	-	(5,245)	9
10	Capitalized Interest Adjustment	-	-	-	-	-	-	-	10
11	Removal Costs	35,143	-	35,143	-	35,143	-	35,143	11
12	Vacation Accrual Reduction	(768)	-	(768)	-	(768)	-	(768)	12
13	Capitalized Other	8,725	-	8,725	-	8,725	-	8,725	13
14	Subtotal Deductions	113,966	9,067	123,033	9,604	132,637	13,447	146,084	14
	CCFT TAXES:								
15	State Operating Expense Adjustment	1,138	-	1,138	-	1,138	-	1,138	15
16	State Tax Depreciation - Declining Balance	-	-	-	-	-	-	-	16
17	State Tax Depreciation - Fixed Assets	236,675	18,892	255,568	20,314	275,882	20,919	296,801	17
18	State Tax Depreciation - Other	-	-	-	-	-	-	-	18
19	Capitalized Overhead	398	-	398	-	398	-	398	19
20	Repair Allowance	37,606	-	37,606	-	37,606	-	37,606	20
21	Subtotal Deductions	389,784	27,959	417,744	29,918	447,661	34,366	482,027	21
22	Taxable Income for CCFT	56,030	14,769	70,799	33,894	104,694	47,282	151,976	22
23	CCFT	4,953	1,306	6,259	2,996	9,255	4,180	13,435	23
24	State Tax Adjustment	-	-	-	-	-	-	-	24
25	Current CCFT	4,953	1,306	6,259	2,996	9,255	4,180	13,435	25
26	Deferred Taxes - Reg Asset	-	-	-	-	-	-	-	26
27	Deferred Taxes - Interest	101	-	101	-	101	-	101	27
28	Deferred Taxes - Vacation	(68)	-	(68)	-	(68)	-	(68)	28
29	Deferred Taxes - Other	-	-	-	-	-	-	-	29
30	Deferred Taxes - Fixed Assets	(1,534)	-	(1,534)	-	(1,534)	-	(1,534)	30
31	Total CCFT	3,451	1,306	4,757	2,996	7,753	4,180	11,933	31
	FEDERAL TAXES:								
32	CCFT - Prior Year	(24,085)	29,038	4,953	1,306	6,259	2,996	9,255	32
33	Federal Operating Expense Adjustment	393	-	393	-	393	-	393	33
34	Fed. Tax Depreciation - Declining Balance	-	-	-	-	-	-	-	34
35	Federal Tax Depreciation - SLRL	-	-	-	-	-	-	-	35
36	Federal Tax Depreciation - Fixed Assets	236,088	16,751	252,839	18,214	271,053	19,558	290,611	36
37	Federal Tax Depreciation - Other	-	-	-	-	-	-	-	37
38	Capitalized Overhead	398	-	398	-	398	-	398	38
39	Repair Allowance	37,606	-	37,606	-	37,606	-	37,606	39
40	Preferred Dividend Credit	49	-	49	-	49	-	49	40
41	Subtotal Deductions	364,416	54,856	419,272	29,123	448,395	36,002	484,397	41
42	Taxable Income for FIT	81,399	(12,128)	69,271	34,689	103,960	45,646	149,606	42
43	Federal Income Tax	28,489	(4,245)	24,245	12,141	36,386	15,976	52,362	43
44	Deferred Taxes - Reg Asset	-	-	-	-	-	-	-	44
45	Tax Effect of MTD & Prod Tax Credits	-	-	-	-	-	-	-	45
46	Deferred Taxes - Interest	138	-	138	-	138	-	138	46
47	Deferred Taxes - Vacation	(269)	-	(269)	-	(269)	-	(269)	47
48	Deferred Taxes - Other	-	-	-	-	-	-	-	48
49	Deferred Taxes - Fixed Assets	49,536	2,228	51,764	2,600	54,363	2,972	57,335	49
50	Total Federal Income Tax	77,894	(2,017)	75,877	14,741	90,618	18,948	109,566	50

APPENDIX E: Table 3 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Adopted 2016 PTYR Results of Operations by UCC
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2016		Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)		
	REVENUE:															
1	Base Revenue Requirement	9,375	65,577	27,321	10,281	670,287	67,323	34,297	8,175	32,806	97,300	35,924	2,770	1,061,436	(a)	1
2	Plus Other Operating Revenue	0	0	0	0	763	777	0	0	0	1,332	0	0	2,871		2
3	Total Operating Revenue	9,375	65,577	27,321	10,281	671,049	68,101	34,297	8,175	32,806	98,632	35,924	2,770	1,064,308		3
	OPERATING EXPENSES:															
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0		4
5	Gathering	113	114	54	19	1,270	21	59	4	30	218	29	0	1,931		5
6	Storage	141	8,262	3,311	235	4,086	68	190	13	97	541	94	0	17,038		6
7	Transmission	2,837	11,547	6,662	1,388	326,981	10,472	15,991	4,120	21,266	50,512	14,029	0	465,805		7
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	355	355		8
9	Customer Accounts	59	153	72	0	1,700	28	79	5	40	225	39	1,185	3,585		9
10	Uncollectibles	30	213	89	33	2,170	221	111	27	106	320	116	9	3,445		10
11	Customer Services	150	391	183	0	4,341	72	202	13	103	575	100	0	6,130		11
12	Administrative and General	1,679	4,372	2,050	0	48,619	809	2,263	150	1,151	6,439	1,118	0	68,650		12
13	Franchise Requirements	88	617	257	97	6,340	640	322	77	309	929	342	26	10,041		13
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0		14
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0		15
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0		16
17	Other Adjustments	(61)	(173)	(49)	0	(38,589)	(313)	(333)	(146)	(2,191)	(6,810)	(1,089)	0	(49,754)		17
18	Subtotal Expenses:	5,035	25,494	12,628	1,772	356,917	12,019	18,885	4,262	20,911	52,948	14,778	1,575	527,226		18
	TAXES:															
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0		19
20	Property	373	2,709	913	532	20,750	4,057	1,319	345	634	3,767	1,622	60	37,081		20
21	Payroll	108	339	236	28	6,551	219	454	136	769	1,689	647	54	11,230		21
22	Business	2	4	2	0	48	1	2	0	1	6	1	0	67		22
23	Other	4	10	5	0	114	2	5	0	3	15	3	0	162		23
24	State Corporation Franchise	(6)	1,025	324	308	1,231	2,119	(35)	21	(30)	(344)	90	55	4,757		24
25	Federal Income	464	6,505	2,430	1,580	44,665	8,683	1,736	502	1,288	4,681	3,320	23	75,877		25
26	Total Taxes	945	10,593	3,910	2,447	73,360	15,080	3,481	1,005	2,665	9,814	5,683	191	129,174		26
27	Depreciation	1,777	11,285	3,926	1,777	74,886	18,709	5,582	1,214	3,332	16,139	4,355	954	143,936		27
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0		28
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0		29
30	Total Operating Expenses	7,757	47,373	20,464	5,996	505,163	45,808	27,949	6,481	26,908	78,901	24,816	2,719	800,336		30
31	Net for Return	1,618	18,204	6,857	4,285	165,886	22,293	6,348	1,694	5,898	19,731	11,108	51	263,972		31
32	Rate Base	20,076	225,903	85,087	53,175	2,058,442	276,644	78,776	21,017	73,195	244,838	137,830	628	3,275,611		32
	RATE OF RETURN:															
33	On Rate Base	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**		33
34	On Equity	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**		34

(a) Excludes Carrying Cost of Working Gas & Load Balancing Gas as shown in Exhibit (PG&E-2), p. 16-2, Table 16-1.

APPENDIX E: Table 4 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Adopted 2017 PTYR Results of Operations by UCC
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2017	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
	REVENUE:														
1	Base Revenue Requirement	9,486	65,595	28,503	9,756	712,503	67,860	34,569	8,560	33,549	115,556	36,724	2,630	1,125,292 (a)	1
2	Plus Other Operating Revenue	0	0	0	0	763	777	0	0	0	1,332	0	0	2,871	2
3	Total Operating Revenue	9,486	65,595	28,503	9,756	713,266	68,637	34,569	8,560	33,549	116,888	36,724	2,630	1,128,164	3
	OPERATING EXPENSES:														
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	4
5	Gathering	116	117	55	20	1,301	22	61	4	31	223	30	0	1,979	5
6	Storage	144	8,488	3,408	241	4,186	70	195	13	99	555	96	0	17,495	6
7	Transmission	2,903	11,815	6,817	1,420	351,701	11,241	15,735	4,289	20,799	66,123	14,183	0	507,026	7
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	364	364	8
9	Customer Accounts	60	157	74	0	1,744	29	81	5	41	231	40	1,216	3,680	9
10	Uncollectibles	31	213	93	32	2,313	223	112	28	109	379	119	9	3,660	10
11	Customer Services	154	401	188	0	4,455	74	208	14	106	590	103	0	6,291	11
12	Administrative and General	1,730	4,503	2,112	0	50,085	833	2,331	154	1,186	6,633	1,152	0	70,721	12
13	Franchise Requirements	89	617	268	92	6,751	645	325	80	316	1,101	351	25	10,659	13
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	14
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0	16
17	Other Adjustments	(120)	(358)	(97)	0	(75,766)	(618)	(660)	(289)	(4,338)	(13,508)	(2,253)	0	(98,007)	17
18	Subtotal Expenses:	5,106	25,953	12,917	1,804	346,772	12,519	18,389	4,299	18,349	62,327	13,821	1,613	523,866	18
	TAXES:														
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0	19
20	Property	389	2,789	972	532	22,924	4,186	1,389	367	758	4,127	1,698	60	40,191	20
21	Payroll	111	347	242	28	6,722	224	465	140	789	1,733	664	55	11,522	21
22	Business	2	4	2	0	48	1	2	0	1	6	1	0	67	22
23	Other	4	10	5	0	114	2	5	0	3	15	3	0	162	23
24	State Corporation Franchise	(13)	951	350	269	3,721	2,046	(24)	32	125	71	183	42	7,753	24
25	Federal Income	457	6,322	2,609	1,442	56,578	8,601	1,856	568	1,990	6,570	3,653	(27)	90,618	25
26	Total Taxes	950	10,423	4,180	2,271	90,107	15,061	3,694	1,107	3,667	12,523	6,201	130	150,313	26
27	Depreciation	1,856	11,691	4,222	1,777	86,035	19,363	5,935	1,326	3,974	18,235	4,816	954	160,182	27
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	28
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	29
30	Total Operating Expenses	7,912	48,066	21,319	5,851	522,914	46,943	28,018	6,732	25,989	93,085	24,838	2,696	834,362	30
31	Net for Return	1,575	17,529	7,184	3,905	190,352	21,694	6,551	1,828	7,560	23,803	11,887	(67)	293,802	31
32	Rate Base	19,544	217,529	89,145	48,458	2,362,053	269,214	81,295	22,685	93,817	295,379	147,493	(830)	3,645,782	32
	RATE OF RETURN:														
33	On Rate Base	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	33
34	On Equity	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	34

(a) Excludes Carrying Cost of Working Gas & Load Balancing Gas as shown in Exhibit (PG&E-2), p. 16-2, Table 16-1.

APPENDIX E: Table 5 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Adopted 2018 PTYR Results of Operations by UCC
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	GT - Gathering (501)	GS - Storage Services - McDonald Island (511)	GS - Storage Services - Los Medanos/Pleasant Creek (512)	GS - Storage Services - Gill Ranch (513)	GT - Local Transmission (520)	GT - Transmission: Northern Path – Line 401 (521)	GT - Transmission: Northern Path – Line 400 (522)	GT - Transmission: Northern Path – Line 2 (523)	GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche (524)	GT - Transmission: Southern Path – Line 300 South Topock to Panoche (525)	GT - Transmission: Bay Area Loop (526)	GT - Customer Access Charge (CAC) (540)	Gas Transmission Total Year 2018	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
	REVENUE:														
1	Base Revenue Requirement	9,817	66,715	30,149	9,340	792,339	68,670	36,371	9,168	38,075	127,242	39,716	2,507	1,230,110 (a)	1
2	Plus Other Operating Revenue	0	0	0	0	763	777	0	0	0	1,332	0	0	2,871	2
3	Total Operating Revenue	9,817	66,715	30,149	9,340	793,102	69,447	36,371	9,168	38,075	128,573	39,716	2,507	1,232,981	3
	OPERATING EXPENSES:														
4	Energy Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	4
5	Gathering	118	120	56	20	1,333	22	62	4	32	228	31	0	2,027	5
6	Storage	148	8,663	3,483	246	4,287	71	200	13	102	568	99	0	17,880	6
7	Transmission	2,968	12,079	6,969	1,453	359,596	11,495	16,096	4,389	21,291	67,682	14,524	0	518,544	7
8	Distribution	0	0	0	0	0	0	0	0	0	0	0	372	372	8
9	Customer Accounts	62	161	76	0	1,790	30	83	6	42	237	41	1,248	3,775	9
10	Uncollectibles	32	216	98	30	2,567	225	118	30	124	417	128	8	3,994	10
11	Customer Services	157	411	193	0	4,571	76	213	14	108	605	105	0	6,455	11
12	Administrative and General	1,782	4,639	2,176	0	51,597	859	2,402	159	1,221	6,834	1,187	0	72,855	12
13	Franchise Requirements	92	627	283	88	7,485	652	342	86	358	1,210	377	24	11,625	13
14	Amortization	0	0	0	0	0	0	0	0	0	0	0	0	0	14
15	Wage Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	0	0	0	0	0	16
17	Other Adjustments	(119)	(325)	(96)	0	(72,300)	(612)	(651)	(286)	(4,279)	(13,280)	(2,037)	0	(93,985)	17
18	Subtotal Expenses:	5,240	26,592	13,238	1,836	360,927	12,819	18,865	4,416	18,999	64,502	14,455	1,652	543,541	18
	TAXES:														
19	Superfund	0	0	0	0	0	0	0	0	0	0	0	0	0	19
20	Property	405	2,870	1,033	532	25,157	4,318	1,461	390	887	4,498	1,776	60	43,387	20
21	Payroll	114	356	248	29	6,896	230	478	144	810	1,778	682	56	11,822	21
22	Business	2	4	2	0	48	1	2	0	1	6	1	0	67	22
23	Other	4	10	5	0	114	2	5	0	3	15	3	0	162	23
24	State Corporation Franchise	(9)	939	406	238	7,094	2,004	26	52	318	517	317	31	11,933	24
25	Federal Income	497	6,398	2,901	1,333	71,369	8,636	2,142	675	2,864	8,644	4,174	(67)	109,566	25
26	Total Taxes	1,013	10,578	4,596	2,132	110,679	15,192	4,114	1,261	4,882	15,458	6,952	80	176,936	26
27	Depreciation	1,937	12,109	4,525	1,777	97,886	20,025	6,297	1,440	4,622	20,129	5,289	954	176,989	27
28	Fossil Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	28
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	29
30	Total Operating Expenses	8,190	49,279	22,359	5,745	569,491	48,036	29,276	7,117	28,503	100,089	26,696	2,685	897,467	30
31	Net for Return	1,627	17,436	7,790	3,596	223,611	21,411	7,095	2,050	9,572	28,484	13,020	(178)	335,514	31
32	Rate Base	20,193	216,385	96,666	44,621	2,775,254	265,701	88,049	25,443	118,793	353,522	161,676	(2,211)	4,164,091	32
	RATE OF RETURN:														
33	On Rate Base	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.06%**	**8.05%**	**8.06%**	**8.06%**	33
34	On Equity	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	**10.40%**	34

(a) Excludes Carrying Cost of Working Gas & Load Balancing Gas as shown in Exhibit (PG&E-2), p. 16-2, Table 16-1. 2018 amount same as 2017 ($2,841)

APPENDIX E: Table 6
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Adopted PTYR Specific Cost Stipulations
(Thousands of Nominal Dollars)

Part 1 - PTYR SPECIAL CAPITAL ADJUSTMENT (Appendix E: Table 7)

Line No.	ILI Program	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
	Traditional ILI Capital				
1	Traditional ILI Capital Filed	71,279	97,651	100,075	na
2	Traditional ILI 2015 Capital Adopted Reduction	(15,023)			
3	Traditional ILI 2015 Capital Adopted Net	56,256			
4	Traditional ILI Capital Adopted Percentage Reduction	21.08%			
5	Traditional ILI Capital Adopted PTYR Adjusted Forecast		77,069	78,983	81,037
	Non-traditional ILI Capital				
6	Non-traditional ILI Capital	2,980	12,897	13,559	13,912
7	Total Filed ILI Capital Forecast	74,259	110,548	113,635	na
8	Total ILI Capital Adopted Forecast	**59,236**	**89,967**	**92,542**	**94,948**

Part 2 - PTYR SPECIAL EXPENSE ADJUSTMENTS (Appendix E: Table 7)

Line No.	Program	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	Traditional ILI, including Direct Exam & Repair	27,831	27,863	52,863	54,057
2	External Corrosion Direct Assessment (ECDA)	14,461	16,684	21,800	22,279
3	Internal Corrosion Direct Assessment (ICDA)	7,664	9,381	11,004	11,246
4	ECDA and ICDA Sum	22,125	26,065	32,804	33,525
5	Hydrostatic Testing Station Facility M&C	**Memo Account**			
6	Total Filed Expense Errata Adjusted	76,967	90,519	140,529	na
7	Total	49,956	53,928	85,667	87,582
8	Incremental Year to Year PTYR Amount		**3,972**	**31,738**	**1,915**

APPENDIX E: Table 7
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Adopted Post Test-Year (PTY) Increase for 2018 (PG&E-ORA Exhibit Joint 3 - Modified) [1]

Line No.	Item at Issue	Chapter No./Other Notes	Stipulation (Exh. Joint-3)	PTY 2018
1	PTY increase (PG&E proposed 2015 revenues)	Excludes specific expense adjustments, Line 407, NOL, and 2014 bonus depreciation extension.	Illustrative only. Actual value will be based on Adopted Test Year value. 2016: $89 million Increase (7.2%) 2017: $109 million Increase (8.2%)	N/A.
2	PTY increase (ORA proposed 2015 revenues)	Excludes specific expense adjustments, NOL, and 2014 bonus depreciation extension. ORA had previously excluded Line 407.	Illustrative only. Actual value will be based on Adopted Test Year value. 2016: $57 million Increase (5.7%) 2018: $86 million Increase (8.1%)	N/A.
3	Incremental Specific Expense Adjustments [2]	Chapter 4A Chapter 6 Chapter 18	For Traditional ILI, including Direct Exam & Repair, and External and Internal Corrosion Direct Assessment, reduce PG&E's PTY proposal for specific expense adjustments by the same percentage that the final decision reduces PG&E's test year proposal for these items.	Labor: Escalate adopted 2017 expense at 2.6%. Materials and supplies: Escalate using IHS Global Insight escalation rates, fixed based on fourth quarter 2012 data.
4	Duration of Rate Cycle	Chapter 18A	Under consideration.	Included.
5	Line 407	Chapter 10 Chapter 16 Chapter 18	[Deleted] PG&E authorized cost recovery up to $157.0 million when Line 407 completed and operational, with all costs subject to reasonableness review in next GT&S application.	
6	Z-factor mechanism	Chapter 18	Use GRC approach, following generally applicable Z factor criteria. Applies only to PTY period.	Use GRC approach, following generally applicable Z factor criteria.
7	Wage escalation rates	Chapter 18	2.79% for 2016 and 2.6% for 2017.	Escalate at 2.6% for 2018.
8	Materials & Supplies (non-labor) escalation	Chapter 18	Escalate using IHS Global Insight escalation rates, fixed based on fourth quarter 2012 data.	Escalate using IHS Global Insight escalation rates, fixed based on fourth quarter 2012 data.
9	Medical program escalation rates	Chapter 18	A&G is allocated to GT&S based on GRC determinations and appropriate allocation factors. Escalate at 6.3% for 2016. Escalate at 6.6% for 2017 as placeholder pending the determination of PG&E's 2017 GRC.	Escalate at 6.6% for 2018 as placeholder pending the determination of PG&E's 2017 GRC.
10	Capital Additions	Chapter 18	Escalate adopted 2015 capital additions at 2.3% and 2.6% for 2016 and 2017, respectively, excluding line 407 and ILI capital costs. Reduce PG&E's PTY proposal for ILI capital expenditures by the same percentage that the final decision reduces PG&E's test year proposal for ILI capital expenditures.	Escalate at 2.6% for 2018, excluding Line 407.

[1] Based on Exhibit PG&E-43 at 18-2 – 18-3, Table 18.2. Table has been modified from original Table 18-2, to reflect updated revenue requirement computations. All figures exclude impacts of specific expense adjustments, 2015 NOL, and impacts of tax bonus depreciation extension adopted by Congress in 2014, including any NOL offset. Because figures provided on lines 1-3 exclude impacts of 2015 NOL they are not comparable to original table.

[2] See Appendix E, Table 6, Part 2 for the specific amounts.

(END OF APPENDIX E)

APPENDIX F

2011 - 2014 CAPITAL EXPENDITURES ABOVE GAS ACCORD V (GAV)

APPENDIX F

Pacific Gas and Electric Company

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

2011 - 2014 Capital Expenditures Above Gas Accord V (GAV)

TABLE INDEX

APPENDIX F: Table 1
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
2011 - 2014 Capital Expenditures Above Gas Accord V (GAV)
Capital Spend Detail Summarized from PG&E Workpapers
(Thousands of Nominal Dollars)

Line	Description	Ex. (PG&E-22) Table 3-1 4-year Total 2011-14	Check Total (1)	Part 1 - Recorded Balances (a) 2011 Actual	(b) 2012 Actual	(c) 2011-2012 Actual	Part 2 - Capital RO Module - CapEx Tab (d) 2013 Forecast	(e) 2014 Forecast	(f) 2013-2014 Forecast	Type of RO Module Change
1	Capital Expenditures Above Adopted	698,400								
2	**A. 104 Projects (2)**	498,890	496,890	50,792	193,248	244,040	132,595	120,255	252,850	Planning order specific, see Exhibit (PG&E-22) Att. A
3	**B. Programs (2)**									
4	Tools and Equipment	34,422	34,422	-	7,522	7,522	14,200	12,700	26,900	Chapter 12, Program specific
5	Buildings	36,855	36,855	-	-	-	-	36,855	36,855	Chapter 12, Program specific (2014 GRC allocation)
6	Pipeline Reliabilty/Safety	31,672	31,672	-	-	-	-	31,672	31,672	Chapter 4A, MWC 75 specific
7	Corrosion	15,690	15,690	-	-	-	-	15,690	15,690	Chapter 7, Program specific
8	Subtotal Programs	118,639	118,639	-	7,522	7,522	14,200	96,917	111,117	
9	Total (not including undefined)	617,529								
10										
11	**C. Undefined** ((2), not shown in Table 3-1)	80,871	80,870	13,967	30,976	44,943	12,259	23,668	35,927	Planning Orders Below $1 million not included in 104 projects or programs
12			696,399	64,759	231,746	296,505	159,054	240,840	399,894	

Note (1) - A $2 million difference exists between order level detail in workpapers and Table 3-1 (Supplemental)
Note (2) - Planning order detail shown in GTS 2011-2014 Capital Spend Workpapers (see 'Capital Spend Over GAV_2011-2014')

APPENDIX F: Table 2
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
2011 - 2014 Capital Expenditures Above Gas Accord V (GAV)
Capital Spend Audit and Disallowed Detail
(Thousands of Nominal Dollars)

		4-year Total		**Part 1 - Recorded Balance**				**Part 2 - Forecast Balance**			
		Project Spend	Spend Over GAV				2-year Total			2-year Total	
Line		2011 - 2014	2011 - 2014	2011	2012	2012 CWIP	2011 - 2012	2013	2014	2013 - 2014	Line
1	**A. Projects Disallowed**	170,283	120,409	19,005	51,882	5,513	76,400	16,077	27,932	44,010	1
2	**B. Projects to be Audited**	641,954	575,991	29,397	153,166	37,543	220,106	142,977	212,908	355,885	2
3	**C. Total**	812,237	696,400	48,402	205,048	43,056	296,506	159,054	240,840	399,895	3

APPENDIX F: Table 3
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
2011 - 2014 Capital Expenditures Above Gas Accord V (GAV)
Results of Operations Summary at Proposed (PG&E Brief) and Adopted - Test Year 2015
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	PG&E Brief (1)	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
	REVENUE:				
1	Retail Revenue Collected in Rates	1,262,815	1,181,638	(81,178)	1
2	Plus Other Operating Revenue	2,871	2,871	0	2
3	Total Operating Revenue	1,265,687	1,184,509	(81,178)	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	1,919	1,919	0	5
6	Storage	18,640	18,640	0	6
7	Transmission	582,705	582,705	0	7
8	Distribution	346	346	0	8
9	Customer Accounts	3,483	3,483	0	9
10	Uncollectibles	4,681	4,381	(300)	10
11	Customer Services	5,955	5,955	0	11
12	Administrative and General	66,612	66,612	0	12
13	Franchise Requirements	11,883	11,121	(762)	13
14	Amortization	0	0	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	997	997	0	17
18	Subtotal Expenses:	697,220	696,158	(1,062)	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	37,672	32,437	(5,235)	20
21	Payroll	12,155	12,155	0	21
22	Business	67	67	0	22
23	Other	162	162	0	23
24	State Corporation Franchise	2,924	2,034	(891)	24
25	Federal Income	93,481	74,548	(18,933)	25
26	Total Taxes	146,461	121,403	(25,059)	26
27	Depreciation	143,665	129,093	(14,572)	27
28	Fossil Decommissioning	0	0	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	987,346	946,654	(40,693)	30
31	Net for Return	278,341	237,856	(40,485)	31
32	Rate Base	3,454,172	2,951,782	(502,391)	32
	RATE OF RETURN:				
33	On Rate Base	**8.06%**	**8.06%**		33
34	On Equity	**10.40%**	**10.40%**		34

(1) *PG&E Opening Brief* model at page 1-17. Further details shown in RO workpapers, Exhibit ALJ-1.

APPENDIX F: Table 4
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
2011 - 2014 Capital Expenditures Above Gas Accord V (GAV)
Income Taxes at Proposed and Adopted - Test Year 2015
Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded
(Thousands of Dollars)

Line No.	Description	PG&E Brief (1)	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
1	Revenues	1,265,687	1,184,509	(81,178)	1
2	O&M Expenses	697,220	696,158	(1,062)	2
3	Nuclear Decommissioning Expense	0	0	0	3
4	Superfund Tax	0	0	0	4
5	Taxes Other Than Income	50,056	44,821	(5,235)	5
6	Subtotal	518,411	443,531	(74,880)	6
	DEDUCTIONS FROM TAXABLE INCOME:				
7	Interest Charges	89,615	76,581	(13,034)	7
8	Fiscal/Calendar Adjustment	1,753	196	(1,557)	8
9	Operating Expense Adjustments	(5,245)	(5,245)	0	9
10	Capitalized Interest Adjustment	0	0	0	10
11	Removal Costs	39,309	39,309	0	11
12	Vacation Accrual Reduction	(768)	(768)	0	12
13	Capitalized Other	8,725	8,725	0	13
14	Subtotal Deductions	133,389	118,798	(14,591)	14
	CCFT TAXES:				
15	State Operating Expense Adjustment	1,144	1,138	(7)	15
16	State Tax Depreciation - Declining Balance	0	0	0	16
17	State Tax Depreciation - Fixed Assets	289,454	239,960	(49,494)	17
18	State Tax Depreciation - Other	0	0	0	18
19	Capitalized Other	401	398	(2)	19
20	Repair Allowance	43,948	43,245	(703)	20
21	Subtotal Deductions	468,336	403,539	(64,797)	21
22	Taxable Income for CCFT	50,075	39,992	(10,083)	22
23	CCFT	4,427	3,535	(891)	23
24	State Tax Adjustment	0	0	0	24
25	Current CCFT	4,427	3,535	(891)	25
26	Deferred Taxes - Reg Asset	0	0	0	26
27	Deferred Taxes - Interest	101	101	(1)	27
28	Deferred Taxes - Vacation	(68)	(68)	0	28
29	Deferred Taxes - Other	0	0	0	29
30	Deferred Taxes - Fixed Assets	(1,536)	(1,534)	1	30
31	Total CCFT	2,924	2,034	(891)	31
	FEDERAL TAXES:				
32	CCFT - Prior Year	(31,832)	(24,078)	7,754	32
33	Federal Operating Expense Adjustment	397	393	(3)	33
34	Fed. Tax Depreciation - Declining Balance	0	0	0	34
35	Federal Tax Depreciation - SLRL	0	0	0	35
36	Federal Tax Depreciation - Fixed Assets	278,229	248,213	(30,016)	36
37	Federal Tax Depreciation - Other	0	0	0	37
38	Capitalized Other	401	398	(2)	38
39	Repair Allowance	43,948	43,245	(703)	39
40	Preferred Dividend Credit	49	49	(0)	40
41	Subtotal Deductions	424,581	387,018	(37,562)	41
42	Taxable Income for FIT	93,830	56,512	(37,318)	42
43	Federal Income Tax	32,841	19,779	(13,061)	43
44	Deferred Taxes - Reg Asset	0	0	0	44
45	Tax Effect of MTD & Prod Tax Credits	0	0	0	45
46	Deferred Taxes - Interest	139	138	(1)	46
47	Deferred Taxes - Vacation	(269)	(269)	0	47
48	Deferred Taxes - Other	0	0	0	48
49	Deferred Taxes - Fixed Assets	60,771	54,900	(5,871)	49
50	Total Federal Income Tax	93,481	74,548	(18,933)	50

(1) *PG&E Opening Brief* model at page 1-17. Further details shown in RO workpapers, Exhibit ALJ-1.

APPENDIX F: Table 5

Pacific Gas and Electric Company

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

2011 - 2014 Capital Expenditures Above Gas Accord V (GAV)

Rate Base at Proposed and Adopted - Test Year 2015

Total Gas Transmission Base Revenue Requirement Request - incl. PSEP Recorded

(Thousands of Dollars)

Line No.	Description	PG&E Brief (1)	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
	WEIGHTED AVERAGE PLANT:				
1	Plant Beginning Of Year (BOY)	5,609,415	5,002,013	(607,402)	1
2	Net Additions	200,102	196,548	(3,554)	2
3	Total Weighted Average Plant	5,809,517	5,198,561	(610,956)	3
	WORKING CAPITAL:				
4	Material and Supplies - Fuel	0	0	0	4
5	Material and Supplies - Other	29,846	29,846	0	5
6	Working Cash	42,713	41,834	(880)	6
7	Total Working Capital	72,559	71,679	(880)	7
	ADJUSTMENTS FOR TAX REFORM ACT:				
8	Deferred Capitalized Interest	4,664	4,653	(11)	8
9	Deferred Vacation	11,535	11,533	(2)	9
10	Deferred CIAC Tax Effects	218	218	0	10
11	Total Adjustments	16,417	16,404	(13)	11
12	CUSTOMER ADVANCES	18,770	18,770	0	12
	DEFERRED TAXES				
13	Accumulated Regulatory Assets	0	0	0	13
14	Accumulated Fixed Assets	537,226	399,705	(137,521)	14
15	Accumulated Other	0	0	0	15
16	Deferred ITC	5,843	5,818	(25)	16
17	Deferred Tax - Other	0	0	0	17
18	Total Deferred Taxes	543,070	405,523	(137,546)	18
19	DEPRECIATION RESERVE	1,882,481	1,910,569	28,088	19
20	TOTAL Ratebase	3,454,172	2,951,782	(502,391)	20

(1) *PG&E Opening Brief* model at page 1-17. Further details shown in RO workpapers, Exhibit ALJ-1.

APPENDIX G

SAFETY PROGRAM COSTS ($850 MILLION)

APPENDIX G

Pacific Gas and Electric Company

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Safety Program Costs ($850 million)

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APPENDIX G: Table 1 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Safety Program Costs ($850 million)
Expense Program Proposal Based on Adopted
(Thousands of Nominal Dollars)

Line	Exhibit (PG&E-1 & 2) Chapter	Chapter Name	Programs	Sub-Programs	Related MWC	2015 D.16-06-056 Adopted	2015 D.15-04-024 Penalty	2015 Adopted
						(A)	(B)	(C)
1	4A	Transmission Pipe Integrity and Emergency Response Programs	ILI		HP, II, JT, KE, KF, 34	31,521		31,521
2				ILI Casings		3,545		3,545
3				Non-Traditional ILI		146		146
4				Non-Traditional ILI DE&R		-		-
5				Traditional ILI		14,521		14,521
6				Traditional ILI DE&R		13,310		13,310
7			Direct Assessment		HP, II	24,982		24,982
8				External Critical Direct Assessment - ECDA		14,461		14,461
9				Internal Critical Direct Assessment - ICDA		7,664		7,664
10				Stress Corrosion Cracking Direct Assessment - SCCDA		2,857		2,857
11			Hydrostatic Testing		HP, II, JT, KE, KF, 34	103,475		2,548
12				Hydrostatic Testing		100,927	(100,927)	-
13				Hydrostatic Testing - LNG/CNG		2,548		2,548
14			Earthquake Fault Crossings		JT	2,590		2,590
15			Geo-Hazard Threat Identification		HP, JT, 34	211		211
16			Programs to Enhance Integrity Management		HP, II, JT, KE, KF	7,315		7,315
17				Risk Analysis		6,263		6,263
18				Root Cause Analysis		1,052		1,052
19			Inoperable and Hard to Operate Valves		KE, JT	242		242
20						170,337		69,410
21	4B	Transmission Pipe Engineering Programs	Class Location Program		HP, JT, KF, JO	3,985		3,985
22			Water and Levee Crossing		JT	1,372		1,372
23			Shallow Pipe Program		JT	3,073		3,073
24						8,429		8,429
25	6	Asset Family - Facilities	Engineering Critical Assessment Phase 2		JT, 34	8,682		8,682
26			Routine Spend M&C		34, JT, KE, KF	8,390		8,390
27			Engineering Critical Assessment Phase 1		JT, KF, 34	15,634		15,634
28						32,705		32,705
29	7	Corrosion Control	Cathodic Protection Rectifier		JO	450		450
30			Cathodic Protection Monitoring		JO	1,820		1,820
31			Cathodic Protection Resurvey		JO	177		177
32			Cathodic Protection Troubleshooting		JO	177		177
33			CP Corrective Maintenance		JO	1,340		1,340
34			Corrosion Investigations		HP, 34	5,455		5,455
35			Close Interval Survey		HP	8,759		8,759
36			AC Interference		HP, 34	528		528
37			DC Interference		HP, 34	2,552		2,552
38			Casings		HP, 34	39,592	(39,592)	-
39			Internal Corrosion		HP	8,784		8,784
40			Atmospheric Corrosion Inspection and Remediation		JO, JT, HP, 34	20,437		20,437
41						90,070		50,478
42	8	Gas Transmission System Operations and Maintenance	Locate and Mark		DF	8,986		8,986
43			Pipeline Maintenance		JO, KE, KF	30,182		30,182
44				Leak Management		6,128		6,128
45				Required Pipeline Patrol		8,553		8,553
46				Pipeline Maintenance and Repair		11,200		11,200
47				Operate Transmission Pipeline		3,406		3,406
48				Right-of-Way Support		895		895
49		Maintenance	Expense Projects		JT, KF	36,960		15,979
50				Pipeline Projects		30,614	(20,981)	9,633
51				Permits and Fees Projects		6,346		6,346
52						76,128		55,147
53					***Grand Total***	377,669	(161,500)	216,169

APPENDIX G: Table 2 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Safety Program Costs ($850 million)
Capital Addition Program Proposal Based on Adopted
(Thousands of Nominal Dollars)

Line	Exhibit (PG&E-1 & 2) Chapter	Chapter Name	Programs	Sub-Programs	Related MWC	2015 D.16-06-056 Gross Additions	2015 D.15-04-024 Penalty	2015 Adopted	2016 D.16-06-056 Increase	2016 D.16-06-056 Gross Additions	2016 D.15-04-024 Penalty (1)	2016 Adopted	2017 D.16-06-056 Increase	2017 D.16-06-056 Gross Additions	Total
						(A)	(B)	(C)=(A)+(B)	(D)	(E)=(A)+(D)	(F)	(G)=(E)+(F)	(H)	(I)=(E)+(H)	(J)=(C)+(G)+(I)
1	4A	Transmission Pipe Integrity and Emergency Response Programs	ILI	Traditional ILI Cost	44, 98	42,212	(42,212)	0	26,014	68,245	(49,937)	18,308	9,779	78,024	96,331
2				Non-Traditional ILI Cost	98	2,649	(2,649)	0	9,444	12,094	(8,849)	3,244	535	12,628	15,873
3						44,861	(44,861)	0	35,458	80,339	(58,787)	21,552	10,313	90,652	112,204
4			Hydrostatic Testing	Hydrotest - LNG/CNG Cost	73	2,781	(2,781)	0	63	2,845	(2,082)	763	73	2,918	3,681
5				Hydrostatic Testing	75	20,136	(20,136)	0	459	20,606	(15,078)	5,528	531	21,137	26,665
6						22,918	(22,918)	0	523	23,451	(17,160)	6,291	604	24,056	30,347
7			Earthquake Fault Crossings		44, 75	4,728	(4,728)	0	108	4,840	(3,541)	1,298	125	4,964	6,262
8			Vintage Pipe Replacement		44, 75	135,152	(135,152)	0	3,082	138,234	(101,151)	37,083	3,563	141,797	178,880
9			Geo-hazard Threat Identification		44, 75	7,055	(7,055)	0	161	7,219	(5,282)	1,937	186	7,405	9,341
10			Valve Automation		75	39,696	(39,696)	0	906	40,619	(29,723)	10,897	1,047	41,666	52,563
11			Inoperable and Hard to Operate Valves		75	6,292	(6,292)	0	144	6,439	(4,712)	1,727	166	6,605	8,333
12						260,701	(260,701)	0	40,381	301,141	(220,356)	80,785	16,004	317,145	397,930
13	4B	Transmission Pipe Engineering Programs	Class Location Program		44, 75	16,021	(16,021)	0	366	16,395	(11,997)	4,398	423	16,817	21,215
14			Water and Levee Crossing Program		44, 75	12,558	(12,558)	0	286	12,849	(9,402)	3,447	330	13,179	16,626
15			Shallow Pipe Program		44, 75	16,189	(16,189)	0	369	16,567	(12,123)	4,444	427	16,994	21,438
16						44,768	(44,768)	0	1,021	45,811	(33,522)	12,289	1,180	46,990	59,280
17	6	Asset Family - Facilities	Gas Transmission SCADA Visibility		76	5,327	(5,327)	0	122	5,451	(3,989)	1,462	141	5,592	7,054
18			Routine Capital Spending - M&C		75, 76	19,309	(19,309)	0	441	19,759	(14,458)	5,301	509	20,268	25,568
19						24,636	(24,636)	0	562	25,210	(18,447)	6,763	649	25,859	32,622
20	7	Corrosion Control	CP Systems - Replace		75	3,061	(3,061)	0	70	3,133	(2,292)	840	80	3,213	4,053
21			CP Systems - New		75	7,704	(7,704)	0	176	7,884	(5,769)	2,115	202	8,086	10,201
22			Coupon Test Stations		75	1,105	(1,105)	0	25	1,131	(827)	303	29	1,160	1,463
23			AC Interference Mitigation		75	4,270	(4,270)	0	97	4,370	(3,198)	1,172	113	4,482	5,655
24			DC Interference Mitigation		44, 75	756	(756)	0	17	774	(566)	208	20	794	1,001
25			Casings		44,75	15,985	(15,985)	0	365	16,357	(11,969)	4,388	421	16,778	21,166
26			Internal Corrosion		75, 84	503	(503)	0	11	514	(376)	138	13	528	665
27			(Reference Information on Other Historical Work)		75	0	0	0	0	0	0	0	0	0	0
28						33,384	(33,384)	0	762	34,162	(24,997)	9,164	879	35,041	44,205
29	9	Program Management Office	Program Management Office		75	6,124	(6,124)	0	140	6,264	(4,584)	1,680	161	6,425	8,106
30						6,124	(6,124)	0	140	6,264	(4,584)	1,680	161	6,425	8,106
31	10	Gas System Operations	Capacity		73	9,710	(9,710)	0	222	9,937	(7,271)	2,666	256	10,193	12,858
32						9,710	(9,710)	0	222	9,937	(7,271)	2,666	256	10,193	12,858
33					Grand Total	379,324	(379,324)	0	43,087	422,524	(309,177)	113,347	19,130	441,654	555,001

(688,501) Net of 2015 and 2016

Note (1) - Penalty applied on a proportional basis using 2016 D.16-06-056 amounts.

APPENDIX G: Table 3 (New)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Safety Program Costs ($850 million)
Revenue Requirement Impact of Rate Base (RB) Adjustment in 2015 and 2016
(Thousands of Dollars)

	Total	2015	2016
2016 Total Company Rate Base Adj - EOY	688,502	379,325	309,177

Line			2015 (A)	2016 (B)	2017 (C)	2018 (D)
	Revenue Requirement Calculations *(Note 1)* **:**					
1	Revenue Requirement	*(L9 + L10)*	**5,298**	**(47,906)**	**(94,657)**	**(93,745)**
2	Uncollectibles	*(L1 x Uncollectible Rate)*	17	(156)	(307)	(304)
3	Franchise Fees	*(L1 x Franchise Fee Rate)*	50	(450)	(889)	(881)
4	Subtotal	*(L2 + L3)*	67	(605)	(1,196)	(1,185)
5	Property Tax	*(Prior Yr Net Plant x L23 / 2) + (Current Yr Net Plant x L23 / 2)*	0	(2,079)	(5,826)	(7,436)
6	Income Taxes	*(L21)*	14,914	(742)	(21,754)	(20,201)
7	Depreciation	*Depreciable Plant x 1/58 (WAVG Life)*	(1,706)	(7,931)	(11,871)	(11,871)
8	Subtotal	*(L5 + L6 + L7)*	13,208	(10,752)	(39,451)	(39,508)
9	Operating Expenses	*(L4 + L8)*	13,275	(11,358)	(40,647)	(40,693)
10	Net for Return	*(L11 x L12)*	(7,977)	(36,548)	(54,009)	(53,053)
11	Wt Avg (WAVG) Rate Base	*(2015 & 2016 Rate Base Adjustment amortized down over 58 years)*	(98,970)	(453,452)	(670,091)	(658,220)
12	Rate of Return %	*(PG&E's Authorized Cost of Capital)*	8.06%	8.06%	8.06%	8.06%
	Income Tax Calculations:					
13	WAVG Rate Base	*(2015 & 2016 Rate Base Adjustment amortized down over 58 years)*	(98,970)	(453,452)	(670,091)	(658,220)
14	WAVG Preferred & Equity	*(PG&E's Authorized Cost of Capital - equity portion)*	5.46%	5.46%	5.46%	5.46%
15	Equity Earnings	*(L13 x L14)*	(5,408)	(24,777)	(36,614)	(35,965)
16	Property Tax Deduction	*(L5)*	0	(2,079)	(5,826)	(7,436)
17	Tax Repair Deduction *(Note 2)*	*(2015 & 2016 Rate Base Adjustment x Auth.Tax Repair Deduction %)*	(27,096)	(21,618)	848	848
18	Subtotal Deductions	*(L16 + L17)*	(27,096)	(23,697)	(4,978)	(6,588)
19	Taxable Income	*(L15 - L18)*	21,688	(1,080)	(31,636)	(29,377)
20	Combined Tax Rate (Incl. NTG)	*Tab FactorsAndRates: L9*	68.765%	68.765%	68.765%	68.765%
21	Income Tax	*(L19 x L20)*	14,914	(742)	(21,754)	(20,201)

Note 1 : Workpapers show revenue requirements through 2075.
Note 2 : FIT Repair Allowance Adjustment, Exhibit (PG&E-2), page 16-18.

APPENDIX G: Table 4 (New)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Safety Program Costs ($850 million)
PG&E-TURN-ORA Exhibit Joint 1, Depreciation Stipulation, Table 15A-1 Extract
Calculation of Weighted Average Survivor Curve Life
(Thousands of Dollars)

Line No.		Future Accruals (A)	Survivor Curve (B)	Weighted Average Life Calculation (C) = (A) x (B)
	GAS PLANT			
	Transmission Plant (excluding Line 401 and Stanpac)			
1	366.1 Compressor Station Structures	11,402,662	50 - R2	570,133,088
2	366.2 Measuring and Regulating Station Structures	8,263,678	50 - R2	413,183,892
3	366.3 Other Transmission System Structures	14,221,117	40 - R2	568,844,688
4	367 Mains	1,935,123,086	62 - R2	119,977,631,326
5	368 Compressor Station Equipment	253,440,118	40 - R2	10,137,604,722
6	369 Measuring and Regulating Station Equipment	195,586,533	45 - R1	8,801,394,005
7	371 Other Equipment	37,224,475	50 - R1.5	1,861,223,764
8	**Total Transmission Plant (excluding Line 401 and Stanpac)**	**2,455,261,669**		**142,330,015,486**
9				**Weighted Average Life = Total (C) / Total (A)** **58**

(END OF APPENDIX G)

APPENDIX H

DISALLOWED CAPITAL

APPENDIX H

Pacific Gas and Electric Company

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Disallowed Capital

TABLE INDEX

APPENDIX H: Table 1
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Summary of Disallowed Capital (Note 1)
(Thousands of Nominal Dollars)

A. 2011-2014 Capital Expenditures (CapEx) Above Gas Accord V (GAV)

Line	Cost Categories	Planning Order Number	MWC	2011 CapEx Above GAV	2012 CapEx Above GAV	2013 CapEx Above GAV	2014 CapEx Above GAV	2011-2014 Total CapEx Above GAV
				(a)	(b)	(c)	(d)	(e)=(a)+(b)+(c)+(d)
1	104 Projects	5723873	98	3,149	509	5	0	3,663
2	104 Projects	5723872	98	0	556	900	0	1,456
3	104 Projects	5723874	98	1,867	408	5	0	2,280
4	104 Projects	5748018	98	0	0	1,389	60	1,449
5	104 Projects	5747997	98	0	0	1,277	4,200	5,477
6	104 Projects	5723868	98	500	3,168	112	0	3,781
7				5,515	4,642	3,688	4,260	18,106
8	104 Projects	5726804	75	0	14,019	(1,057)	0	12,962
9	104 Projects	5735703	75	0	0	1,187	4	1,190
10	104 Projects	5726808	75	0	7,280	0	0	7,280
11				0	21,299	129	4	21,433
12	<$1M (*Note 2)*			13,967	30,976	12,259	23,668	80,870
13				13,967	30,976	12,259	23,668	80,870
14	Total Spend Disallowed			19,482	56,917	16,077	27,932	**120,409**

Line		Capital Through 2017
	B. Corrision Control (Exhibit (PG&E-1), page 7-6, lines 6-12)	
15	Costs incurred through 2017 to bring corroision program into compliance	**21,000**

Line		Capital Through 2017
16	**C. Remedies (Exhibit (PG&E-137))**	**1,398**

Line		2015	2016	2017	2018	Capital Through 2018
17	**D. Shallow Pipe Program** *(Note 3)*	**4,344**	**4,443**	**4,559**	**4,678**	**18,024**

Line		2015	2016	2017	2018	Capital Through 2018
18	**E. Casings Program** *(Note 3)*	**4,048**	**4,141**	**4,249**	**4,359**	**16,797**

Note 1 - Amounts disallowed on a forecast basis may differ from recorded disallowances (amounts spent above Adopted).
Note 2 - Order detail shown on workpaper file "*Planning Order Detail For Cap Over GAV_2011-2014.xlsb*".
Note 3 - 2016 through 2018 escalation based on Appendix E: Table 7.

(END OF APPENDIX H)

APPENDIX I

BALANCING ACCOUNT ADOPTED COSTS

APPENDIX I

Pacific Gas and Electric Company

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Balancing Account Adopted Costs

TABLE INDEX

APPENDIX I: Table 1 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Balancing Account Adopted Costs
Adopted Transmission Integrity Management Program (TIMP) Expense
(Thousands of Nominal Dollars)

			Adopted			
Line	**Ex. (PG&E-1), Ch. 4 TIMP Program Description (Table 4-2)**	**MWC**	**2015**	**2016** [1]	**2017** [1]	**2018** [1]
1	Traditional In-Line Inspections (ILI)	HP	14,521	17,737	34,535	35,315
2	Non-Traditional ILI	HP	146	149	152	156
3	ILI Casings	HP	3,545	3,629	3,714	3,798
4	Traditional ILI - Direct Examinations and Repairs	HP	13,310	10,126	18,328	18,742
5	Non-Traditional ILI - Direct Examinations and Repairs	HP	-	-	-	-
6	External Corrosion Direct Assessments	HP	14,461	16,684	21,800	22,279
7	Internal Corrosion Direct Assessments	HP	7,664	9,381	11,004	11,246
8	Stress Corrosion Cracking Direct Assessments	HP	2,857	2,925	2,993	3,061
9	TIMP Pressure Tests [2]	JT	-	10,469	10,709	10,945
10	Geological Hazard Monitoring	HP	211	216	221	226
11	Root Cause Analyses	HP	1,052	1,077	1,102	1,127
12	Risk Analysis Process Improvements	HP	6,263	6,412	6,562	6,711
13	Total	HP	64,029	78,806	111,121	113,604

Notes:
(1) 2016 through 2018 escalation based on Appendix E: Table 7.
(2) 2015 adjusted based on Appendix G: Table 1 Safety Program Penalty reductions

APPENDIX I: Table 2 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Balancing Account Adopted Costs
Adopted Transmission Integrity Management Program (TIMP) Capital
(Thousands of Nominal Dollars)

			Adopted				
Line	**Ex. (PG&E-1), Ch. 4 TIMP Program Description (Table 4-2)**	**MWC**	**2015 [1]**	**2016 [1]**	**2017**	**2018 [2]**	**Notes**
1	Traditional In-Line Inspections (ILI) Expenditures	98 & 44	12,099	24,831	78,983	81,037	Appendix E: Table 6
2	Non-Traditional ILI Expenditures	98	210	3,640	13,559	13,912	PG&E Chapter 4a workpapers
3	Total ILI Capital Expenditures	98 & 44	12,309	28,472	92,542	94,948	

Notes:
(1) Amounts adjusted based on Appendix G, Table 2 capital addition reductions (including Cost of Removal at 4.61%).
(2) 2018 escalation based on Appendix E: Table 7.

APPENDIX I: Table 3 (Updated)
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Balancing Account Adopted Costs
Adopted Facilities Program Expense (PG&E Chapter 6)
(Thousands of Nominal Dollars)

			Adopted			
Line	Ex. (PG&E-1), Chapter 6 Program Description	MWC	2015	2016	2017	2018
1	Engineering Critical Assessment Phase 1	JT	15,634	16,008	16,384	16,756
			-	-	-	-
2	Engineering Critical Assessment Phase 2	JT	8,682	8,890	9,099	9,305
3	Total	JT	24,316	24,898	25,483	26,061

Note: 2016 through 2018 escalation based on Appendix E: Table 7.

APPENDIX I: Table 4
Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Balancing Account Adopted Costs
Adopted Work Required by Others
(Thousands of Nominal Dollars)

			Adopted				
Line	**Ex. (PG&E-1), Chapter 4b Program Description**	**MWC**	**2015**	**2016**	**2017**	**2018**	**Notes**
1	Work Required by Others	83	17,300	17,698	18,158	18,630	Appendix E: Table 7
2	Total	83	17,300	17,698	18,158	18,630	

(END OF APPENDIX I)

APPENDIX J

RATES

APPENDIX J

Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Rates

TABLE INDEX

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 1 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

Illustrative 2015 GT&S Undercollection with $850 Million Penalty

36-Month Amortization (January 2015 thru July 2016 Undercollection) of 2015 GT&S Authorized Revenue Requirements

($000)

Line		Interim [1] Adopted Total Undercollection Amount	*Less* 2015 [2] D.16-06-056 Authorized	*Add* 2015 [3] Final w/$850M Authorized	2015 Decrease to Undercollection	*Less* 2016 [2] D.16-06-056 Authorized	*Add* 2016 [3] Final w/$850M Authorized	2016 Decrease to Undercollection	Amount Recovered in 2016 8/1/16 thru 12/31/16	Total Unamortized Balance [4] (over 31 months)
	Core	A	B	C	D = C - B	E	F	G = F - E	H	I = A + D + G + H
1	Local Transmission	445,045	384,626	340,493	(44,132)	478,272	453,198	(25,074)	(61,812)	314,027
2	Storage (Includes Carrying Cost on Working Gas)	22,537	61,615	59,922	(1,693)	73,108	72,895	(213)	(3,130)	17,501
3	Backbone [4]	13,515	68,256	56,446	(11,809)	88,814	84,429	(4,385)	(1,877)	(4,556)
4	Subtotal	481,098	514,497	456,861	(57,635)	640,194	610,522	(29,672)	(66,819)	326,972
	Noncore									
5	Local Transmission	203,481	194,023	171,742	(22,281)	229,009	217,089	(11,920)	(28,261)	141,019
6	Storage (Includes Carrying Cost on Working Gas)	(34,979)	13,018	13,454	436	14,563	14,534	(29)	4,858	(29,714)
7	Backbone (Excludes G-XF)	48,885	179,197	165,955	(13,242)	219,046	212,337	(6,709)	(6,790)	22,144
8	Subtotal	217,388	386,238	351,151	(35,088)	462,618	443,960	(18,658)	(30,193)	133,449
9	Line 401 G-XF Contracts	(486)	5,237	5,237	1	6,016	5,986	(31)	68	(449)
10	Customer Access Charge - Transmission	(4,118)	2,384	2,524	140	2,770	2,770	(0)	572	(3,406)
11	**Total 2015 GT&S Undercollection RRQ**	**693,882**	**908,355**	**815,773**	**(92,582)**	**1,111,598**	**1,063,237**	**(48,361)**	**(96,372)**	**456,566**

Notes

1) Undercollection based on interim authorized revenue requirements, approved in AL 3727-G, effective August 1, 2016

2) Revenue Requirement (RRQ) authorized by D.16-06-056 effective August 1, 2016

3) Revenue Requirement (RRQ) Adopted effective January 1, 2017

4) Assumes January 1, 2017 implementation of $850 Million Penalty Decision

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 1 (Updated) (Continued)

PACIFIC GAS AND ELECTRIC COMPANY

Illustrative 2015 GT&S Undercollection with $850 Million Penalty

Amortization Over 36 Months Beginning August 1, 2016

Line		Total Unamortized Balance (over 31 months)	2017 (12 months) Undercollection Recovery	2018 (12 months) Undercollection Recovery	2019 (7 months) Undercollection Recovery
	Core	A	B	C	D
1	Local Transmission	314,027	121,559	121,559	70,909
2	Storage (Includes Carrying Cost on Working Gas)	17,501	6,774	6,774	3,952
3	Backbone	(4,556)	(1,764)	(1,764)	(1,029)
4	Subtotal	326,972	126,570	126,570	73,832
	Noncore				
5	Local Transmission	141,019	54,588	54,588	31,843
6	Storage (Includes Carrying Cost on Working Gas)	(29,714)	(11,502)	(11,502)	(6,710)
7	Backbone (Excludes G-XF)	22,144	8,572	8,572	5,000
8	Subtotal	133,449	51,658	51,658	30,134
9	Line 401 G-XF Contracts	(449)	(174)	(174)	(101)
10	Customer Access Charge - Transmission	(3,406)	(1,318)	(1,318)	(769)
11	**Total 2015 GT&S Undercollection RRQ**	**456,566**	**176,735**	**176,735**	**103,096**

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 2 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

End-User Rates Including Shortfall Collected Over 36 Months From August 1, 2016

Illustrative End-Use Class Average Rates

($/dth) (5)

Line No.		Rates Effective January 1, 2015 (1)	Adopted Rates 2015 GT&S (Year 2015 Components)	$ Change (e)	% Change	Rates Effective Janaury 1, 2016 (2)	Adopted Rates 2015 GT&S (Year 2016 Components)	$ Change (e)	% Change	Adopted Rates 2015 GT&S (Year 2017 Components)	$ Change (e)	% Change	Adopted Rates 2015 GT&S (Year 2018 Components)	$ Change (e)	% Change
		A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Core Retail Bundled Service (3)														
1	Residential Non-CARE**/***	14.9666	15.6878	0.7212	4.8%	14.7271	16.5801	1.8530	12.6%	16.6575	0.0774	0.5%	16.9859	0.3285	2.0%
2	Small Commercial Non-CARE**	10.5090	11.2319	0.7229	6.9%	9.6070	11.4346	1.8276	19.0%	11.5066	0.0720	0.6%	11.8298	0.3233	2.8%
3	Large Commercial	7.7285	8.4554	0.7269	9.4%	6.8696	8.6535	1.7839	26.0%	8.7160	0.0625	0.7%	9.0303	0.3144	3.6%
4	Uncompressed Core NGV	6.1712	6.8977	0.7265	11.8%	5.1829	6.9622	1.7793	34.3%	7.0240	0.0618	0.9%	7.3376	0.3137	4.5%
5	Compressed Core NGV	21.7330	22.4594	0.7264	3.3%	20.9599	22.7392	1.7793	8.5%	22.8010	0.0618	0.3%	23.1147	0.3137	1.4%
	Core Retail Transport Only (4)														
6	Residential Non-CARE**/***	9.0724	10.7277	1.6553	18.2%	10.9000	12.6079	1.7079	15.7%	12.6388	0.0309	0.2%	12.9192	0.2805	2.2%
7	Small Commercial	4.6506	6.4430	1.7924	38.5%	5.9599	7.6678	1.7079	28.7%	7.6987	0.0309	0.4%	7.9791	0.2805	3.6%
8	Large Commercial	2.2158	3.9913	1.7755	80.1%	3.5407	5.2486	1.7079	48.2%	5.2795	0.0309	0.6%	5.5599	0.2805	5.3%
9	Uncompressed Core NGV	1.4281	2.4566	1.0285	72.0%	1.8763	3.5842	1.7079	91.0%	3.6151	0.0309	0.9%	3.8955	0.2805	7.8%
10	Compressed Core NGV	17.0018	18.0183	1.0165	6.0%	17.6533	19.3612	1.7079	9.7%	19.3921	0.0309	0.2%	19.6726	0.2805	1.4%
	Noncore Retail Transportation Only (4)														
11	Industrial – Distribution	1.7763	2.6085	0.8322	46.8%	2.3857	3.0853	0.6996	29.3%	3.0902	0.0048	0.2%	3.2249	0.1347	4.4%
12	Industrial – Transmission	0.3758	1.0508	0.6750	179.6%	0.7880	1.4790	0.6910	87.7%	1.4832	0.0042	0.3%	1.6174	0.1343	9.1%
13	Industrial – Backbone	0.0820	0.4386	0.3566	434.7%	0.4567	0.4575	0.0008	0.2%	0.4382	-0.0192	-4.2%	0.4565	0.0183	4.2%
14	Uncompressed Noncore NGV – Distribution	1.7763	2.4338	0.6575	37.0%	2.1911	2.8907	0.6996	31.9%	2.8956	0.0048	0.2%	3.0303	0.1347	4.7%
15	Uncompressed Noncore NGV – Transmission	0.2826	0.8690	0.5864	207.5%	0.6132	1.3041	0.6910	112.7%	1.3083	0.0042	0.3%	1.4426	0.1343	10.3%
16	Electric Generation – Distribution/Transmission	0.2920	0.6147	0.3227	110.5%	0.3658	1.0610	0.6952	190.0%	1.0658	0.0048	0.5%	1.2002	0.1344	12.6%
17	Electric Generation – Backbone	0.0915	0.0935	0.0020	2.2%	0.1242	0.1328	0.0086	6.9%	0.1140	-0.0188	-14.2%	0.1326	0.0186	16.3%
	Wholesale Transportation Only (4)														
18	Alpine Natural Gas	0.3041	0.5939	0.2898	95.3%	0.3638	1.0392	0.6754	185.6%	1.0419	0.0027	0.3%	1.1751	0.1332	12.8%
19	Coalinga	0.3131	0.5976	0.2845	90.9%	0.3725	1.0429	0.6704	180.0%	1.0454	0.0025	0.2%	1.1784	0.1330	12.7%
20	Island Energy	0.5102	0.7104	0.2002	39.2%	0.5683	1.1656	0.5973	105.1%	1.1622	-0.0034	-0.3%	1.2898	0.1276	11.0%
21	Palo Alto	0.2639	0.5719	0.3080	116.7%	0.3225	1.0141	0.6916	214.5%	1.0184	0.0043	0.4%	1.1527	0.1343	13.2%
22	West Coast Gas - Castle	2.3110	2.5500	0.2390	10.3%	2.3965	3.0259	0.6294	26.3%	3.0262	0.0003	0.0%	3.1573	0.1311	4.3%
23	West Coast Gas - Mather D	2.8711	3.1365	0.2654	9.2%	2.9641	3.6167	0.6526	22.0%	3.6189	0.0022	0.1%	3.7514	0.1325	3.7%
24	West Coast Gas - Mather T	0.3430	0.6084	0.2654	77.4%	0.4015	1.0541	0.6526	162.5%	1.0563	0.0022	0.2%	1.1888	0.1325	12.5%

Notes:

1) 2015 rates are based on PG&E's 2015 Annual Gas True-up (AGT) filing per Advice Letter 3547-G including Interim 2015 Gas Accord V (2014 Rev. Req. + 2% escalator).

2) 2016 rates are based on PG&E's 2016 Annual Gas True-up (AGT) filing per Advice Letter 3644-G and Gas Accord V rates filed in Advice Letter 3547-G.

3) PG&E's bundled gas service is available to core customers only. Intrastate backbone transmission and storage costs addressed in this proceeding are included in end-use rates paid by bundled core customers. Bundled service also includes a procurement cost for gas purchases, shrinkage, transportation on Canadian and Interstate pipelines, core brokerage, and franchise fees and uncollectibles expense. The illustrative annual average rates for these elements are based on the illustrative revenue requirements shown on PG&E's Preliminary Statement Part C2. Core bundled rates also includes the cost of transportation and delivery of gas from the citygate to the customer's burnertip, including local transmission, distribution, customer access, public purpose, and mandated programs and other charges.

4) PG&E's transportation-only gas service is for core and noncore customers. Transportation-only service begins at PG&E's citygate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission, including distribution, customer access, public purpose programs and customer class charges. Transportation-only rates exclude backbone transmission and storage costs.

5) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

Dollar difference are due to rounding.

Non-GT&S rate components for 2016, 2017 and 2018 are held constant at January 1, 2016 levels as filed in PG&E's 2016 AGT Advice Letter 3664-G.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

D.16-06-056

APPENDIX J: Table 3

PACIFIC GAS AND ELECTRIC COMPANY

End-User Rates Including Shortfall Collected Over 36 Months From August 1, 2016
Illustrative End-Use Class Average Rates
($/dth) (5)

Line No.		Rates Effective January 1, 2015 (1)	D. 16-06-056 2015 GT&S (Year 2015 Components)	$ Change (e)	% Change	Rates Effective Janaury 1, 2016 (2)	D. 16-06-056 2015 GT&S (Year 2016 Components)	$ Change (e)	% Change	D. 16-06-056 2015 GT&S (Year 2017 Components)	$ Change (e)	% Change	D. 16-06-056 2015 GT&S (Year 2018 Components)	$ Change (e)	% Change
		A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Core Retail Bundled Service (3)														
1	Residential Non-CARE**/***	14.9666	15.8998	0.9332	6.2%	14.7271	16.6840	1.9569	13.3%	16.9485	0.2645	1.6%	17.1911	0.2427	1.4%
2	Small Commercial Non-CARE**	10.5090	11.4356	0.9266	8.8%	9.6070	11.5363	1.9293	20.1%	11.7931	0.2568	2.2%	12.0304	0.2374	2.0%
3	Large Commercial	7.7285	8.6434	0.9149	11.8%	6.8696	8.7511	1.8815	27.4%	8.9941	0.2430	2.8%	9.2228	0.2287	2.5%
4	Uncompressed Core NGV	6.1712	7.0846	0.9134	14.8%	5.1829	7.0598	1.8769	36.2%	7.3019	0.2421	3.4%	7.5297	0.2279	3.1%
5	Compressed Core NGV	21.7330	22.6463	0.9133	4.2%	20.9599	22.8368	1.8769	9.0%	23.0789	0.2421	1.1%	23.3068	0.2279	1.0%
	Core Retail Transport Only (4)														
6	Residential Non-CARE**/***	9.0724	10.8873	1.8149	20.0%	10.9000	12.6987	1.7987	16.5%	12.9027	0.2040	1.6%	13.0975	0.1949	1.5%
7	Small Commercial	4.6506	6.6026	1.9520	42.0%	5.9599	7.7586	1.7987	30.2%	7.9626	0.2040	2.6%	8.1574	0.1949	2.4%
8	Large Commercial	2.2158	4.1509	1.9351	87.3%	3.5407	5.3394	1.7987	50.8%	5.5434	0.2040	3.8%	5.7383	0.1949	3.5%
9	Uncompressed Core NGV	1.4281	2.6162	1.1881	83.2%	1.8763	3.6750	1.7987	95.9%	3.8790	0.2040	5.6%	4.0738	0.1949	5.0%
10	Compressed Core NGV	17.0018	18.1779	1.1761	6.9%	17.6533	19.4520	1.7987	10.2%	19.6560	0.2040	1.0%	19.8509	0.1949	1.0%
	Noncore Retail Transportation Only (4)														
11	Industrial – Distribution	1.7763	2.6798	0.9035	50.9%	2.3857	3.1245	0.7389	31.0%	3.2172	0.0926	3.0%	3.3019	0.0848	2.6%
12	Industrial – Transmission	0.3758	1.1215	0.7457	198.4%	0.7880	1.5182	0.7302	92.7%	1.6101	0.0920	6.1%	1.6945	0.0843	5.2%
13	Industrial – Backbone	0.0820	0.4382	0.3562	434.2%	0.4567	0.4575	0.0008	0.2%	0.4569	-0.0005	-0.1%	0.4565	-0.0004	-0.1%
14	Uncompressed Noncore NGV – Distribution	1.7763	2.5051	0.7288	41.0%	2.1911	2.9299	0.7389	33.7%	3.0226	0.0926	3.2%	3.1073	0.0848	2.8%
15	Uncompressed Noncore NGV – Transmission	0.2826	0.9397	0.6571	232.5%	0.6132	1.3433	0.7302	119.1%	1.4353	0.0920	6.8%	1.5196	0.0843	5.9%
16	Electric Generation – Distribution/Transmission	0.2920	0.6856	0.3936	134.8%	0.3658	1.1002	0.7344	200.8%	1.1928	0.0926	8.4%	1.2772	0.0844	7.1%
17	Electric Generation – Backbone	0.0915	0.0934	0.0019	2.1%	0.1242	0.1328	0.0086	6.9%	0.1327	-0.0001	-0.1%	0.1326	-0.0001	-0.1%
	Wholesale Transportation Only (4)														
18	Alpine Natural Gas	0.3041	0.6633	0.3592	118.2%	0.3638	1.0785	0.7146	196.4%	1.1689	0.0905	8.4%	1.2521	0.0832	7.1%
19	Coalinga	0.3131	0.6669	0.3538	113.0%	0.3725	1.0821	0.7096	190.5%	1.1724	0.0903	8.3%	1.2554	0.0830	7.1%
20	Island Energy	0.5102	0.7735	0.2633	51.6%	0.5683	1.2048	0.6365	112.0%	1.2892	0.0844	7.0%	1.3668	0.0776	6.0%
21	Palo Alto	0.2639	0.6426	0.3787	143.5%	0.3225	1.0533	0.7308	226.6%	1.1454	0.0921	8.7%	1.2297	0.0843	7.4%
22	West Coast Gas - Castle	2.3110	2.6168	0.3058	13.2%	2.3965	3.0651	0.6686	27.9%	3.1532	0.0881	2.9%	3.2343	0.0811	2.6%
23	West Coast Gas - Mather D	2.8711	3.2052	0.3341	11.6%	2.9641	3.6559	0.6918	23.3%	3.7459	0.0900	2.5%	3.8284	0.0825	2.2%
24	West Coast Gas - Mather T	0.3430	0.6771	0.3341	97.4%	0.4015	1.0933	0.6918	172.3%	1.1833	0.0900	8.2%	1.2658	0.0825	7.0%

Notes:

1) 2015 rates are based on PG&E's 2015 Annual Gas True-up (AGT) filing per Advice Letter 3547-G.

2) 2016 rates are based on PG&E's 2016 Annual Gas True-up (AGT) filing per Advice Letter 3644-G and Gas Accord V rates filed in Advice Letter 3547-G.

3) PG&E's bundled gas service is available to core customers only. Intrastate backbone transmission and storage costs addressed in this proceeding are included in end-use rates paid by bundled core customers. Bundled service also includes a procurement cost for gas purchases, shrinkage, transportation on Canadian and Interstate pipelines, core brokerage, and franchise fees and uncollectibles expense. The illustrative annual average rates for these elements are based on the illustrative revenue requirements shown on PG&E's Preliminary Statement Part C2. Core bundled rates also includes the cost of transportation and delivery of gas from the citygate to the customer's burnertip, including local transmission, distribution, customer access, public purpose, and mandated programs and other charges.

4) PG&E's transportation-only gas service is for core and noncore customers. Transportation-only service begins at PG&E's citygate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission, including distribution, customer access, public purpose programs and customer class charges. Transportation-only rates exclude backbone transmission and storage costs.

5) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

Dollar difference are due to rounding.

Non-GT&S rate components for 2016, 2017 and 2018 are held constant at January 1, 2016 levels as filed in PG&E's 2016 AGT Advice Letter 3664-G.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Changes from D. 16-06-056 with application of $850 million penalty

APPENDIX J: Table 4 (New)

PACIFIC GAS AND ELECTRIC COMPANY

End-User Rates Including Shortfall Collected Over 36 Months From August 1, 2016
Illustrative End-Use Class Average Rates
($/dth)

Line No.		2015 Rate Change from D. 16-06-056 to Adopted	% Change	2016 Rate Change from D. 16-06-056 to Adopted	% Change	2017 Rate Change from D. 16-06-056 to Adopted	% Change	2018 Rate Change from D. 16-06-056 to Adopted	% Change
		A	B	C	D	E	F	G	H
	Core Retail Bundled Service								
1	Residential Non-CARE**/***	-0.2120	-1.3%	-0.1039	-0.6%	-0.2910	-1.7%	-0.2052	-1.2%
2	Small Commercial Non-CARE**	-0.2037	-1.8%	-0.1017	-0.9%	-0.2865	-2.4%	-0.2006	-1.7%
3	Large Commercial	-0.1880	-2.2%	-0.0976	-1.1%	-0.2781	-3.1%	-0.1924	-2.1%
4	Uncompressed Core NGV	-0.1869	-2.6%	-0.0976	-1.4%	-0.2779	-3.8%	-0.1921	-2.6%
5	Compressed Core NGV	-0.1869	-0.8%	-0.0976	-0.4%	-0.2779	-1.2%	-0.1921	-0.8%
	Core Retail Transport Only								
6	Residential Non-CARE**/***	-0.1596	-1.5%	-0.0908	-0.7%	-0.2639	-2.0%	-0.1783	-1.4%
7	Small Commercial	-0.1596	-2.4%	-0.0908	-1.2%	-0.2639	-3.3%	-0.1783	-2.2%
8	Large Commercial	-0.1596	-3.8%	-0.0908	-1.7%	-0.2639	-4.8%	-0.1783	-3.1%
9	Uncompressed Core NGV	-0.1596	-6.1%	-0.0908	-2.5%	-0.2639	-6.8%	-0.1783	-4.4%
10	Compressed Core NGV	-0.1596	-0.9%	-0.0908	-0.5%	-0.2639	-1.3%	-0.1783	-0.9%
	Noncore Retail Transportation Only								
11	Industrial – Distribution	-0.0713	-2.7%	-0.0392	-1.3%	-0.1270	-3.9%	-0.0770	-2.3%
12	Industrial – Transmission	-0.0707	-6.3%	-0.0392	-2.6%	-0.1270	-7.9%	-0.0770	-4.5%
13	Industrial – Backbone	0.0004	0.1%	0.0000	0.0%	-0.0187	-4.1%	0.0000	0.0%
14	Uncompressed Noncore NGV – Distribution	-0.0713	-2.8%	-0.0392	-1.3%	-0.1270	-4.2%	-0.0770	-2.5%
15	Uncompressed Noncore NGV – Transmission	-0.0707	-7.5%	-0.0392	-2.9%	-0.1270	-8.8%	-0.0770	-5.1%
16	Electric Generation – Distribution/Transmission	-0.0709	-10.3%	-0.0392	-3.6%	-0.1270	-10.6%	-0.0770	-6.0%
17	Electric Generation – Backbone	0.0001	0.1%	0.0000	0.0%	-0.0187	-14.1%	0.0000	0.0%
	Wholesale Transportation Only								
18	Alpine Natural Gas	-0.0694	-10.5%	-0.0392	-3.6%	-0.1270	-10.9%	-0.0770	-6.2%
19	Coalinga	-0.0693	-10.4%	-0.0392	-3.6%	-0.1270	-10.8%	-0.0770	-6.1%
20	Island Energy	-0.0631	-8.2%	-0.0392	-3.3%	-0.1270	-9.9%	-0.0770	-5.6%
21	Palo Alto	-0.0707	-11.0%	-0.0392	-3.7%	-0.1270	-11.1%	-0.0770	-6.3%
22	West Coast Gas - Castle	-0.0668	-2.6%	-0.0392	-1.3%	-0.1270	-4.0%	-0.0770	-2.4%
23	West Coast Gas - Mather D	-0.0687	-2.1%	-0.0392	-1.1%	-0.1270	-3.4%	-0.0770	-2.0%
24	West Coast Gas - Mather T	-0.0687	-10.1%	-0.0392	-3.6%	-0.1270	-10.7%	-0.0770	-6.1%

Notes:
Dollar difference are due to rounding.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 5 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

End-User Rates Including Shortfall Collected Over 36 Months From August 1, 2016

Illustrative End-Use Noncore and Wholesale Class Average Rates with Procurement Proxy (4)

($/dth)

Line No.		Rates Effective January 1, 2015 (1)	Adopted Rates 2015 GT&S (Year 2015 Components)	$ Change	% Change	Rates Effective Janaury 1, 2016 (2)(3)	Adopted Rates 2015 GT&S (Year 2016 Components)	$ Change	% Change	Adopted Rates 2015 GT&S (Year 2017 Components)	$ Change	% Change	Adopted Rates 2015 GT&S (Year 2018 Components)	$ Change	% Change
		A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Noncore Retail with Procurement Proxy														
1	Industrial – Distribution	6.2473	7.0496	0.8023	12.8%	5.6923	6.4633	0.7710	13.5%	6.4991	0.0357	0.6%	6.6670	0.1679	2.6%
2	Industrial – Transmission	4.8468	5.4919	0.6451	13.3%	4.0946	4.8570	0.7624	18.6%	4.8921	0.0351	0.7%	5.0595	0.1675	3.4%
3	Industrial – Backbone	4.5530	4.8797	0.3267	7.2%	3.7633	3.8355	0.0722	1.9%	3.8471	0.0117	0.3%	3.8986	0.0515	1.3%
4	Uncompressed Noncore NGV – Distribution	6.2473	6.8749	0.6276	10.0%	5.4977	6.2687	0.7710	14.0%	6.3045	0.0357	0.6%	6.4724	0.1679	2.7%
5	Uncompressed Noncore NGV – Transmission	4.7536	5.3101	0.5565	11.7%	3.9198	4.6821	0.7624	19.4%	4.7172	0.0351	0.7%	4.8847	0.1675	3.5%
6	Electric Generation – Distribution/Transmission	4.7630	5.0558	0.2928	6.1%	3.6724	4.4390	0.7666	20.9%	4.4747	0.0357	0.8%	4.6423	0.1676	3.7%
7	Electric Generation – Backbone	4.5625	4.5346	-0.0279	-0.6%	3.4308	3.5108	0.0800	2.3%	3.5229	0.0121	0.3%	3.5747	0.0518	1.5%
	Wholesale with Procurement Proxy														
8	Alpine Natural Gas	4.7750	5.0350	0.2600	5.4%	3.6704	4.4172	0.7468	20.3%	4.4508	0.0336	0.8%	4.6172	0.1664	3.7%
9	Coalinga	4.7841	5.0387	0.2546	5.3%	3.6791	4.4209	0.7418	20.2%	4.4543	0.0334	0.8%	4.6205	0.1662	3.7%
10	Island Energy	4.9812	5.1515	0.1703	3.4%	3.8749	4.5436	0.6687	17.3%	4.5711	0.0275	0.6%	4.7319	0.1608	3.5%
11	Palo Alto	4.7349	5.0130	0.2781	5.9%	3.6291	4.3921	0.7630	21.0%	4.4273	0.0352	0.8%	4.5948	0.1675	3.8%
12	West Coast Gas - Castle	6.7819	6.9911	0.2092	3.1%	5.7031	6.4039	0.7008	12.3%	6.4351	0.0312	0.5%	6.5994	0.1643	2.6%
13	West Coast Gas - Mather D	7.3421	7.5776	0.2355	3.2%	6.2707	6.9947	0.7240	11.5%	7.0278	0.0331	0.5%	7.1935	0.1657	2.4%
14	West Coast Gas - Mather T	4.8140	5.0495	0.2355	4.9%	3.7081	4.4321	0.7240	19.5%	4.4652	0.0331	0.7%	4.6309	0.1657	3.7%

Notes:

1) Procurement proxy based on PG&E's average core Natural Gas Vehicle (NGV) gas procurement rate filed in AL 3547-G, which includes costs for gas commodity, gas storage, gas transmission (i.e., Canadian, interstate and intrastate backbone) and transmission shrinkage.

2) Procurement proxy based on PG&E's average core Natural Gas Vehicle (NGV) gas procurement rate filed in AL 3644-G, which includes costs for gas commodity, gas storage, gas transmission (i.e., Canadian, interstate and intrastate backbone) and transmission shrinkage.

3) 2016 gas transportation rates are based on PG&E's 2016 Annual Gas True-up (AGT) filing per Advice Letter 3644-G and Gas Accord V rates filed in Advice Letter 3547-G.

4) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

Dollar difference are due to rounding.

Non-GT&S rate components for 2016, 2017 and 2018 are held constant at January 1, 2016 levels as filed in PG&E's 2016 AGT

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

D.16-06-056

APPENDIX J: Table 6

PACIFIC GAS AND ELECTRIC COMPANY

End-User Rates Including Shortfall Collected Over 36 Months From August 1, 2016

Illustrative End-Use Noncore and Wholesale Class Average Rates with Procurement Proxy (4)

($/dth)

Line No.		Rates Effective January 1, 2015 (1)	D. 16-06-056 2015 GT&S (Year 2015 Components)	$ Change	% Change	Rates Effective Janaury 1, 2016 (2)(3)	D. 16-06-056 2015 GT&S (Year 2016 Components)	$ Change	% Change	D. 16-06-056 2015 GT&S (Year 2017 Components)	$ Change	% Change	D. 16-06-056 2015 GT&S (Year 2018 Components)	$ Change	% Change
		A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Noncore Retail with Procurement Proxy														
1	Industrial – Distribution	6.2473	7.1488	0.9015	14.4%	5.6923	6.5122	0.8200	14.4%	6.6450	0.1327	2.0%	6.7628	0.1179	1.8%
2	Industrial – Transmission	4.8468	5.5905	0.7437	15.3%	4.0946	4.9059	0.8113	19.8%	5.0379	0.1321	2.7%	5.1558	0.1179	2.3%
3	Industrial – Backbone	4.5530	4.9072	0.3542	7.8%	3.7633	3.8452	0.0819	2.2%	3.8847	0.0396	1.0%	3.9178	0.0331	0.9%
4	Uncompressed Noncore NGV – Distribution	6.2473	6.9741	0.7268	11.6%	5.4977	6.3176	0.8200	14.9%	6.4504	0.1327	2.1%	6.5682	0.1179	1.8%
5	Uncompressed Noncore NGV – Transmission	4.7536	5.4087	0.6551	13.8%	3.9198	4.7310	0.8113	20.7%	4.8631	0.1321	2.8%	4.9810	0.1179	2.4%
6	Electric Generation – Distribution/Transmission	4.7630	5.1546	0.3916	8.2%	3.6724	4.4879	0.8155	22.2%	4.6206	0.1327	3.0%	4.7384	0.1179	2.6%
7	Electric Generation – Backbone	4.5625	4.5624	-0.0001	0.0%	3.4308	3.5205	0.0897	2.6%	3.5605	0.0400	1.1%	3.5936	0.0331	0.9%
	Wholesale with Procurement Proxy														
8	Alpine Natural Gas	4.7750	5.1323	0.3573	7.5%	3.6704	4.4662	0.7957	21.7%	4.5967	0.1306	2.9%	4.7130	0.1163	2.5%
9	Coalinga	4.7841	5.1359	0.3518	7.4%	3.6791	4.4698	0.7907	21.5%	4.6002	0.1304	2.9%	4.7163	0.1161	2.5%
10	Island Energy	4.9812	5.2425	0.2613	5.2%	3.8749	4.5925	0.7176	18.5%	4.7170	0.1245	2.7%	4.8277	0.1107	2.3%
11	Palo Alto	4.7349	5.1116	0.3767	8.0%	3.6291	4.4410	0.8119	22.4%	4.5732	0.1322	3.0%	4.6906	0.1174	2.6%
12	West Coast Gas - Castle	6.7819	7.0858	0.3039	4.5%	5.7031	6.4528	0.7497	13.1%	6.5810	0.1282	2.0%	6.6952	0.1142	1.7%
13	West Coast Gas - Mather D	7.3421	7.6742	0.3321	4.5%	6.2707	7.0436	0.7729	12.3%	7.1737	0.1301	1.8%	7.2893	0.1156	1.6%
14	West Coast Gas - Mather T	4.8140	5.1461	0.3321	6.9%	3.7081	4.4810	0.7729	20.8%	4.6111	0.1301	2.9%	4.7267	0.1156	2.5%

Notes:

1) Procurement proxy based on PG&E's average core Natural Gas Vehicle (NGV) gas procurement rate filed in AL 3547-G, which includes costs for gas commodity, gas storage, gas transmission (i.e., Canadian, interstate and intrastate backbone) and transmission shrinkage.

2) Procurement proxy based on PG&E's average core Natural Gas Vehicle (NGV) gas procurement rate filed in AL 3644-G, which includes costs for gas commodity, gas storage, gas transmission (i.e., Canadian, interstate and intrastate backbone) and transmission shrinkage.

3) 2016 gas transportation rates are based on PG&E's 2016 Annual Gas True-up (AGT) filing per Advice Letter 3644-G and Gas Accord V rates filed in Advice Letter 3547-G.

4) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

Dollar difference are due to rounding.

Non-GT&S rate components for 2016, 2017 and 2018 are held constant at January 1, 2016 levels as filed in PG&E's 2016 AGT

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Changes from D. 16-06-056 with application of $850 million penalty

APPENDIX J: Table 7 (New)

PACIFIC GAS AND ELECTRIC COMPANY
End-User Rates Including Shortfall Collected Over 36 Months From August 1, 2016
Illustrative End-Use Noncore and Wholesale Class Average Rates with Procurement Proxy
($/dth)

Line No.		2015 Rate Change from D. 16-06-056 to Adopted	% Change	2016 Rate Change from D. 16-06-056 to Adopted	% Change	2017 Rate Change from D. 16-06-056 to Adopted	% Change	2018 Rate Change from D. 16-06-056 to Adopted	% Change
		A	B	C	D	E	F	G	H
	Noncore Retail with Procurement Proxy								
1	Industrial – Distribution	(0.099)	-1.4%	(0.049)	-0.8%	(0.146)	-2.2%	(0.096)	-1.4%
2	Industrial – Transmission	(0.099)	-1.8%	(0.049)	-1.0%	(0.146)	-2.9%	(0.096)	-1.9%
3	Industrial – Backbone	(0.028)	-0.6%	(0.010)	-0.3%	(0.038)	-1.0%	(0.019)	-0.5%
4	Uncompressed Noncore NGV – Distribution	(0.099)	-1.4%	(0.049)	-0.8%	(0.146)	-2.3%	(0.096)	-1.5%
5	Uncompressed Noncore NGV – Transmission	(0.099)	-1.8%	(0.049)	-1.0%	(0.146)	-3.0%	(0.096)	-1.9%
6	Electric Generation – Distribution/Transmission	(0.099)	-1.9%	(0.049)	-1.1%	(0.146)	-3.2%	(0.096)	-2.0%
7	Electric Generation – Backbone	(0.028)	-0.6%	(0.010)	-0.3%	(0.038)	-1.1%	(0.019)	-0.5%
	Wholesale with Procurement Proxy								
8	Alpine Natural Gas	(0.097)	-1.9%	(0.049)	-1.1%	(0.146)	-3.2%	(0.096)	-2.0%
9	Coalinga	(0.097)	-1.9%	(0.049)	-1.1%	(0.146)	-3.2%	(0.096)	-2.0%
10	Island Energy	(0.091)	-1.7%	(0.049)	-1.1%	(0.146)	-3.1%	(0.096)	-2.0%
11	Palo Alto	(0.099)	-1.9%	(0.049)	-1.1%	(0.146)	-3.2%	(0.096)	-2.0%
12	West Coast Gas - Castle	(0.095)	-1.3%	(0.049)	-0.8%	(0.146)	-2.2%	(0.096)	-1.4%
13	West Coast Gas - Mather D	(0.097)	-1.3%	(0.049)	-0.7%	(0.146)	-2.0%	(0.096)	-1.3%
14	West Coast Gas - Mather T	(0.097)	-1.9%	(0.049)	-1.1%	(0.146)	-3.2%	(0.096)	-2.0%

Notes:

Dollar difference are due to rounding.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

D.16-06-056

APPENDIX J: Table 8

PACIFIC GAS AND ELECTRIC COMPANY

2015 AGT with Interim 2015 Gas Accord V (2014 Rev.Req plus 2% escalator)

($/dth) (9)

	Core Retail					Noncore Retail						
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Dist	Trans	BB	Dist	Trans	D/T	BB
End-Use Transportation:												
Local Transmission & Rate Adders (1)	0.4749	0.4749	0.4749	0.4749	0.4749	0.2325	0.2325	0.0000	0.2325	0.2325	0.2325	0.0000
Distribution (6)	6.7276	3.0737	1.2906	0.6758	12.9942	1.4041	0.0892	0.0000	1.4041	0.0000	0.0279	0.0279
Mandated Customer Programs and Other Charges:												
Self Generation Incentive Program	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091
CPUC and AB32 Cost of Implementation Fee (3)(8)	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125	0.0058	0.0058
PSEP	(0.1259)	(0.1259)	(0.1259)	(0.1259)	(0.1259)	(0.0617)	(0.0617)	(0.0298)	(0.0617)	(0.0617)	(0.0617)	(0.0298)
Balancing Accounts (2)	1.9743	1.2064	0.5547	0.3818	3.6371	0.1799	0.0942	0.0902	0.1799	0.0902	0.0784	0.0784
Volumetric End-Use Rate	9.0724	4.6506	2.2158	1.4281	17.0018	1.7763	0.3758	0.0820	1.7763	0.2826	0.2920	0.0915
Customer/ Customer Access Charge (4)	0.0000	0.5888	0.0449	0.0120	0.0000	0.0804	0.0190	0.0161	0.0804	0.0190	0.0111	0.0020
Total End-Use Rate	9.0724	5.2395	2.2607	1.4400	17.0018	1.8567	0.3948	0.0981	1.8567	0.3016	0.3032	0.0934
Gas Public Purpose Program Surcharge (5)	0.8989	0.4472	0.9743	0.2602	0.2602	0.4349	0.3488	0.3488	0.2602	0.2602	0.0000	0.0000
Total Rate (7)	9.9713	5.6867	3.2350	1.7002	17.2620	2.2916	0.7436	0.4469	2.1169	0.5618	0.3032	0.0934
Procurement Charges for Core Bundled Customers:												
Storage	0.2051	0.1744	0.1200	0.1125	0.1125							
Backbone Capacity	0.2683	0.2259	0.1440	0.1395	0.1395							
Backbone Usage	0.1171	0.1171	0.1171	0.1171	0.1171							
WACOG	3.5463	3.5463	3.5463	3.5463	3.5463							
Interstate Capacity and Other	0.8585	0.7587	0.5661	0.5556	0.5556							
Total Core Procurement	4.9953	4.8224	4.4935	4.4710	4.4710							
Total Core Bundled Rates	14.9666	10.5090	7.7285	6.1712	21.7330							

	Wholesale						
	Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans
End-Use Transportation:							
Local Transmission & Rate Adders (1)	0.2325	0.2325	0.2325	0.2325	0.2325	0.2325	0.2325
Distribution (6)					1.7997	2.3831	
Mandated Customer Programs and Other Charges:							
Self Generation Incentive Program							
CPUC and AB32 Cost of Implementation Fee (3)(8)							
PSEP	(0.0617)	(0.0617)	(0.0617)	(0.0617)	(0.0617)	(0.0617)	(0.0617)
Balancing Accounts (2)	0.0736	0.0740	0.0753	0.0749	0.1834	0.2199	0.0749
Volumetric End-Use Rate	0.2444	0.2448	0.2461	0.2457	2.1538	2.7738	0.2457
Customer/ Customer Access Charge (4)	0.0597	0.0683	0.2641	0.0183	0.1571	0.0973	0.0973
Total End-Use Rate	0.3041	0.3131	0.5102	0.2639	2.3110	2.8711	0.3430
Gas Public Purpose Program Surcharge (5)							
Total Rate	0.3041	0.3131	0.5102	0.2639	2.3110	2.8711	0.3430

NOTES

(1) Adopted in Decision 11-04-031 based on Appendix B, Table 11; updated in the 2015 Annual Gas True-Up Filing AL 3547-G Attachment 6, Appendix B, Table 11.

(2) Based on November recorded balances and forecasted through December.

(3) CPUC Fee based on Resolution M-4828, effective January 1, 2016 (including FF&U). G-EG customers pay a reduced CPUC fee per the 2010 BCAP D.10-06-035.

(4) Adopted in Decision 11-04-031 based on Appendix B, Table 12; updated in the 2015 Annual Gas True-Up Filing AL 3547-G Attachment 6, Appendix B, Table 12.

(5) Decision 04-08-010 ordered the removal of PPP cost recovery from transportation rates. On March 1, 2005 PG&E began to treat PPP as a tax. AL 3645-G updated PG&E's 2016 PPP Surcharges effective January 1, 2016.

(6) The G-NGV2 Distribution rate component incudes the cost of compression, station operations and maintenance, and state/federal gas excise taxes, and the average A-10 electric rate.

(7) CARE Customers receive a 20% discount off of PG&E's total bundled rate and are exempt from the CARE portion of PG&E's Public Purpose Program Surcharge (G-PPPS) rates and cost recovery of the California Solar Initiative Thermal Program.

(8) AB32 provides the Air Resource Board recovery of its administration costs associated with the implementation of AB32. Wholesale and certain large customers are directly billed by the ARB, and are exempt from PG&E's cost of implementation component of $0.00108 per therm

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 9 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY
End-User Rates

2015 Average Rate Detail with Proposed 2015 GT&S Rates (Year 2015 Components) By End-Use Customer Class (a)
($/dth)

	Core					Noncore Transportation						
						Industrial			Natural Gas Vehicle		Electric Gen	
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Dist	Trans	BB	Dist	Trans	D/T	BB
End-Use Transportation:												
Local Transmission & Rate Adders (1)	1.2312	1.2312	1.2312	1.2312	1.2312	0.5494	0.5494	0.0000	0.5494	0.5494	0.5494	0.0000
Distribution (b)	6.7276	3.0737	1.2906	0.6758	12.9942	1.4041	0.0892	0.0000	1.4041	0.0000	0.0279	0.0279
2015 GT&S Late Implementation Amortization	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Self Generation Incentive Program	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091
CPUC Fee	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125	0.0125	0.0058	0.0058
PSEP	(0.1259)	(0.1259)	(0.1259)	(0.1259)	(0.1259)	(0.0617)	(0.0617)	(0.0298)	(0.0617)	(0.0617)	(0.0617)	(0.0298)
Balancing Accounts	1.9743	1.2064	0.5547	0.3818	3.6371	0.1799	0.0942	0.0902	0.1799	0.0902	0.0784	0.0784
Volumetric End-Use Rate	9.8288	5.4069	2.9721	2.1844	17.7581	2.0932	0.6927	0.0820	2.0932	0.5995	0.6089	0.0915
Customer/ Customer Access Charge (c)	0.0000	0.5888	0.0449	0.0120	0.0000	0.0804	0.0093	0.0078	0.0804	0.0093	0.0057	0.0020
Total End-Use Rate	9.8288	5.9958	3.0170	2.1964	17.7581	2.1736	0.7020	0.0898	2.1736	0.6088	0.6147	0.0935
Gas Public Purpose Program Surcharge	0.8989	0.4472	0.9743	0.2602	0.2602	0.4349	0.3488	0.3488	0.2602	0.2602	0.0000	0.0000
Total Rate	10.7277	6.4430	3.9913	2.4566	18.0183	2.608	1.051	0.439	2.434	0.869	0.615	0.094
Procurement Charges for Core Bundled Customers:												
Storage	0.2393	0.2034	0.1399	0.1312	0.1312							
Backbone Capacity	0.2250	0.1895	0.1208	0.1170	0.1170							
Backbone Usage	0.0910	0.0910	0.0910	0.0910	0.0910							
WACOG	3.5463	3.5463	3.5463	3.5463	3.5463							
Interstate Capacity and Other	0.8585	0.7587	0.5661	0.5556	0.5556							
Total Core Procurement	4.9601	4.7889	4.4641	4.4411	4.4411							
Total Core Bundled Rates	15.6878	11.2319	8.4554	6.8977	22.4594							

	Wholesale Transportation						
	Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans
End-Use Transportation:							
Local Transmission & Rate Adders (1)	0.5494	0.5494	0.5494	0.5494	0.5494	0.5494	0.5494
Distribution (b)					1.7997	2.3831	
Mandated Customer Programs and Other Charges:							
Self Generation Incentive Program							
CPUC Fee							
PSEP	(0.0617)	(0.0617)	(0.0617)	(0.0617)	(0.0617)	(0.0617)	(0.0617)
Balancing Accounts	0.0736	0.0740	0.0753	0.0749	0.1834	0.2199	0.0749
Volumetric End-Use Rate	0.5613	0.5617	0.5630	0.5625	2.4707	3.0907	0.5625
Customer/ Customer Access Charge (c)	0.0326	0.0360	0.1474	0.0093	0.0792	0.0458	0.0458
Total End-Use Rate	0.5939	0.5976	0.7104	0.5719	2.5500	3.1365	0.6084
Gas Public Purpose Program Surcharge							
Total Rate	0.5939	0.5976	0.7104	0.5719	2.5500	3.1365	0.6084

Notes:

a) Class average rates reflect load shape for bundled core.

b) Distribution rates represent the annual class average.

c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

D.16-06-056

APPENDIX J: Table 10

PACIFIC GAS AND ELECTRIC COMPANY

2016 AGT with Interim 2015 Gas Accord V (2014 Rev.Req plus 2% escalator)

($/dth) (9)

	Core Retail					Noncore Retail						
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Dist	Trans	BB	Dist	Trans	D/T	BB
End-Use Transportation:												
Local Transmission & Rate Adders (1)	0.4749	0.4749	0.4749	0.4749	0.4749	0.2325	0.2325	0.0000	0.2325	0.2325	0.2325	0.0000
Distribution (6)	7.1577	3.1647	1.3674	0.7153	13.0056	1.4937	0.0943	0.0000	1.4937	0.0000	0.0296	0.0296
Mandated Customer Programs and Other Charges:												
Self Generation Incentive Program	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091
CPUC and AB32 Cost of Implementation Fee (3)(8)	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0112	0.0112
Balancing Accounts (2)	2.2183	1.2650	0.5969	0.4015	3.9001	0.1161	0.0907	0.0890	0.1161	0.0890	0.0724	0.0724
Volumetric End-Use Rate	9.8803	4.9339	2.4685	1.6210	17.4100	1.8716	0.4468	0.1184	1.8716	0.3509	0.3547	0.1223
Customer/ Customer Access Charge (4)	0.0000	0.5888	0.0449	0.0120	0.0000	0.0762	0.0190	0.0161	0.0762	0.0190	0.0111	0.0020
Total End-Use Rate	9.8803	5.5228	2.5134	1.6330	17.4100	1.9478	0.4658	0.1345	1.9478	0.3699	0.3658	0.1242
Gas Public Purpose Program Surcharge (5)	1.0197	0.4371	1.0273	0.2433	0.2433	0.4379	0.3222	0.3222	0.2433	0.2433	0.0000	0.0000
Total Rate (7)	10.9000	5.9599	3.5407	1.8763	17.6533	2.3857	0.7880	0.4567	2.1911	0.6132	0.3658	0.1242
Procurement Charges for Core Bundled Customers:												
Storage	0.2055	0.1732	0.1200	0.1125	0.1125							
Backbone Capacity	0.2688	0.2241	0.1440	0.1395	0.1395							
Backbone Usage	0.1171	0.1171	0.1171	0.1171	0.1171							
WACOG	2.4353	2.4353	2.4353	2.4353	2.4353							
Interstate Capacity and Other	0.8004	0.6974	0.5125	0.5021	0.5021							
Total Core Procurement	3.8271	3.6471	3.3289	3.3066	3.3066							
Total Core Bundled Rates	14.7271	9.6070	6.8696	5.1829	20.9599							

	Wholesale						
	Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans
End-Use Transportation:							
Local Transmission & Rate Adders (1)	0.2325	0.2325	0.2325	0.2325	0.2325	0.2325	0.2325
Distribution (6)					1.9031	2.5200	
Mandated Customer Programs and Other Charges:							
Self Generation Incentive Program							
CPUC and AB32 Cost of Implementation Fee (3)(8)							
Balancing Accounts (2)	0.0717	0.0717	0.0717	0.0717	0.1038	0.1142	0.0717
Volumetric End-Use Rate	0.3042	0.3042	0.3042	0.3042	2.2394	2.8668	0.3042
Customer/ Customer Access Charge (4)	0.0597	0.0683	0.2641	0.0183	0.1571	0.0973	0.0973
Total End-Use Rate	0.3638	0.3725	0.5683	0.3225	2.3965	2.9641	0.4015
Gas Public Purpose Program Surcharge (5)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total Rate	0.3638	0.3725	0.5683	0.3225	2.3965	2.9641	0.4015

NOTES

(1) Adopted in Decision 11-04-031 based on Appendix B, Table 11; updated in the 2015 Annual Gas True-Up Filing AL 3547-G Attachment 6, Appendix B, Table 11.

(2) Based on November recorded balances and forecasted through December.

(3) CPUC Fee based on Resolution M-4828, effective January 1, 2016 (including FF&U). G-EG customers pay a reduced CPUC fee per the 2010 BCAP D.10-06-035.

(4) Adopted in Decision 11-04-031 based on Appendix B, Table 12; updated in the 2015 Annual Gas True-Up Filing AL 3547-G Attachment 6, Appendix B, Table 12.

(5) Decision 04-08-010 ordered the removal of PPP cost recovery from transportation rates. On March 1, 2005 PG&E began to treat PPP as a tax. AL 3645-G updated PG&E's 2016 PPP Surcharges effective January 1, 2016.

(6) The G-NGV2 Distribution rate component incudes the cost of compression, station operations and maintenance, and state/federal gas excise taxes, and the average A-10 electric rate.

(7) CARE Customers receive a 20% discount off of PG&E's total bundled rate and are exempt from the CARE portion of PG&E's Public Purpose Program Surcharge (G-PPPS) rates and cost recovery of the California Solar Initiative Thermal Program.

(8) AB32 provides the Air Resource Board recovery of its administration costs associated with the implementation of AB32. Wholesale and certain large customers are directly billed by the ARB, and are exempt from PG&E's cost of implementation component of $0.00108 per therm

(9) Rates are unrounded

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 11 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

End-User Rates Including Shortfall Collected Over 36 Months From August 1, 2016

Rates Effective January 1, 2016 with Adopted 2015 GT&S Rates (Year 2016 Components) By End-Use Customer Class (a)(b)
($/dth)

	Core (a)					Noncore Transportation						
						Industrial			Natural Gas Vehicle		Electric Gen	
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Dist	Trans	BB	Dist	Trans	D/T	BB
End-Use Transportation:												
Local Transmission & Rate Adders	1.6408	1.6408	1.6408	1.6408	1.6408	0.7142	0.7142	0.0000	0.7142	0.7142	0.7142	0.0000
Distribution (b)	7.1577	3.1647	1.3674	0.7153	13.0056	1.4937	0.0943	0.0000	1.4937	0.0000	0.0296	0.0296
2015 GT&S Late Implementation Amortization	0.5420	0.5420	0.5420	0.5420	0.5420	0.2179	0.2179	0.0085	0.2179	0.2179	0.2179	0.0085
Self Generation Incentive Program	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091
CPUC Fee	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0112	0.0112
Balancing Accounts	2.2183	1.2650	0.5969	0.4015	3.9001	0.1161	0.0907	0.0890	0.1161	0.0890	0.0724	0.0724
Volumetric End-Use Rate	11.5882	6.6418	4.1764	3.3289	19.1179	2.5713	1.1464	0.1269	2.5713	1.0505	1.0543	0.1307
Customer/ Customer Access Charge (c)	0.0000	0.5888	0.0449	0.0120	0.0000	0.0762	0.0103	0.0084	0.0762	0.0103	0.0067	0.0021
Total End-Use Rate	11.5882	7.2307	4.2213	3.3409	19.1179	2.6474	1.1568	0.1353	2.6474	1.0608	1.0610	0.1328
Gas Public Purpose Program Surcharge	1.0197	0.4371	1.0273	0.2433	0.2433	0.4379	0.3222	0.3222	0.2433	0.2433	0.0000	0.0000
Total Rate	12.6079	7.6678	5.2486	3.5842	19.3612	3.085	1.479	0.457	2.891	1.304	1.061	0.133
Procurement Charges for Core Bundled Customers:												
Storage	0.2956	0.2491	0.1726	0.1618	0.1618							
Backbone Capacity	0.3372	0.2812	0.1807	0.1750	0.1750							
Backbone Usage	0.1043	0.1043	0.1043	0.1043	0.1043							
WACOG	2.4353	2.4353	2.4353	2.4353	2.4353							
Interstate Capacity and Other	0.7998	0.6969	0.5120	0.5016	0.5016							
Total Core Procurement	3.9722	3.7668	3.4049	3.3780	3.3780							
Total Core Bundled Rates	16.5801	11.4346	8.6535	6.9622	22.7392							

	Wholesale Transportation						
End-Use Transportation:	Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans
Local Transmission & Rate Adders	0.7142	0.7142	0.7142	0.7142	0.7142	0.7142	0.7142
Distribution (b)					1.9031	2.5200	
2015 GT&S Late Implementation Amortization	0.2179	0.2179	0.2179	0.2179	0.2179	0.2179	0.2179
Self Generation Incentive Program							
CPUC Fee							
Balancing Accounts	0.0717	0.0717	0.0717	0.0717	0.1038	0.1142	0.0717
Volumetric End-Use Rate	1.0038	1.0038	1.0038	1.0038	2.9391	3.5664	1.0038
Customer/ Customer Access Charge (c)	0.0354	0.0391	0.1618	0.0102	0.0868	0.0502	0.0502
Total End-Use Rate	1.0392	1.0429	1.1656	1.0141	3.0259	3.6167	1.0541
Gas Public Purpose Program Surcharge							
Total Rate	1.0392	1.0429	1.1656	1.0141	3.0259	3.6167	1.0541

Notes:

a) Class average rates reflect load shape for bundled core.

b) Distribution rates represent the annual class average.

c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 12 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

End-User Rates Including Shortfall Collected Over 36 Months From August 1, 2016

Rates Effective January 1, 2016 with Adopted 2015 GT&S Rates (Year 2017 Components) By End-Use Customer Class (a)(b)

($/dth)

	Core (a)					Noncore Transportation						
						Industrial			Natural Gas Vehicle		Electric Gen	
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Dist	Trans	BB	Dist	Trans	D/T	BB
End-Use Transportation:												
Local Transmission & Rate Adders	1.7539	1.7539	1.7539	1.7539	1.7539	0.7653	0.7653	0.0000	0.7653	0.7653	0.7653	0.0000
Distribution (b)	7.1577	3.1647	1.3674	0.7153	13.0056	1.4937	0.0943	0.0000	1.4937	0.0000	0.0296	0.0296
2015 GT&S Late Implementation Amortization	0.4598	0.4598	0.4598	0.4598	0.4598	0.1716	0.1716	(0.0102)	0.1716	0.1716	0.1716	(0.0102)
Self Generation Incentive Program	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091
CPUC Fee	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0112	0.0112
Balancing Accounts	2.2183	1.2650	0.5969	0.4015	3.9001	0.1161	0.0907	0.0890	0.1161	0.0890	0.0724	0.0724
Volumetric End-Use Rate	11.6191	6.6727	4.2073	3.3598	19.1488	2.5761	1.1513	0.1082	2.5761	1.0553	1.0592	0.1121
Customer/ Customer Access Charge (c)	0.0000	0.5888	0.0449	0.0120	0.0000	0.0762	0.0097	0.0078	0.0762	0.0097	0.0066	0.0020
Total End-Use Rate	11.6191	7.2616	4.2522	3.3718	19.1488	2.6523	1.1610	0.1160	2.6523	1.0650	1.0658	0.1140
Gas Public Purpose Program Surcharge	1.0197	0.4371	1.0273	0.2433	0.2433	0.4379	0.3222	0.3222	0.2433	0.2433	0.0000	0.0000
Total Rate	12.6388	7.6987	5.2795	3.6151	19.3921	3.090	1.483	0.438	2.896	1.308	1.066	0.114
Procurement Charges for Core Bundled Customers:												
Storage	0.3066	0.2584	0.1791	0.1679	0.1679							
Backbone Capacity	0.3594	0.2997	0.1925	0.1865	0.1865							
Backbone Usage	0.1171	0.1171	0.1171	0.1171	0.1171							
WACOG	2.4353	2.4353	2.4353	2.4353	2.4353							
Interstate Capacity and Other	0.8003	0.6974	0.5125	0.5021	0.5021							
Total Core Procurement	4.0187	3.8079	3.4365	3.4089	3.4089							
Total Core Bundled Rates	16.6575	11.5066	8.7160	7.0240	22.8010							

	Wholesale Transportation						
End-Use Transportation:	Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans
Local Transmission & Rate Adders	0.7653	0.7653	0.7653	0.7653	0.7653	0.7653	0.7653
Distribution (b)					1.9031	2.5200	
2015 GT&S Late Implementation Amortization	0.1716	0.1716	0.1716	0.1716	0.1716	0.1716	0.1716
Self Generation Incentive Program							
CPUC Fee							
Balancing Accounts	0.0717	0.0717	0.0717	0.0717	0.1038	0.1142	0.0717
Volumetric End-Use Rate	1.0086	1.0086	1.0086	1.0086	2.9439	3.5712	1.0086
Customer/ Customer Access Charge (c)	0.0333	0.0367	0.1536	0.0097	0.0823	0.0476	0.0476
Total End-Use Rate	1.0419	1.0454	1.1622	1.0184	3.0262	3.6189	1.0563
Gas Public Purpose Program Surcharge							
Total Rate	1.0419	1.0454	1.1622	1.0184	3.0262	3.6189	1.0563

Notes:

a) Class average rates reflect load shape for bundled core.

b) Distribution rates represent the annual class average.

c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 13 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

End-User Rates Including Shortfall Collected Over 36 Months From August 1, 2016

Rates Effective January 1, 2016 with Adopted 2015 GT&S Rates (Year 2018 Components) By End-Use Customer Class (a)(b)

($/dth)

	Core (a)					Noncore Transportation						
						Industrial			Natural Gas Vehicle		Electric Gen	
	Res	Small Comm	Large Comm	Uncomp. NGV	Comp. NGV	Dist	Trans	BB	Dist	Trans	D/T	BB
End-Use Transportation:												
Local Transmission & Rate Adders	1.9503	1.9503	1.9503	1.9503	1.9503	0.8510	0.8510	0.0000	0.8510	0.8510	0.8510	0.0000
Distribution (b)	7.1577	3.1647	1.3674	0.7153	13.0056	1.4937	0.0943	0.0000	1.4937	0.0000	0.0296	0.0296
2015 GT&S Late Implementation Amortization	0.5439	0.5439	0.5439	0.5439	0.5439	0.2207	0.2207	0.0085	0.2207	0.2207	0.2207	0.0085
Self Generation Incentive Program	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091	0.0091
CPUC Fee	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0203	0.0112	0.0112
Balancing Accounts	2.2183	1.2650	0.5969	0.4015	3.9001	0.1161	0.0907	0.0890	0.1161	0.0890	0.0724	0.0724
Volumetric End-Use Rate	11.8995	6.9532	4.4877	3.6403	19.4293	2.7108	1.2860	0.1269	2.7108	1.1900	1.1939	0.1308
Customer/ Customer Access Charge (c)	0.0000	0.5888	0.0449	0.0120	0.0000	0.0762	0.0092	0.0074	0.0762	0.0092	0.0063	0.0019
Total End-Use Rate	11.8995	7.5420	4.5326	3.6522	19.4293	2.7870	1.2952	0.1343	2.7870	1.1993	1.2002	0.1326
Gas Public Purpose Program Surcharge	1.0197	0.4371	1.0273	0.2433	0.2433	0.4379	0.3222	0.3222	0.2433	0.2433	0.0000	0.0000
Total Rate	12.9192	7.9791	5.5599	3.8955	19.6726	3.225	1.617	0.457	3.030	1.443	1.200	0.133
Procurement Charges for Core Bundled Customers:												
Storage	0.3151	0.2655	0.1840	0.1725	0.1725							
Backbone Capacity	0.3818	0.3184	0.2045	0.1982	0.1982							
Backbone Usage	0.1335	0.1335	0.1335	0.1335	0.1335							
WACOG	2.4353	2.4353	2.4353	2.4353	2.4353							
Interstate Capacity and Other	0.8010	0.6980	0.5131	0.5027	0.5027							
Total Core Procurement	4.0667	3.8507	3.4704	3.4421	3.4421							
Total Core Bundled Rates	16.9859	11.8298	9.0303	7.3376	23.1147							

	Wholesale Transportation						
End-Use Transportation:	Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather Dist	WCG Mather Trans
Local Transmission & Rate Adders	0.8510	0.8510	0.8510	0.8510	0.8510	0.8510	0.8510
Distribution (b)					1.9031	2.5200	
2015 GT&S Late Implementation Amortization	0.2207	0.2207	0.2207	0.2207	0.2207	0.2207	0.2207
Self Generation Incentive Program							
CPUC Fee							
Balancing Accounts	0.0717	0.0717	0.0717	0.0717	0.1038	0.1142	0.0717
Volumetric End-Use Rate	1.1434	1.1434	1.1434	1.1434	3.0786	3.7060	1.1434
Customer/ Customer Access Charge (c)	0.0317	0.0350	0.1464	0.0093	0.0787	0.0454	0.0454
Total End-Use Rate	1.1751	1.1784	1.2898	1.1527	3.1573	3.7514	1.1888
Gas Public Purpose Program Surcharge							
Total Rate	1.1751	1.1784	1.2898	1.1527	3.1573	3.7514	1.1888

Notes:

a) Class average rates reflect load shape for bundled core.

b) Distribution rates represent the annual class average.

c) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 14 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

Firm Backbone Transportation
Annual Rates (AFT) -- SFV Rate Design
On-System Transportation Service

		2015 GT&S Rates			
		2015	2016	2017	2018
Redwood Path - Core (a)					
Reservation Charge	($/dth/mo)	7.3544	10.3792	11.2372	12.1906
Usage Charge	($/dth)	0.0007	0.0010	0.0010	0.0010
Total (b)	($/dth @ Full Contract)	0.2425	0.3422	0.3704	0.4018
Baja Path - Core (a)					
Reservation Charge	($/dth/mo)	8.5673	11.5925	12.4506	13.4041
Usage Charge	($/dth)	0.0009	0.0011	0.0011	0.0011
Total (b)	($/dth @ Full Contract)	0.2825	0.3822	0.4104	0.4418
Redwood Path - Noncore					
Reservation Charge	($/dth/mo)	9.0914	12.1823	13.1556	14.1056
Usage Charge	($/dth)	0.0007	0.0009	0.0009	0.0010
Total (b)	($/dth @ Full Contract)	0.2996	0.4014	0.4335	0.4647
Baja Path - Noncore					
Reservation Charge	($/dth/mo)	10.3051	13.3963	14.3696	15.3197
Usage Charge	($/dth)	0.0008	0.0010	0.0010	0.0011
Total (b)	($/dth @ Full Contract)	0.3396	0.4414	0.4735	0.5047
Silverado and Mission Paths					
Reservation Charge	($/dth/mo)	5.5765	7.5837	8.1829	8.8393
Usage Charge	($/dth)	0.0006	0.0007	0.0008	0.0008
Total (b)	($/dth @ Full Contract)	0.1839	0.2501	0.2698	0.2914

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

d) Dollar difference are due to rounding.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 15 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY
Firm Backbone Transportation
Annual Rates (AFT) -- MFV Rate Design
On-System Transportation Service

		2015 GT&S Rates 2015	2016	2017	2018
Redwood Path - Core (a)					
Reservation Charge	($/dth/mo)	5.1773	7.8521	8.3904	8.9347
Usage Charge	($/dth)	0.0723	0.0840	0.0946	0.1081
Total	($/dth @ Full Contract)	0.2425	0.3422	0.3704	0.4018
Baja Path - Core (a)					
Reservation Charge	($/dth/mo)	6.0312	8.7699	9.2964	9.8241
Usage Charge	($/dth)	0.0842	0.0939	0.1048	0.1188
Total	($/dth @ Full Contract)	0.2825	0.3822	0.4104	0.4418
Redwood Path - Noncore					
Reservation Charge	($/dth/mo)	5.9287	8.6934	9.3704	9.9349
Usage Charge	($/dth)	0.1047	0.1156	0.1254	0.1381
Total	($/dth @ Full Contract)	0.2996	0.4014	0.4335	0.4647
Baja Path - Noncore					
Reservation Charge	($/dth/mo)	6.7202	9.5597	10.2351	10.7900
Usage Charge	($/dth)	0.1187	0.1271	0.1370	0.1500
Total	($/dth @ Full Contract)	0.3396	0.4414	0.4735	0.5047
Silverado and Mission Paths					
Reservation Charge	($/dth/mo)	3.7070	5.4866	5.8602	6.2326
Usage Charge	($/dth)	0.0621	0.0697	0.0771	0.0865
Total	($/dth @ Full Contract)	0.1839	0.2501	0.2698	0.2914

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

d) Dollar difference are due to rounding.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 16 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY
Firm Backbone Transportation
Seasonal Rates (SFT) -- SFV Rate Design
On-System Transportation Service

		2015 GT&S Rates			
		2015	**2016**	**2017**	**2018**
Redwood Path					
Reservation Charge	($/dth/mo)	10.9097	14.6188	15.7867	16.9267
Usage Charge	($/dth)	0.0009	0.0011	0.0011	0.0012
Total	($/dth @ Full Contract)	0.3595	0.4817	0.5201	0.5577
Baja Path - Core (a)					
Reservation Charge	($/dth/mo)	10.2808	13.9109	14.9407	16.0850
Usage Charge	($/dth)	0.0010	0.0013	0.0013	0.0014
Total	($/dth @ Full Contract)	0.3390	0.4586	0.4925	0.5302
Baja Path - Noncore					
Reservation Charge	($/dth/mo)	12.3661	16.0755	17.2436	18.3836
Usage Charge	($/dth)	0.0010	0.0012	0.0012	0.0013
Total	($/dth @ Full Contract)	0.4075	0.5297	0.5681	0.6057
Silverado and Mission Paths					
Reservation Charge	($/dth/mo)	6.6918	9.1004	9.8194	10.6072
Usage Charge	($/dth)	0.0007	0.0009	0.0009	0.0010
Total	($/dth @ Full Contract)	0.2207	0.3001	0.3238	0.3497

Notes:

a) Firm Seasonal rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They include exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.

(f) Dollar difference are due to rounding.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 17 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

Firm Backbone Transportation
Seasonal Rates (SFT) -- MFV Rate Design
On-System Transportation Service

		2015 GT&S Rates 2015	2016	2017	2018
Redwood Path					
Reservation Charge	($/dth/mo)	7.1144	10.4321	11.2445	11.9219
Usage Charge	($/dth)	0.1256	0.1387	0.1505	0.1657
Total	($/dth @ Full Contract)	0.3595	0.4817	0.5201	0.5577
Baja Path - Core (a)					
Reservation Charge	($/dth/mo)	7.2374	10.5239	11.1557	11.7890
Usage Charge	($/dth)	0.1011	0.1126	0.1258	0.1426
Total	($/dth @ Full Contract)	0.3390	0.4586	0.4925	0.5302
Baja Path - Noncore					
Reservation Charge	($/dth/mo)	8.0642	11.4716	12.2821	12.9481
Usage Charge	($/dth)	0.1424	0.1526	0.1643	0.1800
Total	($/dth @ Full Contract)	0.4075	0.5297	0.5681	0.6057
Silverado and Mission Paths					
Reservation Charge	($/dth/mo)	4.4484	6.5839	7.0323	7.4791
Usage Charge	($/dth)	0.0745	0.0836	0.0926	0.1038
Total	($/dth @ Full Contract)	0.2207	0.3001	0.3238	0.3497

Notes:

a) Firm Seasonal rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.

f) Dollar difference are due to rounding.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 18 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

As-Available Backbone Transportation
On-System Transportation Service

		2015 GT&S Rates			
		2015	**2016**	**2017**	**2018**
Redwood Path					
Usage Charge	($/dth)	0.3595	0.4817	0.5201	0.5577
Baja Path					
Usage Charge	($/dth)	0.4075	0.5297	0.5681	0.6057
Silverado Path					
Usage Charge	($/dth)	0.2207	0.3001	0.3238	0.3497
Mission Path					
Usage Charge	($/dth)	0.0000	0.0000	0.0000	0.0000

Notes:

a) As-Available rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) Mission path service represents on-system storage to on-system transportation. Customers delivering gas to storage facilities pay the applicable backbone transmission on-system rate from Redwood, Baja or Silverado.

d) Dollar difference are due to rounding.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 19 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY
Backbone Transportation
Annual Rates (AFT-Off)
Off-System Deliveries

		2015 GT&S Rates			
		2015	**2016**	**2017**	**2018**
SFV Rate Design					
Redwood, Silverado and Mission Paths Off-System					
Reservation Charge	($/dth/mo)	9.0914	12.1823	13.1556	14.1056
Usage Charge	($/dth)	0.0007	0.0009	0.0009	0.0010
Total	($/dth @ Full Contract)	0.2996	0.4014	0.4335	0.4647
Baja Path Off-System					
Reservation Charge	($/dth/mo)	10.3051	13.3963	14.3696	15.3197
Usage Charge	($/dth)	0.0008	0.0010	0.0010	0.0011
Total	($/dth @ Full Contract)	0.3396	0.4414	0.4735	0.5047
MFV Rate Design					
Redwood, Silverado and Mission Paths Off-System					
Reservation Charge	($/dth/mo)	5.9287	8.6934	9.3704	9.9349
Usage Charge	($/dth)	0.1047	0.1156	0.1254	0.1381
Total	($/dth @ Full Contract)	0.2996	0.4014	0.4335	0.4647
Baja Path Off-System					
Reservation Charge	($/dth/mo)	6.7202	9.5597	10.2351	10.7900
Usage Charge	($/dth)	0.1187	0.1271	0.1370	0.1500
Total	($/dth @ Full	0.3396	0.4414	0.4735	0.5047
As-Available Service					
Redwood, Silverado, and Mission Paths, (From Citygate) Off-System - Noncore					
Usage Charge	($/dth)	0.3595	0.4817	0.5201	0.5577
Mission Paths (From on-system storage) Off-System					
Usage Charge	($/dth)	0.0000	0.0000	0.0000	0.0000
Baja Path Off-System - Noncore					
Usage Charge	($/dth)	0.4075	0.5297	0.5681	0.6057

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c) California gas and storage to off-system are assumed to flow on Redwood path and are priced at the Redwood path rate.

d) Dollar difference are due to rounding.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 20 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY
Firm Transportation
Expansion Shippers -- Annual Rates (G-XF)
SFV Rate Design

		2015 GT&S Rates			
		2015	**2016**	**2017**	**2018**
SFV Rate Design					
Reservation Charge	($/dth/mo)	5.0824	5.8086	5.7271	5.7955
Usage Charge	($/dth)	0.0001	0.0001	0.0001	0.0001
Total	($/dth @ Full Contract)	0.1672	0.1911	0.1884	0.1906

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, mandated customer programs and other charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c) G-XF charges are based on the embedded cost of Line 401 and a 95 percent load factor.

d) Dollar difference are due to rounding.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 21 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY
Storage Service Rates

		2015 GT&S Rates			
		2015	2016	2017	2018
Core Firm Storage (G-CFS)					
Reservation Charge	($/dth/mo)	$0.1492	$0.1815	$0.1860	$0.1913
Standard Firm Storage (G-SFS)					
Reservation Charge	($/dth/mo)	$0.2891	$0.3123	$0.3024	$0.2962
Negotiated Firm Storage (G-NFS)					
Injection	($/dth/d)	$5.5869	$6.0354	$5.8437	$5.7236
Inventory	($/dth)	$3.4692	$3.7477	$3.6287	$3.5541
Withdrawal	($/dth/d)	$25.5380	$27.5884	$26.7122	$26.1629
Negotiated As-Available Storage (G-NAS) - Maximum Rate					
Injection	($/dth/d)	$5.5869	$6.0354	$5.8437	$5.7236
Withdrawal	($/dth/d)	$25.5380	$27.5884	$26.7122	$26.1629
Market Center Services (Parking and Lending Services)					
Maximum Daily Charge ($/Dth/d)		$1.1491	$1.2328	$1.1942	$1.1650
Minimum Rate (per transaction)		$57.00	$57.00	$57.00	$57.00

Notes:

a) Rates for storage services are based on the costs of storage injection, inventory and withdrawal.

b) Core Firm Storage (G-CFS) and Standard Firm Storage (G-SFS) rates are a monthly reservation charge designed to recover one twelfth of the annual revenue requirement of injection, inventory and withdrawal storage.

c) Negotiated Firm rates may be one-part rates (volumetric) or two-part rates (reservation and volumetric), as negotiated between parties. The volumetric equivalent is shown above.

d) Negotiated As-Available Storage Injection and Withdrawal rates are recovered through a volumetric charge only.

e) Negotiated rates (NFS and NAS) are capped at the price which will collect 100 percent of PG&E's total revenue requirement for the unbundled storage program under all three subfunctions (e.g. inventory, injection, or withdrawal). The maximum rates are based on a rate design assuming an average injection period of 30 days and an average withdrawal period of 7 days.

f) Negotiated Firm and As-available services are negotiable above a price floor representing PG&E's marginal costs of providing the service.

g) The maximum charge for parking and lending is based on the annual cost of cycling one Dth of Firm Storage Gas assuming the full 214 day injection season and 151 day withdrawal season.

h) Gas Storage shrinkage will be applied in-kind on storage injections.

i) Dollar difference are due to rounding.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 22 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY
Local Transmission Rates
$/dth

Customer Groups	2015 GT&S Rates 2015	2016	2017	2018
Core Retail Local Transmission	1.2312	1.6408	1.7539	1.9503
Noncore Retail and Wholesale	0.5494	0.7142	0.7653	0.8510

Notes:
Allocation Method: Cold-Year Coincident Peak Month (December)

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 23 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY
Customer Access Charge Rates
($ per Month)

		2015 GT&S Rates			
		2015	**2016**	**2017**	**2018**
G-EG / G-NT ($/month)					
	(Therms/Month)				
Tier 1	0 to 5,000	$33.95	$37.26	$35.37	$33.73
Tier 2	5,001 to 10,000	$101.12	$110.99	$105.37	$100.46
Tier 3	10,001 to 50,000	$188.21	$206.58	$196.11	$186.98
Tier 4	50,001 to 200,000	$247.01	$271.11	$257.37	$245.39
Tier 5	200,001 to 1,000,000	$358.39	$393.35	$373.42	$356.04
Tier 6	1,000,001 and above	$3,040.06	$3,336.65	$3,167.59	$3,020.14
Wholesale ($/month)					
Alpine		$162.58	$178.44	$169.40	$161.51
Coalinga		$719.02	$789.17	$749.18	$714.31
Island Energy		$487.17	$534.70	$507.61	$483.98
Palo Alto		$2,397.40	$2,631.30	$2,497.97	$2,381.70
West Coast Gas - Castle		$417.68	$458.43	$435.20	$414.94
West Coast Gas - Mather		$381.70	$418.94	$397.71	$379.20

Notes:

a) The 2011-2014 CAC revenue requirements are established in this GT&S Rate Case proceeding. The rate design for the customer access charge may be addressed in PG&E's Biennial Cost Allocation Proceedings (BCAP).

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 24 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY
Self Balancing Credit

	Interim	2015 GT&S Rates			
	2015 & 2016	2015	2016	2017	2018
Self Balancing Credit	($0.0135)	($0.0159)	($0.0191)	($0.0195)	($0.0200)

Notes:

a) Storage balancing costs are bundled in backbone rates. Customers or Balancing agents who elect self balancing on a daily basis can opt out of PG&E's monthly balancing program and receive a self-balancing credit.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 25 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

End-User Rates Including Shortfall Collected Over 36 Months From August 1, 2016

Line No.	RESIDENTIAL CLASS	Rates with Adopted 2015 GT&S [a] (Year 2017 Components)	Rates Adopted 2015 GT&S [a] (Year 2018 Components)
		A	B
1	Non-CARE Residential Illustrative Bundled Rate* ($/th)	$1.56378	$1.59662
2	State-Mandated Residential Public Purpose Program Surcharge ($/th)	$0.10197	$0.10197
3	End-User Total Rate and Surcharge ($/th)	$1.66575	$1.69859
4	Average Monthly Use per Residential Customer (therms)	34	34
5	Present Average Non-CARE Residential Customer Monthly Bill ($)	$56.64	$57.75

	SMALL COMMERCIAL CLASS	Rates with Adopted 2015 GT&S [a] (Year 2017 Components)	Rates Adopted 2015 GT&S [a] (Year 2018 Components)
		A	B
6	Non-CARE Small Commercial Illustrative Bundled Rate* ($/th)	$1.10695	$1.13927
7	State-Mandated Small Commercial Public Purpose Program Surcharge ($/th)	$0.04371	$0.04371
8	End-User Total Rate and Surcharge ($/th)	$1.15066	$1.18298
9	Average Monthly Use per Small Commercial Customer (therms)	284	284
10	Present Average Non-CARE Small Commercial Customer Monthly Bill ($)	$326.79	$335.97

Notes

* CARE customers receive a discount of 20% off of PG&E's bundled residential rates and are exempt from paying CARE-related portions of PG&E's G-PPPS rates.

[a] Non-GT&S rate components are held constant at January 1, 2016 levels as filed in PG&E's 2016 AGT Advice Letter 3664-G.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

D.16-06-056

APPENDIX J: Table 26 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

End-User Rates Including Shortfall Collected Over 36 Months

Line No.	RESIDENTIAL CLASS	2017 Rates with D.16-06-056 2015 GT&S (Year 2017 Components)	2018 Rates with D.16-06-056 2015 GT&S (Year 2018 Components)
		A	B
1	Non-CARE Residential Illustrative Bundled Rate* ($/th)	$1.59379	$1.61804
2	State-Mandated Residential Public Purpose Program Surcharge ($/th)	$0.10197	$0.10197
3	End-User Total Rate and Surcharge ($/th)	$1.69576	$1.72001
4	Average Monthly Use per Residential Customer (therms)	34	34
5	Present Average Non-CARE Residential Customer Monthly Bill ($)	$57.66	$58.48

	SMALL COMMERCIAL CLASS	2017 Rates with D.16-06-056 2015 GT&S (Year 2017 Components)	2018 Rates with D.16-06-056 2015 GT&S (Year 2018 Components)
		A	B
6	Non-CARE Small Commercial Illustrative Bundled Rate* ($/th)	$1.13636	$1.16009
7	State-Mandated Small Commercial Public Purpose Program Surcharge ($/th)	$0.04371	$0.04371
8	End-User Total Rate and Surcharge ($/th)	$1.18007	$1.20380
9	Average Monthly Use per Small Commercial Customer (therms)	284	284
10	Present Average Non-CARE Small Commercial Customer Monthly Bill ($)	$335.14	$341.88

Notes

* CARE customers receive a discount of 20% off of PG&E's bundled residential rates and are exempt from paying CARE-related portions of PG&E's G
Non-GT&S rate components are held constant at January 1, 2016 levels as filed in PG&E's 2016 AGT Advice Letter 3664-G.

2015 Gas Transmission and Storage Rate Case (2015 GT&S)
Adopted
APPENDIX J: Table 27 (New)
PACIFIC GAS AND ELECTRIC COMPANY
Change in Average Monthly Bills from Application of $850 Million Penalty

	2017	2018
Residential		
Average Monthly Bill under D. 16-06-056	$57.66	$58.48
Average Monthly Bill under Proposed Decision	$56.64	$57.75
Change from Application of $850 Million Penalties	($1.02)	($0.73)
% Change	-1.8%	-1.2%
Small Commercial		
Average Monthly Bill under D. 16-06-056	$335.14	$341.88
Average Monthly Bill under Proposed Decision	$326.79	$335.97
Change from Application of $850 Million Penalties	($8.35)	($5.91)
	-2.5%	-1.7%

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 28 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

BACKBONE LOAD FACTOR

NON-EQUALIZED RATES WITH 4-CENT BAJA-REDWOOD DIFFERENTIAL

		2015	2016	2017	2018	Revision Notes
1	**Backbone Demand (MDth/d)**					
2	Core	758	755	754	754	
3	Core distribution shrinkage	18	19	19	19	
4	Noncore industrial + NGV4	508	502	508	508	
5	Wholesale	10	10	10	10	
6	Electric Generation	506	505	497	497	
7	Cogeneration	178	178	178	178	
8	Subtotal, on-system	1,978	1,969	1,966	1,966	*(1)*
9	G-XF off-system	80	80	80	80	
10	Non G-XF off-system (full-rate-equivalent throughput) (a)	98	73	68	63	*(2)*
11	Subtotal, off-system	179	154	148	144	
12	TOTAL	2,157	2,123	2,114	2,110	
13	Remove G-XF contracts	(86)	(86)	(86)	(86)	
14	Adjust for Baja on-system discounts (b)	0	0	0	0	
15	Adjust for G-AA, G-SFT, and G-NFT premiums (c)	35	35	34	34	*(2)*
16	Adjust for reservation charges for un-used firm contracts (d)	72	75	76	75	*(2)*
17	Adjust for disproportionate usage of backbone paths (e)	(88)	(69)	(70)	(65)	*(2)*
18	Subtotal, adjustments	(67)	(44)	(46)	(42)	
19	TOTAL, ADJUSTED	**2,091**	**2,079**	**2,068**	**2,068**	
20	**Backbone Capacity (MDth/d at Delivery Point)**					
21	Redwood Line 401	998	1,008	1,031	1,031	*(3)*
22	Redwood Line 400	1,016	1,026	1,049	1,049	*(3)*
23	Baja Line 300	1,025	1,025	1,025	1,025	*(3)*
24	Silverado "capacity"	128	129	132	132	*(4)*
25	TOTAL	3,167	3,189	3,237	3,237	
26	Remove G-XF contracts	(86)	(86)	(86)	(86)	
27	Remove SMUD equity capacity, Line 401	(43)	(43)	(44)	(44)	
28	Remove SMUD equity capacity, Line 300	(41)	(41)	(41)	(41)	
29	Subtotal, adjustments	(169)	(170)	(171)	(171)	
30	TOTAL, ADJUSTED	**2,998**	**3,019**	**3,066**	**3,066**	
31	Memo: Silverado flow forecast	89	89	89	89	
32	**Backbone Load Factor**	**69.73%**	**68.85%**	**67.45%**	**67.43%**	

REVISION NOTES *

(1) On-system demands are revised consistent with the stipulated demand forecast (see Section 18.1 of D.16-06-056) and the updated core distribution shrinkage rates (see Section 18.8.2 of D.16-06-056).

(2) Revisions to Line Nos. 10, 15, 16, and 17 are explained in the next table.

(3) Redwood and Baja capacities are revised consistent with the updated backbone shrinkage rates (see Section 18.8.2 of D.16-06-056).

(4) Silverado "capacities" are calculated by dividing forecasted Silverado throughput (Line No. 31) by the system average backbone load factor (Line No. 32). Because the backbone load factors are revised, the Silverado capacities are also revised.

General Note: The 2018 backbone load factors were developed by holding all inputs constant at 2017 levels except for backbone revenue requirement and backbone rates.

*** Revision explanations are based on comparisons to Exhibit PGE-043, Chapter 17A, Table 17A-2 and Table 17A-3.**

2015 Gas Transmission and Storage Rate Case (2015 GT&S)

Adopted

APPENDIX J: Table 29 (Updated)

PACIFIC GAS AND ELECTRIC COMPANY

THROUGHPUT ADJUSTMENTS FOR BACKBONE LOAD FACTOR

NON-EQUALIZED RATES WITH 4-CENT BAJA-REDWOOD DIFFERENTIAL

		2015	2016	2017	2018	Revision Notes
1	**(a) Calculate full rate equivalent non-G-XF off-system throughput**					
2	Forecasted revenues ($ '000/yr)	$10,750	$10,750	$10,750	$10,750	
3	Noncore Redwood G-AFT rate ($/Dth)	$0.300	$0.401	$0.433	$0.465	
4	Full rate equivalent throughput (MDth/d)	**98**	**73**	**68**	**63**	*(1)*
5	**(b) Adjust for Baja on-system discounts**					
6	Quantity (MDth/d)	0	0	0	0	
7	Contract rate ($/Dth)	$0.000	$0.000	$0.000	$0.000	
8	Noncore Baja G-AFT rate ($/Dth)	$0.340	$0.441	$0.473	$0.505	
9	Full rate equivalent throughput (MDth/d)	0	0	0	0	
10	Throughput adjustment (MDth/d)	**0**	**0**	**0**	**0**	
11	**(c) Adjust for G-AA, G-SFT, and G-NFT premiums**					
12	G-AA throughput - Core (MDth/d)	0	0	0	0	
13	G-AA throughput - Noncore (MDth/d)					
14	Total on-system throughput	1,978	1,969	1,966	1,966	
15	G-XF on-system throughput	5	5	5	5	
16	Firm throughput excl G-XF	1,889	1,877	1,879	1,879	
17	G-AA throughput - Core	0	0	0	0	
18	G-AA throughput - Noncore (determined residually)	84	86	81	81	*(2)*
19	G-SFT throughput - Core					
20	Core G-SFT MDQ (annualized MDth/d)	65	65	65	65	
21	Core G-SFT average utilization rate	91.9%	91.9%	91.9%	91.9%	
22	Core G-SFT throughput (MDth/d)	60	60	60	60	
23	G-SFT and G-NFT throughput - Noncore					
24	Noncore G-SFT and G-NFT MDQ (annualized MDth/d)	38	36	34	34	
25	Noncore G-SFT and G-NFT average utilization rate	82.6%	82.6%	82.6%	82.6%	
26	Noncore G-SFT and G-NFT throughput (MDth/d)	31	30	28	28	
27	TOTAL (MDth/d)	175	176	170	170	
28	Rate premium	20%	20%	20%	20%	
29	Premium adjustment (MDth/d)	**35**	**35**	**34**	**34**	
30	**(d) Adjust for reservation charges for unused firm contracts**					
31	Total firm contract MDQ excl G-XF (MDth/d)	1,993	1,980	1,983	1,983	*(3)*
32	Average firm contract utilization rate excl G-XF	94.8%	94.8%	94.8%	94.8%	
33	Unused firm MDQ (MDth/d)	104	103	103	103	
34	Average reservation portion of MFV rate	69.8%	73.3%	73.7%	72.7%	*(4)*
35	Unused firm contract adjustment (MDth/d)	**72**	**75**	**76**	**75**	

(TABLE CONTINUED ON NEXT PAGE)

APPENDIX J: Table 29 (Updated) (Continued)
PACIFIC GAS AND ELECTRIC COMPANY
THROUGHPUT ADJUSTMENTS FOR BACKBONE LOAD FACTOR
NON-EQUALIZED RATES WITH 4-CENT BAJA-REDWOOD DIFFERENTIAL

		2015	2016	2017	2018	Revision Notes
36	**(e) Adjust for disproportionate usage of backbone paths**					
37	Core Redwood capacity (MDth/d)	612	612	612	612	
38	Throughput at load factor (MDth/d)	427	421	413	413	
39	Expected Core Redwood utilization rate (incl brokering)	99.6%	99.6%	99.6%	99.6%	
40	Expected Core Redwood throughput (MDth/d)	609	609	609	609	
41	Throughput shift to Core Redwood capacity (MDth/d)	183	188	197	197	
42	Core Redwood rate as percent of system average rate	81.9%	86.1%	86.5%	87.4%	
43	Percent difference relative to system average rate	-18.1%	-13.9%	-13.5%	-12.6%	
44	Throughput adjustment (MDth/d)	(33)	(26)	(27)	(25)	*(5)*
45	Core Baja capacity (MDth/d)	247	247	247	247	
46	Throughput at load factor (MDth/d)	173	170	167	167	
47	Expected Core Baja utilization rate (incl brokering)	96.2%	96.2%	96.2%	96.2%	
48	Expected Core Baja throughput (MDth/d)	238	238	238	238	
49	Throughput shift to Core Baja capacity (MDth/d)	65	68	71	71	
50	Core Baja rate as percent of system average rate	95.4%	96.2%	95.8%	96.1%	
51	Percent difference relative to system average rate	-4.6%	-3.8%	-4.2%	-3.9%	
52	Throughput adjustment (MDth/d)	(3)	(3)	(3)	(3)	*(5)*
53	Noncore Baja capacity (MDth/d; excl SMUD equity)	737	737	737	737	
54	Throughput at load factor (MDth/d)	514	507	497	497	
55	Expected Noncore Baja throughput (MDth/d)	152	140	102	102	
56	Throughput shift to Noncore Baja capacity (MDth/d)	(362)	(367)	(395)	(395)	
57	Noncore Baja rate as percent of system average rate	114.6%	111.1%	110.5%	109.8%	
58	Percent difference relative to system average rate	14.6%	11.1%	10.5%	9.8%	
59	Throughput adjustment (MDth/d)	(53)	(41)	(42)	(39)	*(5)*
60	Noncore Redwood capacity (MDth/d; excl G-XF and SMUD equity)	1,274	1,294	1,338	1,338	
61	Throughput at load factor (MDth/d)	889	891	903	902	
62	Expected Noncore Redwood throughput (MDth/d, excl G-XF and SMUD equity)	983	960	990	986	
63	Throughput shift to Noncore Redwood capacity (MDth/d)	95	69	87	83	
64	Noncore Redwood rate as percent of system average rate	101.1%	101.0%	101.2%	101.1%	
65	Percent difference relative to system average rate	1.1%	1.0%	1.2%	1.1%	
66	Throughput adjustment (MDth/d)	1	1	1	1	*(5)*
67	Total throughput adjustment (MDth/d)	**(88)**	**(69)**	**(70)**	**(65)**	*(5)*

		2015	2016	2017	2018	
68	**Backbone Rate Inputs (G-AFT, $/Dth)**					
69	System average rate (excl Silverado and G-XF)	$0.296	$0.397	$0.428	$0.460	*(6)*
70	Core Redwood rate	$0.243	$0.342	$0.370	$0.402	*(6)*
71	Core Baja rate	$0.283	$0.382	$0.410	$0.442	*(6)*
72	Noncore Redwood rate	$0.300	$0.401	$0.433	$0.465	*(6)*
73	Noncore Baja rate	$0.340	$0.441	$0.473	$0.505	*(6)*

APPENDIX J: Table 29 (Updated) (Continued)
REVISION NOTES *

(1) Full rate equivalent non-G-XF off-system throughputs are revised because the noncore Redwood rates (Line Nos. 3 and 72) are revised.

(2) Noncore G-AA throughputs are revised because of changes to the demand forecast (discussed in Note 1 of the previous table) and minor changes to the forecasted firm contracts (discussed in Note 3 of this table).

(3) Total firm contract MDQs are revised slightly due to minor changes to the firm backbone capacities (discussed in Note 3 of the previous table).

(4) The average reservation portion of the MFV rate is revised consistent with revisions to the backbone revenue requirement.

(5) The adjustments for disproportionate usage of backbone paths are revised for several reasons, chiefly changes to the backbone load factors and the backbone rates themselves. (The backbone load factor and the backbone rates are interdependent and must be calculated in an iterative manner.) The adjustments for disproportionate usage of backbone paths are also affected by revisions to the demand forecast (discussed in Note 1 of the previous table) and minor revisions to the backbone capacities (discussed in Note 3 of the previous table).

(6) The backbone rates are revised to account for changes in the backbone revenue requirements, changes in the backbone load factors, and minor changes in the backbone capacities.

General Note: The 2018 backbone load factors were developed by holding all inputs constant at 2017 levels except for backbone revenue requirement and backbone rates.

*** Revision explanations are based on comparisons to Exhibit PGE-043, Chapter 17A, Table 17A-2 and Table 17A-3.**

(END OF APPENDIX J)