APPENDIX A

PROPOSED CHANGES TO FINDINGS OF FACT AND CONCLUSIONS OF LAW

Findings of Fact

1. On August 26, 2011, PG&E filed and served its Implementation Plan required by D.11 06 017.

2. PG&E's Implementation Plan is comprised of: (A) a Pipeline Modernization Program that provides for testing or replacing pipelines, reducing their operating pressure, conducting in line inspections as well as retrofitting to allow for in line inspection, and adding automatic or remotely controlled shut off valves; and (B) a Pipeline Records Integration Program where PG&E will finish its records review and establish complete pipeline features data for the gas transmission pipelines and pipeline system components, and the Gas Transmission Asset Management Project, a substantially enhanced and improved electronic records system.

3. PG&E's Implementation Plan purports to use~~s~~ a consistent methodology to identify and prioritize recommended actions based on pipeline threat categories ~~and~~ which PG&E organized ~~this methodology~~ into a decision tree to identify actions such as performing pressure tests, replacement of pipe, and in line inspection, to address specific risks~~.~~.

4. PG&E's decision tree methodology is deficient in that it erroneously includes replacement as a default action for certain segments with manufacturing flaws (outcome M2), and bypasses replacement as a default

action for certain segments with fabrication and construction flaws (due to decision point 2F.)

~~3.~~5. Natural gas pipelines carry explosive and flammable gas under pressure and are typically located in public rights of way, at times amidst dense populations. These facilities must be carefully operated and regulated to protect public safety.

6. The Independent Review Panel found numerous deficiencies in PG&E's operations, including data management and pipeline Integrity Management, and recommended improvements that included modifying its corporate culture and engaging in a progression of activities to address pipeline safety using the image of a journey to a new destination.

7. The Independent Review Panel Report concluded that PG&E's Integrity Management Program lacked effective executive leadership, and that "perpetual organizational instability," including corporate bankruptcy, had undermined PG&E's ability to meet its integrity management responsibilities. [PD at 8]

8. The Independent Review Panel Report found that PG&E lacked robust data and document information management systems that impeded the needed quality assurance/quality control to accurately characterize pipeline threats and risk. [PD at 9]

~~4.~~9. The Independent Review Panel Report also identified inadequate assessment of multiple threats to a particular pipeline and inadequate monitoring of third-party activities as deficiencies in PG&E's Integrity Management Program. [PD at 9]

10. PG&E's Decision Tree analysis, while ~~is~~ a promising beginning at a comprehensive decision making process, requires updating and modification to

ensure it is based on safety concerns related to historical pipeline manufacturing, fabrication, and testing practices.

~~5.~~11. PG&E's Implementation Plan often deviates from the Decision Tree based on undefined "engineering judgment"

~~6.~~12. PG&E must improve the safety of its gas system operations, specifically but not only in the areas quality control and field oversight.

~~7.~~13. The Implementation Plan calls for pressure testing 783 miles of pipeline and replacing 185.5 miles of pipeline in Phase 1.

~~8.~~14. PG&E's Decision Tree identifies and prioritizes three unique threats to pipeline integrity – manufacturing threats, fabrication and construction threats, and corrosion and latent mechanical damage threats.

~~9.~~15. The Implementation Plan calls for replacing, automating and upgrading 228 gas shut off valves.

~~10.~~16. The Implementation Plan calls for retrofitting 199 miles of pipeline for in line inspection and inspecting 234 miles of pipeline with in line inspection tools.

~~11.~~17. The Implementation Plan calls for pressure reductions and increased leak inspections and patrols.

~~12.~~18. In D.11 06 017, the Commission required PG&E to include in its Implementation Plan a proposed cost allocation between shareholders and ratepayers, and PG&E's Implementation Plan included a discussion of costs to be absorbed by PG&E's shareholders.

~~13.~~19. PG&E's proposed cost allocation between shareholders and ratepayers reflects existing ratemaking policies established in Gas Accord V adopted in D.11 04 031 and includes no material voluntary cost allocation to shareholders.

~~14.~~20. Generally, post test year ratemaking is disfavored when a forecasted test year revenue requirement is used to set rates.

~~15.~~21. Adopted in 1955, the American Standard Association Code for Pressure Pipeline (ASA B31.8) required pre service pressure testing for natural gas pipelines.

~~16.~~22. PG&E admits that it voluntarily complied with American Standard Association Code for Pressure Pipeline (ASA B31.8), beginning in 1955.

~~17.~~23. Since no later than ~~January 1, 1956~~December 31, 1955, PG&E complied with or stated that it complied with industry standards to pressure test pipeline prior to placing it in service. PG&E is unable to produce the records for certain pressure tests that would have been performed in accord with industry standards from January 1, 1956, or for pipeline of unknown installation date. The lack of pressure test records for pipeline placed into service after ~~January 1, 1956~~December 31, 1955, or with an unknown installation date, reflect ~~an error~~errors and omissions and imprudent management in PG&E's operation of its natural gas system. No evidence was presented that PG&E excluded the costs of pressure testing pipeline from its regulated revenue requirement from ~~January 1, 1956~~December 31, 1955.

~~18.~~24.

~~19.~~ PG&E's cost forecast for pressure testing pipeline is materially higher than DRA's~~, but is based on actual PG&E pressure test costs and is therefore~~

~~reasonable.~~ and is based primarily on data from an out of state contractor, rather than experience with PG&E's system.

25. DRA provided analyses from two expert witnesses supporting lower hydrotest costs: one based on a bottoms up calculation and the other based on a review of industry studies.

~~20.~~26. DRA's cost estimates for hydrotesting are reasonable.

~~21.~~27. Requiring pressure tests of existing pipeline to attain pressures of 90% SMYS for each pipeline component is impractical, and the margin of safety attained in the 49 CFR subpart J pressure test specifications is calculated based on the maximum allowable operating pressure for the pipeline.

~~22.~~28. A valid pressure test record need only comply with the regulations in effect at the time the test was performed, not later adopted regulations.

~~23.~~29. Cost and engineering efficiency may be achieved by pressure testing pipeline segments adjacent to high priority segments.

30. PG&E's cost forecast for replacing pipeline is higher than DRA's~~, but is supported by actual PG&E operational experience and is therefore reasonable.~~ and is based primarily on data from an out of state contractor, rather than experience with PG&E's system. PG&E incorrectly states that its forecast is based on actual pressure test costs.

~~24.~~31. PG&E's cost forecast for replacing pipeline considered specific locations, and increased the estimated unit costs for congested locations. PG&E additionally included ~~as is illustrated by the~~ an unsupported Peninsula Adder ~~for higher forecasted costs on the~~which further increases the forecast for certain projects on the San Francisco peninsula.

~~25.~~32. DRA's cost forecast for replacing pipeline is reasonable.

~~26.~~33. Pipeline segments that end up in the M2 box of the Decision tree have substandard welds and will be operated at a high pressure.

~~27.~~34. In line inspection is a useful means to obtain data on pipeline conditions including indentations, wall loss, pipe strain, metallurgical variations, and certain types of cracks.

~~28.~~35. PG&E's in line inspection proposal expands its existing in line inspection program, focuses on segments operating at high pressure, and is consistent with D.11 06 017.

~~29.~~36. PG&E's valve automation proposal will automate and upgrade 228 valves.

~~30.~~37. Transmission main pipeline installed pursuant to the Implementation Plan will be manufactured to higher standards than pipe installed 40 or more years ago and will be pressure tested prior to being placed in service.

~~31.~~38. The Commission has not authorized a memorandum account into which PG&E may record its Implementation Plan costs incurred prior to the effective date of today's decision.

~~32.~~39. The record shows that since 1998, PG&E revenues are estimated to have exceeded the amount needed to earn its authorized rate of return by $430 million. PG&E retained these amounts in excess of its authorized rate of return during years when it did not spend its full authorized budget for gas pipeline improvements.

40. Improvements, efficiencies, and adjustments based on sound engineering practice to the Implementation Plan in furtherance of the objectives of the Plan

are encouraged and are within the scope of the Plan. Such changes ~~and~~ do not require further Commission review provided they do not materially change the scope, scale, or timeframe for implementing the Plan.

41. From the date installed, PG&E was responsible for creating and maintaining accurate and accessible records of its natural gas system equipment and facilities.

42. Upon discovery that PG&E may have discrepancies in its records, the NTSB and this Commission ordered corrective actions, namely, to aggressively and diligently search for all as built drawings to compile traceable, verifiable, and complete records. [PD at 97]

43. PG&E's failure to possess accurate and accessible records of its gas system over many decades contributed to the San Bruno Explosion and caused the NTSB and this Commission to direct PG&E to correct these deficiencies.

44. The NTSB was clear that it envisioned its directives as "corrective" measures caused by its discovery of "inaccurate records" of PG&E's natural gas transmission system. [PD at 95]

45. The NTSB explained that accurate and reliable records are "critical" to setting a safe operating pressure limitation. [PD at 95]

46. Curing PG&E's unreliable natural gas pipeline records was the goal of the NTSB's recommendation to obtain "traceable, verifiable, and complete" records. [PD at 95]

47. Furnishing and maintaining safe natural gas transmission equipment and facilities requires that a natural gas transmission system operator know the

location and essential features of all such installed equipment and facilities. [PD at 93 94]

48. The NTSB, this Commission, and PG&E's own vice president all agree that accurate and reliable gas transmission system records are essential to safe operation of the system. [PD at 97]

49. The purpose of accurate records is not limited to calculating MAOP. Among the other uses are safely conducting a pressure test. [PD at 97]

50. PG&E's historic gas system revenue requirement has included costs for maintaining gas system records.

51. The document management costs PG&E seeks to recover from ratepayers in this application are for remedial work that stem from its previous failure to prudently perform its document management duties and to maintain accurate and reliable records. [PD at 56]

~~33.~~

52. PG&E's imprudent management decisions to delay pipeline pressure testing and replacement, based on its dysfunctional integrity management system, contributed to the need for and timing of the projects needed pursuant to the Implementation Plan, which led to increased risk of cost overruns on projects.

~~34.~~53. Ratepayers have funded PG&E's integrity management work for over three decades.

~~35.~~54. An escalation rate tied to the overall inflation rate, as proposed by DRA, is a reasonable escalation factor for Implementation Plan projects.

~~36.~~55. The scope of and timing for the extraordinary capital investment needs of the Implementation Plan were caused, in part, by PG&E's imprudent management decisions regarding pipeline records and pressure testing older pipeline.

56. PG&E has committed errors and omissions and has been inefficient and ineffective in its management of it natural gas system, so that PG&E's natural gas system poses a threat to public health and safety.

57. The Overland Report shows that PG&E enjoyed the protection of the rule against retroactive ratemaking when, from 1997 to 2010, PG&E consistently underspent Commission authorized amounts, resulting in approximately $430 million in excess earnings for shareholders. [PD at 84]

58. The need for urgent Commission pre approval action was caused at least in part by PG&E's own actions, and the record shows that PG&E's management and shareholders used the rule prohibiting retroactive rate adjustments to retain substantial benefits in the past. [PD at 84]

~~37.~~59. These circumstances do not justify allowing PG&E to recover Implementation Plan costs incurred prior to the effective date of today's decision. [PD at 84]

60. The amounts in Attachment E are program based upper limits on expense and capital costs to be recovered from ratepayers for the specific projects authorized through the Implementation Plan. To the extent specific authorized Phase 1 projects are not completed by the end of 2014 and not replaced with other higher priority projects consistent with the priority established in PG&E's

"initial" Attachment D filing, the expense and capital cost limit of the balancing account is reduced by the amounts associated with the project not completed.

61. PG&E's estimated hydrotest costs per foot vary significantly depending on the length of pipeline that is tested, and the cost per foot is inversely related to project length.

62. The simple equation provided by DRA provides an approximation of PG&E's estimated hydrotest costs which is more accurate than any single estimate of PG&E's hydrotest costs, particularly for projects less than 10,000 feet long.

63. The average length of PG&E's proposed hydrotest projects is approximately 17 times shorter than proposed replacement projects.

64. PG&E should have retained records for all hydrotests performed after 1955, and its shareholders should bear the cost responsibility for segments where complete records were not found.

65. Pipe segments with a MAOP validation status other than "Complete" do not have complete test records, and hydrotest or replacement costs for these segments should not be allocated to ratepayers.

66. Adding pipe segments in Class 2 locations to Phase 1 projects could increase the overall cost of the Implementation Plan if the Commission finds that in line inspection (ILI) is a more safe and cost effective mitigation option for certain threats.

67. DRA demonstrated that the Implementation Plan includes Class 2 segments without economic or engineering justification.

68. Adding Class 1 or 2 segments to replacement projects is generally not economically justified due to the ratio of fixed to variable costs.

69. The economic analysis to include Class 1 or 2 segments in Phase 1 projects is distorted by PG&E's excessive fixed costs (e.g. an unsupported estimate of $500,000 for Mobilization/demobilization), resulting in the erroneous inclusion of some segments.

70. PG&E increased the diameter of some pipe replacement projects without a showing that increased capacity is needed, or that the increase will ensure pigability of the upgraded line.

71. DRA showed that PG&E's contingency analysis was biased to largely predetermine that the contingency rate for pipeline replacement would be at least 17% and for hydrotesting at least 20%. DRA also showed that PG&E only considered scenarios where costs were higher than expected and ignored the possibility of actual costs being lower than expected.

~~38.~~72. In its report on the Pipeline Safety plan of the Sempra Utilities, DRA showed that over 70% of hydrotest costs are driven by the cost to deliver, handle, and dispose of hydrotest water, and that these cost can be minimized by implementing a strategic water management plan.

Conclusions of Law

1. In D.11 06 017, the Commission declared an end to historic exemptions from pressure testing for natural gas pipeline and ordered all California natural gas system operators to file Natural Gas Transmission Pipeline Testing Implementation Plans.

2. All investor owned public utilities in California, including natural gas transmission operators, are required by Public Utilities Code § 451 to maintain safe equipment and facilities. [PD at 93]

3. ~~As required by §~~Section 451 requires that all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified," as provided in § 454.

4. The obligation of gas pipeline operators to maintain pipeline records that are "traceable, verifiable, and complete" is not a new standard. [PD at 95 99]

5. Furnishing and maintaining safe natural gas transmission equipment and facilities is required by Public Utilities Code § 451 and requires that a natural gas transmission system operator know the location and essential features of all such installed equipment and facilities. [PD at 93 94]

~~2.~~6. PG&E's argument that it had no obligation to maintain accurate and accessible records of the components of its natural gas transmission system because the historical exemption provision of 49 CFR 192.619(c) did not require these records is incorrect. [PD at 97]

~~3.~~ The absence of a regulation specifically prohibiting particular conduct does not excuse a natural gas system operator from recognizing that such conduct is not appropriate or safe under certain circumstances. [PD at 97 98]

~~4.~~7. The burden of proof is on PG&E to demonstrate that it is entitled to the relief sought in this proceeding, including affirmatively establishing the reasonableness of all aspects of the application.

~~5.~~8. Because this proceeding requests a rate increase, PG&E must meet its burden of proof with clear and convincing evidence, ~~The standard of proof that PG&E must meet is that of a preponderance of evidence,~~ which means ~~such~~ evidence so clear as to leave no substantial doubt~~as, when weighed with that opposed to it, has more convincing force and the greater probability of truth~~.

~~6.~~9. The evidentiary record ~~does not~~ supports DRA's request for a ~~comprehensive~~ disallowance of all Implementation Plan costs until PG&E's next rate case. ~~and we deny the request.~~

~~7.~~10. The scope and magnitude of the costs at issue in the Implementation Plan do not justify deviation from the general rule against post test year ratemaking.

11. ~~The public utility code standards for rate recovery, i.e., just and reasonable, and the disallowance concept reflected in § 463 do not combine to provide an analytical basis for disallowing reasonable costs on the basis that the utility should have made the expenditures at an earlier date.~~

~~8.~~ Public Utilities Code § 451, as clarified by § 463, requires disallowance of direct or indirect costs resulting from any unreasonable error or omission by a utility relating to the planning, construction or operation of plant costing more than $50 million.

12. The costs of remedial work made necessary by unreasonable errors and omissions by PG&E in its operation of its gas transmission system should be disallowed.

~~9.~~13. TURN's proposal to disallow all Phase 1 Implementation Plan costs ~~should be denied~~ is supported by the record.

14. PG&E's decision tree for the evaluating manufacturing threats, fabrication and construction threats, and corrosion and latent mechanical damage threats should be approved with the following modifications:

- Eliminate outcome M2
- Eliminate decision point 2F
- Revise footnote to specify that mitigation actions deviating from the decision tree outcomes should be based on approved guidelines, procedures, and protocols, and documented in quarterly reports to the CPUC.

~~10.~~15. PG&E's proposal to retrofit 199 miles of pipeline for in line inspection and inspect 234 miles of pipeline with in line inspection tools should be approved.

~~11.~~16. PG&E's proposal for pressure reductions and increased leak inspections and patrols should be approved.

~~12.~~17. PG&E's proposal to replace, automate and upgrade 228 gas shut off valves in Phase 1 of the Implementation Plan should be approved, and PG&E should continue to monitor industry experience with automated shut off valves for possible revisions to its plans.

~~13.~~18. It is reasonable for PG&E's shareholders to absorb the portion of the Implementation Plan costs which were caused by PG&E's errors, omissions, and imprudent management.

~~14.~~19. Because PG&E's proposed cost allocation between shareholders and ratepayers reflects existing ratemaking policies adopted by Gas Accord V in D.11 04 031 and includes no material voluntary cost allocation to shareholders, notwithstanding the Commission's directive to do so, and due to the scope and consequences of PG&E's errors, omissions, and imprudent management actions, it is reasonable to use exceptional ratemaking measures when considering shareholders' return on equity.

~~15.~~20. It is reasonable for shareholders to absorb the costs of pressure testing pipeline placed into service or hydrotested after ~~January 1, 1956~~December 31, 1955, or for which PG&E has no known installation date, and for which PG&E is unable to produce pressure test records.

21. It is reasonable to impose an equitable adjustment to the replacement cost of pipeline installed or hydrotested ~~from~~ after ~~January 1, 1956~~December 31, 1955~~, to July 1, 1961~~, for which pressure test records are not available, but which require replacement rather than pressure testing. Such an equitable adjustment shall be equal to ~~the~~ an accurate forecast~~ed~~ ~~cost~~ of pipeline pressure testing ~~the~~ costs ~~pipeline~~ and shall reduce the cost of the pipeline replacement included in rate base and revenue requirement.

~~16.~~22. DRA's proposed method of forecasting pipeline pressure testing costs based on project length is reasonably accurate, and should be used to calculate the equitable adjustment to the replacement costs.

~~17.~~23. PG&E's cost forecast for pressure testing pipeline is much higher than any other forecast in the record ~~but~~ and is unreasonable.

~~18.~~24.

~~19.~~ A valid record of a pipeline pressure test must include all elements required by regulations in effect at the time the test was conducted.

25. It is reasonable to require pressure tests of existing pipeline performed pursuant to the Implementation Plan to comply with 49 CFR subpart J pressure test specifications.

26. To comply with 49 CFR 192.619(c), a natural gas system operator must undertake four separate affirmative obligations: (1) Examine and determine that the pipeline segment is in satisfactory condition; (2) Obtain and evaluate its operating history; (3) Obtain and evaluate its maintenance history; and (4) Determine the highest actual operating pressure during the five year period. [PD at 98]

27. No natural gas system operator can comply with the requirements of 49 CFR 192.619(c) without creating and preserving accurate and reliable system installation, operating, and maintenance records. [PD at 98 99]

28. PG&E has failed to demonstrate that long standing regulations excuse incomplete and inaccurate natural gas system record keeping. [PD at 98 99]

29. It would not be just or reasonable to impose the burden of remedial document management costs on ratepayers. [PD at 56 and 89]

~~20.~~30. Because PG&E has not justified including the costs of its gas system record integration projects in revenue requirement the Commission should disallow PG&E's request. [PD at 99]

~~21.~~31. PG&E has not justified wholesale inclusion within Phase 1of ~~including~~ pipeline segments located in Class ~~1 or~~ 2 locations ~~without high consequence areas but adjacent to Class 3 or 4 locations, or~~ with economic or engineering supporting rationale~~,.~~ ~~within Phase 1.~~<u>Such justification should be provided in quarterly reports to the Commission.</u>

~~22.~~<u>32.</u> PG&E's cost forecast for replacing pipeline is substantially higher than DRA's~~, but is supported by significant operational experience and~~ <u>and</u> is ~~therefore~~ <u>un</u>reasonable.

~~23.~~<u>33.</u> The request by TURN and the City and County of San Francisco to disallow pipeline replacement costs for alleged Integrity Management failures ~~should be denied~~<u>is supported by the record and should be granted</u>.

~~24.~~<u>34.</u> PG&E's proposal to replace<u> by default</u>, rather than pressure test, pipeline installed prior to 1970, with weld<u>s</u> that do not meet current standards, operated at over 30% SMYS and located in high population areas is <u>not</u> reasonable.

~~25.~~<u>35.</u> PG&E's proposal to capitalize replacement pipe less than 50 feet in length is not reasonable and is denied. Such pipe must be expensed, consistent with current accounting practice.

<u>36. PG&E should not be allowed to continue to include old pipes that are replaced in rate base because they are no longer "used and useful."</u>

<u>37. PG&E should be required to (1) identify all the amounts earned from the disposition of the pipe material and its costs incurred to transport or dispose of the material: and (2) remove all the unrecovered balance of the old pipelines subject to replacement from PG&E s rate base.</u>

~~26.~~<u>38.</u> It is reasonable to conclude that pipe installed pursuant to the Implementation Plan will have a longer service life than pipe installed over 40 years ago.

~~27.~~39. TURN's proposal to adopt a 65 year service life for transmission main pipe installed pursuant to the Implementation Plan is reasonable, and should be adopted.

~~28.~~40. PG&E has not justified recovering from ratepayers its Implementation Plan costs incurred prior to the effective date of today's decision.

41. Absent extraordinary circumstances, the rule against retroactive ratemaking prevents ratepayer representatives from recovering for ratepayers amounts authorized but unspent by PG&E for gas pipeline improvements.

~~29.~~42.

~~30.~~ PG&E's request for authority to file Tier 3 Advice Letters to modify the Implementation Plan should be denied.

43. "Sound Engineering Judgment" can, and should be documented by PG&E in written guidelines, practices, and protocols to ensure proper judgment is applied consistently across PG&E's territory, throughout the duration of the Implementation Plan, and on an ongoing basis. These documents should be approved by PG&E management, and maintained as company standards. Such documents also allow for the Commission and independent parties or consultants to verify if reasonable engineering judgment is being applied.

44. The Parties to this Proceeding should be ordered to meet and confer no later than 21 days after the effective date of today's decision to develop a plan for an Independent Monitor(s) to be hired by PG&E and to report to the Commission and the public regarding the status and quality of PG&E's work performed pursuant to the Implementation Plan to ensure that PG&E develops accurate and useful record keeping data bases and correctly tests and/or replaces the right

pipelines at the right times. The Parties should be ordered to submit a joint proposal in this proceeding no later than 21 days after their first meeting. At a minimum, the joint proposal should be required to include the following:

- A hiring process for the Independent Monitor(s) that ensures its independence, to the extent practicable;
- PG&E to hire and pay for the Independent Monitor(s);
- PG&E shall permit the Independent Monitor(s) to inspect, inquire, review, examine and participate in all activities of any kind related to the Implementation Plan. PG&E and its contractors shall immediately produce any document, analysis, test result, plan, of any kind related to the Implementation Plan as requested by the Independent Monitor(s), and such request need not be in writing.
- The Independent Monitor(s) to conduct and present all analyses and recommendations independently of any suggestions or conclusions of PG&E, the Commission, or interested parties.
- Quarterly public reporting by the Independent Monitor(s) to a joint meeting of PG&E, the Commission, and interested parties;
- A requirement that the Independent Monitor(s) notify PG&E, the Commission, and interested parties in writing within 10 days of discovery of any potential non compliance with the requirements of the PSEP that presents a potential, but not immediate, threat to public safety;
- A requirement that the Independent Monitor(s) notify PG&E, the Commission, and interested parties in writing within 24 hours of any non compliance or other condition that poses a potential and immediate threat to public safety.
- A requirement that PG&E's contracts with the Independent Monitor(s) shall prohibit the Independent Monitor(s) from seeking work from PG&E while performing the duties of a PSEP Independent Monitor.

~~31.~~45. Authority should be delegated to the Director of CPSD, or designee, (CPSD) to oversee all PG&E's work performed pursuant to the Implementation Plan, including:

A. CPSD shall review all changes to the Implementation Plan proposed by PG&E, and in consultation with the Independent Monitor, shall require such modifications as are necessary to ensure public safety, and may concur in such proposals.

B. CPSD may inspect, inquire, review, examine and participate in all activities of any kind related to the Implementation Plan. PG&E and its contractors shall immediately produce any document, analysis, test result, plan, of any kind related to the Implementation Plan as requested by CPSD, and such request need not be in writing.

C. CPSD may take and order PG&E to take such actions as may be necessary to protect immediate public safety.

D. CPSD may issue immediate stop work orders to PG&E and all its contractors when necessary to protect public safety, and PG&E must comply immediately and consistent with any needed safety protocols.

E. The Director of CPSD, the Commission's Executive Director, and the Chief Administrative Law Judge shall offer PG&E, parties to this proceeding, and the public such procedural opportunities as may be feasible under the specific circumstances of any instance in which CPSD is required to exercise its delegated authority.

~~32.~~46. The Executive Director should be delegated authority to order PG&E to reimburse the Commission for any Commission contract necessary to carry out the directives in today's decision, ~~., not to exceed $15,000,000~~ and PG&E

should not be authorized to ~~record any amounts so expended in its Annual Gas True-Up Balancing Account for recovery~~recover these costs from ratepayers.

47. PG&E should file compliance reports as specified in Attachment D. These reports should be publically available.

48. PG&E should be required to (1) update its Decision Tree to incorporate the most current data available as of the effective date of this decision; and (2) make an "initial" Attachment D filing within 45 days of the effective date of the Decision to describe how it performed the update, the results of the update, and to establish criteria for changing the priorities among projects going forward. ~~file compliance reports as specified in Attachment D.~~ This filing should include approved guidelines, procedures, and protocols as follows to ensure proper judgment is applied uniformly across PG&E's territory, throughout the duration of the Implementation Plan, and on an ongoing basis:

- Deviations from decision tree outcome/mitigation due to new data
- Deviations from decision tree outcome/mitigation due to PG&E engineering judgment
- PG&E implementation of the "ors" in the decision tree
- Acceleration of segments into Phase 1
- Expenditures to increase pigability
- Diameter increases for reasons other than pigability
- Line relocations
- Engineering Condition Assessment
- Hydrotest water management

These documents should be approved by PG&E management, and maintained as company standards.

~~33.~~49. It is not reasonable to adopt a cost overrun contingency allowance because PG&E's imprudent management decisions contributed to risk of such overruns ~~and we adopt cost forecasts at the high end of the range of reasonableness with an added layer for program administration~~.

~~34.~~50. The Commission should impose strong incentives on PG&E to encourage efficient construction management and administration of the Implementation Plan.

~~35.~~51. PG&E's proposal for a 21% contingency adder is not reasonable and should be denied.

~~36.~~52. A rate of 1.5% should be adopted to escalate costs from the effective date of today's decision to the date of project completion.

~~37.~~53. Due to inefficient and ineffective management decisions, PG&E's return on equity for investments made pursuant to the Implementation Plan should be reduced to the incremental cost of debt.

54. A one way balancing account should be approved for all Implementation Plan projects, subject to the following limitation: To the extent PG&E incurs costs beyond the amounts set forth in Attachment E for projects approved in today's decision, the expense and capital overruns should not be recorded in the balancing account and capital cost overruns may not be recorded in regulated plant in service accounts. Similarly, where specific authorized Phase 1 projects are not completed by the end of 2014 and not replaced with other higher priority projects consistent with the priority established in PG&E's "initial" Attachment

D filing, the expense and capital cost limit of the balancing account should be reduced by the amounts associated with the project not completed.

55. Improvements, efficiencies, and adjustments based on sound engineering practice to the Implementation Plan in furtherance of the objectives of the Plan should be documented in quarterly reports to CPSD and should show they do not materially change the scope, scale, or timeframe for implementing the Plan.

O R D E R

IT IS ORDERED that:

1. The Pipeline Safety Enhancement Plan (Implementation Plan) of Pacific Gas and Electric Company (PG&E) is approved as modified herein. PG&E must expeditiously and efficiently pursue the natural gas system safety improvements as described in the Implementation Plan.

2. Pacific Gas and Electric Company shall comply with the Independent Review Panel and National Transportation Safety Board recommendations for improving its Integrity Management Programs. [p. 52]

~~2.~~3. Pacific Gas and Electric Company is authorized to increase its natural gas system regulated revenue requirement to be recovered from ratepayers from the amounts authorized in Decision 11 04 031 by the amounts set forth below in the year indicated:

	~~2012~~	2013	2014	TOTAL
$ 100's million	~~$14,019~~ 0	~~$103,801~~ **Revised Based**	~~$159,984~~ **Revised Based**	~~$277,805~~ **Revised Based**

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		On DRA Proposed Corrections	On DRA Proposed Corrections	On DRA Proposed Corrections

~~3.~~4. All increases in revenue requirement authorized in Ordering Paragraph 2 are subject to refund pending further Commission decisions in Investigations (I.) 11 02 016, I.11 11 009, and I.12 01 007.

~~4.~~5. Pacific Gas and Electric Company is authorized to submit a Tier 1 Advice Letter to revise its Preliminary Statement, Part B, to reflect a new rate component titled the "Implementation Plan Rate" in the customer class charge included in transportation charges to collect the annual increase in revenue requirement adopted in Ordering Paragraph 2, as shown in Attachment F to today's decision.

~~5.~~6. Pacific Gas and Electric Company (PG&E) is authorized to file a Tier 1 Advice Letter to create a one way (downward) Gas Pipeline Expense and Capital Balancing Account to record the difference between forecast and recorded expenses and capital costs authorized for the Implementation Plan costs from the effective date of today's decision through December 31, 2014, for core and noncore customer classes. Any accumulated balance on December 31, 2014, plus interest, will be returned to customers through the Customer Class Charge in PG&E's Annual Gas True Up Filing to be filed shortly before the end of 2014. Any accumulated balance will be allocated 59.5% to the core class and 40.5% to the noncore class.

~~6.~~7. Pacific Gas and Electric Company (PG&E) must limit the amounts recorded in the balancing account authorized in Ordering Paragraph 5 to the adopted expense and capital amounts set forth in Attachment E for each program. Expense and capital amounts in excess of adopted amounts may not be recorded in the balancing account and capital cost overruns may not be recorded in regulated plant in service accounts. The adopted expense and capital amounts for any program shall be reduced by the cost of any Implementation Plan project not completed ~~and not replaced with a higher priority project~~. Subject to these limits, PG&E is authorized to collect from ratepayers only the revenue requirements associated with actual expenses and capital costs recorded in the balancing account.

~~7.~~ 8. PG&E shall (1) identify all the amounts earned from the disposition of the pipe material and its costs incurred to transport or dispose of the material; and (2) remove all the unrecovered balance of the old pipelines subject to replacement from PG&E s rate base.

9. "Sound Engineering Judgment" shall be documented by PG&E in written guidelines, practices, and protocols to ensure proper judgment is applied consistently across PG&E's territory, throughout the duration of the Implementation Plan, and on an ongoing basis. These documents shall be approved by PG&E management, and maintained as company standards. Such documents shall be available to allow for the Commission and independent parties or consultants to verify reasonable engineering judgment is being applied.

10. Pacific Gas and Electric Company is authorized to file a Tier 1 Advice Letter to create a balancing account to record the amount of revenues collected from ratepayers through the Implementation Plan Rate as compared to the adopted revenue requirement. The balance, if any, as of December 31, 2014, shall

be collected from or refunded to ratepayers through the next Annual Gas True Up filing. Any accumulated balance will be allocated 59.5% to the core class and 40.5% to the noncore class.

11. The Parties to this Proceeding shall meet and confer no later than 21 days after the effective date of today's decision to develop a plan for an Independent Monitor(s) to be hired by PG&E and to report to the Commission and the public regarding the status and quality of PG&E's work performed pursuant to the Implementation Plan to ensure that PG&E develops accurate and useful record keeping data bases and correctly tests and/or replaces the right pipelines at the right times. The Parties shall submit a joint proposal in this proceeding no later than 21 days after their first meeting. At a minimum, the joint proposal shall include the following:

- A hiring process for the Independent Monitor(s) that ensures its independence, to the extent practicable;
- PG&E to hire and pay for the Independent Monitor(s);
- PG&E shall permit the Independent Monitor(s) to inspect, inquire, review, examine and participate in all activities of any kind related to the Implementation Plan. PG&E and its contractors shall immediately produce any document, analysis, test result, plan, of any kind related to the Implementation Plan as requested by the Independent Monitor(s), and such request need not be in writing.
- The Independent Monitor(s) to conduct and present all analyses and recommendations independently of any suggestions or conclusions of PG&E, the Commission, or interested parties.
- Quarterly public reporting by the Independent Monitor(s) to a joint meeting of PG&E, the Commission, and interested parties;

- A requirement that the Independent Monitor(s) notify PG&E, the Commission, and interested parties in writing within 10 days of discovery of any potential non compliance with the requirements of the PSEP that presents a potential, but not immediate, threat to public safety;
- A requirement that the Independent Monitor(s) notify PG&E, the Commission, and interested parties in writing within 24 hours of any non compliance or other condition that poses a potential and immediate threat to public safety.
- A requirement that PG&E's contracts with the Independent Monitor(s) shall prohibit the Independent Monitor(s) from seeking work from PG&E while performing the duties of a PSEP Independent Monitor.

~~11.~~12. The Director of the Commission's Consumer Protection and Safety Division, or designee, (CPSD) is delegated the following authority:

A. CPSD shall review all changes to the Implementation Plan proposed by Pacific Gas and Electric Company (PG&E), shall require such modifications as are necessary to ensure public safety, and may concur in such proposals.

B. CPSD may inspect, inquire, review, examine and participate in all activities of any kind related to the Implementation Plan. PG&E and its contractors shall immediately produce any document, analysis, test result, plan, of any kind related to the Implementation Plan as requested by CPSD, and such request need not be in writing.

C. CPSD may take and order PG&E to take such actions as may be necessary to protect immediate public safety.

D. CPSD may issue immediate stop work orders to PG&E and all its contractors when necessary to protect public safety, and PG&E must comply immediately and consistent with any needed safety protocols.

E. The Director of CPSD, the Commission's Executive Director, and the Chief Administrative Law Judge shall offer PG&E, parties to this proceeding, and the public such procedural opportunities as may be feasible under the specific circumstances of any instance in which CPSD is required to exercise its delegated authority.

~~12.~~13. The Executive Director is delegated authority to order Pacific Gas and Electric Company (PG&E) to reimburse the Commission for any Commission contract necessary to carry out the directives in today's decision~~, not to exceed $15,000,000.~~ and PG&E shall not recover these costs ~~is authorized to record any amounts so expended in its Annual Gas True-Up Balancing Account for recovery~~ from ratepayers.

~~13.~~14. Pacific Gas and Electric Company must submit compliance reports on the schedule and including the information set forth in Attachment D to today's decision. Such reports shall be filed and served in this proceeding, with printed copies to the Directors of the Energy Division and the Consumer Protection and Safety Division.

15. PG&E shall (1) update its Decision Tree to incorporate the most current data available as of the effective date of this decision and to eliminate outcome M2 and decision point 2F; and (2) make an "initial" Attachment D filing within 45 days of the effective date of the Decision to describe how it performed the update, the results of the update, and to establish criteria for changing the priorities among projects going forward. ~~file~~

16. PG&E shall, within 45 days of a final decision in this proceeding, file an advice letter providing the guidelines, protocols and procedures PG&E will follow to address the following issues:

- Deviations from decision tree outcome/mitigation due to new data;
- Deviations from decision tree outcome/mitigation due to PG&E engineering judgment;
- PG&E implementation of the "ors" in the decision tree;

- Acceleration of segments into Phase 1;
- Expenditures to increase pigability;
- Diameter increases for reasons other than pigability;
- Line relocations;
- Engineering Condition Assessment; and
- Hydrotest water management plan.

These documents shall be approved by PG&E management, and maintained as company standards.

17. PG&E shall ensure that mitigation actions deviating from the decision tree outcomes are based on approved guidelines, procedures, and protocols, and documented in quarterly reports to the CPUC.