Ratemaking Issues Relating to Pacific Gas and Electric Company's Pipeline Safety Enhancement Plan

Prepared testimony of
William B. Marcus

JBS Energy, Inc.
311 D Street
West Sacramento
California, USA 95605
916.372.0534

on behalf of
The Utility Reform Network

California Public Utilities Commission
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I. Introduction

This testimony is presented by William B. Marcus, Principal Economist of JBS Energy, Inc. on behalf of The Utility Reform Network (TURN). Mr. Marcus has 33 years of experience in energy issues and has appeared before this Commission on many occasions, and has filed testimony or formal comments before about 40 federal, state, provincial, and local courts and regulatory bodies in the U.S. and Canada. Mr. Marcus' qualifications are included as Attachment 1.

This testimony addresses a number of issues relating to the extent to which costs should be divided between ratepayers and shareholders if PG&E is granted any type of memorandum account or balancing account treatment.

This testimony recommends:

1. That funds under Resolution L-411 (bonus depreciation after May, 2011) should be applied to safety capital projects to the extent that those projects qualify.

2. That the Gas Transmission and Storage function (excluding safety funding associated with Phase 1 and 2 projects) should undergo an annual earnings review in each year starting in 2012 and that all excess earnings, grossed up for taxes, be applied to memorandum or balancing accounts to offset safety program revenue requirements.

3. That shareholders should be required to contribute an amount of money equal to executive and top manager incentive compensation approved in the General Rate Case (approximately $24 million) to fund pipeline safety programs; this effectively shifts the ratepayer money from incentive bonuses to safety funding.

4. That PG&E shareholders should be required to fund any incentive compensation that would normally be included in either labor or corporate overheads for safety program spending, whether capitalized or expensed.

5. That the rate of return on common equity (ROE) for gas pipeline safety programs should be reduced by <u>a minimum</u> of 115 basis points to the low end of the range

of reasonableness, reducing the revenue requirement associated with capitalized costs by about 6%. Mr. Long presents testimony supporting a larger reduction in the ROE, which would reduce the revenue requirement associated with capitalized costs by about 26%.

6. That depreciation for plant in FERC Account 367 (entitled "transmission mains") installed under the pipeline safety program should be extended to 60 years, reducing near-term capital revenue requirements by about 4%, though the present value of costs is the same over the life of the projects. Lengthening the depreciable life reduces the near-term rate impact of the program without affecting the long-term balance between ratepayers and shareholders.

This testimony also recommends a correction to reduce PG&E's forecast spending levels for both capital and expense projects by approximately 5%. PG&E inappropriately included Allowance for Funds Used During Construction (AFUDC) in the cost of expensed projects and included excessive AFUDC in the cost of capital projects. The correction becomes necessary if PG&E's proposal for ratemaking is adopted (using forecast expense levels and capping capital costs based on forecast costs) or if PG&E's forecast costs are used in any other way to set rates or a revenue requirement. This correction is not necessary if PG&E is not given cost recovery or if PG&E is given a memorandum or balancing account for actual costs, and rates are not set based on any of PG&E's forecasts.

The testimony provides information as to the ratemaking implications of how the Commission should implement any potential later findings related to deferral of maintenance (whether expensed or capitalized) in the past or related to the use of maintenance practices that were ineffective, as well as general commentary on how the Commission should consider increases in cost due to the large scope of required work and decreases in cost from potential advances in technology.

Finally, the testimony also makes a recommendation to change PG&E's cost functionalization for any costs approved for the Gas Transmission Asset Management Program from 91% local transmission and 9% backbone (based on PG&E's proposed plan for corrective work) to follow total mileage of the transmission system (62% local, 35% backbone, and the remainder to other functions – StanPac, underground storage, and customer class service pipelines).

II. Sources of Funding for Gas Safety before Charging Ratepayers

TURN has identified three internal PG&E sources of funding for Gas Safety work. In the event that a balancing account or memorandum account is adopted and regardless of what specific costs the Commission allows or disallows for recovery, the first dollars of revenue requirement for gas safety work should come from (1) Resolution L-411 (deferred income taxes from 2011-12 bonus depreciation), (2) an earnings review that would identify any earnings in excess of the authorized rate of return for Gas Transmission and Storage programs and use them for safety program funding; and (3) $23.5 million per year from shareholders, which effectively shifts the currently allowed ratepayer funding of executive and top manager bonuses throughout PG&E as a whole (and included in rates in other parts of PG&E's operations today) to gas pipeline safety.

A. Resolution L-411 as corrected by L-411A (bonus depreciation)

Resolution L-411A requires PG&E to track the revenue requirement impacts of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which provided for 100% bonus depreciation from September 9, 2010 through the end of 2011 and 50% bonus depreciation in 2012. The memorandum account tracks the revenue requirement going forward from April 14, 2011. To the extent that the tax savings are invested in pipeline safety spending (or other forms of capital spending not relevant to this case), they are not subject to refund to ratepayers. Regarding the definition of projects where money would not be refunded to ratepayers, the resolution specifically states:

> For gas utilities, projects would include accelerating existing programs of distribution pipeline replacement, replacement of the riskiest or highest priority gas transmissions based on reasonable engineering assessments, and installing "smart pig" and associated plant in gas transmission lines.[1]

[1] Resolution L-411A, page 6.

TURN notes that PG&E can spend money under this resolution arising from deferred taxes for gas plant for gas distribution and for gas transmission and storage, including these projects.[2] Before requesting funding through any balancing or memorandum account, PG&E should in fact first use this source of funding, which has already been approved for this purpose and requires no further Commission action.

Any remaining gas-related money in the memorandum account when the account is closed should be used to pay for additional gas safety investments instead of being returned to ratepayers.

B. Earnings Review for Gas Transmission and Storage

Every year, the Commission should subject gas transmission and storage operations of PG&E (aside from the gas safety funding in this case) to an earnings review. The earnings review will determine the rate of return for GT&S operations from actual revenue, expenses, and rate base, with a limited number of pro forma adjustments.

The earnings review will assure that PG&E shareholders are not earning more than the authorized return on GT&S operations while PG&E ratepayers pay money to fund massive safety programs. According to the Overland Audit, GT&S has earned an average of about 300 basis points more than its authorized return on equity from 1999 through 2010.[3]

One of the first sources of funding for the safety programs should be any such overearnings at GT&S.

The earnings review will also include any reductions in rate base from larger amounts of accumulated deferred income taxes than forecast, capturing remaining benefits from the bonus depreciation rules in effect from 2009-2012 (rather than just the settled amount

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[2] The resolution states that at least 90% of the incremental investment amount must be attributable to the tax benefits associated with the particular service function (gas or electric).

[3] Overland consulting, *Focused Audit of Pacific Gas & Electric Gas Transmission Pipeline Safety-Related Expenditures for the Period 1996 to 2010*, December 30, 2011, page 1 -3.

from the General Rate Case –"GRC" and the amount in revenue requirements after April 14, 2011 in the memorandum account established under Resolution L-411A).

For purposes of this earnings review, three adjustments need to be made. The first two are needed to assure that existing Commission policy is carried out in the review. These are essentially mechanical adjustments that should not be controversial. The last is a policy-related adjustment to assure that incentive bonuses are funded by shareholders (while the costs for bonuses included in rates effectively defray safety spending).

The mechanical adjustments are outlined below:

1. Notwithstanding any differences in timing of receipt of revenues and expenses, pro forma adjustments should be made to treat GT&S balancing accounts as if fully collected in the year under review. That means that revenues shall be adjusted to equal expenses for any costs subject to balancing accounts that are allocated to GT&S from the GRC Settlement (for example, pensions, post-retirement benefits other than pensions). Revenues shall also be adjusted to equal costs associated with the GT&S balancing account for electricity used in compressor stations and prior year true-ups shall be removed. Costs charged to ratepayers under CEMA and the Hazardous Substance Mechanism should also be either removed or assumed to be balanced with revenues, notwithstanding timing differences.

2. Pro forma adjustments need to be made to incentive compensation and Directors' and Officers' liability insurance in an earnings review to conform to the GRC Settlement and to executive severance to assure that PG&E meets its commitments to ratepayers. Specifically, above-the-line short-term incentive compensation should be limited to one-half of the greater of actual or target levels and no long-term incentive compensation should be allocated to GT&S above the line. The language of the GRC Settlement contained a $45 million reduction to incentive compensation (approximately half of the total), and PG&E never even requested long-term incentive compensation. Therefore, this adjustment is needed to be consistent with the spirit of the GRC settlement. In addition any

costs of severance or increased pensions for departing corporate officers including but not limited to former CEO Peter Darbee that are allocated to GT&S must be accounted for below the line to meet the commitment that PG&E gave the Commission that shareholders would not pay for this severance.[4] Finally, half of directors and officers insurance allocated to GT&S needs to be accounted for below the line consistent with a long-standing Commission precedent that was also specifically affirmed in the GRC Settlement.

An additional adjustment to GT&S spending is supported by the gravity of the situation and the high cost of the safety work. **All** costs of incentive compensation (not merely the reduction associated with the GRC settlement) should be adjusted out of the GT&S revenue requirement, in recognition that PG&E paid incentive compensation at levels well above target for a decade, while neglecting safety of gas distribution and transmission systems.

The rate of return on rate base would be computed after these adjustments. The amount of any excess earnings (grossed up for taxes) would be applied to reduce the revenue requirement for any safety-related costs contained a balancing or memorandum account. As part of this process, any duplication between the overall earnings review adjustment and the more limited adjustment already required by Resolution L-411A should be eliminated.

A process for conducting this earnings review could be developed so that the review could be filed in the spring, with review by Energy Division, DRA, and other parties, and approval in mid-summer. If PG&E were to under-earn its rate of return (other than these gas safety projects), it would receive no additional revenue from the review.

C. Executive and Top Manager Bonuses

PG&E has paid out large bonuses over the last five years despite poor performance in a number of areas.

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[4] See David R. Baker "PG&E eases stance on CEO Package, SmartMeters," San Francisco Chronicle, April 26, 2011. http://www.sfgate.com/cgi-bin/article.cgi?f=/c/a/2011/04/25/MNG21J73UH.DTL

If ratepayers are facing billions of dollars of gas safety expenses, then shareholders should make a further contribution toward these costs by paying for at least top manager and executive bonuses at least until the next General Rate Case. Essentially, the money currently collected from ratepayers for these bonuses would remain in rates under the GRC settlement, but the shareholders would make an equivalent dollar payment that would be applied to gas safety. PG&E requested $94,026,000 in expensed short-term incentives in its general rate case.[5] The GRC settlement indicates show that $45 million of this amount was removed from rates, as noted above. Shareholders should pay the remainder of costs for top executives and managers and instead apply that money contained in rates for gas pipeline safety. We therefore recommend that during the current GRC cycle, starting in 2012, shareholders, not ratepayers, should cover the first $23,436,000 per year of allowable revenue requirements remaining after the earnings review. The figure is the total request of $94,026,000 minus $45 million removed in general rate case settlement, multiplied by 50% as a proxy for executives and top managers, and finally multiplied by 95.61% if the GT&S earnings review is adopted. The 95.61% factor reflects that 4.39% of incentives were allocated to GT&S in the GRC.[6] The actual amount of incentive GT&S compensation would be removed through the provisions of the earnings review above, so that GT&S incentive costs would be removed twice without including this factor.

III. Generic Changes to Actual Costs and Revenue Requirements and Project Cost Forecasts

Before considering characteristics of specific projects and specific utility actions, a task discussed in the testimony of Mr. Kuprewicz and Mr. Long, TURN recommends three generic adjustments that need to be adopted, even absent findings related to PG&E's prudence or conduct.

1. The inclusion of standard labor and corporate overhead factors for Short-Term Incentive Program costs should be rejected for PG&E's Gas Pipeline Safety

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[5] TURN DR 2-76 in PG&E General Rate Case. (Attachment 2)

[6] PG&E 2011 TY GRC, Exhibit PG&E-2, Workpaper 7-6.

capital expenditures, and no short-term incentives should be included in labor loaders applied to PG&E's gas safety O&M costs.

2. TURN recommends a reduction to the return on equity so that the utility cannot turn safety investments into a profit center. Mr. Long provides TURN's recommendation for PG&E (equal to the cost of debt). This testimony identifies a theoretical maximum level for all utilities (equal to the low end of the range of reasonableness of ROE identified by the Commission).[7]

3. All safety-related pipeline plant in FERC Account 367 should be assigned to a new sub-account with a 60-year depreciable life.

A fourth adjustment, to PG&E's forecast for Allowance for Funds Used During Construction (AFUDC), does not affect actual costs but is required in the event that PG&E's forecast is used in any way to set rates or cost caps, because PG&E erroneously forecasts that it will incur more AFUDC than it will book in reality.

A. All Capitalized and Expensed Overheads Associated with Incentive Compensation Should Be Disallowed on an Actual Basis

The first generic issue involves the treatment of performance incentives that would be assigned to safety project capital expenditures and expenses as overhead factors in the normal course of business.

TURN believes that ratepayer funding of performance incentives associated with any GT&S activities at this time is inappropriate giving the magnitude of the problems and associated rate impacts. We therefore recommend that incentive bonuses be removed from PG&E's corporate overheads and overheads assigned to PG&E labor for both capitalized and expensed transmission safety projects. We do not know the precise impact on GT&S, but PG&E's company-wide forecast of capitalized short-term incentive

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[7] TURN understands that this phase of the proceeding relates only to PG&E's pipeline safety proposal and that cost responsibility issues for other utilities will be addressed elsewhere.

bonuses for 2011 was $29,349,000.[8] The STIP bonuses represent approximately 69.9% of PG&E's forecast capitalized A&G costs in Account 922.[9]

B. Return on Equity – All Gas Safety Capital Expenses Should be Granted No More than the Low End of the Commission's Range of Reasonableness of ROE

The testimony of Mr. Long recommends a rate of return equal to the return on debt (6.05% at the present time). Mr. Long's recommendation would reduce the revenue requirements for capital costs by 448 basis points (28.6%) in the first year and reduce the present value of revenue requirements over the life of the equipment by 26.0%. Approximately 59% of the reduction is to return and 41% to income taxes on a present-value basis.

This testimony identifies the other end of the spectrum - an upper bound for the return on equity below current authorized returns that provides the lowest cost of equity capital found by the Commission and no more. The upper bound would set PG&E's (and Sempra's) rate of return on safety projects at the bottom of the "fair and reasonable ROE range," which was 10.2% in its 2008 cost of capital decision.[10] This is a reasonable return by the Commission's own finding. Such an ROE reduction balances the interests of ratepayers and shareholders by limiting utilities' profit from safety-related work.[11]

The minimum reduction of the ROE from 11.35% to 10.2% would reduce PG&E's after tax return by about 99 basis points, reducing capital-related first-year revenue requirements by 6.21% and reducing revenue requirements over the life of the project by 5.65% When setting a maximum cost of capital in this way, in future cost of capital cases, the Commission should continue to set the ROE for this safety-related plant 115

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[8] PG&E TY 2011 GRC, TURN DR 2-76.

[9] PG&E TY 2011 GRC, PG&E -2 Workpaper 7-16

[10] Dec. No. 07-12-049, slip op. at 35.

[11] Sempra is already explaining to shareholders how safety -related work will be a profit center for its shareholders by increasing its growth in ratebase. Sempra Energy, Barclay's Capital 2011 CEO Energy-Power Conference, September 7, 2011, pages 7-10. http://files.shareholder.com/downloads/SRE/1213505664x0x496003/84d73668-28fb-4557-af7f-b6481806021e/Barclays_09_11.pdf

basis points below the authorized ROE, unless the Commission were to find a different relationship between the low end of the range of reasonableness and the authorized ROE in a later case

The Commission can and should grant a lower return if it finds that there are reasons to reduce the rate of return based on utility past actions, for example as recommended in Mr. Long's testimony, but under no circumstances should it exceed the minimum reasonable return that it finds in cost of capital decisions for the billions of dollars of safety-related work now slated for construction. Within the range of reasonableness, the Commission can consider issues of management effectiveness and efficiency when setting the ROE. The very need for PG&E to spend as much as $10 billion on gas pipeline safety to make up for problems that developed over decades, suggests that management has not been effective or efficient in this important area. As a result, spending to correct the safety problem should not be rewarded with a rate of return "at the upper end of an ROE range found to be just and reasonable,"[12] which is how the Commission currently sets PG&E's ROE.

C. TURN Recommends a Longer Depreciable Life for Pipeline Replacements Made Due to Safety Concerns

The current depreciable life of pipelines is approximately 45 years, a rate established in 1996 that has not been changed, although many of PG&E's pipelines have lasted longer. PG&E's depreciable life for gas transmission pipelines (FERC Account 367, "transmission mains") has not been reviewed since 1996. SoCal proposes a 57-year depreciable life in its current rate case, while TURN proposes a 65-year depreciable life in that case.[13]

With the new assured safety testing of new lines, TURN suggests that it would be reasonable to adopt a longer lifespan for the replacement pipes. Therefore, all new transmission plant in FERC Account 367 installed under safety replacement programs

[12] Dec. No. 07-12-049, slip op. at 46.

[13] Prepared Testimony of Jacob Pous on behalf of TURN in A. 10 -12-005, pages 13-15.

should be assigned to a separate subaccount for depreciation purposes and given a life of 60 years with the current 15% negative net salvage rate. This change would reduce the depreciation of new pipe from 2.556% to 1.917%. The impact of this change is a reduction of approximately 4.2% to the first year revenue requirement associated with new capital, though over the life of the plant there is virtually no change in present value of revenue requirements.

D. Required Correction for AFUDC if PG&E's Forecast Costs are Used for Ratemaking

PG&E proposes that the Commission adopt its Phase 1 forecast of capital expenditures and expenses based on its proposals, and that its costs be capped at this forecast level unless PG&E files an advice letter to increase cost recovery, and such an advice letter is approved. If PG&E spends less than the Phase I amount over the three-year period, it would refund money to ratepayers. On a year-by-year basis, the expenses would be based on forecast amounts, and the capital expenditures would be actual costs of in-service projects.

In the event that PG&E's cost recovery proposal is adopted, either as proposed by PG&E or if modified so that any rates or caps are adopted using PG&E's forecast costs for either capital or expenses in any way, a critical PG&E forecasting error must be corrected. The correction would reduce PG&E's forecasts of both capital and expenses by about 5%. The correction of PG&E's error is separate from any actual costs that PG&E should recover from shareholders instead of ratepayers and is not a disallowance. It simply reflects that about 5% of PG&E's forecast costs will never materialize in the real world.

Specifically, PG&E has included AFUDC of 5.24% of all other costs in its estimates of overhead expenses for hydrotesting and 7.58% in its overhead estimates of capital projects.[14]

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[14] See for example TURN DR 13 -01, Attachment 1 for the AFUDC figure for capital projects and TURN DR 13-02, Attachment 1 for the AFUDC figure for hydrotesting (expensed) projects.

These numbers are just plain wrong. To start, elementary utility accounting dictates that ***there is no AFUDC whatsoever on expensed projects***. Thus any costs allowed for any expensed project that is forecast using a PG&E estimating model must be reduced by 4.979% (1 divided by 1 plus 5.24%). This is not a disallowance. This is simply reflecting reality and removing a forecast cost that does not exist.

Even for capital projects, the higher amount of AFUDC (7.58%) is far too high. Remember that PG&E's rate of return is 8.79%. An AFUDC rate of 7.58% is the equivalent of assuming that the pipeline replacement project will take 10 months of financing **<u>at its full cost</u>** before it goes into service.[15] A typical project will have a period of engineering and design where a limited amount of money is spent and then will be built over a short period of time, be tested, and come into service. This kind of a project cannot yield this much AFUDC. TURN therefore recommends a 5% reduction in the average cost of all pipe replacement projects for forecasting purposes if PG&E's forecasting models are used. This is the equivalent of assuming an average AFUDC percentage of 2.2% - a figure much more in line with the construction schedule for these pipeline replacements.

IV. Ratemaking in the Event of a Finding of Deferred or Ineffective Maintenance

TURN offers some analytical commentary below as to how to implement any findings relating to deferred maintenance (expense or capital) that might flow from this or other cases.

To the extent that a finding is made in this proceeding or other proceedings regarding deferred maintenance, a pool of money should be created that becomes an offset to ratepayer funding for the pipeline safety program (along with the earnings review and incentive bonus dollars). Deferred maintenance reductions should be implemented at an

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[15] See the detailed analysis of labor costs in materials such as TURN DR 13 -1 Attachments 13-24, which shows 8-50 direct crew-days for approximately 2 miles of work, depending on the size of the pipe and congestion.

aggregate level (instead of being tied to specific projects) so that incentives are not created to choose to skip specific types of projects to avoid a disallowance or reduction.

Dollars that PG&E failed to spend on pipeline safety in the past should not be recovered a second time. Instead, PG&E should be required to provide shareholder funding for its program equal to that funding.

Similarly if a future finding were made that certain types of work were largely ineffective and had to be redone using a different methodology, then whatever reduction is made for the ineffective work would be added to the fund.

For pipeline integrity capital projects, dollars that PG&E did not spend in the past were essentially trued up in later rate cases. However, shareholders gained from the underspending for a period of time until costs were trued up. Thus the full amount of capital dollars does not offset current capital. Instead, if the Commission finds deferred capital maintenance in 2007 or prior years, a reduction of 30% should be taken. This amount approximates carrying costs multiplied by an average of 2 years prior to true-up in the next case. If there were to be a finding of deferred capitalized maintenance from 2008-2010, the reduction should be 43%. Beyond the 30% received by shareholders prior to true-up, there should be a 13% additional reduction. By deferring capital spending until 2013 or later, PG&E would have permanently given up bonus depreciation that reduces the present value of capital-related revenue requirements by 13% of the deferred maintenance capital amount.

Finally, if the Commission wishes to match the deferred maintenance funding by shareholders with long-term revenue requirements, a portion of this money could be treated as a rate base offset (to offset return and income taxes on new capital projects) amortized back to ratepayers (to offset depreciation on new capital projects) over a significant period of time (e.g., 20 years).

V. Dealing with Potential Cost Increases and Decreases

A. *Potential Increases in Contractors' Costs Given Multi-Billion Dollar Scope of Work*

TURN has a concern that the massive scope of work of this project (both Phases 1 and 2) and the Sempra safety projects that will be conducted at the same time could cause unit costs to rise significantly. We asked PG&E about it and received the following response:

> **QUESTION [13-]4**
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> Has PG&E conducted any analyses conducted by PG&E regarding the availability and cost of specialized labor (utility hired and contract) to do the work requested by PG&E in the timelines projected by PG&E, including analyses of available labor in California given the Sempra construction programs being implemented concurrently? If so please provide them. If not, please explain why PG&E believed it unnecessary to prepare such studies or analyses.
>
> **ANSWER [13-]4**
>
> No, PG&E has not conducted any analyses on the availability and cost of pipeline engineering and construction labor specific to the Pipeline Safety Enhancement Plan (PSEP) work. Pipeline construction contract resources mobilize throughout the United States based upon where the work is located. PG&E and Sempra's proposed construction programs are substantial in relationship to their effect on the gas transmission system in California, but make up only a small percentage of all pipeline engineering and construction work occurring throughout the U.S. in future years.

We hope PG&E turns out to be right, but we are not as sanguine as PG&E that cost pressures will not occur as a result of California's multi-billion dollar work program and therefore need to alert the Commission as to what should happen if PG&E is wrong.

The 2007 Census data (latest available at this time) shows gas and oil pipeline construction to be an industry with $30 billion of revenue, with approximately half of its revenue from companies in Texas, Louisiana, and Oklahoma. Slightly over $2 billion of the work is done in California.

The oil and gas pipeline construction industry appears to operate regionally. For instance, in 2007, the value of construction work for California firms from California projects equaled 97 percent of their revenues and business done.[16] Census data do not detail any income from projects in Texas for California firms.

For Texas-based firms, that same year, work in Texas provided 89 percent of their revenue. Adding regional projects, in Louisiana and Mississippi increased the income to 94 percent of their revenue. Projects in California provided only 0.8 percent of the revenue for the year, approximately $73 million out of $9.3 billion. [17] That amounted to less than 4 percent of the work done in California.

TURN is therefore flagging this issue now as a topic that would require reasonableness review in the event that unit costs of labor, equipment, or contractor profits start to rise significantly from current estimates as the utilities mobilize large construction programs. If such costs do start to rise, TURN is likely to suggest that some increment should be borne by shareholders because the increase would have been avoidable had work been done over time rather than through a large crash program.

Attachment 3 provides the Census data referenced above. Attachment 4 and Attachment 5 (confidential) contain labor and equipment and other unit costs from TURN DR 13-01, which should be considered as a benchmark for current unit cost conditions based on what is known today.[18]

B. Cost Reducing Technology

In addition to being concerned about cost increases, TURN believes that there is a significant potential for cost-reducing technology to become available, which could

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[16] U.S. Census Bureau, American Factfinder, All Sectors, Geographic Area Series, Economy -Wide Key Statistics: 2007, NAICS Code 237120

[17] U.S. Census Bureau, American FactFinder, Construction Summary Series, 2007 Economic Census: Report EC0723SG04, NAICS Code 237120, Oil and gas pipeline and related structures construction.

[18] We provide one of the twelve estimating cases as an example of the unit cost forecast data provided by PG&E in this case (highly congested area, pipe less than 12 inches). In reviewing the data, we believe PG&E made a spreadsheet programming error that understates hourly rates for the assistant superintendent and foreman positions, but we cannot figure out how the cost sheets match up to the total cost sheets (for example how data from TURN DR 13-01, Attachment 13 (labor cost) are used to construct Attachment 1 (total cost). Similar public unit cost data are found in TURN DR 13-01, Attachments 2-12 while confidential unit cost data similar to Attachment 13 exists in TURN DR 13-01 Attachments 14-24.

reduce the need for both hydrotests and replacements. If such technology becomes available TURN believes it should be incorporated into PG&E's program as quickly as possible to reduce costs. The reasonableness review process should encourage the potential for new technology to be used to inspect a pipe that eliminates the need for replacement or more costly forms of testing by allowing costs of the cheaper technology and reducing disallowances associated with more costly actions.

An example of this type of technology came to light in the Sempra General Rate Case, where Sempra referenced then TIGRE robotic platform for inspection of unpiggable pipelines of 20-26 inches in diameter. The research arm of the Northeast Gas Association (NYSEARCH) has been developing robotic inspection techniques for unpiggable pipelines with Pipetel Technologies, Inc. SoCal spent its R&D money to field test some of this equipment on at both the 8 inch and 20-26 inch robots. This technology now exists for pipelines of 6-8 inches in diameter (Explorer 6-8) and will be commercialized in diameters up to 14 inches (Explorer 10-14) and in the 20-26 inch range (TIGRE) in 2011-2012. Attachment 6 contains some material describing the operation and status of this technology.[19]

VI. Cost Allocation

TURN has reviewed PG&E's proposed cost functionalization and allocation, which assigns safety-related costs to functions based on the type of pipeline being replaced or tested. Our only concern relates to costs of information technology related to the Gas Transmission Asset Management (GTAM) project. This program is designed to capture, validate, and retain large amounts of data related to all of PG&E's pipelines. PG&E appears to assign IT costs in proportion to the amount of work being done on the system – approximately 91.35% to local transmission, 8.65% to backbone and none to storage or customer-related service pipes. TURN recommends that any GTAM costs allowed to be recovered in rates be assigned to functions by total miles of pipeline, since GTAM

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[19] The document included in Attachment 6 that is labeled "confidential" on its face is not truly confidential. It was available on a public internet site of the Northeast Gas Association and could be downloaded by the public without any password or other protection. An ordinary "Google" search on the topic identified the specific document. http://northeastgas.org/pdf/d_dzurko_update.pdf

collects, validates, and stores data for all transmission pipelines on the PG&E system, not just segments being worked on under Phases 1 and 2 of the current program.

TURN's recommended allocation is based on the following estimates of total mileage from DR 8-01.[20] This allocation change would assign about 35% of the costs to backbone transmission, while assigning limited amounts of costs to underground storage and customer class charges for service mains.

GTAM Allocation using Pipeline Mileage

Backbone	2026	34.85%
StanPac	55	0.94%
Local Trans/DFM	3580	61.57%
Service Main	110	1.90%
Underground Storage	43	0.75%
Total	5814	

We will ask PG&E a data request to provide an analysis of its estimated costs by function using TURN's allocation of GTAM costs and to compare it to PG&E's proposed allocation.

[20] It is possible that some costs need to be allocated to g athering, but we do not have the information to do that at this time. That consideration will be part of our data request to PG&E.