Decision **PROPOSED DECISION OF ALJ YIP-KIKUGAWA (Mailed 5/5/16)**

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 AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S REVENUE REQUIREMENT FOR 2015-2017 FOR GAS TRANSMISSION AND STORAGE SERVICES

Table of Contents

Title **Page**

DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S REVENUE REQUIREMENT FOR 2015-2017 FOR GAS TRANSMISSION AND STORAGE SERVICES 1
Summary 2
1. Background 12
1.1. The Case in Chief 12
1.2. The Order to Show Cause 14
1.3. Fines and Remedies Arising From the San Bruno Investigations 15
2. Issues Before the Commission 17
3. Burden and Standard of Proof 20
4. PG&E's Risk Management Approach 22
5. Impact on Customers 27
6. Transmission Pipe 28
6.1. Overview 28
6.2. Transmission Integrity Management Programs 30
6.2.1. In-Line Inspection Program 30
6.2.1.1. PG&E's Proposal 30
6.2.1.2. Intervenors' Response 34
6.2.1.3. Discussion 37
6.2.2. Direct Assessment 40
6.2.2.1. PG&E's Request 40
6.2.2.2. Intervenors' Response 43
6.2.2.3. Discussion 45
6.2.3. Hydrostatic Testing 48
6.2.3.1. PG&E's Request 49
6.2.3.2. Intervenors' Response 52
6.2.3.3. Discussion 57
6.2.4. Earthquake Fault Crossings Program 61
6.2.4.1. PG&E's Request 61
6.2.4.2. Intervenors' Response 62
6.2.4.3. Discussion 65
6.2.5. Vintage Pipe Replacement Program 68
6.2.5.1. PG&E's Request 68
6.2.5.2. Intervenors' Response 70
6.2.5.3. Discussion 78

Table of Contents (cont.)

Title **Page**

6.2.6. Geo-Hazard Threat Identification and Mitigation Program 83
6.2.6.1. PG&E's Request 83
6.2.6.2. Intervenors' Response 85
6.2.6.3. Discussion 85
6.2.7. Programs to Enhance Integrity Management 86
6.3. Emergency Response Programs 87
6.3.1. Valve Automation Program 87
6.3.2. Public Awareness Program 88
6.3.3. Inoperable and Hard-to-Operate Valves Program 91
6.4. Transmission Pipe Engineering Programs 94
6.4.1. Class Location 94
6.4.1.1. PG&E's Request 94
6.4.1.2. Intervenors' Response 95
6.4.1.3. Discussion 97
6.4.2. Water and Levee Crossing 98
6.4.3. Shallow Pipe Program 100
6.4.3.1. PG&E's Request 100
6.4.3.2. Intervenors' Response 102
6.4.3.3. Discussion 104
6.4.4. Gas Gathering Program 106
6.4.5. Work Required by Others 107
6.4.5.1. PG&E's Request 107
6.4.5.2. Intervenors' Response 108
6.4.5.3. Discussion 109
7. Storage 111
8. Facilities 114
8.1. Overview 114
8.2. ECA Phase 1, ECA Phase 2 and Hydrostatic Station Testing 117
8.2.1. PG&E's Request and Joint Stipulation with ORA 117
8.2.2. Intervenors' Response 119
8.2.3. PG&E's Response to Intervenors 123
8.2.4. Discussion 125
8.3. Critical Documents 127
8.4. Data Acquisition and Metric Development 130

Table of Contents (cont.)

Title **Page**

8.5. Physical Security 132
8.6. Becker System Upgrades 133
8.7. Gas Quality Practice Assessment 133
8.8. Gill Ranch O&M 134
8.9. Routine Expense 134
8.10. Burney K-2 Compressor Replacement 134
8.11. Los Medanos K-1 Compressor Replacement 135
8.12. Compressor Unit Control Replacements 135
8.13. Upgrade Station Controls 136
8.14. Emergency Shutdown System Upgrades 137
8.15. Rebuild Santa Rosa Compressor Station Electrical Substation 137
8.16. Upgrade Pleasant Creek Processing Facilities 138
8.17. Gas Transmission Electrical Upgrades – Hinkley and Topock Compressor Stations 138
8.18. Gas Transmission Electrical Upgrades – Compressor Stations (Excluding Hinkley, Topock, and Santa Rosa) 139
8.19. Hinkley Compressor Unit Retrofit Project 139
8.20. Install Active Fire Suppression Systems 141
8.21. Perform Simple Station Rebuilds 141
8.22. Perform Complex Station Rebuilds 143
8.23. Perform Transmission Terminal Upgrades 143
8.24. SCADA Visibility 143
8.25. Replace Obsolete Bristol Controllers 144
8.26. Replace Obsolete Limitorque Valve Actuators 144
8.27. Electrical Upgrade Program 145
8.28. Biomethane Interconnects 145
8.29. Routine Capital Spending 147
9. Corrosion Control 147
9.1. Overview 147
9.1.1. PG&E's Request 147
9.1.2. Intervenors' Positions 151
9.1.3. Discussion 157
9.2. Routine Cathodic Protection Maintenance 160
9.3. Cathodic Protection Systems 162

Table of Contents (cont.)

Title **Page**

9.3.1. Replace CP Systems 162
9.3.2. Install New CP Systems 163
9.3.3. Coupon Test Stations 164
9.3.4. Corrosion Investigations 168
9.4. Close Interval Survey 170
9.5. AC Interference 171
9.5.1. PG&E's Request 171
9.5.2. Intervenors' Positions 173
9.5.3. Discussion 175
9.6. DC Interference 175
9.6.1. PG&E's Request 175
9.6.2. Intervenors' Positions 176
9.6.3. Discussion 177
9.7. Casings 178
9.7.1. PG&E's Request 178
9.7.2. Intervenors' Positions 179
9.7.3. Discussion 182
9.8. Internal Corrosion 185
9.8.1. PG&E's Request 185
9.8.2. Intervenors' Positions 186
9.8.3. Discussion 187
9.9. Atmospheric Corrosion 188
9.9.1. PG&E's Request 188
9.9.2. Intervenors' Positions 189
9.9.3. Discussion 191
10. Gas Transmission System Operations and Maintenance Activities 191
10.1. Overview 191
10.2. Locate and Mark 193
10.3. Pipeline Maintenance 193
10.4. Station Maintenance 196
10.5. Transmission Expense Projects 197
10.6. Stanpac 197
11. Other GT&S Support Plans 198
11.1. Overview 198

Table of Contents (cont.)

Title **Page**

11.2. Expense Forecast 199
11.2.1. Buildings and Process Safety Organization 200
11.2.2. Environmental Operational Costs 201
11.2.3. Habitat and Species Protections 202
11.2.4. Hazardous Waste Disposal and Transportation Costs 202
11.2.5. Research and Development Costs 202
11.2.6. Customer Access Charge Costs 203
11.3. Capital Expenditures 203
11.3.2. Tools and Equipment 204
11.3.3. Building Management Expenditures 205
12. Gas System Operations 206
12.1. Overview 206
12.2. Expenses 207
12.2.1. Gas System Operations Staff 207
12.2.2. Electricity Costs for Gas Compressor Operations 208
12.2.3. Greenhouse Gas Compliance Instrument Costs 209
12.3. Capital Expenditures 211
12.3.1. New Business 211
12.4. Capacity Projects 212
12.4.1. Normal Operating Pressure Reductions 213
12.4.2. Pipe Betterment 215
12.4.3. Customer Demand Growth (New Capacity) 215
12.4.4. Line 407 216
12.5. Network Investment Plans 218
12.6. Allocation of Storage Assets to Pipeline Load Balancing 219
12.7. Daily Balancing (Gill Ranch Proposal) 221
13. Information Technology 222
14. Reporting Requirements and Program Management 226
14.1. Reporting Requirements 226
14.1.1. PG&E/ORA Joint Stipulation 226
14.1.2. PG&E/Calpine Joint Stipulation 227
14.2. Program Management Office 229
15. Results of Operations (RO) 230
15.1. Operating and Maintenance Expenses 231

Table of Contents (cont.)

Title **Page**

15.2. Administrative and General Expenses 232
15.3. Capital Related Inputs 232
15.3.1. Plant 233
15.3.2. Depreciation 233
15.3.3. Rate Base 235
15.3.4. PSEP Recovery 2011-2014 235
15.4. Income Taxes 236
15.4.1. Net Operating Loss and Bonus Depreciation 236
15.5. Taxes Other than Income 238
16. Cost Recovery Issues 238
16.1. Transmission Revenue Balancing Account 238
16.2. Transmission Integrity Management Program Balancing Account 240
16.3. Z-Factor Mechanism 246
16.3.1. Adjustment Mechanism for Costs Determined in Other Proceedings Beyond 2014 246
16.3.2. Recovery of Line 407 Costs 246
16.3.3. Actual Costs for Electricity Used to Provide GT&S Services, and GHG Compliance Costs Incurred for Natural Gas Compressor Stations 247
16.3.4. Tax Act Memorandum Account 247
16.4. Post Test Year Ratemaking 247
17. Other Revenue Requirement and Cost Recovery Issues 250
17.1. 2011-2014 Capital Expenditures 250
17.1.1. PG&E's Position 250
17.1.2. TURN's Position 254
17.1.3. Discussion 258
17.1.3.1. Expenditures Under $1 Million 262
17.1.3.2. Expenditures for Four Projects 263
17.1.3.3. Expenditures for 104 Projects Detailed in Exh. PG&E-22 264
17.1.3.4. Disposition of 2011-2014 Capital Expenditures 268
17.2. Disallowance Associated with Delay 269
17.3. Adjustment for Overlapping Work 272
17.3.1. Overview of Parties' Positions 272

Table of Contents (cont.)

Title **Page**

17.3.2. Allocation of Common Overhead Applicable to the Transmission Function 274
17.3.2.1. Discussion 276
17.3.3. Sufficiency of Rigor Applied in Quantifying Revenue Requirement Reductions 277
17.3.3.1. Discussion 278
18. Rate Issues 279
18.1. Throughput Forecasts 279
18.2. Backbone Rate Design 284
18.2.1. Equalization of Baja and Redwood Path Rates for Core and Noncore 284
18.2.1.1. Background 284
18.2.1.2. Parties' Proposals 285
18.2.1.3. Discussion 291
18.2.2. Backbone Load Factor Calculation 297
18.2.3. Backbone Capacity for the Baja and the Redwood Path 299
18.3. Local Transmission Cost Allocation and Rate Design 299
18.3.1. PG&E Proposal 299
18.3.2. Proposed Change in PG&E's Allocator for Local Transmission Costs 300
18.3.3. Proposed Allocation of Local Transmission Costs Based on Public Safety 304
18.3.4. Discussion 305
18.4. Storage Rate Design 307
18.4.1. Storage Capacity 307
18.4.2. Allocation of Storage Costs 307
18.4.3. Core Injection and Withdrawal 309
18.5. Transmission Level Customer Access Charges 310
18.6. Electric Generation Rate Design 310
18.6.1. Overview 310
18.6.2. Parties' Positions 311
18.6.3. Discussion 317
18.6.4. Alternatives to the Single-Rate Proposal 324
18.7. Modification of Noncore Customer Class 328

Table of Contents (cont.)

Title **Page**

18.8. Other System Values that Impact Cost Allocation or Rate Design....331
18.8.1. British Thermal Unit Value....331
18.8.2. Shrinkage....332
18.9. Illustrative Rates....333
19. Core Gas Supply....333
19.1. Core Capacity Allocations....333
19.1.1. Core Intrastate Pipeline Capacity....333
19.1.2. PG&E Firm Storage Capacity....335
19.2. Adjustments to 1-Day-in-10-Year Core Capacity Planning Standard....336
19.3. Changes to Core Procurement Incentive Mechanism....336
19.4. Core Aggregation Program Adjustments....339
19.4.1. Pipeline Capacity Allocation Methodology....339
19.4.1.1. PG&E's Proposal....339
19.4.1.2. Commercial Energy's Proposal....341
19.4.1.3. Other Parties' Comments....342
19.4.1.4. Discussion....346
19.4.2. Incremental Storage Capacity Allocation....347
20. Core Transport Agent Issues....348
20.1. Core Load Forecast Model....348
20.2. CTA Procurement of Intrastate Pipeline Capacity and Gas Storage Capacity....353
20.2.1. CTAC....354
20.2.2. Commercial Energy....356
20.2.3. PG&E....358
20.2.4. TURN....359
20.2.5. Independent Storage Providers....360
20.2.6. Discussion....362
20.3. Modifying the Firm Winter Capacity Requirement....364
20.4. Billing and Operational Issues....367
20.4.1. Allocation of Partial Payments for Past Due Accounts....367
20.4.2. Access to Customer Information....370
20.4.3. Payment Plan Notice and Negotiation....374
21. Programs Directed Towards Small and Medium Sized Businesses....380

Table of Contents (cont.)

Title **Page**

22. Application of $850 Million Penalty for Future Pipeline Safety Improvements 380
23. Amortization of Revenue Requirement 384
24. Motions 384
25. Transcript Corrections 385
26. Comments on Proposed Decision 386
27. Assignment of Proceeding 386
Findings of Fact 386
Conclusions of Law 411
ORDER 443

APPENDICES

A - List of Appearances
B - List of Acronyms
C - Summary of Results of Operations
D - Summary of Adopted Costs
E - Post Test-Year Ratemaking (PTYR)
F - 2011-2014 Capital Expenditures Over Gas Accord V
G - Safety Program Costs ($850 million)
H - Disallowed Capital
I - Balancing Account Adopted Costs
J - Illustrative Rates
K - Adopted Transcript Corrections

DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S REVENUE REQUIREMENT FOR 2015-2017 FOR GAS TRANSMISSION AND STORAGE SERVICES

Summary

This decision adopts a revenue requirement for 2015 of $1,108.986 million for Pacific Gas and Electric Company (PG&E) to provide gas transmission and storage (GT&S) services. The adopted revenue requirement, however, is reduced by $164.003 million, 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. This results in 2015 revenues to be recovered from ratepayers of $944.984 million, an increase of $299.605 million, or 32.1% over 2014 gas transmission and storage rates.

Appendix C contains the approved revenue requirement increases and the results of operations supporting tables for PG&E, which incorporates the forecast costs we find to be reasonable and which are adopted in today's decision. The adopted revenue requirements, in comparison to PG&E's requested amounts, are summarized below:

2015 Revenue Requirements
PG&E Requested Versus Commission Adopted
($ in Millions)

	2015 Revenue Requirement	Increase over 2014 Authorized[1]	% Increase
PG&E Proposed Increase	$1,286.9	$ 571.515	79.9%
Adopted Increase	$ 945.0	$229.605	32.1%

[1] 2014 authorized revenue requirement = $715,380 million (consisting of amounts authorized in D.11-04-031 (Gas Accord V) and D.12-12-030 (PSEP)).

2016-2017 Post Test-Year Results
PG&E Requested Versus Commission Adopted
($ in Millions)

	2016 Revenue Requirement	2017 Revenue Requirement
PG&E Proposed	$1,347.0	$ 1,515.0
Adopted	$1,182.7	$1,308.9
% Change	(12.2$)	(13.6)

Appendix D contains tables summarizing adopted expenses and capital expenditures by program and by Major Work Category.

The difference in revenue requirement reflects the following revenue adjustments:

- For in-line inspection, the pace of work to make pipelines piggable shall be extended from 10 years to 12 years. This results in 2015 capital expenditures of $59.236 million, or a reduction of $15.023 million.

- The forecast Direct Assessment expenses are reduced to reflect: (1) a 50% disallowance in ICDA expenses; (2) a lower dig-to-project ratio; and (3) a 50% disallowance in ECDA expenses. This results in 2015 ICDA expenses of $7.664 million and 2015 ECDA expenses of $12.979 million.

- The forecast hydrotest expenses are adjusted to reflect a 19.2% disallowance to reflect costs to hydrotest 97 miles of pipe installed between January 1, 1956 and June 30, 1961. This results in authorized 2015 expenses of $148.390 million, or a disallowance of $33.402 million. PG&E remains responsible for hydrotesting its projected 510 miles of pipe during the Rate Case Period, as well as up to 50 miles of pipe installed after 1961 for which it has no pressure test records.

- The forecast expense and capital expenditures for the Earthquake Fault Crossings Program are reduced as follows: (1) the annual inflation rate is reduced to 2.1%, decreasing forecast unit cost from $1.6 million per site to $1.5 million per site and (2) the number of studies to be conducted during the Rate Case Period is reduced from 98 to 49. As a result of these adjustments, PG&E's 2015 capital expenditures are $5.121 million and its 2015 expenses are $2.590 million.

- The forecast capital expenditures for the Vintage Pipeline Replacement Program are reduced as follows: (1) the unit costs for pipeline replacement are adjusted to $4.51 million/mile for pipe with diameter under 12" and $7.985 million/mile for pipe with diameter 12" or greater; and (2) the escalation rate to be applied to the adopted unit costs is reduced from 7% to 4.4%. These adjustments result in 2015 capital expenditures of $164.534 million, or a reduction of $29.288 million.

- The annual inflation rate in the Geo-Hazard Threat Identification and Mitigation Program is reduced from 3% to 2.1%. This results in 2015 capital expenditures of $7.469 million.

- The forecast expenses for the Public Awareness Program is reduced from $4.334 million to $3.558 million.

- The forecast 2015 expenses for unit cost for strength testing in the Class Location Program are reduced from $6.411 million to $3.985 million, a reduction of $2.426 million.

- The forecast capital expenditures for the Shallow Pipe Program are adjusted to disallow the 30% Mobilization/Demobilization adder. This results in 2015 capital expenditures of $17.228 million.

- The forecast 2015 capital expenditures for the Work Required by Others Program is reduced by $7.3 million,

resulting in an authorized 2015 capital expenditures of $17.3 million. Additionally, PG&E shall establish a one-way balancing account to track the difference between the capital expenditure amounts for the Work Required by Others Program adopted in this decision and the portion of costs assigned to customers over the 2015 GT&S rate cycle - $17.3 million in 2015, $17.697 million in 2016 and $18.158 million in 2017 – and return any unspent funds in the balancing account shall be returned to customers as part of the Annual Gas True-Up filing.

- PG&E's forecast expenses for ECA Phase 1, ECA Phase 2 and Hydrostatic Station Testing (C&P and M&C) are adopted. However, PG&E shall establish a one-way balancing account to track the difference between amounts adopted in this decision and the actual costs to perform Hydrostatic Station Testing work during the Rate Case Period on stations installed on or before January 1, 1956. This difference reflects costs for Hydrostatic Station Testing work on stations installed on or after January 1, 1956 which should be borne by shareholders.

- PG&E's forecast expenses for the Critical Documents Program are adopted. However, PG&E shall establish a one-way balancing account to track the difference between amounts adopted in this decision - $11.573 million in 2015, $11.850 million in 2016 and $12.129 million in 2017 - and the actual costs of Critical Documents Program work for facilities built on or before December 31, 1955.

- The forecast $4.8 million in 2015 capital expenditures for Biomethane Interconnects is removed from the revenue requirement request, as the mechanism for the utilities to recover funds for biomethane interconnections has been addressed in D.15-06-029.

- The number of coupon test stations to be installed as part of the Corrosion Control Program is reduced from over 900 to 180 during the Rate Case Period. This results in 2015 capital expenditures of $1.176 million.

- The Casings Program is reduced to reflect a disallowance of $4.074 million in capital expenditures and $8.911 million in expenses in for casing mitigations in 2015. This results in authorized 2015 capital expenditures of $16.991 million and 2015 expenses of $39.592 million.

- Pursuant to the allocation of costs between transmission and distribution functions adopted in D.14-08-032, the 2015 forecast expense for Buildings and Process Safety Organization Support is revised to $5,479,692 and the 2015 forecast capital expenditures for Building Management Expenditures is revised to $18,492,258.

- The 2015 forecast expenses of $3.191 million for Greenhouse Gas Compliance Instrument Costs (MWC JT) are removed from PG&E's request pursuant to D.15-10-032, which determined that PG&E's recovery of expense for GHG compliance instruments will be recovered as part of the annual Gas True-Up process.

- Gill Ranch Storage LLC's proposal for daily balancing is denied.

- The $696.4 million associated with 2011-2014 capital expenditures in excess of the amount authorized in Decision 11-04-031 is removed from PG&E's request. Of the amount removed, $120.409 million is permanently disallowed and shall not be recovered by PG&E in future rates. The remaining $575.991 million shall be subject to a third-party audit and may be recovered in a future application.

- PG&E shareholders will be responsible for the incremental amount of 2015 revenues that would be amortized over a five-month period, or $164.003 million associated with the delay caused by PG&E's violation of the ex parte rules.

- PG&E's original revenue requirements forecast in this proceeding is reduced to reflect costs for work associated with remedies adopted in Decision 15-04-024 that overlap

> with the GT&S forecast. The reductions: $1.775 million (for 2015), $1.99 million (for 2016), and $1.25 million (for 2017), for a three-year total reduction of $4.224 million based on $5.1576 million in remedy costs.

With respect to PG&E's Storage Asset Family, this decision orders PG&E to provide additional information concerning its gas storage facilities in light of the methane leak emergency at the Aliso Canyon Gas Storage Facility. Therefore, PG&E shall provide a report on its gas storage risk management and safety initiatives within 60 days of the effective date of this Decision. The report shall include, at a minimum, 1) an overview of the work performed on PG&E's proposed Well Integrity Management Program, 2) an overview of data centralization efforts, 3) supply copies of Gamma-Ray Neutron surveys, noise and temperature surveys, and casing inspection surveys, as well as any analysis of such surveys and an overview of any follow-up measures performed or proposed, 4) the status of PG&E's proposed Storage Rework Projects, and 5) responses to the specific questions about PG&E's McDonald Island storage facility.

This Decision also addresses the various cost allocation and rate design proposals of PG&E and other parties and adopts the following:

- PG&E's request to discontinue the GTSRSM and replace it with a two-way balancing account revenue structure is denied.
- PG&E is authorized to establish a new Transmission Integrity Management Program Memorandum Account to track costs associated with any new transmission integrity management statutes or rules.
- PG&E's proposal to terminate the Tax Act Memorandum Account (TAMA) balancing account is denied.

- PG&E's proposal to allocate 130 MMcf/d (133 MDth/d) of injection capacity and 200 MMcf/d (204 MDth/d) of withdrawal capacity to balancing, along with the associated revenues has been struck from the record and its proposed allocation of storage costs should be based on the storage units is denied.

- PG&E's proposal to equalize the backbone rates for the Redwood and Baja paths is denied and the existing differential backbone rate structure of $0.40/Dth continues to apply.

- Dynegy's and NCGC's proposals for a single EG transportation rate are denied. Dynegy's alternate proposals to a single EG transportation rate are also denied.

- Commercial Energy's proposal to lower the current 250 Dth/year threshold to qualify for noncore status to 100 Dth/year is denied.

- PG&E's proposed changes to the CPIM are adopted.

- PG&E's proposal to change the pipeline capacity allocation methodology from a January Capacity Factor to a Seasonal Capacity Factor, and Commercial Energy's proposal to change the pipeline capacity allocation methodology from a January Capacity Factor to a Peak Day Usage Factor are denied.

- PG&E's proposed modifications to the Core Load Forecasting Model are adopted. Additionally, the Decision requires PG&E to meet regularly with the CTAs to explore future changes to the CLFM and to consider how to incorporate gas SmartMeter data to improve the accuracy of Determined Usage.

- PG&E is directed to provide the CTAs detailed gas SmartMeter usage data for their customers to the extent this data can be provided without imposing undue

operational burden on PG&E. Additionally, PG&E is directed to hold a workshop within 60 days of the effective date of this decision to explore how CTA customer usage data generated by gas SmartMeters may be provided to CTAs, including the format for the data, and the timing for when PG&E shall begin providing the data.

Further, this Decision resolves various issues raised by Core Transport Agents:

- CTAC and Commercial Energy's proposals that PG&E no longer procure intrastate capacity on behalf of the CTAs are denied.

- CTAC and Commercial Energy's proposals that PG&E no longer procure storage services on behalf of the CTAs are granted. The Decision adopts a 10-year period for this transition.

- CTAC's proposal to modify the second and third options for complying with the Firm Winter Capacity and to add a fourth option for complying with the Firm Winter Capacity is granted. Gas Schedule G-CT will be modified to adopt these modifications.

- CTAC and Commercial Energy's proposal to change Gas Rule 23 to allocate partial payments on past due (delinquent) accounts pro rata between PG&E charges and CTA charges is denied. However, the Decision clarifies that PG&E may not designate accounts as "delinquent" simply based on a CTA customer's history of late payment or because the CTA carries a balance.

- The Decision finds that CTAs are agents, not third-parties, with respect to CTA customers. The Decision directs PG&E and the CTAs to revise Form 79-845A to explicitly state that customer billing information will be disclosed to the CTAs.

- Commercial Energy's proposal to include the CTA in any negotiations of payment plans is denied.

Additionally, the following joint stipulations are adopted:

- Joint stipulation between PG&E, TURN and ORA, *Joint Depreciation Stipulation* (Exh. Joint-1).
- Joint stipulation between PG&E and ORA, *Joint Stipulation on Treatment of NOLC and Bonus Depreciation* (Exh. Joint-2).
- Joint stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 5 – Asset Family – Storage* (Exh. Joint-3 at -5).
- Joint stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 9 – Program Management Office* (Exh. Joint-3 at 6-8).
- Joint stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 12 – Other GT&S Support Costs* (Exh. Joint-3 at 13-15), regarding tools and equipment.
- Joint stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 13 – Reporting and Communications* (Exh. Joint-3 at 16-18).
- Joint stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 14 – Throughput Forecast* (Exh. Joint-3 at 19-22).
- Joint stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 9 – Program Management Office* (Exhibit Joint-3 at 6-8), with corrections to footnote 2 on page 26 of Exh. Joint 3.
- Joint stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 11 – Information Technology* (Exh. Joint-4), concerning IT programs and projects.

- Joint stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year Mechanism* (Exh. Joint-3 at 23-28).
- Joint stipulation between PG&E and the City of Palo Alto, Joint Redwood and Baja Capacity Allocation Stipulation (Exh. Joint-5).
- The February 26, 2015 oral stipulation between PG&E and Calpine concerning the posting of certain GT&S revenue and rate information on PG&E's website.

The stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 10 – Gas Operations* (Exh. Joint-3 at 9-12) is adopted in part, and denied in part. We adopt those portions of the joint stipulation concerning Electricity Costs for Gas Compressor Operations and deny those portions concerning Greenhouse Gas Compliance Instruments.

The stipulation between PG&E and ORA, *ORA-PG&E Joint Stipulation, Engineering Critical Assessment and Hydrostatic Testing (Chapter 6)* (Exh. Joint-6) is denied.

Illustrative rates, based on the adopted 2015 revenue requirement of $944.984 million are presented in Appendix J.

Based on the revenue requirement adopted in this Decision, the difference between the authorized revenue requirements in this decision and the placeholder revenue requirement incorporated in gas rates PG&E has collected in the Gas Transmission and Storage Memorandum Account pursuant to Decision 14-06-012 will be amortized over 18 months.

Finally, this Decision finds that, based on the safety enhancements approved in this Decision, the $850 million shareholder-funded safety improvements ordered in Decision 15-04-024 would be exhausted in this Rate

Case Period. This Decision therefore proposes an allocation of the $850 million and seeks comments from parties as part of their comments and reply comments to the Proposed Decision.

Application 13-12-012 and Investigation 14-06-016 remain open.

1. Background

1.1. The Case in Chief

On December 19, 2013, Pacific Gas and Electric Company (PG&E) filed its application concerning the revenue requirement, cost allocation and rate design for its gas transmission and storage services for the period 2015–2017.[2] A prehearing conference (PHC) was held on March 12, 2014, and the *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge (Scoping Memo)* was issued on April 17, 2014. As set forth in the *Scoping Memo*, evidentiary hearings were set for October 6-24, 2014, and a decision was anticipated to be adopted by March, 2015.

On September 15, 2014, PG&E filed a *Notice of Improper Ex Parte Communications* detailing a series of improper contacts with Commissioners and Commission advisors regarding the assignment of the Administrative Law Judge (ALJ) to this proceeding. As a result of PG&E's filing, the proceeding was suspended and, subsequently, reassigned to a new ALJ.[3]

The suspension was lifted on October 7, 2014. A second PHC was held on October 20, 2014. On November 13, 2014, the *Ruling of Assigned Commissioner and*

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[2] The 2015-2017 period is referred to in this Decision as the "Rate Case Period" or the "rate case cycle."

[3] *See Ruling Granting Joint Motion of the Office of Ratepayer Advocates and The Utility Reform Network for a Ruling Suspending the Procedural Schedule and Other Relief and Imposing an Ex Parte Communication Ban*, issued September 25, 2014; *Notice of Reassignment*, issued October 1, 2014.

Administrative Law Judge Amending Scoping Memo and Schedule (Amended Scoping Memo) was issued. The *Amended Scoping Memo* added an issue to consider potential remedies to be imposed as the result of delays in this proceeding caused by PG&E.[4]

A total of 25 days of evidentiary hearings were held from February 2-27 and March 16-23, 2015. In addition, ten Public Participation Hearings were held between August 12 and September 9, 2014. Concurrent Opening Briefs were filed on April 29, 2015 by PG&E, the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), Northern California Generation Coalition (NCGC), Core Transport Agent Consortium (CTAC), Calpine Corporation (Calpine), Southern California Generation Coalition (SCGC), the Coalition of California Utility Employees (CCUE), School Project for Utility Rate Reduction (SPURR), jointly by the Canadian Association of Petroleum Producers (CAPP), Gas Transmission Northwest, LLC (GTN) and the City of Palo Alto (Redwood Path Parties), Sacramento Municipal Utility District (SMUD), Dynegy Inc. (Dynegy), jointly by Central Valley Gas Storage LLC, Gill Ranch Storage LLC and Wild Goose Storage LLC (Independent Storage Providers), jointly by the California Manufacturers & Technology Association and the California League of Food Processors (CMTA/CLFP), Indicated Shippers, Commercial Energy of California (Commercial Energy), and Tiger Natural Gas Inc. (Tiger). Concurrent Reply Briefs were filed on May 20, 2015 by PG&E, ORA, TURN, NCGC, SMUD, CMTA/CLFP, Calpine, CTAC, Redwood Path Parties, Commercial Energy, Independent Storage Providers, Dynegy, CCUE, Indicated Shippers, SPURR,

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[4] *Amended Scoping Memo* at 4.

United Energy Trading LLC, California Asian Pacific Chamber of Commerce (CAPCC) and jointly by CLFP, CMTA, Kern River Gas Transmission Company, Questar Southern Trails Company and SCGC (Rate Equalization Parties). In addition, Commercial Energy's Reply Brief included a request for Oral Argument. Final Oral Argument was held on October 28, 2015.

1.2. The Order to Show Cause

In addition to suspending the proceeding in response to PG&E's September 15 filing, a law and motion judge ordered PG&E to appear and show cause why it should not be held in contempt and punished for violating Rules 1.1 and 8.3(f) of the Commission's Rules of Practice and Procedure.[5] Following a hearing, the law and motion judge issued a ruling finding that PG&E violated Rules 1.1 and 8.3(f) and imposed various sanctions. On November 26, 2014, the Commission issued *Decision Modifying Law and Motion Judge's Ruling Imposing Sanctions for Violation of Ex Parte Rules (Ex Parte Sanctions Decision)* [Decision (D.) 14-11-041], which generally affirmed the law and motion judge's ruling, but modified the sanctions in some respects. Among other measures, the *Ex Parte Sanctions Decision* ordered:

> PG&E's shareholders will be required to fund a disallowance of a portion of revenues no larger than would be amortized over the five-month period of the original scheduled final decision in this proceeding (March 2015) and the modified schedule (August 2015)

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[5] Rule 1.1 requires, in part, that any person who transacts business with the Commission agrees "to maintain the respect due to the Commission, members of the Commission and its administrative law judges."

Rule 8.3(f) provides "Ex parte communications regarding the assignment of a proceeding to a particular Administrative Law Judge, or reassignment of a proceeding to another Administrative Law Judge, are prohibited."

contained within a revised scoping memo issued November 13, 2014.[6]

Based on the schedule adopted in the *Amended Scoping Memo*, the additional issue raised by the *Ex Parte Sanctions Decision* was considered concurrently with the case in chief.

1.3. Fines and Remedies Arising From the San Bruno Investigations

On April 9, 2015, the Commission issued *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 (Penalties Decision)* [D.15-04-024], which imposed sanctions on PG&E for violations arising from three investigations associated with the September 9, 2010 gas transmission pipeline explosion and subsequent fire in San Bruno, California (San Bruno explosion and fire).[7] As it pertains to this proceeding, the *Penalties Decision* directed PG&E to implement over 75 remedies proposed by the Commission's Safety and Enforcement Division and other intervenors to enhance pipeline safety and imposed an $850 million disallowance to be spent on safety improvements of PG&E's gas transmission pipeline system. Ordering Paragraph 7 of the *Penalties Decision* stated that the $850 million disallowance for safety-related projects or programs would be applied to expenses and capital expenditures authorized for funding in this proceeding.[8]

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[6] *Ex Parte Sanctions Decision* [D.14-11-041] at 34, Ordering Paragraph 3 (*slip op.*).

[7] These three investigations were Investigation (I.) 12—01-007, I.11-02-016 and I.11-11-009. The investigations are collectively referred to as the "Pipeline OIIs."

[8] *Penalties Decision* at 242-243, Ordering Paragraph 7 (*slip op.*).

The *Penalties Decision* was issued after the close of evidentiary hearings in the case in chief, and shortly before opening briefs were to be filed. As such, the issues raised in that decision, as they apply to this proceeding, were addressed separately.

On May 4, 2015, PG&E filed *Motion of Pacific Gas and Electric Company to Adopt a Proposed Procedural Schedule to Implement the San Bruno Penalty Decision*. On May 21, 2015, the assigned Administrative Law Judge issued a ruling granting in part PG&E's motion. The ruling also directed PG&E to file the following information:

> (1) for each remedy adopted in D.15-04-024, whether PG&E believed there was overlap with any work proposed in the application, and the associated cost; and
>
> (2) which of the programs and projects in its application PG&E believed were safety-related, as defined in D.15-04-024, and subject to the $850 disallowance.[9]

PG&E filed this information on June 1, 2015. A PHC was held on June 3, 2015 and a second amended scoping memo was issued on June 11, 2015.[10] On June 30, 2015, PG&E held a workshop on the remedies overlap. Evidentiary hearings were held on September 1, 2015.

Opening comments on the overlap of work proposed in this proceeding with remedies adopted in the *Penalties Decision* were filed on September 16, 2015. Reply comments were filed on September 23, 2015. As provided in the *Second*

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[9] *ALJ May 21, 2015 Ruling* at 5.

[10] *See Ruling of Assigned Commissioner and Administrative Law Judge Amending Scope to Consider Remedies and Disallowances Adopted in Decision 15-04-024* (*Second Amended Scoping Memo*), issued June 11, 2015.

Amended Scoping Memo, the dates for comments on the disallowance for safety-related programs and projects shall be set once a final decision on authorized revenue is adopted.[11]

2. Issues Before the Commission

The scope of issues to be resolved in this proceeding are:

1. Whether PG&E's proposed 2015 revenue requirement for its gas transmission and storage (GT&S) services is just and reasonable, and should PG&E's proposed revenue requirement, or a different revenue requirement, be adopted;

2. Whether PG&E's proposed post test year attrition adjustments for 2016-2017 are just and reasonable, and should PG&E's proposed attrition adjustments, or different attrition adjustments, be adopted;

3. Will the adopted revenue requirements provide adequate, efficient, just and reasonable service that promotes the safety of the public and the employees of the utility;

4. Will the adopted revenue requirements provide sufficient funds for PG&E to meet its safety responsibilities contained in the Public Utilities Code and in various Commission decisions;

5. Whether PG&E's proposed risk management approach and asset family categories reasonable;

6. Whether PG&E's proposed rates for GT&S services for 2015, 2016, and 2017 are just and reasonable, and should PG&E's proposed rates be adopted, or should different rates be adopted;

7. Whether PG&E's cost allocation and rate design proposals are just and reasonable, and should PG&E's proposals be adopted,

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[11] *See Second Amended Scoping Memo* at 7.

or should different cost allocation and rate design proposals be adopted;

8. Whether PG&E's capital expenditures for capital assets with in-service dates between January 1, 2011 and December 31, 2014 should be rolled into PG&E's rate base as of January 1, 2015;

9. Should full balancing account treatment for all GT&S revenues (excluding revenues associated with the Gill Ranch storage facility) be authorized;

10. Should PG&E's proposed two-way balancing account for Transmission Integrity Management costs be adopted;

11. Should PG&E's proposal to adjust for the difference between the costs filed in this application and the costs ultimately adopted in certain separate proceedings be adopted;

12. Should PG&E's proposals to equalize the rates of the Redwood and Baja paths for core and noncore customers be adopted;

13. Should PG&E's proposal for a fifth nomination cycle for on-system storage and Citygate transactions be adopted;

14. Should PG&E's proposal for adjustments and improvements to the Core Load Forecasting Model be adopted;

15. Should PG&E's proposed changes to its Gas Transaction System be adopted;

16. Should PG&E's proposals to reallocate storage assets for load balancing and to modify core storage injection and withdrawal rights be adopted, or should alternative proposals be adopted;

17. Should PG&E's proposal to replace the Gas Transmission Control Center's (GTCC) Supervisory Control and Data Acquisition (SCADA) system, and to upgrade other information technology related to the GTCC be adopted;

18. Should PG&E's throughput and demand forecasts be adopted, or should alternative forecasts be adopted;

19. Should PG&E's Core Gas Supply proposal to alter its capacity elections be adopted;

20. Should PG&E's Core Gas Supply proposal to adjust the 1-day-in-10 year core capacity planning standard be adopted;

21. Should PG&E's Core Gas Supply proposed changes to the Core Procurement Incentive Mechanism be adopted;

22. Should PG&E's Core Gas Supply proposal to revise the methodology for allocating pipeline capacity between core providers be adopted;

23. Are there other operational issues concerning PG&E's GT&S services that need to be considered;

24. Should PG&E's proposal for reporting to the Commission be adopted;

25. Pursuant to D.14-11-041, what penalty should be imposed on PG&E's shareholders for the five-month delay in the anticipated issuance of final decision in the *Scoping Memo* (March 2015) and the *Amended Scoping Memo* (August 2015) due to PG&E's improper ex parte communications;

26. Which remedies adopted in D.15-04-024, and subject to shareholder funding, overlap with work forecast in this proceeding and how much should PG&E's proposed revenue requirement be reduced to account for the costs for this overlapping work; and

27. Which programs and projects are safety-related and should be funded by the $850 million disallowance adopted in D.15-04-024.

Consistent with the *Second Amended Scoping Memo*, this decision resolves issues 1–26.

The *Second Amended Scoping Memo* had contemplated resolving Issue 27 in a separate decision so that parties could address the prioritization of safety-

related programs and projects once an authorized revenue requirement is adopted. Based on the determination in this proceeding that there will be more than $850 million in safety-related spending in this Rate Case Cycle, we seek parties' comments on whether a separate decision is in fact necessary, or whether Issue 27 may be resolved in this Decision.

3. Burden and Standard of Proof

Pursuant to Pub. Util. Code § 451 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."[12] The Commission requires that the public utility demonstrate with admissible evidence that the costs which it seeks to include in revenue requirement are reasonable and prudent. The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable.

PG&E must meet the burden of proving that it is entitled to the relief sought in this proceeding, and PG&E has the burden of affirmatively establishing the reasonableness of all aspects of the application. TURN and Indicated Shippers have argued in their Opening Briefs that various forecast expenditures should be disallowed in full due to PG&E's past imprudent management of its gas transmission system.

Costs are just and reasonable when they "have been prudently incurred by competent management exercising the best practices of the era, and using well-trained, well-informed and conscientious employees and contractors who

[12] Pub. Util. Code § 454.

are performing their jobs properly."[13] In considering whether proposed costs are "just and reasonable," it is true we will often consider the prudency of the utility's actions. PG&E's forecast costs are not unreasonable and subject to ratemaking disallowance simply because its management imprudently delayed or deferred work. Rather, as we have previous found, disallowances are warranted where costs have been incurred resulting from clear and identifiable utility failures and errors. For example, in *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering* (*PSEP Decision)* [D.12-12-030], we found that remedial document management costs were unreasonable "because PG&E should not have had to incur them, not because they should have been done at an earlier date."[14] Thus, a disallowance is warranted when the forecast work is necessary because: (1) PG&E had not originally performed the work properly, or (2) PG&E had failed to comply with regulatory requirements that it was previously funded to satisfy.

With the burden of proof placed on PG&E, the Commission has held that the standard of proof PG&E must meet is that of a preponderance of evidence. Preponderance of the evidence usually is defined "in terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more

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[13] *Decision Implementing a Safety Enhancement Plan and Approval Process for San Diego Gas & Electric Company and Southern California Gas Company; Denying the Proposed Cost Allocation for Safety Enhancement Costs; and Adopting a Ratemaking Settlement* (*Sempra PSEP Decision)* [D.14-06-007] at 31.

[14] *PSEP Decision* at 55.

convincing force and the greater probability of truth'."[15] In short, PG&E must present more evidence that supports the requested result than would support an alternative outcome.

We have analyzed the record in this proceeding within these parameters.

4. PG&E's Risk Management Approach

PG&E notes there have been significant legislative and regulatory changes mandating a greater priority on safety. Among other things, it notes the enactment of the Natural Gas Pipeline Safety Act of 2011 (Pub. Util. Code § 955 et seq.), which

> requires gas corporations to develop a plan to "identify and minimize hazards and systemic risk" to protect the public and employees. It also requires gas corporations such as PG&E to develop safety plans that are consistent with "best practices in the gas industry."[16]

PG&E further states that on March 2012, the Executive Director ordered PG&E to base its 2014 Test Year General Rate Case (GRC) on an "explicit safety and security risk assessment."

As part of its transition to risk-based decision making in every aspect of its operations, PG&E instituted new asset management and enterprise and operational risk management processes. This included dividing its gas assets into asset families.[17] The five transmission asset families are Transmission Pipe;

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[15] *Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project* [D.08-12-058] at 19 (citing Witkin, Calif. Evidence, 4th Edition, Vol. 1 at 184).

[16] Exh. PG&E-1 at 2-8.

[17] Exh. PG&E-1 at 2-3.

Natural Gas Storage; Compression and Processing; Measurement and Control; and Liquefied Natural Gas and Compressed Natural Gas. PG&E states that associating each asset with a family ensures that PG&E can: "(1) adequately identify each threat; (2) appropriately assess the condition of the asset and the quality of the data about the asset; (3) identify and assess the threats and risks facing the asset; and (4) develop and effectively execute mitigation efforts."[18]

PG&E states that at the time it submitted its GT&S application, the Commission had not yet adopted a risk management framework applicable to a rate case application.[19] The risk management process used in this GT&S application consists of the following phases:

1. development of Gas Operations Asset Families;[20]
2. identification of asset threats and assessment of asset risk;[21]
3. development of proposed mitigation programs within Asset Families;[22] and
4. development of an executable investment plan that encompasses work proposed by all Asset Families.[23]

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[18] *PG&E Opening Brief* at 2-3.

[19] *PG&E Opening Brief* at 2-2. The Commission opened Rulemaking (R.) 13-11-006, *Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities*, to examine whether to make changes to the existing General Rate Case Plan on November 22, 2013. PG&E filed its GT&S application on December 19, 2013.

[20] Exh. PG&E-1 at 2-12 – 2-14.

[21] Exh. PG&E-1 at 2-14 – 2-16. PG&E uses the ASME B31.8S standard as the basis for categorizing and evaluating threats to assets and ranks risks in a Risk Register.

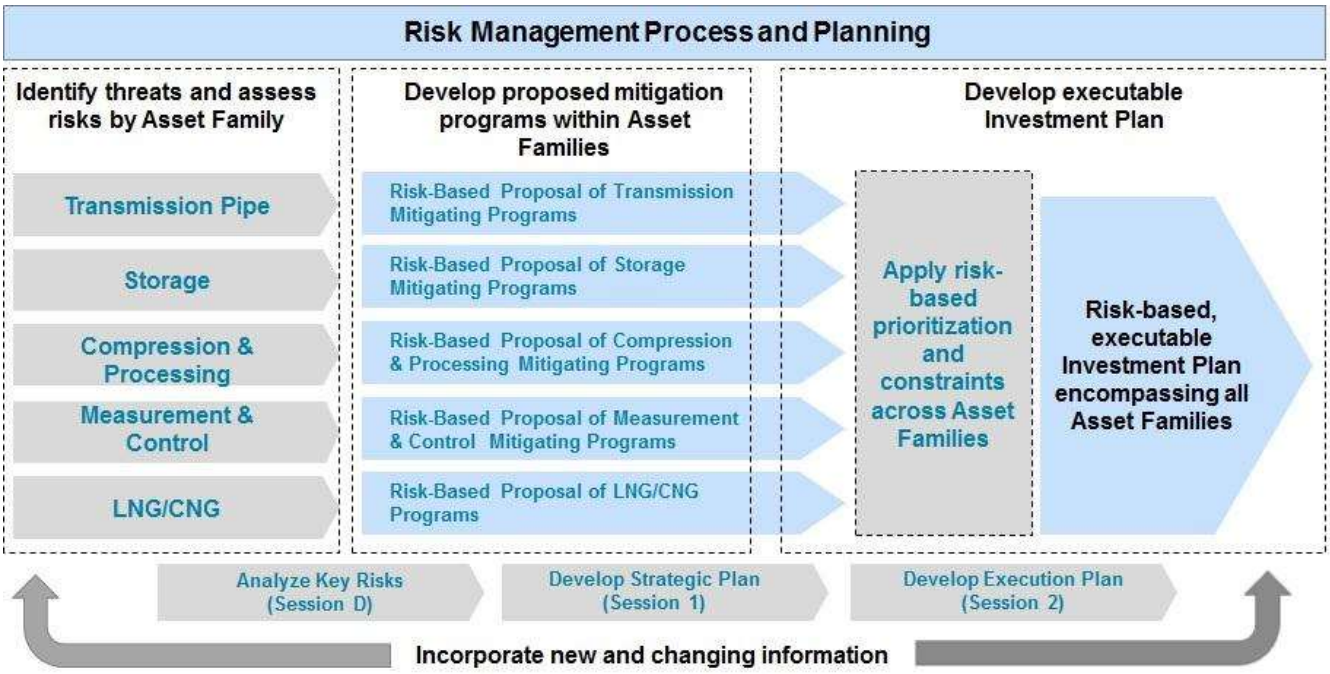
[22] Exh. PG&E-1 at 2-16.

[23] Exh. PG&E-1 at 2-16 – 2-17.

PG&E's Gas Operations Risk Management Process is summarized below:

Figure 1

Gas Operations Risk Management Process[24]



Based on this process, "PG&E identified the threats, assessed the risks by considering likelihood and consequences, and developed appropriate monitoring and mitigation programs to address and reduce those risks."[25] PG&E's Risk Mitigation Summary (Exh. PG&E-1 at 2-20, Figure 2-2) presents the resulting monitoring and mitigation programs and requested funding.

PG&E asserts that its risk management process is consistent with the processes used in the natural gas pipeline industry and incorporates industry best practices.[26] PG&E notes that in the *2014 GRC Decision*, the Commission

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[24] Exh. PG&E-1 at 2-12, Figure 2-1.

[25] Exh. PG&E-1 at 2-18.

[26] Exh. PG&E-1 at 2-7 – 2-8.

articulated a number of principles to consider in balancing the need to adopt "an appropriate level of utility funding to ensure safe and reliable service, while keeping rates affordable and allowing a fair rate of return."[27] PG&E asserts that it has met all these principles, as its testimony explains in detail the risk assessment performed, provides justification for each mitigation program, demonstrates the safety benefits of the proposed mitigation programs, uses historical cost data to demonstrate that its forecast captures expected costs and presents alternatives to its proposed mitigation programs.[28]

Indicated Shippers acknowledges that this is the first GT&S case where PG&E is required to develop a revenue requirement explicitly based on risk. However, it maintains that PG&E's Risk Management Program is not "new and evolving" as represented by PG&E, but rather contains elements that "bear a strong resemblance to the processes PG&E relied on in the year 2000."[29] Indicated Shippers sharply criticizes PG&E's risk management process and catalogs a detailed list of problems,[30] asserting that in light of the multiple shortcomings identified "the Commission cannot conclude that any of PG&E's specific program proposals are just and reasonable."[31]

Despite its criticism, Indicated Shippers concedes: "PG&E does need to move forward on much of the work it proposes."[32] As such, Indicated Shippers

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[27] *PG&E Opening Brief* at 2-5 (citing to D.14-08-032 at 19).

[28] *PG&E Opening Brief* at 2-6.

[29] *Indicated Shippers Opening Brief* at 22.

[30] *Indicated Shippers Opening* Brief at 22-75; Exh. Indicated Shippers-8.

[31] *Indicated Shippers Opening Brief* at 76.

[32] *Indicated Shippers Opening Brief* at 76.

advocates that the Commission adopt the disallowances and alternative ratemaking treatment it has proposed.

There is no disagreement that PG&E must move forward with the proposed GT&S work. While PG&E disputes much of Indicated Shippers allegations, it nonetheless agrees that its risk management program is evolving. As PG&E notes, the Commission adopted a framework for utilities to use for risk-based rate case applications on December 4, 2014.[33] That decision, *Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan and Modifying Appendix A of Decision 07-07-004* [D.14-12-025], established two new procedures, which feed into the GRC applications in which the utilities request funding for such safety-related activities: (1) the filing of a Safety Model Assessment Proceeding (S-MAP) by each of the large energy utilities, which are to be consolidated; and (2) a subsequent Risk Assessment Mitigation Phase. PG&E filed its S-MAP application on May 1, 2015. We agree with PG&E's conclusion that many of the concerns Indicated Shippers has raised concerning PG&E's risk management process shall be considered within the scope of PG&E's S-MAP application and we should not prejudge those issues here.

We find that PG&E's risk management process provides a framework for purposes of evaluating the reasonableness of PG&E's forecast revenue requirement in this GT&S proceeding. We have considered the funding requests for each of the programs and have made adjustments as warranted. Consequently, we find PG&E's proposed risk management approach and asset family categories reasonable.

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[33] *PG&E Reply Brief* at 2-1.

5. Impact on Customers

PG&E requests approval of an expense forecast of $648 million in 2015, and capital expenditures forecasts of $779 million for 2015, $874 million for 2016, and $926 million for 2017.[34] PG&E is seeking recovery of a revenue requirement of $1.267 billion for 2015, and revenue requirements of $1.349 billion for 2016 and $1.518 billion for 2017.[35] PG&E maintains that its requested revenue requirement, while significant, is reasonable and necessary to meet the mandates of Senate Bill (SB) 705.[36] PG&E further notes that even if its full request were granted, "PG&E's average monthly residential gas bill would still be below the national average."[37]

Indicated Shippers disputes PG&E's claims that the proposed increase is reasonable. It notes that, notwithstanding PG&E's argument that the average rate would still be below the national average, PG&E's proposed increase still represents a doubling of the 2014 revenue requirement and increases generation rates for transmission level industrial customers by 91% and for transmission

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[34] Exh. PG&E-1 at 3-1.

[35] Exh. PG&E-2 at 16-2. In its opening brief, PG&E revised these revenue requirements to reflect errata filed by PG&E and updated information. The revised revenue requirements result in revenue requirements of $1.263 billion in 2015, $1.346 billion in 2016 and $1.488 billion in 2017. (*Opening Brief of Pacific Gas and Electric Company* (*PG&E Opening Brief*), filed April 29, 2015, at 1-17.)

[36] *PG&E Opening Brief* at 1-11–1-12. SB 705 (Stats. 2011, ch. 522) enacted Pub. Util. Code §§ 961 and 963. Pub. Util. Code § 961 requires gas operators to develop and implement plans for the safe and reliable operation of their commission-regulated gas pipeline facilities. Among other things, Pub. Util. Code § 963 mandates that "each gas corporation place safety of the public and gas corporation employees as the top priority."

[37] *PG&E Opening Brief* at 1-13.

level electric generators by 135%.[38] Indicated Shippers contends that PG&E did not consider the affordability of its revenue request as it did not perform any analysis of whether individual customers could afford the rate increase.[39] In particular, Indicated Shippers notes that PG&E had not calculated the impact of its proposed increase on industrial customers.[40]

We agree with Indicated Shippers that customer affordability must be considered in determining the reasonableness of PG&E's requested revenue requirement. To that end, this Decision makes various adjustments to PG&E's forecast in instances where we have found PG&E's forecast to be unreasonable and slowed the pace of work where appropriate.

6. Transmission Pipe

6.1. Overview

PG&E's Transmission Pipe Asset Family consists of line pipe used in transporting natural gas through PG&E's system as well as related components such as valves. PG&E manages its transmission pipe assets through 15 programs – ten programs are associated with Transmission Pipe Integrity and Emergency Response, and five programs are associated with Transmission Pipe Engineering. The Transmission Pipe Integrity and Emergency Response programs monitor and mitigate the risks posed by threats to pipeline integrity,[41] while the Transmission Pipe Engineering programs "encompass engineering analyses that

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[38] *Opening Brief of the Indicated Shippers (Indicated Shippers Opening Brief)*, filed April 29, 2015 at 81-82.

[39] *Indicated Shippers Opening Brief* at 83.

[40] *Indicated Shippers Opening Brief* at 84.

[41] Exh. PG&E-1 at 4A-1.

allow PG&E to proactively identify, plan and execute essential transmission pipeline projects, while aligning with regulatory compliance requirements."[42]

PG&E's Forecast 2015 capital expenditures and expenses for these programs is summarized in Table 1 below.

Table 1
Transmission Pipe
2015 Forecast[43]

	Capital Expenditures	Expense
Transmission Integrity Management Programs		
In-Line Inspections	$ 74,259,306	$ 31,521,213
Direct Assessment		46,522,327
Hydrostatic Testing	24,315,750	181,792,325
Earthquake Fault Crossings	5,441,714	4,494,300
Vintage Pipe Replacement	193,824,038	
Geo-Hazard Threat Identification and Mitigation	8,006,886	210,518
Programs to Enhance Integrity Management		7,315,325
Emergency Response Programs		
Valve Automation	52,501,812	
Public Awareness		4,344,490
Inoperable and Hard-to-Operate Valves	7,066,815	242,439
Transmission Pipe Engineering Programs		
Class Location Program	17,056,000	6,410,738
Water and Levee Crossing Program	13,359,714	1,371,500
Shallow Pipe Program	21,571,200	3,072,677

[42] Exh. PG&E-1 at 4B-1.

[43] *PG&E Opening Brief* at 7-3 – 7-4, Tables 7-1 and 7-2.

Gas Gathering Program	1,627,383	
Work Required by Others Program	24,610,000	738,500
Total	**$443,640,618**	**$288,036,352**

PG&E states that this forecast was developed using risk-based decision-making consistent with the Commission's decisions and SB 705.[44] (*See* discussion in Section 4 above.) It states that its transmission programs follow standards set by the American Society of Mechanical Engineers (ASME) B31.8S, and are in compliance with Federal and State regulations, including 49 CFR 192 and General Order (GO) 112-E.

6.2. Transmission Integrity Management Programs

6.2.1. In-Line Inspection Program

6.2.1.1. PG&E's Proposal

In-line inspection (ILI) is a pipeline integrity assessment tool that allow gas pipeline operators to assess the internal and external condition of transmission pipe. "It involves running technologically advanced inspection tools, often called 'smart pigs,' through the inside of the pipeline to collect data about the pipe, and then using that data to identify anomalies that may require further investigations or repair."[45] "Traditional" ILI uses tools that move through the pipeline driven by pressure differentials generated by gas flow. Thus, pipeline will need to be a consistent pipe diameter. "Non-traditional" ILI tools move through the interior of the pipeline by means other than through the use of gas propulsion, such as robotic and tractor tools or using specially designed low

[44] Exh. PG&E-1 at 4-2.

[45] Exh. PG&E-1 at 4A-5.

friction tools. These tools are used in those instances where gas flow or system configuration would not support the use of a traditional ILI tool.[46]

PG&E notes that in 2011, the Commission "began requiring all natural gas transmission pipelines in California to 'be capable of ILI (where warranted).'"[47] Further, PG&E argues "Moving to ILI as the primary integrity assessment tool (where feasible) both in HCAs [High Consequence Areas] and non-HCAs not only aligns PG&E with industry best practices, but also provides PG&E with the opportunity to develop better data upon which it can more effectively evaluate and manage both the current and future asset health of its pipelines."[48]

PG&E notes that its use of ILI assessment (the percentage of total miles made piggable) though 2012 is 19% -- significantly lower than the industry.[49] Consequently, PG&E has adopted a 10-year plan "to upgrade the system in order to in-line inspect over 4,273 transmission pipeline miles by the end of 2024, which is approximately 63% of PG&E's gas transmission pipeline system.[50] PG&E states that by the end of the 10-year plan, it will have reduced the risk posed by time dependent and resident threats for approximately 80% of the population living within the potential impact radius of PG&E's pipelines.

PG&E's ILI program over the Rate Case Period is designed to upgrade 531 miles to accommodate traditional and non-traditional ILI tools and inspect

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[46] Exh. PG&E-1 at 4A-5 – 4A-6.

[47] Exih. PG&E-1 at 4A-9 (citing D.11-06-017 at 20).

[48] Exh. PG&E-1 at 4A-10.

[49] Exh. PG&E-1 at 4A-10, Table 4A-3. As depicted on Table 4A-3, 59% of total miles in the Sempra utilities' transmission system are made piggable.

[50] Exh. PG&E-1 at 4A-12.

over 885 miles using traditional ILI tools. As part of the 10-year plan, four Direct Assessment projects would be converted to ILI. PG&E states that inclusion of these four projects increases the mileage made piggable during the Rate Case Period and increases the use of ILI in place of External Corrosion Direct Assessment for reassessment of certain segments during that time.[51]

PG&E's proposed scope of work[52] during the Rate Case Period is:

1. Upgrades to 486 miles to accommodate traditional ILI tools.
2. Conduct traditional ILI for the first time and re-inspections on a total of 54 projects covering 885 miles.
3. Upgrade the pipeline system to accommodate the use of non-traditional tools, completing 45 miles during the Rate Case Period.
4. Conduct 264 traditional ILI Direct Examination and Repair (DE&R) digs.
5. Use non-traditional tools to assess pipelines that are contained in a "cased crossing" (i.e., pipeline housed inside a metal tube and installed under roads, railroads or canals).

PG&E's projected expenses and capital expenditures over the Rate Case Period are summarized below.

Table 2[53]
Forecasted In-Line Inspection Expenses and Capital Expenditures
($ Thousands of Nominal Dollars)

	2015	2016	2017
Expenses			

[51] Exh. PG&E-1 at 4A-17.

[52] Exh. PG&E-1 at 4A-12 – 4A-15.

[53] Exh. PG&E-1 at 4A-15, Table 4A-5 and 4A-16, Table 4A-6

Traditional ILI	$14,521	$17,737	$34,535
Non-Traditional ILI	146	(a)	(a)
ILI Casings	3,545	(a)	(a)
Traditional ILI DE&R	13,310	10,126	18,328
Non-Traditional ILI DE&R	-	(a)	(a)
Total Expenses	**$31,521**	**$27,863**	**$52,863**
Capital Expenditures			
Traditional ILI	$71,279	$97,651	$100,075
Non-Traditional ILI	2,980	12,897	13,559
Total Capital Expenditures	**$74,259**	**$110,548**	**$113,635**

(a) Scope of work in program expected to expand significantly in the attrition years.

Cost estimates for the proposed ILI work were derived from a study conducted by Wilbros Engineering, which utilized PG&E's pipeline features list database in addition to historical cost data from actual projects.[54] PG&E acknowledges that the program costs for traditional ILI will increase significantly "due to a ramp up of ILI inspection and mitigation work over the three years."[55]

PG&E states that it had considered a number of alternatives regarding the pace of the work, and selected the 10-year plan because "it moves PG&E closer to the CPUC's mandate and National Transportation Safety Board's (NTSB) recommendation for making all pipelines capable of ILI, while ensuring continued reliable service to customers."[56] The 10-year plan includes a conversion of four Direct Assessment projects to ILI, which results in a potential

[54] Exh. PG&E-1 at 4A-19 – 4A-20.

[55] *PG&E Opening Brief at 7-9.*

[56] *PG&E Opening Brief* at 7-10.

risk reduction to an additional 4% of the population in proximity to PG&E's transmission lines over the 12-year plan.

6.2.1.2. Intervenors' Response

Both TURN and Indicated Shippers maintain that PG&E's forecasts for ILI should be reduced. TURN proposes three reductions associated with overstated cost estimates, unreasonable pace of work and past imprudence.

First, TURN proposes that the Commission reduce the make piggable construction costs by 20%. According to TURN, Wilbros Engineers had identified three areas for cost savings and that PG&E had indicated that it was pursuing each of these cost savings recommendations.[57] However, PG&E's cost estimates are based on historical costs and do not include the cost savings identified by Wilbros Engineers. According to TURN, "PG&E should not be allowed to charge ratepayers costs that PG&E's own engineers viewed higher than the true costs PG&E would incur."[58] Thus, TURN recommends that PG&E's forecast for the construction portion of the ILI Upgrade be reduced by 20% as follows: $10.129 million in 2015, $15.302 million in 2016 and $16.772 million in 2017.[59]

TURN next proposes to reduce the pace of work to make pipelines piggable. TURN notes that PG&E witness Barnes had testified that under the PSEP program, the pace for making its pipelines piggable was 48 miles per year.[60] In comparison, PG&E proposes to convert an average of 162 miles per

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[57] *TURN Opening Brief* at 85.

[58] *TURN Opening Brief* at 85.

[59] *TURN Opening Brief* at 86-87.

[60] *TURN Opening Brief* at 87.

year to accommodate traditional ILI tools and 15 miles per year to accommodate the use of non-traditional ILI tools during the Rate Case Period. TURN asserts that PG&E's proposed pace of work does not show a significant mitigation benefit compared to a slower pace of work, "particularly in light of the mandated hydrotesting program and other assessment methods available to the company."[61] TURN proposes that the pace of work should be set at 100 miles per year, which would result in a 44% reduction to the capital budget, if all of TURN's proposed reductions are adopted.[62] TURN asserts: "As long as PG&E properly prioritizes the segments to be made piggable under a 100-mile per year pace, the overall decrease in risk reduction compared to PG&E's proposal … will be minimal but the cost impact would be significant."[63]

Finally, TURN proposes to reduce expenses for Integrity Management assessments. TURN contends that numerous deficiencies in PG&E's operations have increased the "number of anomalies and indications to be addressed through ILI and DA."[64] TURN cites to various instances where the Commission had found that PG&E's integrity management assessment was inadequate, thus resulting in the need for remediation work.[65] TURN states that based on its assessment, PG&E's initial Integrity Management Assessments were inadequate, as the number of anomalies/indications found between initial and reassessments did not decline significantly. According to TURN's witness Berger, if the

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[61] *TURN Opening Brief* at 87; *see* also, Exh. TURN-1 at 12.

[62] *TURN Opening Brief* at 88.

[63] *TURN Opening Brief* at 88.

[64] *TURN Opening Brief* at 89.

[65] *TURN Opening Brief* at 89-92.

baseline ILI had been performed properly and mitigated properly, time-dependent problems, such as corrosion, should not re-appear in a subsequent assessment a few years later.[66]

TURN notes that a significant portion of PG&E's expense forecast for ILI consists of work to repair anomalies. In light of the above, TURN believes that some portion of this work is the result of past imprudence by PG&E. TURN maintains that PG&E should only recover from ratepayers the costs for repair work that is not the result of imprudence. From TURN's perspective, PG&E bears the burden of demonstrating that it acted prudently and for demonstrating that it did not seek or obtain funding for work for integrity management assessments and remediation work in past rate cases.[67]

TURN argues that since PG&E has not identified the amount of work resulting from past imprudence, and because "PG&E cannot reasonably contend that it has not sought a received ratepayer funding for the cost to avoid unnecessary corrective work in ILI and DA assessments," the Commission should disallow at least half of the costs of the forecast corrective work resulting from ILI and Direct Assessment inspection.[68] TURN proposes that this disallowance be from the Traditional ILI DE&R work category. TURN notes that the bulk of ILI repair work is forecast in that category, which is described as "digs, and where necessary, repairs for anomalies identified through ILI that

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[66] Exh. TURN-1 at 10-12.

[67] *TURN Opening Brief* at 95-96.

[68] *TURN Opening Brief* at 95.

could pose an integrity threat."[69] This would result in a reduction of $6.65 million in 2015, $5.1 million in 2016 and $9.15 million in 2017.

Indicated Shippers proposes that the Commission disallow $23,978,150 in capital costs that PG&E added to its ILI funding request based on a study performed by Gas Transmission Systems. This study modified the ILI cost study prepared by Wilbros Engineers.[70] Indicated Shippers argues that the Gas Transmission Systems' study provides no evidence to support the increased costs and was the result of a high level analysis. Indicated Shippers further maintains that the Gas Transmission Systems study was not an arms-length evaluation, as seven of the nine individuals performing the study are current or former PG&E employees.[71] According to Indicated Shippers: "Using a consultant staffed by former PG&E employees to increase the costs derived by an independent consultant further calls the reasonableness of the [Gas Transmission Systems] increases into question."[72] Based on these assertions, Indicated Shippers maintains that the increased costs associated with the Gas Transmission Systems study are not reasonable and should be disallowed. This would equate to a reduction of $6.467 million in 2015, $11.580 million in 2016 and $5.932 in 2017.[73]

6.2.1.3. Discussion

We have considered the various arguments and determine that the pace of work to make pipelines piggable should be reduced and that this work shall be

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[69] *TURN Opening Brief* at 96.

[70] *Indicated Shippers Opening Brief* at 96.

[71] *Indicated Shippers Opening Brief* at 99.

[72] *Indicated Shippers Opening Brief* at 100.

[73] *Indicated Shippers Opening Brief* at 100.

performed over a 12-year period, rather than a 10-year period. Aside from slowing the pace of work, we make no further adjustments to PG&E's forecast expenses or capital expenditures.

TURN has proposed that the pace of work for the ILI Upgrade program be reduced and that 20% of the forecast costs be disallowed. TURN argues that the pace of work should be 100 miles per year, rather than PG&E's proposed pace of 177 miles per year. TURN notes that its proposed pace is double the pace of work under PSEP. However, as discussed by PG&E witness Barnes, if the pace of work were 100 miles per year, it would take PG&E 26 years to make its system piggable.[74] We find such a length of time is not acceptable.

Although we do not adopt TURN's recommendation, we do find that the accelerated pace proposed by PG&E could impose additional costs on ratepayers due to the higher demand for limited construction resources. Consequently, we adopt PG&E's alternate 12-year plan. The additional two years would have a minimal direct impact to the Total Occupancy Count, while lowering the cost of traditional ILI upgrades by approximately $84 million over the Rate Case Period.[75] While this delay will have some impact on PG&E's collection of data, a two-year extension over PG&E's proposed ten-year plan should not adversely impact PG&E's overall decision-making process.

TURN recommends that the forecast make piggable construction costs be reduced by 20%. While we agree with TURN that PG&E would likely achieve some savings by pursuing the areas identified in the Wilbros Engineering study,

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[74] 20 Reporter's Transcript (RT) at 2191:17-20(.

[75] Exh. PG&E-1 at 4A-18.

we decline to adopt TURN's recommendation. The ability to reduce costs by 20% during each year of the Rate Case Period is speculative at best. PG&E notes in its response to TURN's data request that while it is seeking cost efficiencies,

> PG&E continues to recognize that there are upward cost pressures on the ILI retrofit work that were not addressed in the referenced report, such as limited availability of experienced construction crews. [sic] primarily due to a high demand for gas transmission pipeline integrity driven construction services across the nation and within California.[76]

We further decline to adopt Indicated Shippers' recommendation to disallow $23,978,150 in capital costs. As explained by PG&E, the Gas Transmission Systems' study evaluated the 83 ILI Upgrade projects to be completed during the Rate Case Period and "focused its evaluation on five key areas that Wilbros did not consider in depth in its study."[77] Further, the study proposed both increases and decreases to these various projects, with a net increase of $23,978,150. The Gas Transmission Systems' study fully explains the work performed. Additionally, we find no basis to conclude that Gas Transmission Systems did not perform an independent evaluation, even though some of the individuals performing the study were current or former PG&E employees.

Finally, we are not persuaded that PG&E's forecast expenses should be reduced by 50%, as proposed by TURN. TURN bases its recommendation on violations found in Citation ALJ 274 15-01-002, a Safety and Enforcement Division (SED) investigative report in I.12-01-007 and internal audit findings in a

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[76] Exh. TURN-5, PG&E's Response to TURN Data Request 6, Question 6(d) at 2.

[77] *PG&E Reply Brief* at 7-9.

2012 report of Audit of Gas Damage Prevention Program, as well as the number of anomalies/indications found between initial and re-assessments. We find that PG&E has provided sufficient evidence that none of the ILI and Direct Assessment work proposed during this Rate Case Period include costs to address these prior violations and findings.

PG&E has fully explained why ILI anomaly rates found during reassessments would not reflect the quality of the initial assessment.[78] While this may be true for the first reassessment conducted, we believe that subsequent reassessments should reflect lower anomaly rates. This conclusion is supported by PG&E's witness, who stated "until you get that second run of data, kind of like two data points, you can't really begin to draw that straight line to fully comprehend what kind of changes you need to be making."[79] Accordingly, we do not adopt TURN's recommendation to reduce DE&R expenses by 50%.

In summary, we revise PG&E's forecast to slow the pace of work to make pipelines piggable from 10 years to 12 years. This results in 2015 capital expenditures of $59.236 million, or a reduction of $15.023 million. PG&E's forecast 2015 expenses of $31.521 millionare reasonable and are adopted.

6.2.2. Direct Assessment

6.2.2.1. PG&E's Request

In situations where ILI is not technically feasible, PG&E uses Direct Assessment as an assessment tool to identify pipeline integrity.[80] Direct

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[78] Exh. PG&E-51 at 4A-2 – 4A-3.

[79] 20 RT at 2228:20-24 (PG&E/Barnes).

[80] PG&E notes that hydrostatic testing is an alternative to Direct Assessment, but is not a feasible alternative because it requires many system outages. (Exh. PG&E-1 at 4A-31.)

Assessment is used to evaluate the possible presence of the time-dependent threats of external corrosion, internal corrosion, and stress corrosion cracking. The three types of direct assessment are:

1. External corrosion direct assessment (ECDA)
2. Internal corrosion direct assessment (ICDA)
3. Stress corrosion cracking direct assessment (SCCDA)

"Each assessment methodology is designed to proactively address the pipeline threat of corrosion and is meant to discover and prevent anomalies from growing to a size that affects the structural integrity of the pipeline." PG&E states it will continue to use direct assessment to assess pipeline segments in HCA's in the following situations:

1. Segments within an HCA due for reassessment which are not yet piggable;
2. New HCA pipeline segments created as a result of PG&E's change in its definition of transmission pipelines; and
3. When required based upon evaluation of cathodic protection data and a determination that more detailed data from a direct assessment process is required to ascertain the asset health of a line segment.[81]

PG&E expects to conduct ECDA on 355 miles of transmission pipe in high consequence areas and ICDA on approximately 67 miles of pipeline in high consequence areas during the Rate Case Period. It also expects to conduct SCCDA on approximately 60 miles of pipeline in high consequence areas in 2015.[82]

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[81] Exh. PG&E-1 at 4A-26.

[82] Exh. PG&E-1 at 4A-27.

PG&E states that it expects a significant increase in ECDA and ICDA work over the case period. It states this increase is a result of the reassessment interval requirements contained in 49 CFR 192.939.[83] The forecasted Direct Assessment expenses over the Rate Case Period are summarized below.

Table 3[84]

Forecasted Direct Assessment Expenses
($ Thousands of Nominal Dollars)

	2015	2016	2017
ECDA	$28,337	$32,694	$42,717
ICDA	$15,328	$18,762	$22,008
SCCDA	$2,857	*	*
Total	$46,522	$51,455	$64,728

* Although not requesting special attrition, PG&E expects the scope of work will expand significantly in the attrition years.

PG&E also proposes to reclassify approximately 920 miles of pipe from distribution to transmission starting in 2015. PG&E explains that prior to 2015, it had applied a definition of transmission to its pipelines for federal reporting purposes, which resulted in classifying 920 miles of pipe being treated as distribution for purposes of Pipeline and Hazardous Materials Safety Administration (PHMSA) reporting and integrity management, even though the pipe operated at greater than 60 pounds per square inch gauge.[85] However, starting in 2015, PG&E defines pipelines using the definition of transmission

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[83] *PG&E Opening Brief* at 7-17.

[84] Exh. PG&E-1 at 4A-28 (Table 4A-28).

[85] *PG&E Opening Brief* at 7-18.

pipelines in 49 CFR 192.3. This resulted in defining the additional 920 miles as transmission, and subjecting them to the requirements of 49 CFR 192, Subpart O, Transmission Integrity Management requirements.[86] PG&E estimates that this reclassification results in an additional 133 miles of high consequence area miles that will need to be assessed during this rate period. PG&E notes that since this reclassified pipe had never been subject to transmission-level work, it had not recovered any costs for this work in its 2014 GRC, since distribution pipe is subject to the Distribution Integrity Management Program rules pursuant to 49 CFR 192, Subpart P.[87] Consequently, since the transmission-level work is incremental to what was recovered in prior GRCs, there is no double recovery between this proceeding and PG&E's 2014 GRC.

6.2.2.2. Intervenors' Response

Similar to its arguments concerning ILI expenses, TURN believes that the forecast Direct Assessment costs are inflated due to the need to remediate PG&E's past imprudence. Therefore, it recommends that 50% of the forecast costs for work within the third phase of ECDA, "Direct Examination and NDE" or "Digs," be disallowed.[88] This would result in the following disallowance: $6.38 million in 2015, $7.88 million in 2016, and $11.2 million in 2017.[89] TURN

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[86] *PG&E Opening Brief* at 7-19.

[87] *PG&E Opening Brief* at 7-20.

[88] *TURN Opening Brief* at 97.

[89] *TURN Opening Brief* at 97-98. TURN also notes that its proposed disallowance does not take into consideration the 920 miles of distribution pipeline that PG&E proposes to reclassify as transmission pipeline. TURN supports ORA's position that this pipeline should not be reclassified until 2017.

also proposes a 50% disallowance to the forecast costs ICDA as follows: $3.95 million in 2015, $5.35 million in 2016 and $6.65 million in 2017.[90]

ORA does not oppose PG&E's forecast for SCCDA.[91] However, it opposes PG&E's request for funding to assess the reclassified pipeline. ORA argues:

> The 920 miles of distribution pipelines PG&E is proposing to re-classify as transmission pipelines are already accounted for in its most recent General Rate Case (PG&E 2014 GRC, A.12-11-009). The costs to operate and maintain these distribution pipelines are currently embedded in rates for 2014 through 2016.[92]

According to ORA, PG&E cannot clearly state whether it had received funding for the reclassified pipe through the 2014 GRC. Moreover, ORA notes that PG&E's witness had testified that these 920 miles of reclassified pipe had received Distribution Integrity Management Program funds in the 2014 GRC.[93] Based on this testimony, ORA concludes that these 920 miles are currently being paid for by ratepayers in the 2014 distribution GRC. ORA further disputes PG&E's assertion that the reclassified pipe had never been subject to any assessments. It notes that starting in 1970, PG&E was required to test all pipelines placed into service. Consequently, "PG&E appears to be implying that they have not used any assessment methods, apparently contrary to the requirements of the Distribution Integrity Management Program or general operation requirements under [49 CFR §§192.505, 192.507, and 192.509]."[94] As a

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[90] *TURN Opening Brief* at 98.

[91] *ORA Opening Brief* at 26.

[92] Exh. ORA-7 at 5.

[93] *ORA Opening Brief* at 27.

[94] *ORA Reply Brief* at 21.

result, ORA advocates that PG&E not be allowed to collect further funds from ratepayers in 2015 and 2016, and that the shift in reclassifying the 920 miles of distribution pipe be delayed until 2017.

ORA further challenges the dig to project ratio used by PG&E to derive its 2015 ECDA forecast. ORA believes that PG&E has inflated its request by multiple upward roundings of partial digs. As support, it notes that PG&E's listing of actual January-June 2013 projects and estimates shows an average ratio of 4.5 digs to projects. However, PG&E's forecast uses an average ratio of 6.8 digs.[95] ORA argues that "across a multi-year program there certainly can be partial digs, and certainly there can be fractions of digs for ratemaking purposes."[96] Therefore, ORA recommends that the dig to project ratio be reduced to 4.5 digs. Along with its proposed disallowance of reclassified distribution pipe, ORA recommends that the ECDA forecast be $12.849 million.

6.2.2.3. Discussion

As discussed in Section 6.2.1.3 above, we do not find that any of the Direct Assessment work proposed in this Rate Case Period is to address prior violations. However, unlike our findings regarding Integrity Management Assessments using ILI, we agree with TURN that there should be a disallowance for ECDA and ICDA work. As noted by PG&E witness Barnes, PG&E would not be able to understand what the frequency of anomaly rates mean until after the "second run of an assessment." At that point, PG&E would then be able to review both the initial and reassessment to determine what actions would need

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[95] Exh. ORA-7 at 12 (ORA/Phan).

[96] *ORA Opening Brief* at 26.

to be taken.[97] Unfortunately, PG&E cannot make such a determination in this instance, since it does not "separately track immediate indications between those found in the baseline assessments and those found in the reassessments" for ECDA.[98]

As stated by TURN, "It only makes sense that an operator who is assessing and managing corrosion effectively would see fewer problems over time."[99] However, if PG&E cannot determine whether the immediate indications were from the baseline assessment or from the second run of an assessment, it would not be able to understand frequency trends or determine what actions would need to be taken. Given this gap in data, we cannot conclude that PG&E's forecast for ECDA and ICDA are reasonable. Accordingly, we agree with TURN that PG&E's shareholders should be responsible for 50% of the ECDA and ICDA expenses.

We do not adopt ORA's recommendation to shift the reclassification of the 920 miles of distribution pipe to 2017. At issue is whether PG&E has received funding in its 2014 GRC to perform transmission integrity management assessments on the proposed reclassified pipe. As PG&E notes, the transmission integrity management requirements under 49 CFR § 192, Subpart O are more stringent than the requirements for distribution integrity management under 49 CFR § 192, Subpart P. There is no evidence that PG&E received funding in its 2104 GRC to perform transmission integrity management activities. Further, PG&E states in its Opening Brief that the Distribution Integrity Management

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[97] 20 RT at 2228 (PG&E/Barnes).

[98] 20 RT at 2225:21-24 (PG&E/Barnes); *see* also, Exh. PG&E-51 at 4A-5, Answer 14.

[99] *TURN Reply Brief* at 52.

Program focuses on the entire distribution system, not particular segments of pipe. Given the number of miles of distribution pipe and gas service lines, "the integrity management costs included in the 2014 GRC to address the approximately 920 miles are de minimus."[100] Accordingly, PG&E's proposed reclassification of 920 miles of distribution pipeline is adopted.

We do, however, agree with ORA that PG&E's 2015 forecast dig-to-project ratio is overstated as a result of rounding. We agree with ORA that there can be partial digs over multi-year projects, and that fractions of digs can be used for ratemaking purposes. As illustrated by the table below, rounding up to the nearest whole number results in a higher number of digs.

Table 4
Number of Digs Per Project Per Year[101]

Year	Projects	Digs	Average Digs/Project (Rounded up to nearest whole number)	Average Digs/Project (no rounding)
2004	6	49	9	8.17
2005	9	91	11	10.11
2006/2007	45	400	9	8.89
2008	8	32	4	4.00
2009	19	108	6	5.68
2010	19	89	5	4.68
2011	24	102	5	4.25
2012	49	195	4	3.98
2013	24	107	5	4.46
Average Per Project Per Year			**7**	**6.02**

[100] *PG&E Opening Brief* at 7-19.

[101] Exh. PG&E-39 at 4A-22, Table 4A-22. PG&E's table consists of the first four columns. The fifth column, Average Digs/Project (no rounding) was calculated by dividing the number of digs by the number of projects.

Based on the above, we reduce the dig-to-project ratio to 6.02. While it may be true that there cannot be a partial dig in a project, PG&E has provided no persuasive explanation why rounding up to the nearest whole number is warranted in its forecast expenses. We decline to adopt ORA's recommendation to utilize only 2013 data, as we believe the longer historical data is a better representation of PG&E's experience. While the number of digs-per-project is lower than PG&E's forecast, it is consistent with PG&E's actual experience between 2008 and 2013.

In summary, we revise PG&E's forecast Direct Assessment forecast as follows:

- PG&E shall recover from ratepayers 50% of the forecast ICDA expenses ratepayers, and the other 50% from shareholders. Therefore, PG&E is authorized to recover from ratepayers $7.664 million in expenses for ICDA in 2015.
- PG&E's forecast ECDA expenses are reduced to account for a lower dig-to-project ratio. This results in forecast 2015 expenses of $25.958 million. Of this amount, PG&E shall recover from ratepayers 50% of the forecast ECDA expenses, and the other 50% from shareholders. Therefore, PG&E is authorized to recover from ratepayers $12.979 million in expenses for ECDA in 2015.
- The total amounts to be recovered for ECDA and IDCA from ratepayers are $24.326 million in 2016 and $30.599 million in 2017.
- PG&E's forecast 2015 SCCDA expenses of $2.857 million are adopted.

6.2.3. Hydrostatic Testing

Hydrostatic testing is used to test the yield strength of pipe for the presence of defects, such as lack of fusion in a seam weld. Further, as part of the PSEP, hydrostatic strength testing has been used to validate the integrity and

assure a margin of safety for those gas transmission pipelines that lack a documented strength test record.[102] PG&E states that all tests will be conducted in accordance with 49 CFR § 192.619.

6.2.3.1. PG&E's Request

PG&E requests funding to test approximately 170 miles of pipeline per year. It states that this pace would be similar to the pace during PSEP. Based on this pace, PG&E estimates that it will "strength test or replace all of PG&E's gas transmission pipelines, not previously tested, in roughly 12-14 years from the state of strength testing in 2011.[103] PG&E states that it had considered accelerating the pace to strength test more miles, but determined that doing so would strain resources and could impact its ability to serve customers.[104]

The forecast unit cost for testing each mile of pipe is $0.97 million per mile for 2015 for the expense portion of the testing, based on historical costs combined with forecasts for 2013.[105] This expense forecast is similar to the forecasted 2013 cost per mile.[106] PG&E also forecasts approximately $5 million expense in 2015 to reflect the annual cost associated with strength tests needed to address pressure restoration work or uprates for pressure increases to pipelines requiring a higher maximum allowable operating pressure (MAOP) to support increased customer load.

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[102] Exh. PG&E-1 at 4A-31 – 4A-32.

[103] Exh. PG&E-1 at 4A-32 – 4A-33.

[104] Exh. PG&E-1 at 4A-36.

[105] Exh. PG&E-1 at 4A-40. 19 RT 2084 (PG&E/Barnes).

[106] Exh. PG&E-1 at 4A-41.

PG&E's capital expenditures are forecasted to be similar to historical costs in 2012-2013. PG&E states that the capital work is non-discretionary and "driven by the number of plug valves and Pressure Control Fittings (PCF) that obstruct the pipeline that have to be replaced or removed."[107] PG&E states that the tests planned for this rate cycle will be similar in scope to work in 2013.

PG&E's projected expenses and capital expenditures over the Rate Case Period are summarized below.

Table 5[108]

Forecasted Hydrostatic Testing Expenses and Capital Expenditures ($ Thousands of Nominal Dollars)

	2015	2016	2017
Expenses	$181,792		
Capital Expenditures	$24,316	$22,818	$22,167

PG&E includes in its forecast costs associated with hydrostatic testing of approximately 47 miles of pipe installed between 1956 and 1961 that do not have a corresponding pressure test record. PG&E argues that even though the *PSEP Decision* had previously denied recovery of pressure test costs associated with pipe installed between 1956-1961, it should be allowed to recover these costs for the following reasons:[109]

> (1) there were no requirements to hydrostatically test pipe when it was installed between 1956-1961;

[107] Exh. PG&E-1 at 4A-42.

[108] Exh. PG&E-1 at 4A-32, Tables 4A-8 and 4A-9.

[109] Exh. PG&E-1 at 4A-43.

(2) at the time of enacting pipeline safety regulations, the Commission and federal government consciously chose not to require hydrostatic tests for pipe installed prior to that time;

(3) the hydrostatic test provision in the American Standards Association (ASA) code was new and not widely applied in the industry, so it cannot be considered an established practice in 1956-1961;

(4) the ASA code did not require a pressure test duration, which is required by both GO 112 and 49 CFR part 192 (a point which was not addressed by the recent Commission decisions denying recovery of certain PSEP costs); and

(5) it was unlikely the CPUC would have provided rate recovery for hydrostatic testing activities in 1956-1961 given that it was not a requirement.

As support for its arguments, PG&E presents a side by side comparison of the strength test standards contained in the 1955 American Standard Code for Gas Transmission and Distribution Piping Systems (1955 ASA) and the strength test requirements adopted in 1961 under GO 112.[110] PG&E argues that comparison shows that the pressure limits and the test durations under the 1955 ASA would not have met the requirements adopted in the 1961 GO 112. Thus, PG&E argues that "what was required under the 1955 ASA and what was required to meet GO 112 were so different as to discredit any blanket disallowance of cost recovery for hydrostatic tests performed today to meet current standards."[111] Consequently, PG&E contends that even if it had complied with 1955 ASA, it would have still had to perform a strength test again to meet the requirements in *Decision Determining Maximum Allowable Operating*

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[110] Exh. PG&E-110.

[111] *PG&E Opening Brief* at 7-33.

Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans [D.11-06-017] (*MAOP Decision)*.

Further, PG&E argues that the *PSEP Decision* is not binding in this proceeding, as "these differences were not the focus of the PSEP proceeding."[112] It further notes that the Commission had "tentatively approved cost recovery for San Diego Gas and Electric Company and Southern California Gas Company (SoCalGas) (together Sempra) for hydrostatic testing costs of the same vintage pipe for which Sempra had no pressure test records."[113]

6.2.3.2. Intervenors' Response

ORA and TURN both challenge PG&E's forecast unit cost of $0.97 million per mile. Both believe PG&E's forecast is too high and should be reduced. TURN, ORA and Indicated Shippers all oppose PG&E's inclusion of costs to hydrostatically test pipes installed between 1956-1961 for which PG&E has no corresponding pressure test records.

Although ORA agrees with PG&E's programmatic approach to forecasting the costs for hydrostatic testing, it maintains PG&E's application of the approach improperly used forecasted costs, rather than actual or historical costs.[114] ORA agrees that while PG&E "had to use some level of forecasting of 2013 costs to prepare its Application," over 92% of the 2013 costs were based on forecasts.[115]

ORA next contends that PG&E did not take into consideration the downward trend in hydrotest costs between 2011 and 2013 due to efficiency

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[112] *PG&E Opening Brief* at 7-33.

[113] *PG&E Opening Brief* at 7-30.

[114] *ORA Opening Brief* at 32.

[115] *ORA Opening Brief* at 35.

gains and changes in the nature of the hydrotest program.[116] It further notes that the project lengths during the Rate Case period are projected to be similar in length to the projects conducted in 2013.[117] ORA notes that PG&E has testified that longer hydrotest projects generally have lower unit costs.[118] As such, ORA asserts that PG&E's forecast, which does not take into consideration declining costs nor the longer projects to be conducted, is unreasonable.

ORA further notes that PG&E's forecast improperly includes the following PSEP costs that were not reported in the quarterly PSEP Compliance Reports:

1. Costs associated with cancelled or deferred projects;
2. General hydrotest program costs; and
3. Over $2 million in costs incurred after individual projects became operational.[119]

ORA maintains that PG&E's arguments why it was not required to include all PSEP costs in the PSEP Compliance Reports should be disregarded. It asserts that Attachment D of the *PSEP Decision* "fully intended to include <u>specifically</u> the type of information PG&E excluded in this instance."[120] ORA further cites to the *PSEP Decision* in disputing PG&E's claim that information contained in the Compliance Reports were not intended to be used to develop forecasts.[121] Based on this, ORA concludes that PG&E should have provided all PSEP cost

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[116] *ORA Opening Brief* at 37-38. ORA witness Roberts further provided examples of areas for further cost reductions. (*See*, *ORA Opening Brief* at 40-42.)

[117] *ORA Opening Brief* at 43-44.

[118] 17 RT at 1751:19-26 (PG&E/Barnes).

[119] *ORA Opening Brief* at 52 (citing Exh. PG&E-39 at 4A46 – 4A-48.)

[120] *ORA Opening Brief* at 54 (emphasis in original).

[121] *ORA Opening Brief* at 55.

information in the Quarterly Compliance Reports, and that failure to do so is a violation of both the *PSEP Decision* and Rule 1.1 of the Commission's Rules of Practice and Procedure.[122] Moreover, since the unreported PSEP costs are in excess of $100 million, ORA contends that an audit of PG&E's PSEP accounting and expenditures, as well as an audit of the expenditures in this Rate Case, is warranted. ORA believes that such an audit would provide invaluable information for future forecasts.[123]

Based on the above, ORA urges the Commission to adopt a unit cost forecast of $0.56 million per mile for 2015.[124] This amount reflects ORA's 2013 unit cost calculation of $0.72 million per mile, based on actual 2013 PSEP costs, adjusted downward to account for falling hydrotest costs during the Rate Case Period.[125]

Similar to ORA, TURN argues that since PG&E has maintained that the 2013 costs are the best representation of likely 2015 unit costs, the maximum unit cost for hydrotesting should be PG&E's recorded unit cost for 2013, or $0.84 million per mile tested.[126] TURN further believes that the adopted forecast should be even lower, as PG&E may reduce costs through work by the Program Management Office and is studying the use of nitrogen to cut costs on certain types of strength tests.[127]

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[122] *ORA Opening Brief* at 56.

[123] *ORA Opening Brief* at 58.

[124] *ORA Opening Brief* at 32 and 64.

[125] *ORA Opening Brief* at 64.

[126] *TURN Opening Brief* at 105.

[127] *TURN Opening Brief* at 106-107.

TURN, ORA and Indicated Shippers all urge the Commission to reject PG&E's proposal to include costs to hydrostatically test pipelines installed between 1956-1961 for which there are no corresponding pressure test records. These intervenors maintain that PG&E is re-arguing its PSEP position. As noted by TURN, the *PSEP Decision* had already considered and rejected PG&E's arguments that between 1956-1961, there were no requirements to hydrostatically test pipe, that the hydrostatic test provisions in 1955 ASA were not established practice and that it was unlikely the Commission would have provided rate recovery for hydrostatic testing.[128] Further, TURN notes that PG&E has not presented any evidence showing that it did not attempt to comply with 1955 ASA or that the pressure testing between 1956-1961 was not funded by ratepayers.[129]

Similarly, ORA notes that PG&E had a statutory obligation to maintain and operate its system safely since 1909. Moreover, PG&E had represented to the Commission at the time GO 112 was adopted, that it complied with industry standards.[130] ORA asserts that PG&E's arguments contradict its previous representations and should be disregarded. Therefore, ORA contends that the Commission should disallow costs associated with testing pipe installed after 1955 where there are no "traceable, verifiable and complete hydrotest records."[131]

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[128] *TURN Opening Brief* at 99 (citing *PSEP Decision* at 59).

[129] *TURN Opening Brief* at 99-100; *see* also, *Indicated Shippers Opening Brief* at 103 (stating that PG&E's argument that the Commission may not have provided rate recovery for hydrostatic testing activities in 1956-1961 is speculative).

[130] *ORA Opening Brief* at 61.

[131] *ORA Opening Brief* at 65.

Indicated Shippers states that regardless of PG&E's arguments that the hydrostatic tests performed at the time were not legally required, "PG&E nonetheless actually conducted the testing without retaining proper records."[132] It further notes that PG&E's arguments concerning the differences between the requirements of 1955 ASA and of 1961 GO 112 had been struck from the record as procedurally improper.[133]

Finally, TURN argues that PG&E shareholders should be required to pay for hydrotesting all pipe installed after January 1, 1956 for which it does not have a pressure test record. Based on PG&E's response to TURN Data Request 30, Question 2, which revises PG&E's Table 4A-12 to reflect the correct effective date of GO-112,[134] TURN contends that the Commission should disallow costs to test 195 miles of pipe installed after January 1, 1956. If the Commission were to reject this recommendation, TURN urges that at a minimum, the 98 miles installed between January 1, 1956-June 30, 1961 should be disallowed.[135] TURN therefore recommends that the Commission apply at 38.2% disallowance to the adopted expenses. TURN also maintains that since "the amount of the capital costs is directly related to the number of pipelines that are hydrotested," 38.2% of the adopted capital costs should also be disallowed. TURN argues this disallowance is warranted because of the higher percentage of pipeline that needs to be tested due to PG&E's past imprudence.[136] TURN additionally proposes that the

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[132] *Indicated Shippers Opening Brief* at 104.

[133] *Indicated Shippers Opening Brief* at 104.

[134] *See*, Exh. TURN-48.

[135] *TURN Opening Brief* at 101.

[136] *TURN Opening Brief* at 103.

Commission "specify the total number miles of pipe that PG&E is required to test in the Rate Case Period, and provide a ratepayer cost cap for this work."[137]

6.2.3.3. Discussion

PG&E states that the cost calculator developed by PG&E and adopted in the *PSEP Decision* for estimating PSEP projects had "typically under-estimate[d] the cost of the project.[138] Based on its experience with the cost calculator in 2011-2012, PG&E forecast its 2015 expenses based on the forecasted 2013 cost per mile. PG&E notes that when looking at PG&E's Hydrostatic Testing Program unit and cost performance between 2011 and 2014, its 2015 forecast of $0.97 per mile is reasonable.[139] In contrast, PG&E notes that ORA's proposed unit cost of $0.54 million per mile is "a clear outlier compared to PG&E's programmatic experience."[140]

We decline to adopt ORA and TURN's recommendation. As PG&E notes, its forecast is based on three years of actual experience.[141] PG&E has further explained that its $0.97 million per mile unit cost is justified because

> there are high variable costs or costs which at a project level cannot be accurately predicted until a certain level of engineering is reached. These costs include cleaning the pipe, if mercury is present, water management, permitting and environmental, and most importantly excavating taps off of the mainline, as well as the cost to provide gas service to these taps (supply Compressed

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137 *TURN Opening Brief* at 101.

138 Exh. PG&E-1 at 4A-40.

139 *PG&E Reply Brief* at 7-12. As presented on page 7-12 of the *PG&E Reply Brief*, average unit costs during those years were between $0.85 million per mile to $1.42 million per mile.

140 *PG&E Reply Brief* at 7-12.

141 *PG&E Reply Brief* at 7-12.

Natural Gas (CNG) or Liquefied Natural Gas (LNG) to keep customers' gas flowing).[142]

While we generally agree with TURN and ORA that hydrostatic testing costs should decrease over time as the result of efficiency gains and non-emergency nature of the work (as opposed to PSEP), the potential level of decrease is unknown at this time. Further, as PG&E has testified, its 2015 forecast, which analyzed recorded costs 2011-2013 and forecast costs for 2014, showed that hydrostatic testing costs would increase to $1.86 million per mile. Nonetheless, PG&E believes that its 2015 forecast is reasonable "[d]ue to the number of efficiencies that PG&E has realized through its lessons learned from PSEP."[143] We therefore find PG&E's 2015 forecast capital expense of $0.97 million per mile reasonable.

We disagree with PG&E's arguments that it should be allowed to recover costs for hydrostatic testing of pipe installed between 1956 and 1961 for which it has no records. The *PSEP Decision* found that "PG&E's practice was generally to pressure test natural gas pipeline before placing the pipeline into service, with record retention being part of the practice."[144] PG&E now argues that 1955 ASA only requires pressure testing and retention of records in some situations. Under its new reading of 1955 ASA, PG&E contends it should be allowed recovery of costs to hydrotest pipe installed between 1956-1961 for which it has no pressure test record. However, PG&E's new understanding of what is required by 1955 ASA ignores the fact that it consistently represented that between 1956-1961, it

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[142] Exh. PG&E-39 at 4A-42 – 4A-43.

[143] Exh. PG&E-39 at 4A-50.

[144] *PSEP Decision* at 59; *see* also, *PSEP Decision* at 117-118 (FOF 18).

pressure tested and retained records for all pipe.[145] Moreover, even if we were to accept PG&E's argument, PG&E has provided no evidence that the pipes for which there are no pressure test records were in fact not required to have pressure testing or, if pressure testing were required, that that there was no requirement that the records be retained. Thus, there is no basis to conclude that PG&E's ratepayers should fund the costs for pressure testing of pipe installed between 1956-1961 for which PG&E has no pressure test record.

We further agree with TURN that PG&E ratepayers should not be responsible for costs associated with hydrotesting of pipe installed after January 1, 1956 for which PG&E has no pressure test records. As we had found in the *PSEP Decision*, and as affirmed in today's decision, between January 1, 1956 and June 30, 1961, PG&E's practice was to pressure test natural gas pipeline before placing the pipeline into service and retain the test records. Further, since July 1, 1961, GO 112 mandated that operators pressure test their transmission pipelines and that pressure test records be retained. As such, PG&E should have had pressure test records for all pipeline segments installed after January 1, 1956. To the extent it does not, PG&E's shareholders should pay for these costs.

Based on Exh. TURN-48, we find that the cost to hydrotest the 98 miles of pipe installed between January 1, 1956 to June 30, 1961 should be disallowed. We agree with TURN that PG&E's modified and updated Table 4A-12, which reflects the proper effective date of GO 112, should be used to determine the miles to be disallowed. Therefore, the adopted expenses shall be reduced by

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[145] *See*, e.g., *PSEP Decision* at 56; *Modified Presiding Officer's Decision Regarding Allegations of Violations Regarding Pacific Gas and Electric Company's Operations and Practices with Respect to Facilities Records for its Natural Gas Transmission System Pipelines* [D.15-04-021] at 96.

19.2%. While we reduce the forecast expenses, we decline to reduce the forecast capital expenditures for hydrotesting. We do not agree that the absence of pressure test records means PG&E failed to perform prior capital improvements. As PG&E notes, the unpiggable features associated with the test may have been installed after the initial hydrotest.[146] This conclusion is consistent with our determinations in the *PSEP Decision*, which states:

> Certain pipeline segments, for reasons unrelated to PG&E's poor document management, require replacement, rather than just re-testing. PG&E shareholders should be held to their obligation for re-testing costs, but not extended to replacement costs.[147]

Further, we decline to disallow costs associated with hydrotesting the 97 miles of pipe installed on or after July 1, 1961. While it may be true that some of this mileage does not have pressure test records, PG&E has "confirmed its commitment not to charge customers for the costs of testing the post-1961 miles of pipe for which PG&E does not have strength test records."[148] PG&E estimates that it will test an additional 15-30 miles per year of pipe installed after 1961 for which is has no pressure test records. PG&E will not seek recovery for testing these additional miles.[149]

In summary, we reduce PG&E's forecast hydrotest expenses by 19.2%, or $33.402 million, to reflect the 97 miles of pipe installed between January 1, 1956 and June 30, 1961. This results in authorized 2015 expenses of $148.390 million. We adopt PG&E's forecast capital expenditures. PG&E is required to hydrotest

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[146] Exh. PG&E-39 at 4A-54.

[147] *PSEP Decision* at 60.

[148] *PG&E Reply Brief* at 7-24.

[149] Exh. PG&E-39 at 4A-55.

510 miles of pipe during the Rate Case Period. In addition to the 510 miles of pipe forecast by PG&E, PG&E shall test up to 50 miles of pipe installed after 1961 for which it has no pressure test records. Finally, consistent with the *PSEP Decision*, PG&E shall file quarterly compliance reports of its hydrotest work. The reports shall follow the format in Attachment D of the *PSEP Decision*, revised to reflect the projects proposed for the Rate Case Period. PG&E's first compliance filing shall cover the period between January 1, 2015 and the quarter in which this Decision is issued, and shall be due no later than 30 days after the end of the quarter.

6.2.4. Earthquake Fault Crossings Program

6.2.4.1. PG&E's Request

The Earthquake Fault Crossings program addresses the specific threat of land movement strains at known earthquake faults damaging a pipeline due to seismic events and consists of four activities:

1. conducting studies of locations where gas transmission pipelines cross known earthquake fault lines;
2. mitigating fault crossings;
3. establishing a new long-term ongoing monitoring program for fault creep of mitigated crossings; and
4. conducting the engineering necessary to support fault crossing mitigations.[150]

During the Rate Case Period, PG&E proposes to complete 98 studies of the earthquake fault crossings, with studies completed "in the order of highest risk with the focus on population protected as being the initial driver followed by

[150] Exh. PG&E-1 at 4A-44.

level of total risk posed by the fault crossing."[151] The result of the study will then determine the need for mitigation. Based on past experience, PG&E expects that 33% of the fault studies will result in mitigation. However, PG&E proposes to focus on the highest risk mitigations and forecasts nine mitigations during the Rate Case Period.[152]

The forecasted costs for the program are based on "average costs for past studies and mitigation projects for pipe replacement."[153] PG&E's projected expenses and capital expenditures over the Rate Case Period are summarized below.

Table 6[154]

Forecasted Earthquake Fault Crossing Program Expenses and Capital Expenditures
($ Thousands of Nominal Dollars)

	2015	2016	2017
Expenses	$4,494		
Capital Expenditures	$5,442	$5,031	$5,630

6.2.4.2. Intervenors' Response

TURN contends that the pace of work proposed during the Rate Case Period is unreasonable. It notes that between 2008 and 2014, PG&E will have studied 45 fault crossings, an average of six or seven studies per year. However, PG&E now proposes to study 98 fault crossings during the Rate Case Period, an

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151 Exh. PG&E-1 at 4A-46.

152 Exh. PG&E-1 at 4A-46 – 4A-47.

153 Exh. PG&E-1 at 4A-50.

154 Exh. PG&E-1 at 4A-47, Tables 4A-14 and 4A-15.

average of 32 or 33 per year. TURN argues that PG&E has known about the problems of crossing earthquake faults since 1985, and given its prior pace of work, "it appears that much of this necessary work has been deferred to be included in the 2015-2017 rate case years rather than being done on a continuing basis in the past."[155]

Indicated Shippers raises similar arguments. It notes that although PG&E's Earthquake Fault Crossing program was first implemented in 1985, PG&E has only undertaken a total of 21 mitigation projects since then.[156] Indicated Shippers further notes that although industry standards have required pipeline operators to actively mitigate earthquake threats since at least 1996, PG&E did not actively implement mitigation efforts until 2010.[157] Thus, Indicated Shippers concludes "PG&E's proposed acceleration suggests that it has imprudently administered the program in the past. Unless PG&E can provide additional evidence demonstrating that its past actions were reasonable, PG&E's accelerated pace should not be approved."[158]

TURN notes that more than half of the proposed fault studies will be in Class I areas, where the Total Occupancy Count is zero and that PG&E has failed to demonstrate the risk-reduction benefits that justify the incremental burden on ratepayers.[159] It therefore maintains that the pace of work be reduced by 50%, with a corresponding reduction in proposed expenses and capital

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[155] Exh. TURN-1 at 13 (TURN/Berger).

[156] *Indicated Shippers Opening Brief* at 107-108.

[157] *Indicated Shippers Opening Brief* at 109-110.

[158] *Indicated Shippers Opening Brief* at 110.

[159] *TURN Opening Brief* at 107-108.

expenditures.[160] TURN states that this proposed pace of work, which would allow 16 or 17 studies per year "would still allow PG&E to study all of the HCA, Class 3 and Class 2 crossings, as shown in Table 4A-13."[161] TURN further proposes that the proposed budget for capital mitigation projects also be reduced by 50%. It notes, however, that this reduction would still double the pace of mitigation in 2012.[162]

Indicated Shippers further challenges PG&E's cost forecasts. First, it notes that PG&E has front-loaded the study costs for 2015, which results in insufficient funds to conduct the studies contemplated in 2016 and 2017.[163] Indicated Shippers further contends that PG&E's forecast unit cost per study is overstated. It notes that the unit cost is derived from the average of six historical projects, one of which is almost double the cost of the others. Indicated Shippers states that inclusion of this project results in an average project cost of $94,736, while the average excluding this project would be $75,683.[164] Indicated Shippers states that since PG&E did not provide any justification for including this project, the Commission should remove it from the unit cost calculation and adopt a unit cost of $75,683.

Indicated Shippers next argues that PG&E's forecast cost to mitigate earthquake fault crossings erroneously assumes a fixed forecast cost of $1.6 million per site because it does not take into consideration the length of the

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160 *TURN Opening Brief* at 108.

161 *TURN Opening Brief* at 108-109.

162 *TURN Opening Brief* at 109.

163 *Indicated Shippers Opening Brief* at 111.

164 *Indicated Shippers Opening Brief* at 112.

mitigation project or any site characteristics.[165] Indicated Shippers believes the proper method to determine the unit costs is by weighting the historical projects identified by PG&E.

Finally, Indicated Shippers notes that PG&E's approach to expenses for this program only included data from 2012-2013. In contrast, PG&E's historical cost project samples for mitigation projects only included one mitigation project from 2012-2013, with the other projects are taken from 2003-2006. Indicated Shippers notes that PG&E used an annual inflation rate of 4% to convert these recorded project costs into 2013 dollars. However, Indicated Shippers argues that the appropriate way to account for historic inflation is to use the United States Gross Domestic Product Implicit Price Deflater (GDPIPD). Using the GDPIPD, the average annual inflation rate between 2003 and 2013 would be 2.1%. Indicated Shippers therefore proposes that PG&E's mitigation cost proposals be adjusted to reflect this lower inflation percentage.[166]

6.2.4.3. Discussion

PG&E opposes TURN's recommendation. It maintains that although it is proposing to study 98 fault crossings during the Rate Case Period, it is only proposing to mitigate nine crossings during this period, even though it anticipates that at least 33 crossings will need mitigation. Thus, according to PG&E, its risk mitigation period is 10 years.[167] It asserts that adopting TURN's recommendation would double this period to 20 years at a minimum, a pace it

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165 *Indicated Shippers Opening Brief* at 113-114.

166 *Indicated Shippers Opening Brief* at 115.

167 *PG&E Reply Brief* at 7-26.

considers too slow given the risk mitigation benefits of the program. PG&E further notes that it proposes to conduct 44 studies in the test year because these fault crossings were in close proximity to population.[168]

Despite these assertions, however, PG&E fails to explain the urgency to accelerate the pace of studying fault crossings at this time, especially since the mitigations would occur over a longer period of time. Further, there is no explanation of the benefits to conduct fault crossing studies now, when the actual mitigation work may not be performed for almost 10 years. One would suspect that at the time of mitigation, PG&E would need to update or refresh these studies – thus bringing to question any benefits to ratepayers for conducting the studies so early. We therefore agree with TURN that the pace of work should be slowed so that it more closely matches the mitigations that would be performed.

PG&E has proposed nine mitigations during the Rate Case Period, stating: "The rate of risk-based mitigation will be balanced with system constraints such that the resulting outages do not overly strain gas supplies."[169] We believe this is a reasonable pace, and decline to decrease the number of mitigations as proposed by TURN. In this manner, even with studies performed at a slower pace, PG&E would still be able to perform all mitigation work over its projected 10-year period.

We are not persuaded by Indicated Shippers arguments that the forecast unit cost per fault crossing study should be reduced. While it is true one fault crossing study costs more than the others, Indicated Shippers has not provided

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[168] *PG&E Reply Brief* at 7-26 – 7-27.

[169] Exh. PG&E-1 at 4A-47.

any reasons to support excluding this study, other than to point at the cost. A further examination of the projects used to calculate the average fault crossing study cost shows that four of the projects included multiple crossings, while the $190,000 "outlier" identified by Indicated Shippers consisted of only one crossing.[170] Although this "outlier" is comparable to the other projects on a total project cost basis, PG&E's methodology for calculating unit cost has caused it to be higher on an average fault crossing study basis. This alone is not enough to conclude that inclusion of this fault crossing study cost is unreasonable. We therefore decline to adjust PG&E's forecast unit cost.

We further decline to adopt Indicated Shippers' proposal to determine the unit costs for mitigation by weighting the historical project costs. We are persuaded by PG&E's argument that the unit cost should not be based on the length of the project since no two fault crossing mitigation projects are exactly the same. We further find that forecasting mitigation costs on a per project basis is reasonable, even though PG&E has not identified the location of the mitigation project nor the site specifics. As noted by PG&E, the "earthquake fault crossing program first assesses the condition of the crossing and then engineers and implements a detailed mitigation plan."[171]

Nonetheless, we agree with Indicated Shippers that the project cost should be adjusted to reflect the average annual inflation rate between 2003 and 2013. Although PG&E had conducted ten mitigation projects between 2010-2013, only data from one project was used in its cost calculator. The four other projects

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[170] Exh. PG&E-4 at WP 4A-24.

[171] *PG&E Reply Brief* at 7-28.

used in the cost calculator were from 2003-2006.[172] As Indicated Shippers notes, the 4% assumed annual inflation rate used by PG&E is almost double the GDPIPD rate of 2.1%. PG&E provides no explanation why a higher inflation rate is warranted. While we do not question PG&E's decision to rely on older data in its forecast, PG&E should not use this as an opportunity to benefit from the use of older data, when more recent historical data is available. Therefore, we adopt Indicated Shippers' proposal and adjust PG&E's annual inflation rate to 2.1%. This adjustment thus decreases PG&E's forecast unit cost from $1.6 million per site to $1.5 million per site. Based on the forecast nine mitigations, PG&E's authorized 2015 capital expenditures are $5.121 million.

Further, as discussed above, we adopt TURN's recommendation and reduce the number of studies from 98 to 49, but make no change to the cost per study. This will result in 2015 authorized expenses of $2.590 million

6.2.5. Vintage Pipe Replacement Program

6.2.5.1. PG&E's Request

PG&E defines "vintage pipe" as "pipe manufactured or constructed and fabricated using certain historic practices that are no longer being used today."[173] The Vintage Pipe Replacement (VPR) Program seeks to remove vintage pipe that is not readily assessed using ILI or hydrostatic testing in locations in which those construction defects interact with land movement. The program will also provide "an 'on ramp' to add segments into the program for pipe to be replaced

[172] Exh. PG&E-5 at WP 4A-484.

[173] Exh. PG&E-1 at 4A-51.

when [PG&E] determine[s] it is impractical to strength test that segment and the segment would be better suited for pipe replacement."[174]

PG&E notes that it did not forecast a VPR Program in Gas Accord V.[175] PG&E seeks to replace approximately 370 miles of vintage pipe by the end of 2025. PG&E notes that this will include "those pipe segments subjected to a pressure test but not replaced during PSEP", as assessing the pipeline's integrity at the time of the pressure test did not include assessment of interacting threats.[176]

For the Rate Case Period, PG&E expects to replace 60 miles of vintage pipe, focusing on the areas with the greatest population density.[177] The number of miles actually mitigated may be more or less than the targeted mileage, but PG&E "will use the revenues authorized to continue to reduce risk posed by the threat of construction defects interacting with land movement."[178] The costs to replace vintage pipe are "based on unit costs for varying diameters of pipe and historical costs for those various diameters of pipe during PSEP pipe replacement projects."[179] PG&E's forecast is based on nine PSEP projects. The unit cost for each of the three diameters of pipe is as follows:

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[174] Exh. PG&E-5 at WP 4A-710.

[175] Exh. PG&E-1 at 4A-56.

[176] Exh. PG&E-1 at 4A-57.

[177] Exh. PG&E-1 at 4A-55.

[178] Exh. PG&E-1 at 4A-59.

[179] Exh. PG&E-1 at 4A-58.

Table 7
Unit Cost Analysis[180]

Diameter	Number of Projects	$/mile based on PSEP actuals and forecast 2012 & 2013 (x $1,000)
24-30″ – Highly congested SF Peninsula/San Jose	4	$13,200
12-16″ – Congested Sacramento	4	$5,808
<12″ – Congested	1	$5,280

PG&E's projected capital expenditures over the Rate Case Period are summarized below.

Table 8[181]
Forecast Vintage Pipe Replacement Program Capital Expenditures
($ Thousands of Nominal Dollars)

	2015	2016	2017
Capital Expenditures	$193,624	$198,715	$203,968

6.2.5.2. Intervenors' Response

TURN, ORA and Indicated Shippers oppose PG&E's request. All three challenge PG&E's methodology for deriving unit costs. While TURN and ORA propose reductions to the forecast capital expenditures, Indicated Shippers proposes deferring recovery of PG&E's capital expenditures until PG&E can

[180] Exh. PG&E-5 at WP 4A-722.

[181] Exh. PG&E-1 at 4A-55, Table 4A-16.

justify its proposal.[182] Additionally, Indicated Shippers challenges PG&E's proposed pace of work and recommends that the Commission order PG&E to identify an optimal pace for this program "using a valid risk management analytical model."[183]

ORA provides the most detailed analysis of PG&E's forecast. It notes that that although PG&E claimed that the nine selected projects are similar in congestion and project length to the VPR work to be performed during the Rate Case Period, PG&E was unable to provide any discernable selection criteria for its choice of projects.[184] While ORA does not dispute the general concept that shorter average project lengths increase program fixed costs, its analysis found that the differences between the PSEP and VPR average project lengths did not result in significant cost increases because:

1. The fixed costs per project would only add $7.4 million to the total VPR program cost of $596.5 million.
2. Based on PG&E's PSEP forecast cost data, for pipe replacement projects longer than 500 feet, the variable costs per foot are a driving factor in total project cost.[185]

According to ORA, "for pipeline replacement projects, project length has minimal impact on project unit costs, except for projects shorter than 500 feet."[186] ORA notes that PG&E's workpapers indicate that less than 10% of the VPR

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[182] *Indicated Shippers Opening Brief* at 142-143.

[183] *Indicated Shippers Opening Brief* at 145.

[184] *ORA Opening Brief* at 72.

[185] *ORA Opening Brief* at 83-84.

[186] *ORA Opening Brief* at 86.

projects planned during the Rate Case Period are shorter than 500 feet, as compared to 50% of the planned PSEP projects. Consequently, ORA argues that the impact of shorter project lengths on the unit cost will be small. TURN supports ORA's position.[187]

Indicated Shippers supplements ORA's arguments, noting that PG&E's updated pipeline segment replacement cost data shows that there is "no statistically significant relationship between project length and average cost."[188]

ORA next disputes PG&E's decision to only use the unit costs projects located in congested areas as the basis for the forecast. ORA presents seven reasons why PG&E's justification to rely only on "congested" areas fails.[189] Among its arguments, ORA notes that projects in the VPR Program are based on pipe characteristics and disposition for land movement, not population. However, it is not evident that that these projects will be located in more densely populated areas than the PSEP projects. Further, ORA states that over the course of the Rate Case Period, the VPR Program will implement projects in less populated locations.[190] Finally, ORA challenges PG&E's definition of "congestion", which includes "complexities based on the location of the pipe."[191] However, ORA notes, the VPR projects are located throughout the state, and

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[187] *TURN Opening Brief* at 122.

[188] *Indicated Shippers Opening Brief* at 140; *see* also, *Indicated Shippers Opening* Brief at 142, Figure 1.

[189] *ORA Opening Brief* at 87-94.

[190] *ORA Opening Brief* at 92; *see* also, Figure 7.6-2.

[191] *ORA Opening Brief* at 93.

PG&E has not provided evidence that costs in one municipality are higher than another.

Similarly, TURN argues that PG&E's claims that the complexity of working in congested areas on the Peninsula reflects the conditions of the planned VPR work is not supported by the 2015-2017 VPR projects.

> A close inspection of the project map shows that at least 22 of the 81 VPR projects for 2015-2017 are located north of Vallejo, along the corridor from Petaluma to Fairfield, or east of Concord. The complete list of project locations further shows that about 36 of the 52 large pipeline projects are located in the greater San Francisco Bay area, including many in unincorporated Santa Clara and San Mateo. Of the 15.50 miles of large diameter pipeline scheduled for replacement in 2015, about 5.76 miles are located outside the San Francisco Bay Area, in San Bernardino, Alameda and Contra Costa counties. Of the 22.38 miles of large diameter pipeline scheduled for replacement in 2016-2017, about 18.23 miles are on Line 300.[192]

ORA and TURN next accuse PG&E of cherry-picking the PSEP projects used as the basis for the VPR Program. Among other things, both note that PG&E's forecast is based on only nine PSEP pipeline replacement projects.[193] Consequently, as observed by ORA,

> Unit costs for small diameter pipes were calculated based on only one project; unit costs for medium diameter pipes were calculated based on four projects; and unit costs for large diameter pipes were calculated based on four projects, but all of those projects were located on Line 109.[194]

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[192] *TURN Opening Brief* at 120 (citations omitted).

[193] *ORA Opening Brief* at 66; *TURN Opening Brief* at 110.

[194] *ORA Opening Brief* at 71.

As argued by Indicated Shippers, "The sample size of the three pipe diameter categories is too small to be statistically relevant, especially when viewed in the context of the roughly 75 segment replacements in the PSEP and a forecast of 874 segments in the VPR."[195]

ORA recommends that the VPR program forecast include the 13 PSEP small diameter (under 12") projects completed in 2012-2013, the 10 PSEP medium diameter (12"-20") projects and the 19 PSEP large diameter (over 20") projects.[196] ORA notes that its forecast is based on the following:

1. All 2012 and 2013 completed PSEP replacement projects, with project costs and mileage data obtained from the PSEP Quarterly Compliance Reports.[197]
2. Betterment costs are excluded, as PG&E has separately requested $21.7 million for betterment projects.[198]
3. The forecast for 2015 VPR unit costs does not escalate the 2012 and 2013 PSEP costs. ORA argues that due to the lower pace of work, increased cost efficiencies and the increasing number of projects that will occur in increasingly less congested locations, VPR costs should not increase during the Rate Case Period.[199]

ORA's forecast 2015 VPR Program costs, as compared to PG&E's forecast, are summarized in the table below:

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[195] *Indicated Shippers Opening Brief* at 131-132.

[196] Exh. ORA-131; *see* also, *ORA Opening Brief* at 73-77.

[197] *ORA Opening Brief* at 104.

[198] *ORA Opening Brief* at 105.

[199] *ORA Opening Brief* at 105-107.

Table 9
Comparison of PG&E and ORA Forecasts[200]

	PG&E GT&S Application		ORA Recommendation	
Diameter Range (Inch)	Number of Projects	Unit Cost (M$/mi)	Number of Projects	Unit Cost (M$/mi)
< 12	1	$5.3	13	$3.9
12 to 20	4	$5.8	10	$3.9
≥ 24	4	$13.2	19	$7.2

ORA notes that the most significant difference between PG&E's forecast and ORA's forecast is the unit cost for large diameter pipe. ORA maintains that its forecast, which includes projects in both "congested" and "rural" locations is more representative of the VPR projects. It contends "less than half of the 27 currently proposed large diameter [VPR] projects will be located in the San Francisco Peninsula region, so it is unreasonable to apply the unit costs from this high cost region to all 27 proposed projects to be performed across PG&E's service territory."[201] In particular, ORA notes that projects on Line 109 and Line 101 include an adder of $200 per foot to reflect the working on the San Francisco Peninsula region.

TURN echoes ORA's criticism that the much higher unit cost for large pipelines are based entirely on only four PSEP projects.[202] It notes that the selected projects are all high cost projects, due to congestion and short segments.

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[200] Exh. ORA-131.

[201] *ORA Opening Brief* at 77.

[202] *TURN Opening Brief* at 114.

TURN contends that these projects are not reflective of the projects proposed during the Rate Case Period. For example, TURN notes that the cost for large diameter pipe is based entirely on Line 109, "a large diameter pipeline located exclusively on the San Francisco peninsula."[203] However, of the 13 identified projects on Line 300 during the Rate Case Period, nine are located south of San Jose and "at least five of the projects do not appear to be located near any population centers, whether cities or town or suburbs."[204]

TURN further notes that PG&E's Capacity Projects Program forecasts costs for pipe replacements and for new pipe "based on either historical costs or detailed engineering estimates."[205] One of the main projects is the construction of Line 407, a new 25.5 mile 30-inch pipeline. TURN notes that, based on the detailed engineering and vendor quotes obtained in 2013, the unit cost of Line 407 is approximately $6.74 million per mile, or about half the forecast $13.2 million per mile forecast for large diameter pipeline in the VPR.[206] Further, TURN states that Line 407 extends from Yolo to Roseville, through terrain that is more populated than the terrain traversed by Line 300 before it reaches the Bay Area. As such, TURN argues that there is no rational why the unit cost for Line 300 projects and other VPR pipeline projects located outside of the immediate Bay Area should be twice the cost of the Line 407 project.[207] Accordingly, TURN recommends that the Commission adopt ORA's unit cost

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[203] *TURN Opening Brief* at 114.

[204] *TURN Opening Brief* at 118.

[205] *TURN Opening Brief* at 128.

[206] *TURN Opening Brief* at 129.

[207] *TURN Opening Brief* at 129.

forecast of $7.2 million per mile for all VPR projects on pipelines that are greater than or equal to 24 inches in diameter.[208] At a minimum, TURN states that the Commission should apply ORA's unit cost to the Line 300 projects.[209]

Finally, TURN argues that while PG&E did not include an explicit contingency in its VPR forecast, the forecast includes a built-in contingency based on PG&E's statement that its top-down forecasting approach builds variability into the unit cost "to make sure there's enough dollars in the program to properly deal with that variability."[210] Similarly, ORA maintains that contrary to PG&E's claims, the VPR Program forecast was "developed through a 'top-down' process where PG&E determined the revenue requirement it hoped to achieve, and then identified the PSEP projects and unit prices necessary to get there."[211] Thus ORA also concludes that PG&E's forecast include an implicit contingency provision.[212]

Indicated Shippers supports ORA's analysis. Additionally, it sharply criticizes PG&E's development of the VPR Program, stating that PG&E's risk assessment is not pipe-segment specific and fails to take likelihood of failure into consideration when ranking pipelines according to risk.[213] Consequently, Indicated Shippers asserts that PG&E's proposed pace of work cannot be risk-

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[208] *TURN Opening Brief* at 130.

[209] *TURN Opening Brief* at 128 and 130.

[210] *TURN Opening Brief* at 124.

[211] *ORA Opening Brief* at 100.

[212] *ORA Opening Brief* at 101.

[213] *Indicated Shippers Opening Brief* at 123-124.

based and that PG&E's representations that it aims for 90% coverage in 2017 is erroneous.[214]

6.2.5.3. Discussion

The reasonableness of PG&E's VPR Program hinges on whether PG&E's use of nine projects to determine forecast unit costs is reasonable. PG&E argues that its selection of these nine projects reflects a level of precision, as the projects have similar characteristics to the projects expected to be performed during the Rate Case Period. Yet at the same time, PG&E states that the list of projects may grow and further prioritization of projects will be necessary.[215] We find it troubling that such a small sample size was used as the basis for the forecast of this program, especially when the characteristics considered in the selection of the projects to be used are so broad. As explained by PG&E's witness, the projects were selected because:

> these projects represented areas of congested work, which would be representative of the projects PG&E expects to complete in the Vintage Pipeline Replacement Program during the rate case period. Second, these projects represented the diameter ranges (<12 inch, 12 inch to 24 inch, and >24 inch) that were representative of the segments of pipe in the Vintage Pipeline Replacement Program.[216]

We find that the first criteria, location of pipe, would be a reasonable basis to select projects to be included in the forecast if all the projects during the Rate Case Period were in similar locations. However, as Intervenors note, PG&E's large diameter pipe forecast is based on four projects on Line 109, while half of

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[214] *Indicated Shippers Opening Brief* at 128.

[215] Exh. PG&E-1 at 4A-58 -4A-59.

[216] Exh. PG&E-39 at 4A-71.

the expected large diameter pipe projects are outside of the San Francisco Bay Area. PG&E's assertion that Line 109 is representative of all expected VPR projects is unconvincing. We further note that PG&E's definition of "congested" has changed over the course of the Rate Case Period. As defined by PG&E, "congested" locations are

> heavily residential and/or commercial. In these areas, the pipeline is generally laid under existing streets, parking lots, and utility corridors. PG&E anticipates significant road reconstruction, many road bores, and select Horizontal Directional Drillings (HDDs), as a result.
>
> The definition of "congested" also includes areas that are typically suburban communities, large property parcels, or small towns where the pipeline is generally located within existing easements adjacent to a road or utility corridor such that road repair, road bores and HDDs will be required. For ≥24 inch pipe diameters, it also includes representative pipelines that have high complexity to complete.[217]

Based on this data response, it appears that PG&E has broadly defined "congestion" to the point that pipeline projects located in rural areas should have also been included in the forecast. However, none of the selected projects are in rural locations.

PG&E's second articulated criterion, pipe diameter size, does not appear to be a screen for selecting projects, but rather the method for grouping costs. Although all the PSEP projects would fall into one of three pipe diameter sizes, it is unclear how this criterion, combined with "congested" pipelines, would result in such a small number of projects to be evaluated. This is especially of concern for small diameter pipe, where only one of 13 projects was used as the basis for

[217] Exh. ORA-123, Data Response ORA_127-01Rev01, Answer 1(c).

the unit cost forecast. As ORA states, "basing a forecast on a single data point is fundamentally a bad practice, unless the exclusion of other projects can be justified."[218]

Finally, we note that PG&E's workpapers state:

> PG&E has identified approximately 630 miles of its natural gas transmission pipeline system with characteristics that make it more susceptible to certain construction threat features. This includes pipe that is constructed with wrinkle bends, coupled pipe (mechanical/compression couplings or "dresser couplings"), and miter bends as well as other non-standard fittings like orange peel reducers, chill ring welds, bell and spigot joints, or pipe that was constructed with acetylene girth welding process.[219]

Despite identifying this construction characteristic, we find it surprising that PG&E does not appear to consider it as a criterion for identifying PSEP projects with similar characteristics to the expected VPR projects.

PG&E further argues that higher unit costs are warranted due to the length of the pipeline projects. While we generally agree with PG&E's proposition that projects with shorter pipe segments will increase unit costs because fixed costs will be spread over fewer miles in the unit cost calculation, we are not persuaded that the shorter pipe segments associated with the VPR projects would result in unit prices per mile that are double that of PSEP projects. As highlighted in ORA's analysis, the degree of the impact of shorter pipeline projects is only significant for projects under 500 feet in length. PG&E has offered no persuasive arguments to refute this analysis.

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[218] *ORA Opening Brief* at 73.

[219] Exh. PG&E-39 at WP 4A-709.

While PG&E argues that the VPR Program should be evaluated on a programmatic level, we find that it is unreasonable to adopt a forecast based on nine PSEP projects, especially when it appears that a larger number of PSEP projects would have met the selection criteria. We find that PG&E's selection of a small number of projects in congested areas has resulted in unit costs that are not representative of the work to be performed in the VPR Program during the Rate Case Period. Indeed, PG&E's inclusion of six more projects in its Rebuttal Testimony further supports our conclusion that PG&E had not included all eligible projects in its forecast.

In Exhibit ORA-131, ORA identified overlapping (common) projects used by both PG&E and ORA in their analyses. The number of common projects, by pipe size are: 11 common projects for small diameter pipe, 8 common projects for medium diameter pipe, and 10 common projects for large diameter pipe. We believe that using all common projects will result in unit costs that are more representative of the work to be performed during the Rate Case Period.

We also agree with ORA's argument that any betterment costs included in the PSEP project costs should be removed from the forecast. As noted by ORA, PG&E has separately requested funding for betterment projects as part of its forecast for Gas System Operations, Capacity Projects. PG&E describes the betterment projects as the incremental costs associated with "installing larger-diameter or longer pipe in certain circumstances when replacing vintage pipe in anticipation of load growth or to gain system efficiencies."[220] As such, the forecast for the VPR Program shall exclude betterment costs. Based on

[220] Exh. PG&E-2 at 10-4.

Exhibit ORA-131, the unit costs per mile for the common projects, excluding betterment, are:

- Small Diameter (<12″) - $4.51 million
- Medium Diameter (12″ – 20″) - $3.67 million
- Large Diameter (≥ 24) - $12.3 million

In analyzing the unit costs for medium and large diameter pipe, we note a discrepancy in PG&E's workpapers. PG&E's Unit Cost Analysis identifies Medium Diameter Pipe as pipe between 12″ – 20″ and Large Diameter Pipe as pipe 24″ or greater.[221] However, the Cost Calculator considers Medium Diameter Pipe as pipe between 12″ and 24″ and Large Diameter Pipe as pipe greater than 24″.[222] Given this discrepancy and the large number of projects during the Rate Case Period that involve 24″ pipe, we are concerned that if separate unit costs were adopted for Medium Diameter and Large Diameter pipe, the costs would not properly reflect the work to be performed. Accordingly, we average the unit costs for Medium Diameter and Large Diameter pipe and adopt a unit price for all pipe 12″ or greater. We therefore adopt the following unit costs:

- Pipe with Diameter <12″ - $4.51 million per mile
- Pipe with Diameter 12″ or greater - $7.985 million per mile[223]

We find that the unit costs adopted above reflect unit costs that are representative of the work to be performed.

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[221] *See*, Exh. PG&E-5 at WP 4A-722.

[222] *See*, Exh. PG&E-5 at WP 4A-711 – 4A-720.

[223] This number is the simple average of the unit costs for Medium Diameter Pipe and Large Diameter Pipe ($3.67 million + $12.3 million/2 = $7.985 million).

Finally, we revise the escalation rate to be applied to the adopted unit costs. PG&E used a 7% escalation rate, which assumed all PSEP costs were incurred in 2012. We find that this amount is too high. In contrast, ORA has not provided for any escalation of 2012 and 2014 PSEP costs, arguing that there were "counteracting trends that should have reduced projects cost during PSEP."[224] It further asserts that absent any counteracting trends that would reduce project costs, the escalation should be approximately 4.4%. We find no evidence in the record to support ORA's conclusion project costs would have decreased during PSEP. We therefore adopt the 4.4% escalation rate identified by ORA, which "assumes annual inflation of 1.75%, the mid-point between 1.6% and 1.9% above, and that 50 % of projects were completed in 2012 and 2013, and escalated 5.34% and 3.53% respectively."[225]

Based on the above, we reduce PG&E's forecast capital expenditures to replace 60 miles of vintage pipeline for the VPR Program by $29.288 million. This results in 2015 capital expenditures of $164.534 million.

6.2.6. Geo-Hazard Threat Identification and Mitigation Program

6.2.6.1. PG&E's Request

The Geo-Hazard Threat Identification and Mitigation program is a complementary program to the Vintage Pipeline Replacement program. It is intended to "refine data about land movement that will help [the Vintage Pipeline Replacement program] more effectively address the interactive threats

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[224] *ORA Opening Brief* at 106.

[225] *ORA Opening Brief* at 106, fn. 427.

created by land movement."[226] Although both programs address the same interactive threat, this program does not consider the nature of the pipe as a factor.[227] Rather, this program will compile an inventory of site-specific slow moving geo-hazards, such as soil creep, which will improve the accuracy of the VPR Program over time.

During the Rate Case Period, the work to be completed "involves risk assessment of geo-hazard sites, prioritizing the sites for mitigation and/or monitoring activities depending on the circumstances for each site, and performing the mitigation/monitoring work."[228]

Site mitigation forecasts are based on actual costs for four landslide mitigation projects performed by PG&E during 1998-2013, with five sites to be mitigated during the Rate Case Period. Site monitoring forecasts assume ten sites will be monitored in 2015, at an annual cost of $20,000 per site. PG&E's projected expenses and capital expenditures over the Rate Case Period are summarized below.

Table 10[229]

Forecasted Geo-Hazard Threat Identification and Mitigation Program Expenses and Capital Expenditures ($ Thousands of Nominal Dollars)

	2015	2016	2017
Expenses	$211		
Capital Expenditures	$8,007	$8,209	$8,426

[226] Exh. PG&E-1 at 4A-59.

[227] Exh. PG&E-1 at 4A-60.

[228] *PG&E Opening Brief* at 7-48.

[229] Exh. PG&E-1 at 4A-61 – 4A-62, Tables 4A-17 and 4A-18.

6.2.6.2. Intervenors' Response

Indicated Shippers contends that although PG&E's testimony identifies a range of mitigation options, its forecast mitigation costs are based solely on the costs of pipe replacement.[230] Further, Indicated Shippers notes that although there is a "clear linkage" between this program and the VPR Program, "PG&E has made no adjustments to either forecast to account for the overlap," thus allowing PG&E to over-recover costs.[231] Indicated Shippers further argues that PG&E's average cost per project is overstated because it uses an assumed 3% annual inflation adjustment to convert actual 1998-2013 project costs to 2013$ rather than the 2.1% GDPIPD. Moreover, Indicated Shippers maintains that PG&E's cost per project has not taken into account other characteristics that will impact replacement costs, such as the degree of congestion and pipe diameter.[232]

Based on these considerations, Indicated Shippers recommends that the Commission defer recovery on any capital costs until PG&E explains the overlap between this program and the VPR Program. Alternatively, Indicated Shippers recommends that the cost per project be reduced to $1.373 million, and that PG&E only recover costs for 2.5 projects per year.[233]

6.2.6.3. Discussion

We do not find any overlap between the Geo-Hazard Threat Identification and Mitigation program and the VPR program. As noted by PG&E, this

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[230] *Indicated Shippers Opening Brief* at 147.

[231] *Indicated Shippers Opening Brief* at 149.

[232] *Indicated Shippers Opening Brief* at 150.

[233] *Indicated Shippers Opening Brief* at 150.

program is not focused on replacing vintage pipe, but rather identifying and mitigating threats to pipeline, regardless of vintage, caused by the risk associated with the Weather Related Outside Force (WROF) threat, such as seismic activity. Given the complementary nature of this program with the VPR Program, we reject Indicated Shippers' recommendation that recovery of capital costs be deferred.

We do, however, agree with Indicated Shippers that PG&E's per project cost should be adjusted to reflect a 2.1% GDPIPD inflation rate. PG&E has not provided any explanation to justify its 3% annual inflation rate, especially since it had utilized a different annual inflation rate for the Earthquake Fault Crossings program. We reject Indicated Shippers' recommendation to revise the average cost per project to $1.37 million per project and to allow PG&E to recover costs for 2.5 projects per year.

Based on the adjusted annual inflation rate, PG&E's per project cost is reduced to $1.4 million per year, resulting in forecast 2015 capital expenditures of $7.469 million. We adopt PG&E's forecast 2015 expenses of $210,518.

6.2.7. Programs to Enhance Integrity Management

PG&E proposes the following programs to enhance its Integrity Management Program: 1) Root Cause Analysis program and 2) Risk Analysis Process Improvement program. PG&E states that root cause analysis is required under state and federal pipeline safety regulations. PG&E seeks to enhance its Root Cause Analysis program to include a deeper investigation of incidents. Further, it proposes to institute further risk analysis process improvements in

response to NTSB and Independent Review Panel findings.[234] PG&E forecasts 2015 expenses of $1.052 million for Root Cause Analysis and $6.263 million for Risk Analysis Process Improvement.

PG&E's request is unopposed. We find the amount reasonable and adopt PG&E's forecast expenses for this program.

6.3. Emergency Response Programs

6.3.1. Valve Automation Program

PG&E seeks recovery of costs associated with the second phase of its Gas Transmission Valve Automation Program.[235] The purpose of the program is to enhance emergency response in the event of a gas transmission pipeline rupture by replacing, automating and upgrading gas shut-off valves. During the Rate Case Period, PG&E proposes to automate an additional 120 isolation valves at 60 individual sites.[236] The valves would be on larger diameter high pressure gas transmission pipelines located primarily within Class 3 HCA and Class 3 non-HCA areas."[237]

PG&E forecasts the costs per valve to be $1.34 million, compared to $0.58 million per valve for the first phase authorized in the *PSEP Decision*. PG&E states that this increased unit cost is due to lower economies of scale due to fewer valves to be automated; a greater percentage of valves requiring vaults; increased number of new valves and new valve sites; more valve sites requiring electrical

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[234] Exh. PG&E-1 at 4A-63 – 4A-65.

[235] Exh. PG&E-1 at 4A-72. The first phase was approved in the *PSEP Decision*.

[236] Exh. PG&E-1 at 4A-69.

[237] Exh. PG&E-1 at 4A-61.

power and new SCADA communications; and more work associated with the installation of new valves due to the location of the new valves.[238]

PG&E's forecast capital expenditures over the Rate Case Period are summarized below.

Table 11[239]
Forecast Valve Automation Program Capital Expenditures
($ Thousands of Nominal Dollars)

	2015	2016	2017
Capital Expenditures	$52,502	$55,772	$44,181

PG&E's request is unopposed. We find the amount reasonable and adopt PG&E's forecast capital expenditures for this program.

6.3.2. Public Awareness Program

PG&E's Public Awareness program is implemented pursuant to 49 CFR 192.616(a)-(i) and the American Petroleum Institute's Recommended Practice 1162 1st Edition.[240] The purpose of the program is to increase public awareness of the presence and purpose of PG&E's natural gas transmission pipelines and programs; reduce third-party damage to pipelines through educational outreach; provide information to ensure emergency response readiness; and provide outreach to enhance emergency official response readiness.[241] Further, following the San Bruno explosion and fire and at the request of U.S. Representative Jackie Speier, PG&E will send letters to home

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[238] Exh. PG&E-1 at 4A-74 – 4A-75.

[239] Exh. PG&E-1 at 4A-47, Tables 4A-14 and 4A-15.

[240] *PG&E Opening Brief* at 7-51.

[241] Exh. PG&E-1 at 4A-75.

owners and businesses within 2,000 feet of PG&E's transmission pipelines every three years.[242]

In order to reach these larges groups, PG&E forecasts $4.344 million in 2015 to implement this program. PG&E states that this forecast is based on its "historical costs for the multiple communications streams and outreach methods used in this program, including mailings, public meetings and appearances, and outreach to special stakeholders such as police, firefighters, and excavators."[243]

ORA opposes PG&E's forecast, noting that the proposed request "represents a 235% increase over 2013 recorded expenses."[244] ORA believes PG&E's forecast for public awareness is overly aggressive and notes the variability of spending in the past. It questions PG&E's statement that the forecast was based on historical costs for each component of the Public Awareness Program, as PG&E's response to an ORA data request stated that PG&E "has not tracked the costs for each component of the Public Awareness Program historically, and is only providing the total program costs for each year."[245] Based on PG&E's response, ORA calculates that in 2009-2010 PG&E had spent an average of $0.6 million on Public Awareness activities pursuant to the Federal Regulations, a spending level significantly below 2011-2013.[246]

Based on the variability in spending levels on this program, and ORA's belief that the information letters are the result of PG&E's past imprudent

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[242] Exh. PG&E-1 at 4A-75; *PG&E Opening Brief* at 7-51.

[243] Exh. PG&E-1 at 4A-77.

[244] *ORA Opening Brief* at 123.

[245] Exh. ORA-38 at 6.

[246] Exh. ORA-38 at 8, Table 04E-6.

actions, ORA recommends that the 2015 forecast be $2.6 million, which represents a three year average of expenses, less the costs of sending informational letters to homeowners and businesses.[247]

Although it is not unexpected that PG&E's spending on its Public Awareness Program increased after 2011, PG&E's 2009-2010 spending level suggests that prior to the San Bruno explosion and fire, its Public Awareness program only met the minimum Federal requirements. PG&E's increased spending would imply that it will now be exceeding the minimum Federal requirements. Despite PG&E's testimony that it developed its 2015 forecast based on the costs for the various communication streams and outreach methods, PG&E has not provided any detail of the amount spent for each component. As such, with the exception of approximately $5.3 million to be spent in 2017 for the informational letters, it is unknown what other work will be performed. It is further unknown whether any portion of the work performed between 2011-2014 represented one-time expenses, or whether there will be future efficiencies in sending out the informational letters. Notwithstanding PG&E's commitment to send out informational letters every three years, we cannot agree that PG&E's forecast is reasonable. By spreading out the cost for these letters over the Rate Case Period, PG&E masks the actual costs for this program.[248]

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[247] *ORA Opening Brief* at 124; Exh. ORA-38 at 9-10.

[248] PG&E's Rebuttal Testimony further calls to question the amount to be spent on activities in this program other than the informational letters, as it would not contest using the amounts in ORA Table 04E-6 (Exh. ORA-38) to calculate the three-year average if the $5 million for informational letters were included. Under this calculation, PG&E's 2015 forecast would be $4.227 million. (Exh. PG&E-39 at 4A-93 – 4A-94.)

PG&E's recorded and forecast expenses between 2012-2014 are summarized below:

Table 12
Public Awareness Program
Summary of Expenses[249]

2012	$3.769 million (recorded)
2013	$3.762 million (forecast)
2014	$8.444 million (forecast)

Based on PG&E's commitment to Congresswoman Speier, the 2014 forecast would include approximately $5.3 million for mailing the informational letters. If this amount were to be removed, the 2014 forecast for Public Awareness activities would be approximately $3.144 million. This would result in an average spending level of $3.558 million over the three-year period. Thus, we reduce PG&E's 2015 expenses for this program to $3.558 million.

6.3.3. Inoperable and Hard-to-Operate Valves Program

To mitigate the threat of inadequate emergency response, this program replaces inoperable and hard-to-operate valves. Since 2009, "PG&E initiated more robust valve maintenance procedures in order to reduce or eliminate future incidents of inoperable or hard-to-operate valves."[250] PG&E contends that mitigation of hard-to-operate valves "will prevent valves from becoming inoperable, and therefore ensure emergency valves are always available for use in an emergency."[251] Additionally, PG&E maintains that this approach will

[249] Exh. PG&E-1 at 4A-77, Table 4A-25.

[250] Exh. PG&E-1 at 4A-79.

[251] Exh. PG&E-1 at 4A-81.

reduce cost, as it can schedule resources and have adequate time to procure material on a non-emergency basis.

PG&E forecasts replacing approximately 99 inoperable or hard-to-operate valves during the Rate Case Period, or 33 valves each year. Replacement work is prioritized based on the population surrounding the values, with the highest priority given to valves located in HCAs and Class Locations 3 or 4.[252]

Costs for this program are to address identified inoperable and hard-to – operate valves.[253] PG&E bases its forecast on "unit costs for historical inoperable and hard-to-operate valves."[254] PG&E's projected expenses and capital expenditures over the Rate Case Period are summarized below.

Table 13[255]

Forecast Inoperable and Hard-to-Operate Valves Expenses and Capital Expenditures ($ Thousands of Nominal Dollars)

	2015	2016	2017
Expenses	$242		
Capital Expenditures	$7,067	$7,250	$7,871

ORA notes that PG&E's capital expenditures "jumps from a negative capital expenditure requirement in 2013 to $3.7 million in 2014 and $7.1 million in 2015 because of the inclusion of valves that do not require immediate

[252] Exh. PG&E-1 at 4A-79.

[253] *PG&E Opening Brief* at 7-52. The valves are identified as part of PG&E's annual inspections. The costs for inspections are part of PG&E's forecast for Operations and Maintenance.

[254] Exh. PG&E-1 at 4A-82.

[255] Exh. PG&E-1 at 4A-80 – 4A-81, Tables 4A-27 and 4A-28.

replacement."[256] It contends that "any valve PG&E considers being on the verge of becoming inoperable should be repaired under routine maintenance and not included in this program."[257] ORA states that based on PG&E's actual recorded capital expenditures from 2009 to 2013, PG&E's average annual expenditure is $4.029 million.[258] It therefore recommends that the $4.029 million be used as the test year capital expenditures.[259]

PG&E disagrees with ORA's proposal, noting that in 2013, it had changed its definition of inoperable valve to include "valves have become so difficult to operate that the best option becomes a capital valve replacement."[260] Due to this changed definition, PG&E argues that the costs for 2009-2012 are not representative. Rather, PG&E maintains that 2013 and 2014 costs are representative of the new definition and contends that ORA's recommendation should be rejected.

We agree with PG&E that this program should look at not only inoperable valves, but also hard-to-operate valves that are trending to becoming inoperable. As PG&E notes "implementation of this program will significantly reduce the number of inoperable valves discovered over time and thereby increase effectiveness of pipeline isolation in the event of an emergency."[261] Due to PG&E's expansion of the program we find the forecast to be reasonable and

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[256] Exh. ORA-4 at 4 (ORA/Lee).

[257] *ORA Opening Brief* at 124.

[258] Exh. ORA-4 at 4 (ORA/Lee).

[259] *ORA Opening Brief* at 124; Exh. ORA-4 at 5 (ORA/Lee).

[260] Exh. PG&E-39 at 4A-95.

[261] Exh. PG&E-1 at 4A-79.

adopt PG&E's forecast expenses and capital expenditures. However, because of the changed scope, we feel that it would be appropriate to set PG&E's forecast capital expenditures as the maximum amount that it may recover for work in this program. Consequently, PG&E shall replace 99 inoperable or hard-to-operate valves during the Rate Case Period, with the maximum amount to be recovered from ratepayers set at $22.188 million. Any costs above this amount to perform the work shall be paid for by shareholders.

6.4. Transmission Pipe Engineering Programs

The Transmission Pipe Engineering Programs "encompass engineering analyses that allow PG&E to proactively identify, plan and execute essential transmission pipeline projects, while aligning with regulatory compliance requirements."[262]

6.4.1. Class Location

6.4.1.1. PG&E's Request

PG&E's Class Location program is a compliance requirement pursuant to 49 CFR 192.613 to ensure that pipelines are operating within the appropriate class as determined by population density. The scope of work includes an annual class location study and the associated mitigation of identified class location changes.[263] Mitigation will include strength testing, reduction in operating pressure or pipeline replacement. Based on historical class change averages, PG&E forecasts that approximately 2.1 miles are expected to require

[262] Exh. PG&E-1 at 4B-1.

[263] Exh. PG&E-1 at 4B-7.

strength testing (an expense) and 1.7 miles are expected to require replacement (a capital expenditure) each year.[264]

PG&E's annual class location study costs are based on 2011-2013 costs, adjusted to account for advances in technology and improvement of data processing. PG&E's pipeline replacement and strength testing costs are based on costs associated with PSEP. PG&E's projected expenses and capital expenditures over the Rate Case Period are summarized below.

Table 14[265]

Forecast Class Location Expenses and Capital Expenditures
($ Thousands of Nominal Dollars)

	2015	2016	2017
Expenses	$6,411		
Capital Expenditures	$17,156	$17,486	$17,948

6.4.1.2. Intervenors' Response

ORA disagrees with PG&E's forecast unit cost for strength testing and the 2015 capital expenditures. First, ORA notes that the forecast expenses for the planned strength test (MWC HP) is $2.2 million per test mile. However, the broader Hydrotest Program forecast is $0.97 million per test mile.[266] ORA notes that its witness had forecast $0.54 million per test mile for the Hydrotest Program. ORA recommends that the expense forecast for MWC HP be reduced

[264] Exh. PG&E-1 at 4B-10 (.

[265] Exh. PG&E-1 at 4B-9 – 4B-10, Tables 4B-3 and 4B-4.

[266] Exh. ORA-39 at 7.

to $1.1 million per test mile, or a reduction of $2.462 million. This will result in 2015 expenses of $3.985 million.[267]

ORA next states that the miles per year used to develop the forecast capital expenditures for pipeline replacement projects is based on weighted historical data (2000-2005) and recent data (2011-2013).[268] ORA believes too much weight is given to historical data and accuses PG&E of cherry-picking timeframes to "to derive the result it seeks."[269] ORA contends that PG&E has provided no justification for using both historical and recent data. Therefore, ORA recommends only recent data be used, which would reduce the number of pipeline replacement miles from 1.68 to 1.02 miles per year. This would result in a forecast capital expenditure of $10.828 million.[270]

Finally, ORA suggests that reducing the maximum allowable operating pressure is an inexpensive alternative that PG&E has not considered.[271]

Indicated Shippers notes that in Investigation 11-11-009, the Commission found that PG&E had failed to comply with the federal regulations governing class location.[272] Indicated Shippers argues that it is not clear whether any of the proposed work is to address PG&E's prior non-compliance. Further, Indicated Shippers maintains that PG&E should provide additional testimony to

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[267] Exh. ORA-39 at 4.

[268] Exh. ORA-39 at 9.

[269] *ORA Opening Brief* at 125.

[270] Exh. ORA-39 at 8.

[271] *ORA Opening Brief* at 125.

[272] *Indicated Shippers Opening Brief* at 152-153 (citing D.15-04-022).

demonstrate that the proposed work is in compliance with federal regulations.[273] Thus, Indicated Shippers recommends that the Commission defer ratepayer cost recovery of the forecast expense and capital expenditures for this program pending a reasonableness review.[274] In the alternative, Indicated Shippers supports ORA's recommendation to disallow $2.462 million in expenses for 2015.

6.4.1.3. Discussion

We agree with ORA that PG&E's forecast expenses should be reduced. Although PG&E explains why the strength testing mitigation in the Class Location Program cannot be directly compared to the Hydrotest Program, we are not convinced that the differences highlighted by PG&E fully justify a unit cost that is more than double what had been proposed in the Hydrotest Program. PG&E witness Mojica testified "PG&E used the historical pipeline replacement and strength testing costs per mile associated with large diameter pipe from PG&E's Pipeline Safety Enhancement Plan (PSEP)."[275] As we have determined in the Vintage Pipeline Replacement Program, PG&E's estimates of costs resulting from shorter segments of pipe and larger diameter of pipe are overstated due to the selective use of projects. Accordingly, we reduce the unit cost for strength testing to $1.1 million per test mile, which results in forecast 2015 expenses of $3.985 million.

We disagree with ORA that PG&E has failed to justify the use of historical and recent data to calculate the number of replacement miles per year. PG&E

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[273] *Indicated Shippers Opening Brief* at 155.

[274] *Indicated Shippers Opening Brief* at 155.

[275] Exh. PG&E-1 at 4B-11.

explained "The historical data represents a portion of the most likely scope of work for the 2015-2017 period, whereas the recent data is representative of another portion of the expected level of work and associated costs to perform the work."[276] We are persuaded that PG&E's use of these two time periods is reasonable and make no adjustments to PG&E's capital expenditures.

We further decline to adopt Indicated Shippers' recommendation to defer ratepayer cost recovery of the forecast expense and capital expenditures for this program. The investigation into PG&E's non-compliance was opened in November of 2011, and PG&E's 2011-2012 class location studies addressed these non-commensurate pipeline segments. The fines and remedies associated with the PG&E's violation of federal regulations governing class location have been addressed in the *Penalties Decision*. Accordingly, we do not find that PG&E's proposed work is to address prior non-compliance.

In sum, PG&E's unit cost for strength testing is reduced by $2.426 million, which results in forecast 2015 expenses of $3.985 million. PG&E's forecast capital expenditures are approved.

6.4.2. Water and Levee Crossing

The Water and Levee Crossing Program identifies and evaluates erosion, third-party damage threats and other hazards to trenched-in pipeline installations located under waterways and within levee structures. The program is composed of the following components:

1. Jurisdictional Water Crossing – pipelines crossing under waterways which are owned by the State of California and within the jurisdiction of the California State Lands Commission.

[276] Exh. PG&E-39 at 4B-5.

2. Jurisdictional Levee Crossing – pipelines within man-made structures for controlling the flow of water under the ownership of the United States or the state of California and administered by the US Army Corps of Engineers and the California Department of Water Resources.
3. Non-Jurisdictional Water Crossing – pipeline installed under waterways that are not under state or federal jurisdiction.[277]

The scope of work to be performed under this program consists of conducting surveys in accordance with permitting requirements, the California Code of Regulations and other agreements and identifying mitigation measures (including replacement or retirement of at risk pipe).[278]

PG&E's projected expenses and capital expenditures over the Rate Case Period are summarized below.

Table 15[279]

Forecasted Water and Levee Crossing Program Expenses and Capital Expenditures

($ Thousands of Nominal Dollars)

	2015	2016	2017
Expenses	$1,372		
Capital Expenditures	$13,359	$7,240	$3,803

TURN challenges the pace of work forecast to mitigate at-risk pipe during the Rate Case Period. It notes that "many of the crossings are not in inhabited areas, and PG&E gives this program one of its lowest risk ranking scores."[280]

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[277] Exh. PG&E-1 at 4B-13 – 4B-14.

[278] Exh. PG&E-1 at 4B-18.

[279] Exh. PG&E-1 at 4B-18 – 4B-19, Tables 4B-5 and 4B-6.

[280] *TURN Opening Brief* at 134.

TURN asserts that PG&E has provided no justification for sharply accelerating the pace of work during the Rate Case Period, nor why the mitigation projects are front loaded to 2015. Accordingly, TURN recommends that the Commission slow the pace of the program by one-third and spread the work out evenly over the three-year Rate Case Period. Even with this reduction, TURN notes that the level of spending would be almost double PG&E's recorded spending for 2011 and 2012.[281]

TURN's arguments fail to take into consideration PG&E's obligation to meet the requirements under the master lease agreements with the California State Lands Commission. Further, PG&E's jurisdictional levee crossing work is performed in conjunction with the Army Corps of Engineers and the California Department of Water Resources. As PG&E notes, these governmental agencies expect PG&E to continue this risk mitigation work. While this program may have a lower risk ranking than others proposed, TURN has not provided persuasive arguments that PG&E's proposed pace of work or the forecast expenses are unreasonable.

In sum, we adopt PG&E's forecast expenses and capital expenditures.

6.4.3. Shallow Pipe Program

6.4.3.1. PG&E's Request

The purpose of PG&E's Shallow Pipe Program is to identify, prioritize and mitigate locations where pipeline has insufficient cover and is vulnerable to exposure from third parties. PG&E notes that while the depth of pipelines meet or exceed the minimum depth requirements at the time of installation, there is a

[281] *TURN Opening Brief* at 135.

risk of pipe exposure over time due to third-party activities, such as excavation or grading, ground penetrating activities, cultivation for agriculture or erosion.[282] PG&E's mitigation methods to address shallow pipes consist of:

- Expense mitigation – excavation along the length of the pipeline to allow lowering to an acceptable depth of cover or protection of the pipeline by installing additional cover, concrete cap or permanent bridging structure over the shallow location
- Capital mitigation – replacement or relocation of the pipeline at an acceptable depth of cover. PG&E will also retire shallow pipeline not necessary for operations.[283]

PG&E identifies shallow pipe locations through ECDA, Pipeline Center Line survey and pipeline patrol initiatives. It forecasts to perform 356 miles of engineering analysis (an expense), excavate or add cover to 1 mile of pipe (an expense) and replace or relocate 8.4 miles (a capital expenditure) during the Rate Case Period.[284] PG&E states that the proposed pace of work take into consideration system and resource constraints. The projects are prioritized based on the Average Occupancy Count (AOC) along the pipeline.[285]

The forecasted expense mitigation measures are based on historical costs for other projects similar in nature. The forecasted capital cost of $8 million/mile is based on recent pipeline replacement unit costs from PSEP, as well as historical

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[282] Exh. PG&E-1 at 4B-19 – 4B-20.

[283] Exh. PG&E-1 at 4B-21 – 4B-22.

[284] Exh. PG&E-1 at 4B-25.

[285] Exh. PG&E-1 at 4B-26. AOC is a new method of risk prioritization and is based on "a length-weighted average of the actual number of people who live, work or otherwise may be within the radius of the potential impact circle in the event of a catastrophic failure of the pipeline."

cost data. PG&E's projected expenses and capital expenditures over the Rate Case Period are summarized below.

Table 16[286]

Forecasted Shallow Pipe Program Expenses and Capital Expenditures ($ Thousands of Nominal Dollars)

	2015	2016	2017
Expenses	$3,073		
Capital Expenditures	$21,571	$22,116	$30,219

6.4.3.2. Intervenors' Response

PG&E's request is opposed by TURN and Indicated Shippers

TURN notes that PG&E has admitted that it had major problems patrolling its pipelines in the past, and that it has admitted that "it would be inappropriate to file for a recovery of expenditures that could have been avoided if proper patrols had been done along those pipelines in the past which would have prevented incompatible vegetation and noncompatible structures."[287] Further, TURN notes that two PG&E internal audit reports have criticized PG&E's work to remediate problems.[288] Further, TURN asserts that while PG&E has claimed that its Pipeline Centerline Project has been a means of identifying shallow pipe, the need for that project is due to PG&E's "past ineffectiveness in its efforts to ensure adequate depth of cover for its buried pipelines."[289]

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[286] Exh. PG&E-1 at 4B-25, Tables 4B-8 and 4B-9.

[287] *TURN Opening Brief* at 20-21 (citing 12 RT 842:27 – 843:5 (PG&E/Stavropoulos).)

[288] *TURN Opening Brief* at 135-136.

[289] *TURN Opening Brief* at 136.

TURN asserts "inadequate knowledge of the location of PG&E's underground pipelines and obstructions and encroachments on the actual [right of ways] would seem to create significant problems for many of PG&E's past activities, such as leak patrols and inspections for problems such as shallow pipe."[290]

TURN further notes that PG&E's proposed methods to identify shallow pipe locations, such as ECDA and patrolling, have been required since 1970. As such, TURN believes PG&E should have "been aware of and mitigated its shallow pipe problems earlier than this rate case."[291]

TURN notes that PG&E has not requested ratepayer funding for costs resulting from its "imprudent management of its right of ways" (the Pipeline Pathways program). Similarly, TURN believes that PG&E should not receive ratepayer funding for the shallow pipe forecast cast as they "would have been avoided if PG&E had competently carried out its shallow pipe prevention efforts in the past."[292] Moreover, TURN notes that PG&E has acknowledges that its work to prevent shallow pipe has been "sprinkled among other programs."[293] As such, PG&E has received funding in the past to mitigate shallow pipe.

Indicated Shippers argues that PG&E's expense forecast is speculative as the workpapers do not provide data to support PG&E's forecast 0.3 miles of pipeline to be mitigated or any historical cost data demonstrating that expense

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[290] *TURN Opening Brief* at 22.

[291] *TURN Opening Brief* at 137.

[292] *TURN Opening Brief* at 137.

[293] *TURN Opening Brief* at 138; *see* also, Exh. TURN-1 at 16.

mitigation will be around $7.4 million per mile.[294] Indicated Shippers further criticizes PG&E's capital expenditure forecast, as it contains unit cost adders based on location of the work (non-congested, semi-congested or highly congested areas) and other adders that may not apply to the actual pipe replacement projects.[295] Indicated Shippers contends that since PG&E's witness for this program "was not familiar with and failed to explain how PG&E developed its Shallow Pipe cost forecast" the Commission should defer cost recovery until PG&E demonstrates the reasonableness of its proposal. At a minimum, Indicated Shippers argues that the 30% Mob/Demob Charge adder and the 15% Shallow Pipe Construction Risk Adder should be removed.[296]

Finally, Indicated Shippers contends that work in the Shallow Pipe program may overlap with work in other programs, such as the VPR Program. Thus, Indicated Shippers maintains that PG&E should be required to account for any overlap.[297]

6.4.3.3. Discussion

We disagree with TURN that PG&E's audit reports demonstrate that PG&E has acted imprudently with respect to identifying and mitigating shallow pipe problems in the past. PG&E's Audit of Gas Damage Prevention Program[298] and Pipeline Centerline Project Audit (Part 2)[299] do not identify any existing

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294 *Indicated Shippers Opening Brief* at 161.

295 *Indicated Shippers Opening Brief* at 163.

296 *Indicated Shippers Opening Brief* at 164.

297 *Indicated Shippers Opening Brief* at 165.

298 Exh. TURN-20.

299 Exh. TURN-36.

errors or find that PG&E is in violation of federal regulations. Rather, both audits identified various issues that, if unaddressed, would result in negative consequences. In its response to these audits, PG&E's management has specified actions to address these issues.

We find that PG&E's expense mitigation forecasts are reasonable. As noted by PG&E, it had historically addressed shallow pipe on a case-by-case basis. PG&E's forecast of work on a program level is based on estimates from the PSEP program as well as "similar expense repair and mitigation projects from Major Work Category JT."[300]

However, we agree with Indicated Shippers that PG&E's capital expenditures forecast should be adjusted to disallow the 30% Mobilization/Demobilization adder. In cross examination, PG&E's witness had testified that the recorded PSEP project costs, which served as the basis for the forecast in this program, included mobilization and demobilization costs. However, PG&E then included a 30% increase in total project costs for mobilization and demobilization costs based solely on a conversation with the PSEP Team, with no further explanation.[301] We find that this increase is unsupported by the record and therefore unreasonable.

We find PG&E's 15% Shallow Pipe Construction Risk Adder reasonable. PG&E has fully explained the need for this adder to reflect additional protection requirements when working around pipe with shallow cover. This includes "appropriate protective mitigation, including concrete caps or additional soil

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[300] Exh. PG&E-6 at WP 4B-11.

[301] 21 RT at 2420:19 – 2422:6.

haul along the pipeline route, as well as equipment weights limitations, resulting in the use of smaller/lighter equipment thus extending the duration/cost of such projects."[302]

Disallowance of the 30% Mob/Demob Charge adder results in forecast 2015 capital expenditures of $17.228 million. There will be corresponding disallowances for 2016 and 2017.[303]

6.4.4. Gas Gathering Program

The purpose of the Gas Gathering Program is to retire or divest PG&E's gas gathering assets as it phases out its gathering operations. Assets include "gas gathering pipelines, dehydration stations and meters to extend PG&E's system to individual gas wells under procurement agreements where PG&E purchased production gas at the wellhead."[304] PG&E notes that the retirement of idle gas gathering assets reduces operating risks associated with gas and liquid leaks, vandalism, and hazards associated with unused facilities.[305]

PG&E forecasts retiring approximately 27 idle meters, 14.4 miles of gas gathering pipeline and 2.5 miles of associated local transmission pipeline during the Rate Case Period. Its estimated costs for retiring these assets are based on combined historical costs. PG&E's projected capital expenditures over the Rate Case Period are summarized below.

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302 Exh. PG&E-6 at WP 4B-21.

303 *See* Appendix H, Table H-1, Line 18.

304 *PG&E Opening Brief* at 7-65.

305 Exh. PG&E-1 at 4B-28.

Table 17[306]

Forecast Gas Gathering Program Capital Expenditures
($ Thousands of Nominal Dollars)

	2015	2016	2017
Capital Expenditures	$1,627	$1,668	$1,661

PG&E's request is unopposed. We find the amount reasonable and adopt PG&E's forecast for this program.

6.4.5. Work Required by Others

6.4.5.1. PG&E's Request

The Work Required by Others (WRO) program covers work on transmission pipeline performed by PG&E at the request of others (governmental agencies, local governments, regional transportation agencies or private developers). Work under the program may be the result of freeway new construction work, improvements to existing roadways, public improvement projects sponsored by Regional Transportation Authorities or school districts, or private developments. Depending on its agreement with these individual entities, PG&E is reimbursed between 0 to 100% of the costs to remove and relocate utility facilities to accommodate construction.[307]

PG&E notes that WRO is cyclical and based on the economy. It forecasts an increase in the number of high-speed and light rail projects and highway and freeway projects during the Rate Case Period.[308] Based on historical data, PG&E projects that approximately 60% of total project costs will be paid by the

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[306] Exh. PG&E-1 at 4B-31, Table 4B-10.

[307] Exh. PG&E-1 at 4B-35.

[308] Exh. PG&E-1 at 4B-35.

requesting party. Thus, it seeks recovery in rates of the remaining 40%. PG&E's projected expenses and capital expenditures over the Rate Case Period are summarized below.

Table 18[309]

Forecast Work Required by Others Program Expenses and Capital Expenditures

($ Thousands of Nominal Dollars)

	2015	2016	2017
Expenses	$739		
Capital Expenditures	$24,610	$26,328	$28,150

6.4.5.2. Intervenors' Response

TURN contends that PG&E has failed to justify the steep increase in forecast capital spending. It notes that the based on recorded costs, the average spending between 2011–2013 is $11.5 million per year. Consequently, TURN recommends a capital budget of $17.3 million, a $7.3 million reduction from PG&E's 2015 forecast. This amount would result in a 50% increase over the three year average and "still recognize[ ] the cyclical nature of these costs."[310]

Indicated Shippers also argues that PG&E's capital cost forecast is overstated. It notes that between 2008-2013, PG&E averaged four projects per year, with the average length of each project being 683 feet.[311] In contrast, it notes that PG&E proposes an average of 46 projects per year for the Rate Case Period, with the average length of each project 1,075 miles. Indicated Shippers asserts

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[309] Exh. PG&E-1 at 4B-36, Tables 4B-11 and 4B-12 (PG&E/Mojica).

[310] *TURN Opening Brief* at 140.

[311] *Indicated Shippers Opening Brief* at 169-170.

that PG&E's forecast is not supported by any evidence and is contrary to historical recorded costs. Moreover, Indicated Shippers notes that PG&E forecasts a significant amount of work for the California High Speed Rail Authority, for which PG&E will be reimbursed 100% of the costs.

Indicated Shippers recommends that the Commission remove from PG&E's forecast all costs associated with High Speed Rail projects.[312] It further recommends that recovery of the remaining capital should be deferred, subject to further reasonableness review and a showing of how much of the costs were unrecoverable from third parties.[313] As an alternative, Indicated Shippers recommends that the Commission limit PG&E's costs to the last recorded annual amount, or $8.843 million.[314]

6.4.5.3. Discussion

We generally agree with PG&E that the improving economy will result in an increase in the number of WRO projects. We further find that PG&E's forecast unit cost and the average length of each project to be reasonable. PG&E has provided historical data to support its request. On this basis, we adopt PG&E's forecast 2015 expenses of $0.739 million for Work Required by Others.

However, we are reluctant to include in rates the capital expenditures associated with the High Speed rail projects. Although PG&E notes that its forecasts are net of any reimbursement it receives from the requesting party,[315] the California High Speed Rail Act (Pub. Util. Code § 185000 et seq.) specifically

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[312] *Indicated Shippers Opening Brief* at 172.

[313] *Indicated Shippers Opening Brief* at 173.

[314] *Indicated Shippers Opening Brief* at 173.

[315] Exh. PG&E-1 at 4B-35.

provides that the California High Speed Rail Authority shall pay the reasonable and necessary costs for the removal or relocation of utility facilities.[316] The California High Speed Rail Authority, however, would be entitled certain credits, such as betterment or salvage value.[317]

PG&E has argued that "there has yet to be any contractual agreement executed between PG&E and [California High Speed Rail Authority] that establishes … the credit amounts the [California High Speed Rail Authority] is entitled to."[318] This statement, however, does not alter the requirements under the California High Speed Rail Act. It is clear that the California High Speed Rail Authority shall pay for reasonable costs to remove or relocate utility facilities and that it is entitled to certain credits. To the extent that the California High Speed Rail Authority finds any costs are not reasonable (and thus does not reimburse PG&E for those amounts), it does not follow that PG&E should be allowed to recover the "unreasonable" portion of the costs in rates. Further, PG&E's forecast assumes that it will recover 60% of project costs from the requesting party. Given the mandates of Pub. Util. Code §§ 185501(a), 185502(c) and 185503, and the specific credits that the California High Speed Rail Authority could receive under Pub. Util. Code § 185504(a), we find that this assumption is unreasonable with respect to High Speed Rail projects. Accordingly, we adopt TURN's recommendation and reduce PG&E's capital budget for WRO to $17.3 million.

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316 *See*, Pub. Util. Code §§ 185501(a), 185502(c) and 185503.

317 Pub. Util. Code § 185504(a).

318 *PG&E Reply Brief* at 7-44.

Although we reduce the forecast amount, we acknowledge the forecasted capital expenditures for WRO may still be too high, given the large number of High Speed Rail projects included in the forecast and the fact that no master agreement has yet been approved by the Commission. Accordingly, PG&E shall file a Tier 2 Advice Letter to establish a one-way balancing account to track the difference between the capital expenditure amounts adopted in this decision and the portion of costs assigned to customers over the 2015 GT&S rate cycle - $17.3 million in 2015, $17.697 million in 2016 and $18.158 million in 2017. At the end of the 2015 GT&S rate case cycle, any unspent funds in the balancing account shall be returned to customers as part of the Annual Gas True-Up filing.

PG&E's forecast 2015 expenses for WRO is reasonable and adopted.

7. Storage

PG&E's proposals for Storage Asset Family consist of only the mitigation programs for storage well facilities.[319] The purpose of storage facilities is to: (1) support system reliability especially in times of high demand; and (2) balance the overall gas system. PG&E proposes to perform the following scope of work during the Rate Case Period:

- Operate and maintain PG&E's Storage facilities in accordance with the CPUC's General Order 112-E and Senate Bill (SB) 705, the Natural Gas Pipeline Safety Act of 2011, and California Code of Regulations (CCR) Title 14, Section 1724.3.
- Implement an industry-leading Well Integrity Management Program designed to assess and recommend mitigations to the

[319] Exh. PG&E-1 at 5-2. The Storage Asset Family consists primarily of storage well facilities, but also contains transmission pipe, control equipment, and fittings/valves. PG&E notes that other components in the Storage Asset Family are addressed in other chapters in this application.

operational threats to storage wells and reservoirs consistent with SB 705.

- Enhance decision making regarding integrity management efforts by ensuring greater access to data through centralizing storage records related to gas storage well and reservoir construction and maintenance activities, storage data quality information, field and well pressures, and performance data in the Gas Storage Database.
- Conduct Gamma-Ray Neutron (GRN) Surveys, Noise and Temperature Surveys, and Casing Inspection Surveys to assess the risk of internal/external corrosion and erosion within PG&E's storage wells.
- Conduct a total of 24 Storage Rework Projects over the 2015-2017 Gas Transmission and Storage (GT&S) Rate Case Period to ensure compliance with California Code of Regulations (CCR) Title 14, Section 1724.3, which requires functional downhole safety valves for storage wells. Additionally, reworks are performed to maintain the storage well integrity and mitigate decreased performance that could impact storage system capacity and reliability.
- Upgrade the flow controls at the Pleasant Creek storage facility to mitigate the risk of reduced storage capacity and reliability resulting from overflow events.[320]

PG&E's projected expenses and capital expenditures over the Rate Case Period are summarized below.

[320] Exh. PG&E-1 at 5-3.

Table 19[321]

Forecasted Storage Asset Family Expenses and Capital Expenditures
($ Thousands of Nominal Dollars)

	2015	2016	2017
Expenses	$637		
Capital Expenditures	$12,456	$12,708	$7,302

ORA did not oppose PG&E's forecast. On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 5 – Asset Family – Storage* (Exh. Joint-3 at -5), was entered into the record. PG&E and ORA stipulated that PG&E's 2015 expense and capital expenditure forecasts were reasonable.[322] Further, PG&E and ORA stipulated that expenses for 2016 and 2017 and Storage Well Work and Well Overflow Protection capital expenditures for 2016 and 2017 were subject to post test-year escalation, as included in the PG&E-ORA joint stipulation for Chapter 18, Post Test Year Stipulation.[323]

No comments were filed on the Joint Stipulation. We find the joint stipulation of the Storage asset family to be reasonable and adopt the 2015 expense forecast of $630,000 and capital expenditure forecast of $12.456 million, as shown on page 5-4 Exhibit PG&E-1 (Tables 5-1 and 5-2). Storage expenses and capital expenditures for 2016 and 2017 will be subject to post test-year escalation, as included in pages 23-28 of Exhibit Joint-3, the PG&E-ORA joint stipulation for Chapter 18, Post Test Year Stipulation.

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321 Exh. PG&E-1 at 5-4, Tables 5-1 and 5-2.

322 Exh. JOINT-3 at 3-5.

323 Exh. JOINT-3 at 5.

8. Facilities

8.1. Overview

Facilities consists of the Compression and Processing (C&P) and Measurement and Control (M&P) Stations asset families. PG&E forecasts $65.7 million in expense and $141.3 million in capital expenditures in 2015 for 31 programs and projects to help PG&E safely and reliably operate its transmission and underground storage compression and gas processing equipment, and approximately 500 gas terminals and regulating stations that regulate and control pressure throughout PG&E's gas transmission system.[324] Forecast 2015 expenses and capital expenditures are summarized below:

Table 20
Forecast Facilities Expense Programs and Projects[325]
($ Thousands of Nominal Dollars)

Project/Program	2015 Forecast
ECA Phase 1	$15,633
ECA Phase 2	8,682
Hydrostatic Station Testing	5,926
Critical Documents	11,573
Data Acquisition and Metric Development	1,583
Physical Security	1,055
Becker System Upgrades	
Gas Quality Practice Assessment	2,110

[324] *PG&E Opening Brief* at 9-1.

[325] Exh. PG&E-1 at 6-4, Table 6-2.

Gill Ranch O&M	2,306
Routine Expense	16,830
Total	**$65,698**

Table 21
Forecast Facilities Capital Programs and Projects[326]
($Thousands of Nominal Dollars)

Project/Program	2015 Forecast	2016 Forecast	2017 Forecast
Compression and Processing Projects/Programs			
Burney K-2 Compressor Replacement	$26,750	$27,425	
Los Medanos K-1 Compressor Replacement			$28,150
Compressor Unit Control Replacements	1,617	1,658	1,701
Upgrade Station Controls		1,574	1,616
Emergency Shutdown System Upgrades	2,675	2,743	2,815
Rebuild Santa Rosa Compressor Station Electrical Substation	3,745		
Upgrade Pleasant Creek Processing Facilities	2,140		
Gas Transmission Electrical Upgrades – Hinkley and Topock Compressor Stations			1,418
Gas Transmission Electrical Upgrades – Compressor Stations (Excluding Hinkley, Topock and Santa Rosa)		1,841	
Physical Security	2,706	2,774	2,847
Hinkley Compressor Unit Retrofit Project		6,034	6,193

[326] Exh. PG&E-1 at 6-7, Table 6-4.

Install Active Fire Suppression Systems	535	1,646	563
Routine Capital Spending	32,867	33,697	34,587
Total Compression and Processing	**$73,035**	**$79,392**	**$79,890**
Measurement and Processing Projects/Programs			
Perform Simple Station Rebuilds	$19,660	$26,875	$27,585
Perform Complex Station Rebuilds	8,186	8,392	8,614
Perform Transmission Terminal Upgrades	2,140	2,194	2,252
SCADA Visibility	5,671	5,814	5,968
Replace Obsolete Bristol Controllers	1,473	1,511	1,551
Replace Obsolete Limitorque Valve Acutuators	1,311	1,344	1,380
Electrical Upgrade Program	1,064	1,090	1,119
Becker System Upgrades	3,437	3,524	3,013
Biomethane Interconnects	4,815	4,937	5,067
Routine Capital Spending	20,505	21,022	21,578
Total Measurement and Processing	**$68,262**	**$76,703**	**$78,127**
Total Capital Spending	**$141,297**	**$156,095**	**$158,017**

Indicated Shippers argues that PG&E is unable to forecast costs for these asset families because:

- PG&E lacks asset condition data;
- PG&E cannot identify which costs are properly borne by ratepayers; and

- The scope of the programs and required work is speculative.[327]

Indicated Shippers further argues that each forecast suffers from "unique deficiencies." Consequently, it contends that PG&E's costs for these programs and projects should be tracked in a memorandum account, subject to a later reasonableness review, or disallowed.[328]

Despite alleging "unique deficiencies" in the forecast costs, Indicated Shippers does not identify the specific shortcomings in every program and project. We decline to adopt a blanket deferral or disallowance of costs without further support. Accordingly, we will consider each proposed program and project separately to determine whether PG&E's proposal should be adopted.

8.2. ECA Phase 1, ECA Phase 2 and Hydrostatic Station Testing

8.2.1. PG&E's Request and Joint Stipulation with ORA

PG&E has identified three mitigation programs to address potential manufacturing related defects:

- Engineering Critical Assessment (ECA), Phase 1 – Work would consist of reviewing records containing manufacturing data and operating specifications to identify discrepancies that may compromise station asset integrity. A focus of the review is on obtaining traceable, verifiable and complete records, consistent with PHMSA's May 7, 2012 advisory bulletin.[329]
- ECA, Phase 2 – Mitigation of discrepancies through viable low-risk procedures relative to hydrostatic testing. This can include

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[327] *Indicated Shippers Opening Brief* at 174.

[328] *Indicated Shippers Opening Brief* at 174.

[329] Exh. PG&E-1 at 6-28 – 6-29.

non-destructive and destructive testing, fatigue life calculations and other evaluations that can substitute for a pressure test.[330]

- Hydrostatic Testing Stations – Pressure testing of station piping sections as required following results of ECA Phases 1 and 2. PG&E proposes to pressure test stations over a 20-year schedule, which it believes is a good compromise among project execution, operational risk, and expedient completion.[331]

Due to the limited industry experience of ECA type work, there is a limited amount of historical forecasting data on which to base scope and cost for ECA projects. PG&E's hydrostatic station testing forecast is largely based on third-party estimates and preliminary data from the 2013 station records research.

ORA did not propose a disallowance, but recommended that PG&E receive no funding for these programs until PHMSA had established its new Integrity Verification Process rules. At that time, PG&E should be directed to "file an advice letter or application to establish a memorandum account to track the costs of these three programs, if they are still required."[332]

On April 22, 2015, a stipulation between PG&E and ORA, *ORA-PG&E Joint Stipulation, Engineering Critical Assessment and Hydrostatic Testing (Chapter 6)* (Exhibit Joint-6), which represented a hybrid of their two proposals, was entered into the record. Under the joint stipulation, PG&E would receive 50% of the forecast funding for ECA, Phase 1 and Phase 2, and Hydrostatic testing up front. Upon adoption of PHMSA regulations, PG&E would incorporate the remaining

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[330] Exh. PG&E-1 at 6-29.

[331] Exh. PG&E-1 at 6-30 – 6-31.

[332] Exh. ORA-11 at 6.

50% of the adopted 2015-2017 forecast in rates. The joint stipulation further states:

> In the event that PHSMA does not issue the new regulations within this rate case cycle, PG&E does not anticipate spending more than these stipulated amounts nor does it anticipate completing the original scope of work associated with the proposed PHSMA regulations.[333]

Finally, PG&E would not seek cost recovery from ratepayers for the foundational work in 2013 and 2014 to obtain records. The expense forecast to be initially included in rates is as follows:

Table 22
ECA, Phase 1 and Phase 2/Hydrostatic Testing Expense Programs[334]
(Amounts shown in thousands)

	2015	2016	2017
Hydrostatic Testing	$2,963	$5,601	$11,471
ECA Phase 1 and 2	$12,158		

8.2.2. Intervenors' Response

Indicated Shippers maintains that the ECA Phase 1 program is preliminary and speculative, and reflects PG&E's records retention failure.[335] It notes that although no one in the industry has engaged in ECA work, PG&E provides limited support for the reasonableness of its comparison and cost estimates of the program. Moreover, Indicated Shippers argues that PG&E's forecast fails to take

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333 Exh. Joint-6 at 2.

334 Exh. Joint-6 at 2.

335 *Indicated Shippers Opening Brief* at 179.

into account any potential economies of scale in the ECA program.[336] Consequently, Indicated Shippers recommends that the Commission defer recovery of costs for ECA Phase 1. In addition, Indicated Shippers argues that PG&E should be denied recovery for any project reflecting work previously covered by GO 112.[337]

Indicated Shippers next notes that the scope of ECA Phase 2 depends on the results of ECA Phase 1. It argues that the uncertainties of the ECA Phase 1 forecast exacerbate the uncertainty of ECA Phase 2 costs, resulting in forecast costs that are likely overstated.[338] Thus, similar to its recommendations for ECA Phase 1, Indicated Shippers recommends that recovery of costs should be deferred, subject to reasonableness review, and that PG&E should be denied recovery for any project reflecting work previously covered by GO 112.[339]

TURN also argues that that ECA Phase 1 and ECA Phase 2 are to remedy past recordkeeping deficiencies. Relying on the *Penalties Decision*, TURN notes that the Commission has clearly stated that a "gas system operator is obligated by Pub. Util. Code § 451 to operate a safe system and that adequate recordkeeping is a key part of that obligation."[340] It further asserts that ECA Phase 1 and ECA Phase 2 are analogous to the pipeline MAOP Validation Project. TURN notes that the *PSEP Decision* specifically disallowed recovery of costs for the MAOP Validation Project, finding that PG&E's responsibility

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336 *Indicated Shippers Opening Brief* at 180.

337 *Indicated Shippers Opening Brief* at 181.

338 *Indicated Shippers Opening Brief* at 182.

339 *Indicated Shippers Opening Brief* at 183.

340 *TURN Opening Brief* at 141.

"includes creating and maintaining records of the location and engineering details of system components."[341] TURN states that PG&E's recordkeeping obligations apply to all facets of PG&E's gas transmission system recordkeeping, including its station facilities. As such, TURN believes that if PG&E had performed its past recordkeeping duties prudently, the ECA Phase 1 and Phase 2 Programs would not be necessary.[342]

In addition, TURN notes that PG&E has acknowledged that its forecast includes costs that should not be recovered from ratepayers because they are for "components installed since the promulgation of GO 112 in 1961 for which PG&E does not have traceable, verifiable and complete strength test records."[343] TURN berates PG&E for not identifying the amount of forecast costs that should be recovered from shareholders and for not proposing a mechanism to return unrecoverable costs to ratepayers in the event PG&E's forecast is accepted.[344] Therefore, TURN asserts that costs for ECA Phase 1 and Phase 2 should be disallowed since the work proposed is to remedy past recordkeeping imprudence and deficiencies.[345]

TURN further argues that recovery of costs for the Hydrostatic Station Testing Program should be postponed. It notes that the program is to hydrotest certain station facility components where PG&E lacks adequate and reliable records of a pressure test and PG&E has been unable, through ECA Phase 1 and

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[341] *TURN Opening Brief* at 142 (citing *PSEP Decision* at 95).

[342] *TURN Opening Brief* at 148.

[343] *TURN Opening Brief* at 146.

[344] *TURN Opening Brief* at 146-147.

[345] *TURN Opening Brief* at 149.

ECA Phase 2, to establish a reliable MAOP. TURN contends that the forecast costs are speculative, since the need and extent of this program will be determined by the outcomes of the ECA Phase 1 and ECA Phase 2, which are still unknown. Moreover, as with ECA Phase 1 and ECA Phase 2, the forecast includes costs that should not be recovered from ratepayers due to the vintage of the components being tested.[346] TURN believes that since it is unlikely that this project will get underway during the Rate Case Period, PG&E should not be allowed rate recovery of its forecast costs in this Rate Case Period. Instead, TURN recommends:

> ... the Commission should authorize PG&E: (1) to track in a memorandum account any HST costs it may incur in the rate case period, and (2) to seek recovery of any tracked costs in a subsequent application in which PG&E must demonstrate the reasonableness of its incurred costs. In lieu of tracking costs in a memorandum account, if PG&E anticipates little, if any, spending on HST in this rate case period, PG&E should be allowed to renew its request for HST rate recovery in the next GT&S rate case.[347]

Finally, TURN and Indicted Shippers urge the Commission to reject the ORA-PG&E joint stipulation, as the stipulation does not consider any of the concerns they have raised.[348] Additionally, TURN notes that the stipulation would allow potential full recovery of PG&E's forecast, even though PG&E has acknowledged that some of the forecast costs should not be recovered from

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[346] *TURN Opening Brief* at 150-151.

[347] *TURN Opening Brief* at 154.

[348] *TURN Opening Brief* at 152; *Indicated Shippers Opening Brief* at 177.

ratepayers.[349] Finally, TURN disagrees that PG&E should be allowed to delay the ECA Phase 1 and ECA Phase 2 work if PHMSA has not issued its final Integrity Verification Process rule before the end of the Rate Case Period. From TURN's perspective, this work should begin immediately since "PG&E lacks the necessary information to establish accurate and reliable MAOPs for its station components and believes it needs these programs in order to remedy that problem."[350]

8.2.3. PG&E's Response to Intervenors

PG&E maintains that its forecast for ECA Phase 1, ECA Phase 2 and Hydrostatic Station Testing are reasonable. First, it notes that the costs to gather station documents, which was a similar effort to the record gathering effort descripted in PSEP, has been completed and was funded by shareholders. The work to perform ECA Phase 1 would re-confirm the maximum allowable operating pressures for PG&E's transmission station piping.[351] PG&E agrees that any costs to address station components that do not have but were required to have traceable, verifiable and complete records should be borne by shareholders. As with its arguments concerning hydrotesting of transmission pipe, PG&E contends that the 1955 ASA standard applicable between 1956 and 1961 did not require pressure test records to be maintained for all tests.[352] Therefore, it believes that it should be allowed to recover costs to perform ECA Phase 1 and

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[349] *TURN Opening Brief* at 153.

[350] *TURN Opening Brief* at 153.

[351] *PG&E Reply Brief* at 9-1.

[352] *PG&E Reply Brief* at 9-1; *see also*, Section 6.2.3, *supra*.

ECA Phase 2 on pre-1961 station components from customers. After 1961, shareholders should cover the cost when these records cannot be located.

PG&E acknowledges that it "does not currently have the ability to identify the amount of funding included in its forecast to perform ECA Phases 1 and 2 and Hydrostatic Station Testing work on stations with post-1961 components or features for which PG&E lacks required traceable, verifiable, and complete records."[353] It therefore proposes a method to proportion cost responsibility between ratepayers and shareholders using an allocation methodology based on the number of components identified at each station and to establish a balancing account to track the difference between amounts adopted by the Commission (and included in rates) and the portion of costs assigned to customers.[354]

Finally, PG&E argues that TURN's recommendation to defer recovery of costs for Hydrostatic Station Testing be rejected.[355] PG&E argues that the pre-1961 Hydrostatic Station Testing costs are appropriately recovered from ratepayers. Further it advocates for the need to fund safety work in this proceeding and argues that the joint stipulation "strikes the right balance between cost recovery for legitimate safety programs in this rate case and the uncertainty associated with the cost forecast given the PHMSA's rulemaking remains pending."[356]

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[353] *PG&E Reply Brief* at 9-3.

[354] *PG&E Reply Brief* at 9-4.

[355] *PG&E Reply Brief* at 9-4.

[356] *PG&E Reply Brief* at 9-5.

8.2.4. Discussion

We find that the *ORA-PG&E Joint Stipulation, Engineering Critical Assessment and Hydrostatic Testing* is not reasonable in light of the record and not in the public interest. While the joint stipulation resolves the timing for PG&E to recover costs to perform ECA Phase 1, ECA Phase 2 and Hydrostatic Station Testing work, it fails to require PG&E to ensure that it has traceable, verifiable and complete records for its C&P and M&P stations. Pursuant to Pub. Util. Code § 451 and GO 112, PG&E is required to create and maintain the necessary records to ensure safe operation of its gas transmission facilities. This mandate exists regardless of whether PHMSA has established its Integrity Verification Process rules.

Further, the joint stipulation fails to account for the fact that PG&E has included in its forecast costs that clearly should be paid by PG&E shareholders. PG&E has, in its Reply Brief, proposed a methodology for proportioning costs between ratepayers and shareholders. This proposal, however, assumes that costs associated with pre-1961 assets would be recovered from ratepayers. This assumption, however, is contrary to ORA's position that PG&E should be responsible for costs associated with assets installed after January 1, 1956. Accordingly, we reject the *ORA-PG&E Joint Stipulation, Engineering Critical Assessment and Hydrostatic Testing*.

Although we reject the joint stipulation, we are not persuaded that recovery of the costs to perform ECA Phase 1, ECA Phase 2 or Hydrostatic Station Testing work during the Rate Case Period should be deferred and subject to a later reasonableness review. We acknowledge that there is little historical data on which PG&E could base its forecasts. Nonetheless, we find that PG&E has fully explained how its forecasts were developed. Authorizing PG&E's

requested funding will allow PG&E to perform the scope of work contemplated to ensure that records for its C&P and M&P Stations are traceable, verifiable and complete.

Further, we adopt PG&E's proposed methodology to proportion cost responsibility between shareholders and ratepayers, except that, consistent with our findings concerning recovery of costs for Hydrostatic Testing of Transmission Pipe, PG&E shall recover from shareholders all costs to address station components installed on or after January 1, 1956, that do not have but were required to have traceable, verifiable and complete records. Contrary to PG&E's arguments, we do not find that the 1955 ASA should be interpreted differently for transmission pipe and transmission stations.

Accordingly, we adopt PG&E's forecast 2015 expenses of $15.633 million for ECA Phase 1, $8.682 million for ECA Phase 2, $455,403 for hydrostatic station testing (C&P) and $5.470 million for hydrostatic station testing (M&C). PG&E shall file a Tier 2 Advice Letter to establish a one-way balancing account to track the difference between amounts adopted in this decision and the actual costs to perform Hydrostatic Station Testing work during the Rate Case Period on stations installed on or before December 31, 1955. This difference reflects costs for Hydrostatic Station Testing work on stations installed on or after January 1, 1956 which should be borne by shareholders. Therefore, at the end of the 2015 GT&S rate case cycle, any unspent funds in the balancing account shall be returned to customers.

The 2015 amounts to be tracked in the balancing account are: $455,403 for hydrostatic station testing (C&P) and $5.470 million for hydrostatic station testing (M&C). The 2016 amounts to be tracked are: $466,318 for hydrostatic station testing (C&P) and $11.200 million for hydrostatic station testing (M&C).

The 2017 amounts to be tracked are: $477,263 for hydrostatic station testing (C&P) and $22.940 million for hydrostatic station testing (M&C).

8.3. Critical Documents

The purpose of the Critical Documents program is to ensure that all C&P and M&P facilities have documentation which will enhance safe operation of a station facility. The program involves "developing a standardized document set that is matched to the complexity and risk associated with the function of a facility."[357] PG&E's requirements are identified in Utility Standard TD 4551S "Station Critical Documentation." PG&E maintains that this program is not to remediate prior records management deficiencies, but to "ensure that PG&E's current work force have the critical documentation needed to safely and efficiently operate these complex facilities."[358] PG&E forecasts $11.6 million for this program in 2015.

ORA and Indicated Shippers oppose PG&E's request. ORA states that standardizing critical documents is a longstanding requirement and recommends zero funding for this program since it "should have been conducted by PG&E as part of the safe operations of its system."[359] As support, ORA cites to the *PSEP Decision*, which noted

> PG&E became responsible for its natural gas transmission system the day it installed facilities and equipment for the system. That

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[357] Exh. PG&E-1 at 6-32.

[358] *PG&E Opening Brief* at 9-12.

[359] *ORA Opening Brief* at 127.

> responsibility includes creating and maintaining records of the location and engineering details of system components.[360]

Indicated Shippers notes it is unclear why PG&E has not previously collected and maintained these "critical" documents, and argues that this project is the result of poor records management. Additionally, Indicated Shippers asserts that PG&E overestimates the potential scope of the program, as it does not take into account that in some cases PG&E already has the document, but rather assumes that new documents will be created in all instances.[361] Indicated Shippers contends that, as explained in the *PSEP Decision*, PG&E received funding to maintain its records, "and to the extent these documents are critical they should have been collected."[362] Accordingly, Indicated Shippers recommends that PG&E should be required to perform this work, but should not recover these costs from ratepayers.

PG&E disputes ORA's and Indicated Shippers' assertions. PG&E states that the objective of the Critical Documents Program is not to remediate past deficiencies in records management, but rather to develop a consistent set of station documents and drawings. PG&E notes that its stations have a wide range of construction vintage, consequently the types and formats of drawings included in station documentation packages vary widely.[363] As such, the work to be performed is not remedial in nature. Additionally, PG&E notes that unlike

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[360] *ORA Opening Brief* at 127 (citing *PSEP Decision* at 87.).

[361] *Indicated Shippers Opening Brief* at 185.

[362] *Indicated Shippers Opening Brief* at 186.

[363] Exh. PG&E-39 at 6-12.

the PSEP, the scope of work does not include record research and validation activities.[364]

PG&E's workpapers state that Critical Documents Program is to:

> identify and close gaps found between the standard TD-4551S and actual drawings by modifying existing drawings and/or developing new drawings. This project involves a concerted effort of research of the existing documents, review, validate (with field verification), update the existing documents <u>and create any new documents missing from existing records</u>.[365]

PG&E has identified 500 Measurement & Control facilities and 17 Control & Processing facilities requiring attention from this program.[366] Although PG&E has stated that vintage stations may be missing certain documents because those documents and diagrams were not required at the time the station was built, it has not specifically addressed whether the existing station document packages are otherwise traceable, verifiable and complete. However, in light of PG&E's testimony in other areas, such as ECA Phase 1, and the recordkeeping shortcomings found in the San Bruno Investigations, it would be reasonable to conclude that some of the missing documents are due to deficient records management practices.

We agree with PG&E that existing station documentation packages should be updated to reflect the requirements of TD-4551S (for example, including piping and instrumentation diagrams for vintage stations) and should be recovered from ratepayers. Accordingly, we approve PG&E's forecast expenses

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[364] Exh. PG&E-39 at 6-13.

[365] Exh. PG&E-8 at WP 6-11 (emphasis added).

[366] Exh. PG&E-8 at WP 6-12.

for this program. The costs to be recovered, however, are subject to the requirements below to ensure that the Critical Documents Program is not used to correct past records management deficiencies.

Consistent with our discussion concerning recovery of costs for Hydrostatic Testing of Transmission Pipe, ECA Phase 1, ECA Phase 2 and Hydrostatic Station Testing. PG&E may recover from ratepayers costs to update existing station documentation or create new documentation to meet the standard set in Utility Standard TD-4551S for all Measurement & Control facilities and Control & Processing facilities built on or before December 31, 1955. For all Measurement & Control facilities and Control & Processing facilities built on or after January 1, 1956, PG&E shall recover from PG&E shareholders costs to update existing station documentation or create new documentation to meet the standard set in Utility Standard TD-4551S if those documents were required to be created and maintained at the time of or post-installation.

PG&E shall file a Tier 2 Advice Letter to establish a one-way balancing account to track the difference between amounts adopted in this decision - $11.573 million in 2015, $11.850 million in 2016 and $12.129 million in 2017 - and the actual costs of Critical Documents Program work for facilities built on or before December 31, 1955. At the end of the rate case cycle, the difference between the amount authorized and the actual costs for facilities built on or before December 31, 1955 shall be returned to ratepayers, in keeping with our mandate that shareholders bear the cost of Critical Documents Program work on facilities built on or after January 1, 1956.

8.4. Data Acquisition and Metric Development

This program will acquire data on asset health and performance. This information will be used to develop key performance indicators and operational

metrics for the C&P and M&P assets.[367] PG&E notes "Developing this program will enable PG&E to obtain a comprehensive understanding of how certain assets perform and when replacements and repairs are necessary."[368] The scope of the program will include development and implementation of database tools to automate data collection and trending. PG&E forecasts $1.6 million for this program in 2015.

Indicated Shippers contends that this program is also the "direct result of PG&E's failure to collect and maintain data."[369] Further, Indicated Shippers argues that the scope of the program is preliminary since PG&E has not identified the metrics to be measured, the data to be collected and the cost of data collection. Therefore, it maintains that PG&E should be required to complete this work, but should not receive recovery for the collection of any data PG&E should have already collected. Indicated Shippers proposes that all costs for this program should be tracked in a memorandum account and PG&E should be permitted to seek recovery in a later reasonableness review.[370]

PG&E disputes Indicated Shippers assertions, noting that the documents gathered in the Critical Documents Program are facility drawings, which do not feed into the analysis of asset health. The intent of the Data Acquisition and Metric Development Program, on the other hand, is to capture this data in an automated form that allows for continual update and communication of station health and performance to enable identification of appropriate mitigation

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[367] Exh. PG&E-1 at 6-33.

[368] Exh. PG&E-1 at 6-33.

[369] *Indicated Shippers Opening Brief* at 187.

[370] *Indicated Shippers Opening Brief* at 188.

actions.[371] Further, PG&E states that its cost forecast is based on a defined scope of work that includes the specifications and software tools necessary to calculate the metrics.

We find PG&E's request for this program to be fully supported by the evidence and adopt its forecast of $1.6 million for this program in 2015.

8.5. Physical Security

The Physical Security Program would include projects to enhance security measures at critical facilities. PG&E notes that while its critical facilities have been outfitted with security technology, including alarms, access systems and cameras, additional security measures are required.[372] PG&E's requests mitigation measures above what is currently recommended by the Transportation Security Administration, but what PG&E believes is appropriate in light of recent experience. These measures would address emerging threats, including small arms and improvised explosive devices.[373]

PG&E forecasts $1 million in expense and $2.7 million in capital expenditures for this program in 2015. No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this project.

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[371] Exh. PG&E-39 at 6-15.

[372] Exh. PG&E-1 at 6-42 – 6-43.

[373] Exh. PG&E-1 at 6-43.

8.6. Becker System Upgrades

This program would upgrade operational abilities of Becker Control Valve Systems and increase the safety and quality of PG&E gas control systems. The following initiatives would be included:

- Retrofitting approximately 300 Becker racks/cabinets installed at approximately 70 stations throughout the PG&E service territory.
- Replacing 12 Becker High Pressure Positioners installed at five gas transmission stations.[374]

PG&E expects the program to be completed during the Rate Case Period. PG&E forecasts $3.4 million in 2015 capital expenditures for the program. No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this project.

8.7. Gas Quality Practice Assessment

This program would combine new and existing PG&E activities in the area of gas quality into a single, comprehensive program. The program would implement new rules considered by the Commission that would require operators to: 1) develop and implement a program to monitor, analyze and prevent liquid nitrogen intrusion and sulfur buildup in the pipeline system and 2) require operators to accept and transport landfill gas.[375] PG&E forecasts $2.1 million in expense for this program.

No party raised specific objections to PG&E's forecast expenditures. We find the forecast reasonable and adopt PG&E's forecast for this project.

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[374] Exh. PG&E-1 at 6-53.

[375] Exh. PG&E-1 at 6-55.

8.8. Gill Ranch O&M

This program provides funding for operating and maintenance expenses related to the operation of the Gill Ranch Storage Facility. PG&E is a minority partner (25% ownership) in the facility and must provide funding for its share of operating and maintenance costs.[376] PG&E forecasts $2.3 million in expenses for 2015 based on historical costs. No party raised specific objections to PG&E's forecast expenditures. We find the forecast reasonable and adopt PG&E's forecast for this program.

8.9. Routine Expense

Routine expense projects arise in the course of normal operation of M&C and C&P facilities and include repair or replacement of failed or malfunctioning equipment, compressor unit overhauls, inspection and testing of asset components, and needed modifications to address equipment safety or performance issues.[377] PG&E's forecast $16.0 million in costs for 2015 based on historical five-year data.

We find the forecast reasonable and adopt PG&E's forecast for Routine Expense.

8.10. Burney K-2 Compressor Replacement

This project would replace the compressor unit at Burney Compressor Station. The station was put into service in 1969, and turbine unit 9 (the K-2 Unit) is no longer able to receive direct parts and service support from the

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[376] Exh. PG&E-1 at 6-56.

[377] Exh. PG&E-1 at 6-57.

original equipment manufacturer.[378] PG&E therefore proposes to replace the K-2 Unit with a unit that is fully supported by the manufacturer. PG&E forecasts capital expenditures of $26.75 million in 2015.

We find the forecast reasonable and adopt PG&E's forecast for this project.

8.11. Los Medanos K-1 Compressor Replacement

This project would replace the compressor unit at the Los Medanos Underground Storage Facility. This compressor was put in service in 1981 and is used to inject gas into the gas reservoir. PG&E states that the compressor is reaching the end of its service life and has experienced frequent unscheduled outages which impact service reliability and operating flexibility. PG&E forecasts capital expenditures of $28 million in 2017.[379] PG&E further notes that if the joint stipulation with ORA regarding Post Test Year Ratemaking is adopted, this project cost would be subsumed within the 2017 revenue requirement computation.[380]

We find the forecast reasonable and adopt PG&E's forecast for this project.

8.12. Compressor Unit Control Replacements

This program will systematically replace the Programmable Logic Controller (PLC) in compressor units. The unit PLC monitors and controls the operation of the compressor unit. PG&E states that life span of a compressor unit PLC is 15-20 years and the oldest units are reaching the end of their service

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[378] Exh. PG&E-1 at 6-34.

[379] Exh. PG&E-1 at 6-34 – 6-35.

[380] *PG&E Opening Brief* at 9-18.

life.[381] PG&E has been notified by the manufacturer that these PLCs will no longer be supported, which will make obtaining replacement parts and technical support difficult.

PG&E plans to replace three PLCs during the Rate Case Period, or one per year. It forecasts $1.6 million in capital expenditures in 2015. No party raised specific objections to PG&E's forecast expenditures. We find the forecast reasonable and adopt PG&E's forecast for this program.

8.13. Upgrade Station Controls

The station PLCs are part of a complex process control system that enables operators to control the direction and flow rate of incoming natural gas, and are responsible for the quick and safe activation of the emergency shutdown system in the event of an emergency.[382] The manufacturer of the input/output interface module used by the station PLCs has informed PG&E that it will stop supporting this product in the near future. PG&E proposes to replace station controls at a pace that will minimize impact on operations and the need to replace an unacceptably large number of units at one time. During the Rate Case Period, PG&E will replace two station PLCs – one in 2016 and one in 2017 – at a cost of $1.6 million each year.[383]

No party raised specific objections to PG&E's forecast of these expenditures. PG&E's forecast is adopted. Further, in accordance with Exhibit Joint-3, *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year Mechanism*,

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[381] Exh. PG&E-1 at 6-35.

[382] Exh. PG&E-1 at 6-36.

[383] Exh. PG&E-1 at 6-37.

the costs for the Upgrade Station Controls project will be subsumed within the 2016 and 2017 revenue requirement computations.

8.14. Emergency Shutdown System Upgrades

The Emergency Shutdown System is installed at all compressor stations and underground gas storage facilities. These systems are designed to immediately, automatically and safely stop operation of equipment, isolate the station piping and safely vent the natural gas within the station to the atmosphere upon detection of an emergency condition.[384] The gas and fire detection sensors currently installed at the facility utilize an older technology. PG&E's program would upgrade the gas and fire sensors to newer technology at one facility each year.

PG&E forecasts $2.7 million in capital expenditures for this program in 2015. No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this program.

8.15. Rebuild Santa Rosa Compressor Station Electrical Substation

PG&E proposes to replace the electrical system at the Santa Rosa Compressor Station, which was put into service in 1968. The station operates primarily during the winter months to help meet Cold Winter Day gas demands. PG&E has identified a need to replace the electrical system to improve the reliability of overall station operations and safety for employees working on the equipment.[385]

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[384] Exh. PG&E-1 at 6-37.

[385] Exh. PG&E-1 at 6-39.

PG&E forecasts $3.7 million in capital expenditures for this project. No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this project.

8.16. Upgrade Pleasant Creek Processing Facilities

This project would upgrade the processing equipment at the Pleasant Creek facility. PG&E states that the upgrade would restore reliability and integrity while keeping the withdrawal rate at 60 Million Standard Cubic Feet per Day.

PG&E forecasts $2.1 million in capital expenditures for this project in 2015. No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this project.

8.17. Gas Transmission Electrical Upgrades – Hinkley and Topock Compressor Stations

This program will update the switch gear sections (SWGR) and Motor Control Centers (MCC) located within station fences. PG&E states that maintaining the condition of these components is important to the reliability of the compressor station and the safety of station personnel.[386] The Hinkley and the Topock Compressor Stations were constructed in the 1950s and contain originally installed electrical equipment. To minimize operational impacts, the program would update the electrical equipment for the Hinkley or the Topock Compressor Station during the Rate Case Period.

PG&E forecasts $1.7 million in capital expenditures for the upgrades. The upgrades would occur in 2017.[387] No party raised specific objections to PG&E's

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[386] Exh. PG&E-1 at 6-41.

[387] *PG&E Opening Brief* at 9-22.

forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this project. In accordance with Exhibit Joint-3, *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year Mechanism*, the costs for this program will be subsumed within the 2017 revenue requirement computation.

8.18. Gas Transmission Electrical Upgrades – Compressor Stations (Excluding Hinkley, Topock, and Santa Rosa)

This program will upgrade the electrical equipment installed at compressor stations other than Hinkley, Topock or Santa Rosa Compressor Stations. It provides for the replacement of up to four SWGR sections and four MCC sections during the Rate Case Period.[388]

PG&E forecasts $1.8 million in capital expenditures for the upgrades. The upgrades would occur in 2016.[389] No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this project. In accordance with Exhibit Joint-3, *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year Mechanism*, the costs for this program will be subsumed within the 2016 revenue requirement computation.

8.19. Hinkley Compressor Unit Retrofit Project

PG&E proposes to equip a non-retrofitted compressor at Hinkley Compressor Station with a High-Pressure Fuel Injection Nitric Oxide retrofit which would reduce the overall Nitric Oxide emission of the facility. PG&E

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[388] Exh. PG&E-1 at 6-42.

[389] *PG&E Opening Brief* at 9-22.

states that seven compressors at the Hinkley Compressor Station are already equipped with the retrofit. PG&E notes that the retrofitted compressor units are permitted to operate 365 days a year, 24 hours a day, while the five non-retrofitted compressor units are limited to 1,500 hours per (rolling) year. PG&E maintains that retrofitting an additional non-retrofitted compressor unit would increase the overall reliability of the station.[390] PG&E forecasts $6.0 million in capital expenditures in 2016 and $6.2 million in capital expenditures in 2017 for this project.

ORA opposes the request to retrofit an additional compressor unit at Hinkley. It states that based on PG&E's response to an ORA data request, the current retrofitted compressors do not operate close to their permitted operating hours.[391] ORA therefore asserts that "the current mixed [sic] of compressors are providing reliable service, therefore no funding should be provide[d] to retrofit an additional unit."[392]

PG&E disagrees with ORA's conclusions. It notes that because the non-retrofitted compressor units are limited based on a rolling 12-month timeframe, there have been instances where multiple non-retrofit units have approached the 1,500-hour limits.[393] Further, it notes that due to the different horsepower ratings of the compressor units,"[s]everal of the non-retrofit units were approaching a usage of 45 percent, which is a rate that would consume the

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[390] Exh. PG&E-1 at 6-44.

[391] *ORA Opening Brief* at 129 (citing Exh. ORA-68 at 13).

[392] *ORA Opening Brief* at 129.

[393] Exh. PG&E-39 at 6-20.

rolling 12-month run-hours in a four to five-month period."[394] Finally, PG&E argues that "[h]igh Baja Path utilization coupled with a long duration K11 or K12 outage would exhaust available non-retrofit operating hours."[395]

We find that PG&E has presented persuasive arguments why an additional compressor unit should be retrofitted. We therefore adopt PG&E's forecast.

8.20. Install Active Fire Suppression Systems

PG&E proposes to install active, fixed fire suppression systems at gas transmission and processing compression facilities. PG&E states that a fixed fire suppression system would supplement the Emergency Shutdown System and help contain the fire and mitigate equipment damage and loss of service.[396]

PG&E forecasts $0.5 million in capital expenditures in 2015. No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this project.

8.21. Perform Simple Station Rebuilds

Simple station rebuild projects are intended to address station equipment aging and obsolescence.[397] The frequency of station rebuilds is based on the condition of the station and on maintaining an overall average age of approximately 30 years.

PG&E plans a total of 22 rebuilds of pressure regulating facilities that have simple controls and operation over the life of the program. Thirteen facilities

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[394] Exh. PG&E-39 at 6-21.

[395] Exh. PG&E-39 at 6-22.

[396] Exh. PG&E-1 at 6-46.

[397] Exh. PG&E-1 at 6-46.

will be rebuilt during the Rate Case Period. PG&E forecasts $19.66 million of capital expenditures for the program in 2015.

Indicated Shippers raises two concerns with respect to PG&E's proposed station rebuilds. It questions whether PG&E will be collecting critical documents for stations to be rebuilt and the appropriateness of adopting a replacement strategy based on asset age, with no consideration of asset condition.[398] Consequently, Indicated Shippers recommends that costs associated with station rebuilds be placed in a memorandum account and that PG&E demonstrate that complete rebuilding was a least-cost risk management strategy.[399] Further, it recommends that PG&E exclude from recovery in this proceeding rebuild of any stations that are more appropriately treated as distribution stations.

PG&E addressed Indicated Shippers' concerns in rebuttal testimony. PG&E states that it will coordinate both station rebuild programs and the Critical Documents Program to avoid duplication and optimize efficiencies. Further, it states that its station rebuild strategy considers a number of factors in addition to the age of the station, such as operational issues and cost of maintaining the station. Finally, PG&E states that it has defined its transmission station assets based on PG&E Utility Standard TD-4551S, so no distribution stations are included.[400]

We find that PG&E has addressed all of Indicated Shippers' concerns. We find PG&E's forecast for simple station rebuilds reasonable and adopt PG&E's forecast for this program.

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[398] Exh. IS-6 at 134-135.

[399] Exh. IS-6 at 135.

[400] Exh. PG&E-39 at 6-24.

8.22. Perform Complex Station Rebuilds

The complex station rebuild projects are also intended to address station equipment aging and obsolescence. PG&E uses similar criteria for determining priority of complex station rebuilds as it does for simple station rebuilds. PG&E plans to perform a total of six complex station rebuilds during the Rate Case Period.[401] PG&E forecasts $8.2 million of capital expenditures for the program in 2015.

Indicated Shippers raise the same concerns as with simple station rebuilds. These concerns have been considered and addressed above. As noted, PG&E has addressed all of Indicated Shippers' concerns. We find PG&E's forecast for complex station rebuilds reasonable and adopt PG&E's forecast for this program.

8.23. Perform Transmission Terminal Upgrades

PG&E plans to upgrade all three existing transmission terminals during the Rate Case Period. The upgrade work will include replacing piping, manual valves, control valves, metering equipment, pipe supports, and SCADA equipment within the station block valves as warranted.[402]

PG&E forecasts $2.1 million in capital expenditures in 2015. No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this project.

8.24. SCADA Visibility

This program provides for additional pressure and flow measurement sensors that will be connected to PG&E's Transmission SCADA system. PG&E

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[401] Exh. PG&E-1 at 6-48.

[402] Exh. PG&E-1 at 6-49.

states that the new data points will allow it to better monitor the stations and respond more quickly to inadvertent valve closures within stations.[403]

PG&E forecasts $5.7 million in capital expenditures in 2015. No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this project.

8.25. Replace Obsolete Bristol Controllers

This program will replace obsolete valve control equipment manufactured by Bristol Controls. PG&E states that these controllers have limited parts and service support and have reached the end of their useful lives. There are approximately 95 Bristol valve controllers in PG&E's gas system, and PG&E plans to replace up to 12 of these controllers every year beginning in 2015.[404]

PG&E forecasts $1.5 million in capital expenditures in 2015. No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this program.

8.26. Replace Obsolete Limitorque Valve Actuators

This program will replace valve actuators manufactured by Limitorque that have limited parts and service support, and have reached the end of their useful lives. There are approximately 50 of these actuators remaining in the gas system, and PG&E plans to replace up to 12 actuators each year beginning in 2015.[405] Based on the pace of work, the replacement program is expected to be completed by 2018.

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[403] Exh. PG&E-1 at 6-49.

[404] Exh. PG&E-1 at 6-50.

[405] Exh. PG&E-1 at 6-51.

PG&E forecasts $1.5 million in capital expenditures in 2015. No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this program.

8.27. Electrical Upgrade Program

This program was developed to find those gas transmission stations that have installed electrical equipment or station design that do not meet the National Fire Protection Association Standard 70 (National Electric Code) or Standard AGA XL 1001, "Classification of Locations for Electrical Installations in Gas Utility Areas" requirements.[406] When deficiencies are found, remediation can include replacement or relocation of electrical equipment and wiring, rerouting piping, or enlarging the station footprint.

PG&E forecasts $1.1 million in capital expenditures in 2015, which would provide for upgrades at three stations each year over the Rate Case Period. No party raised specific objections to PG&E's forecast of these expenditures. We find the forecast reasonable and adopt PG&E's forecast for this program.

8.28. Biomethane Interconnects

Assembly Bill (AB) 1900 (Stats. 2012, ch. 602) establishes a process to promote and facilitate the injection and use of biomethane in to common carrier pipelines. AB 1900 also required the Commission to adopt standards by December 31, 2013 for acceptance of biomethane into the pipeline system. The Commission opened Rulemaking (R.) 13-02-008 to implement AB 1900.

The Biomethane Interconnects Program provides for the installation of nine (three per year) interconnection stations during the Rate Case Period

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[406] Exh. PG&E-1 at 6052.

necessary to accommodate biomethane from sources such as landfills and water treatment plants.[407] PG&E forecasts $4.8 million in capital expenditures in 2015.

On January 16, 2014, the Commission issued D.14-01-034, which adopted monitoring, testing, reporting, and recordkeeping protocols. However, it deferred to a second phase the issue of who should bear the costs of meeting the standards and requirements adopted in D.14-01-034.

ORA opposed PG&E's forecast, noting that PG&E's current tariffs require the supplier of gas to the system to pay for interconnection costs, including biomethane gas suppliers.[408] ORA therefore recommends that ratepayer funding for this program should be rejected.

PG&E argues that since it has included the forecast of interconnect costs in this proceeding, it would be more appropriate for the Commission to address them here. It maintains "once the cost recovery allocation issues are resolved, the decision on cost recovery can then be applied to whatever costs are adopted in this proceeding."[409]

On June 11, 2015, the Commission issued D.15-06-029, which determined that the costs of complying with the standards and protocols adopted by D.14-01-034 should be borne by the biomethane producers.[410] However, the decision included a five-year monetary incentive program to encourage biomethane producers to design, construct, and to successfully operate biomethane projects

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[407] Exh. PG&E-1 at 6-54.

[408] Exh. ORA-11 at 11.

[409] *PG&E Opening Brief* at 9-30.

[410] D.15-06-029 at 1.

that interconnect with the gas utilities' pipeline systems.[411] Further, the decision adopted the mechanism for the utilities to recover any monetary incentive distributed from ratepayers.[412] Since D.15-06-029 has addressed how PG&E may recover funds from ratepayers for biomethane interconnections, PG&E's request for funding in this program is now moot and is denied.

8.29. Routine Capital Spending

PG&E requests $53.4 million in capital expenditures in its Routine Capital Spending program. This forecast is based on historical five-year data after removing large dollar one-time projects.[413] No party raised specific objections to PG&E's forecast. We find the forecast reasonable and adopt PG&E's forecast for routine capital spending.

9. Corrosion Control

9.1. Overview

9.1.1. PG&E's Request

Corrosion is a naturally occurring process that reduces the effectiveness of steel to contain pressurized natural gas. It is defined as a "time dependent" threat that occurs over time and adversely affects the longevity and reliability of natural gas pipelines, valves, pressure vessels, and other pipeline appurtenances such as compressors, metering and regulator stations. There are four types of

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[411] D.15-06-029 at 44-46 (Ordering Paragraph 2).

[412] D.15-06-029 at 46-47 (Order Paragraphs 3 and 4).

[413] Exh. PG&E-1 at 6-57.

corrosion threats to pipelines, three of which are addressed in the Corrosion Control Program[414]:

- External Corrosion – This is a loss of metal that starts on the outside of the pipeline or appurtenance. It occurs when moisture in the soil comes in contact with the steel surface of the pipeline, and can be exacerbated by site-specific factors such as alternating current (AC) and direct current (DC) interference. AC interference can be present when natural gas pipelines are near or adjacent to electrical transmission lines; DC interference occurs when the pipeline picks up a stray current that is leaked by an external DC power system (such as from transit systems) and into the soil.

  Cathodic Protection (CP) systems help prevent external corrosion by use of either a galvanic anode that corrodes in place of the protected material or a rectifier.
  49 CFR 192.455-473 set forth the requirements for external corrosion control.

- Internal Corrosion – This is a loss of metal that starts on the inside of the pipeline or appurtenance and a consequence of exposure to natural gas containing certain constituents, such as oxygen, hydrogen sulfide, and/or carbon dioxide, combining with liquid water, chlorides or microbes. 49 CFR 192.475-477 set forth the requirements for internal corrosion control.

- Atmospheric Corrosion – This involves metal loss on the outside surfaces of appurtenances when exposed to moisture in the air.[415] 49 CFR 192.479-481 set forth the requirements for atmospheric corrosion

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[414] PG&E notes that the programs to address the fourth type of corrosion threat, stress corrosion cracking, is discussed in Transmission Integrity Management and Emergency Response Programs.

[415] Exh. PG&E-1 at 7-8 – 7-10.

PG&E ranks corrosion as one of its top risks for natural gas transmission assets. Consequently, starting in 2013, it has initiated significant improvements to its Corrosion Control Program to bring the program in alignment with industry practices and reduce the risk of corrosion-related incidents. PG&E notes that this will require a significant increase in corrosion control spending. PG&E's corrosion-related capital and expense forecasts are summarized below:

Table 23
Corrosion Control
Forecast 2015 Expenses[416]
($ Thousands of Nominal Dollars)

Cathodic Protection (CP) Rectifier	$ 450
CP Monitoring	1,820
CP Resurvey	177
CP Troubleshooting	177
CP Corrective Maintenance	1,340
Corrosion Investigations	5,455
Close Interval Survey	8,759
Alternating Current Interference	528
Direct Current Interference	2,552
Casings	48,504
Internal Corrosion	8,784

[416] Exh. PG&E-1 at 7-3, Table 7-1.

Atmospheric Corrosion Inspection and Remediations	20,437
Total Expenses	**$98,982**

Table 24
Forecast Corrosion Control Capital Expenditures[417]
($ Thousands of Nominal Dollars)

Description	2015 Forecast	2016 Forecast	2017 Forecast
External Corrosion			
CP Systems – Replace	$ 3,252	$ 3,335	$ 3,423
CP Systems – New	8,186	8,393	8,614
Coupon Test Stations	5,136	6,582	6,756
AC Interference Mitigation	10,350	16,518	15,051
DC Interference Mitigation	802	822	844
Casings	21,039	21,141	13,068
Internal Corrosion	535	658	845
Total Capital Expenditures	**$43,900**	**$57,448**	**$48,600**

PG&E acknowledges that its historical corrosion control program had not been fully compliant with regulatory requirements. However, it maintains that the increased costs as a result of the expanded corrosion control program are not to remediate any existing non-compliance with regulation. PG&E states it has

[417] Exh. PG&E-1 at 7-4, Table 7-2.

excluded $23 million in expenses and $21 million in capital expenditures from its forecast to correct the non-compliance.[418]

9.1.2. Intervenors' Positions

Intervenors all attribute the significant increase in forecast expenses and capital expenditures to PG&E's failure to perform necessary corrosion control activities in the past. They also believe PG&E has not excluded all costs associated with its failure to comply with regulatory requirements.

ORA

Although ORA agrees that PG&E's corrosion control program requires increased funding, it believes that the shareholder portion should be larger because "much of PG&E's capital and expense forecast appears to consist of deferred maintenance to be performed in order to bring PG&E's gas transmission facilities into compliance with longstanding federal regulations."[419] In particular, ORA notes that much of the increased corrosion control forecast is to mitigate pipeline with contacted casings dating back to at least 2004, even though there were "multiple audits over a period of years warning PG&E of its lack of compliance with applicable regulations."[420] Consequently, ORA recommends cost caps for ratepayers in order to ensure that shareholders are also responsible for some of the costs associated with PG&E's deferral of pipeline maintenance.

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[418] *PG&E Opening Brief* at 10-3.

[419] Exh. ORA-40 at 1.

[420] *ORA Opening Brief* at 132.

ORA recommends reductions in capital expenditures and expenses for certain programs. ORA's recommendations, as compared to PG&E's request, are summarized below.[421]

Table 25
PG&E Forecast vs. ORA Recommendation
Corrosion Control 2015 Forecast Expenses[422]

Description	PG&E Forecast	ORA Recommend
AC Interference	$ 527,5007	$ 0
DC Interference	2,551,869	2,024,231
Casings	48,503,848	4,895,618
Atmospheric Corrosion Inspection and Remediations	20,437,046	16,143,948
Total	**$72,020,263**	**$23,063,797**

Table 26
PG&E Forecast vs. ORA Recommendation
Corrosion Control 2015 Capital Expenditures[423]

Description	PG&E Forecast	ORA Recommend
AC Interference Mitigation	$10,349,647	$ 5,750,555
DC Interference Mitigation	801,786	400,893

[421] ORA notes "the lack of a specific ORA disallowance or forecast in some program areas should not be taken to constitute agreement with PG&E's proposals." (Exh. ORA-40 at 2.)

[422] *ORA Opening Brief* at 132-133; *see* also, Exh. ORA-40 at 2 (Table 7-1).

[423] *ORA Opening Brief* at 132-133; *see* also, Exh. ORA-40 at 3 (Table 7-2).

Casings	21,083,693	1,935137
Total	**$32,235,126$**	**$8,086,585**

Indicated Shippers

Indicated Shippers believes PG&E has neglected its corrosion control activities in the past, often leading to regulatory non-compliance. Indicated Shippers argues that PG&E had historically deferred work on corrosion control. As support, it points to the magnitude of PG&E's proposed spending and the proposed pace of work in comparison to work over the past decade.[424] Indicated Shippers further notes that the Exponent Phase 1 report, which assessed PG&E's compliance with corrosion control requirements, disclosed serious concerns with PG&E's corrosion control program, including that 15% of PG&E's corrosion control activities were noncompliant with federal code.[425]

Indicated Shippers also notes that PG&E's corrosion control witness was unfamiliar with and unable to explain the corrosion control proposals. It cites to multiple instances where the witness demonstrated his lack of knowing how the cost forecasts were developed, the details encompassed within the proposed mitigation work, PG&E's Risk Management Program.[426] It argues that in light of the sponsoring witness's unfamiliarity with the program, he could not demonstrate that PG&E's proposals were just and reasonable.

Finally, Indicated Shippers asserts that PG&E has underestimated the amount of costs that should be excluded due to non-compliance. It notes that the

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[424] *Indicated Shippers Opening Brief* at 195.

[425] *Indicated Shippers Opening Brief* at 197-199.

[426] *Indicated Shippers Opening Brief* at 199-200.

Exponent reports assessing PG&E's compliance and best practices were not issued until after PG&E had filed its application in this case. Therefore Indicated Shippers believes the full extent of PG&E's non-compliance issues is yet to be determined.[427]

Indicated Shippers recommends that the Commission deny recovery of costs for the corrosion control program and that all costs be funded by PG&E shareholders. It argues that full disallowance is justified in light of PG&E's failure to demonstrate that the costs were just and reasonable. Indicated Shippers states that if the Commission declines to adopt this recommendation, it should adopt ORA's forecast costs. Further, Indicated Shippers urges that the Commission require an independent third-party financial audit and separate engineering audit of the corrosion control program be performed, with costs of the audits funded by PG&E shareholders.[428]

TURN

TURN also urges that the Commission disallow recovery of all of PG&E's requested expense and capital amounts for corrosion. In the alternative, it proposes disallowances for the individual activities, ranging from 50% to 100%.[429]

TURN contends that PG&E had known its corrosion control program was deficient. As support, TURN cites to two PG&E internal audits, conducted in 2010 and 2011, 49 separate Commission adverse audit findings from 2008

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[427] *Indicated Shippers Opening Brief* at 202.

[428] *Indicated Shippers Opening Brief* at 203.

[429] *TURN Opening Brief* at 156.

through 2013 and 11 self-reported violations by PG&E.[430] TURN further references corrosion control issues identified in the March 2014 Exponent report and summarizes:

> as PG&E was preparing its forecast for this case, the company knew or should have known that: (1) there were significant and widespread deficiencies in PG&E's corrosion control program; (2) the company had allowed these problems to fester for a long time; and (3) these deficiencies would need to be addressed in the coming years.[431]

TURN notes that despite the deficiencies in its corrosion control program, PG&E failed to provide the "fundamental information necessary for the Commission to determine whether PG&E's exclusion amounts are reasonable."[432] It discusses in detail various instances where PG&E's testimony or responses to data requests failed to explain the basis for the exclusion amounts, how the amounts were calculated, or the specific work activities PG&E considered to be remedial in nature.[433] Further, similar to Indicated Shippers, TURN references the fact that PG&E's exclusions do not take into account non-compliance issues identified in the Exponent reports.

TURN further notes that PG&E did not exclude any costs for casing remediation, even though both the PHMSA interpretation and PG&E's own internal auditors found the company out of compliance.[434] Moreover, TURN

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[430] *TURN Opening Brief* at 158-159.

[431] *TURN Opening Brief* at 160.

[432] *TURN Opening Brief* at 157.

[433] *TURN Opening Brief* at 161-162.

[434] *TURN Opening Brief* at 170 (citing Exh. PG&E-40 at 7-16 (Table 7-4).

accuses PG&E of narrowly applying the PHMSA guidance regarding AC Interference inspection and mitigation, Atmospheric Corrosion mitigation and Corrosion Investigations to limit excluded amounts to only those instances where the forecast work was to remedy regulatory violations.[435]

TURN also challenges the credibility of PG&E's corrosion control witness, noting that he did not work in the corrosion engineering group and had no role in developing PG&E's corrosion control forecast. In particular, TURN notes the marked differences between the witness' responses during cross-examination and re-direct examination.[436] TURN argues that the witness' responses upon re-direct examination should be given no weight, since it was the result of coaching by counsel. Consequently, TURN contends that PG&E has failed to demonstrate that its forecasts and exclusions for corrosion control are just and reasonable.

TURN argues that in light of PG&E's past actions, the Commission should disallow the full $99 million of expenses and $49 million of capital expenditures that PG&E proposes to recover from ratepayers in 2015. TURN states, "such a determination would be entirely fair in light of PG&E's willful failure to make the case that its forecast work is not the result of imprudence, even in the face of PG&E's own admission of significant deficiencies in its corrosion control work."[437]

Finally, TURN recommends that all capital disallowance amounts should be permanent disallowances. TURN makes this recommendation because PG&E has stated that while it proposed to keep the self-determined capital exclusion

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[435] *TURN Opening Brief* at 171.

[436] *TURN Opening Brief* at 166-168.

[437] *TURN Opening Brief* at 172.

amounts out of rate base during the Rate Case Period, it intends to seek rate recovery for excluded capital expenses in the next rate period. TURN notes that PG&E's position is contrary with its prior representation to SED that any remedial work to comply with regulations would be funded by PG&E's shareholders. Additionally, TURN argues that its recommendation is consistent with both the *PSEP Decision* and the *Penalties Decision*, in which disallowed capital expenditures were permanently excluded from PG&E's rate base.[438]

9.1.3. Discussion

While there is no dispute that the corrosion control programs are needed, there is significant disagreement over whether PG&E shareholders should bear responsibility for a portion of these costs. PG&E maintains that the significant increases are in response to the heightened awareness of the impact of corrosion on transmission pipelines. It notes that its shareholders are already bearing a portion of these costs, as it has already excluded costs associated with work due to non-compliance from its forecast. Further, PG&E argues, even if Intervenors were correct that PG&E acted imprudently in the past, the forecast rates are still just and reasonable, as PG&E had not received ratepayer funding for the work it is proposing.

We disagree with PG&E's proposition that PG&E shareholders cannot be responsible for a greater portion of corrosion control costs. As we have previously discussed, PG&E bears the burden of showing that its forecasts are just and reasonable. While discussion of the exclusions may support PG&E's arguments that its forecasts are reasonable, it does not have greater weight than

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[438] *TURN Opening Brief* at 173.

other evidence presented. Here, Intervenors have presented evidence to support their arguments that the amount of exclusions does not account for all instances of prior imprudence. We therefore must consider all evidence in determine whether further disallowances are warranted to ensure that rates are just and reasonable.

We disagree with PG&E's proposition that, notwithstanding any prior imprudence on the part of PG&E's management, the forecast costs can only be considered unreasonable if PG&E had previously recovered these amounts in rates and never performed the work. PG&E appears to believe that even if it acted imprudently in the past, any disallowances of costs for work that had previously not been funded by ratepayers would be a "penalty."[439] PG&E is incorrect. We considered a similar argument raised by the Sempra Utilities in connection with potential disallowance of certain PSEP costs and concluded:

> SDG&E and SoCalGas's witness would have us believe that any disallowance for unreasonable, imprudent costs, i.e., a regulatory disallowance, is a penalty. We do not believe that. A better descriptor would be "consequences" which can be defined as "a result or affect, typically one that is unwelcome or unpleasant," and the Oxford English Dictionary uses the example "to bear the consequences," meaning "accept responsibility for the negative results or effects of one's choices or action." The Oxford English Dictionary also defines the word penalty as "a punishment imposed for breaking a law, rule, or contract."
>
> It is quite clear that any costs which may be disallowed in a subsequent proceeding are merely the proper consequences of imprudent actions by the utility and do not constitute a penalty. In addition to those consequences however, the Commission has

[439] *PG&E Reply Brief* at 10-4.

> the authority and may in fact impose a penalty when the act that was imprudent also breaks a law, a rule, or contract.[440]

We therefore find that, if warranted, PG&E shareholders should bear a greater portion of corrosion control costs. Consistent with our discussion in Section 3 above, we will consider, for each of the corrosion control programs identified, whether the forecast work is the result of: (1) PG&E's failure to originally perform the work properly, or (2) PG&E's failure to comply with regulatory requirements that it was previously funded to satisfy. If we find either of the above reasons to exist, we will determine what portion, if any, of the forecast costs should be borne by PG&E shareholders.

We decline to adopt TURN and Indicated Shippers' recommendation to disallow all forecast corrosion control costs. Taking such an approach would require us to conclude that none of PG&E's past corrosion control work had been performed properly and that had it so been, no future ongoing corrosion control work would be needed. However, there is no evidence to support such a conclusion.

We decline to adopt Indicated Shippers' recommendation for an independent third-party financial audit and a separate engineering audit of the corrosion control program. Pursuant to the *Gas Accord V Decision*, PG&E has been preparing and filing spending reports every six months that compare recorded spending to adopted funding. Further, the *PSEP Decision* directed PG&E to submit quarterly compliance reports. In its reply brief, PG&E states that it will continue to prepare these reports unless ordered otherwise.[441] Since

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[440] *Sempra PSEP Decision* [D.14-06-007] at 32 (citations omitted).

[441] *PG&E Reply Brief* at 10-33.

we have determined that the quarterly compliance reports should continue, and in light of the future financial audits required as part of the *Penalties Decision*, we find no need for any additional financial audits. We also find no need to order a separate engineering audit at this time. An assessment of PG&E's corrosion control program was performed by Exponent within the past five years. Indicated Shippers has not demonstrated the need for another outside review at this time.

Finally, we agree with TURN that PG&E's self-identified exclusions and any disallowances for capital expenditures for corrosion control adopted in this decision should be permanently excluded from rate base. As we noted in the *Penalties Decision*, "if PG&E were allowed to collect a rate of return on capital expenditures that its shareholders are required to fund as part of the penalties imposed in these proceedings, this would mute the financial impact of the disallowance over many decades."[442] Similarly, PG&E should bear the full consequence of its prior non-compliance and imprudent actions in the context of its corrosion control programs.

9.2. Routine Cathodic Protection Maintenance

PG&E forecasts $3.963 million of expenses for Routine Cathodic Protection Maintenance (MWC JO) in 2015. The work to be performed consists of the following activities:

- CP Rectifier Maintenance – This activity is mandated under 49 CFR 192.465(b). PG&E's 2015 expense forecast of $0.45

[442] *Penalties Decision* at 95.

million is based on the 2013 budget as well as an estimated increase of 35 new rectifier assets.[443]

- CP Monitoring – This activity is mandated under 49 CFR 192.465(b). PG&E's 2015 expense forecast of $1.82 million is based on the yearly average derived from 2012 unit costs and the forecasted number of monitoring units in 2015.[444]

- CP Resurvey – This activity includes an evaluation of leak history, field current measurement as necessary, and documentation updates to ensure that CP systems are operating effectively. PG&E implemented new procedures for resurveys of transmission Cathodic Protection Areas (CPAs) based on criteria including the amount of pipeline installation and modification, close interval survey data, and external corrosion leak history. PG&E's 2015 expense forecast of $0.177 million is based on recorded costs for distribution CP resurveys, adjusted to take into account more transmission CPA characteristics.[445]

- CP Troubleshoot and Corrective Maintenance – 49 CFR 192.465(d) requires operators to take prompt remedial action to correct any deficiencies indicated by CP monitoring. PG&E's practice is to troubleshoot and mitigate any transmission low reads within 60 calendar days of discovery, if feasible, or to implement temporary measures to bring the cathodic protection back into conformity with acceptable operating criteria and ensure that these locations are permanently mitigated within 12 months. PG&E's 2015 expense forecast of $0.177 million for CP Troubleshoot is based on the 2013 budget; the 2015 expense forecast of

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[443] Exh. PG&E-1 at 7-16 -7-17.

[444] Exh. PG&E-1 at 7-17 – 7-18.

[445] Exh. PG&E-1 at 7-18 – 7-19.

> $1.340 million for CP Corrective Maintenance is based on 2013 actual spend through October 2013.[446]

Both Indicated Shippers and TURN have recommended full disallowance of all maintenance costs. Based on the scope and type of work, we find no basis to conclude that any of the proposed ongoing maintenance work is to correct prior work that had been performed improperly or for work that had previously been included in rates but never performed. Therefore, we adopt PG&E's forecast for Routine Cathodic Protection Maintenance (MWC JO).

9.3. Cathodic Protection Systems

9.3.1. Replace CP Systems

Over time, CP systems will degrade over time and no longer provide adequate levels of protection to the pipeline. PG&E forecasts replacing approximately 38 CP systems each year through the Rate Case Period, at a unit cost per CP replacement of $81,313. PG&E forecasts total capital expenditures for replacing CP systems (MWC 75A) of $3.252 million in 2015, $3.335 million in 2016 and $3.423 million in 2017.[447]

Both Indicated Shippers and TURN have recommended full disallowance of all capital expenditures to replace CP systems. We decline to adopt this recommendation, as there is no evidence that any of the CP stations PG&E proposes to replace are due to prior improper operation or maintenance or operation. Therefore, we adopt PG&E's forecast for Replace CP Systems (MWC 75A).

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[446] Exh. PG&E-1 at 7-19 – 7-20

[447] Exh. PG&E-1 at 7-20 – 7-21.

9.3.2. Install New CP Systems

PG&E plans to install new CP systems on transmission pipelines where CP levels are determined to be inadequate. Additionally, it plans to enhance cathodic protection levels by adopting a more conservative protection criterion of -850 mV "off" as described in the NACE Standard Practice 0169-2007. PG&E estimates over the Rate Case Period, 230 new CP systems will be installed to meet the enhanced criterion and an additional 18 new CP systems will be installed due to routine needs not related to meeting the enhanced criterion.[448] PG&E forecasts the cost of each new CP system at $91,877, for total capital expenditure forecasts of $8.186 million in 2015, 8.393 million in 2016 and $8.614 million in 2017.[449]

Although TURN believes a disallowance of all corrosion control costs is warranted, it notes that if the Commission does not adopt its primary recommendation, the Commission should still disallow all costs for new CP systems. TURN's witness concluded, based on experience and expertise, that a high proportion of the new CP system costs are to bring PG&E's levels of cathodic protection into compliance with 49 CFR 192.455-463. He argues that if PG&E had engaged in continuing surveillance as required by 49 CFR 192.613, PG&E would have determined that its cathodic protection criteria were not effective in stopping external corrosion. Additionally, TURN contends that while PG&E's adoption of a more conservative protection criterion may help PG&E comply with the code requirements, PG&E should have adopted this criterion sooner. In sum, TURN notes that PG&E has been funded by ratepayers

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[448] Exh. PG&E-1 at 7-22.

[449] Exh. PG&E-1 at 7-22 – 7-23.

to meet state and federal cathodic protection requirements and PG&E has failed to demonstrate that the new CP systems are not to remediate past failure to comply with regulatory requirements.[450]

We do not find TURN's arguments compelling. PG&E states that the new CP systems are to enhance cathodic protection levels. Although TURN argues PG&E should have adopted these enhanced requirements earlier, we do not find evidence to support a conclusion that PG&E's failure to do so was to remediate prior improper work or that PG&E had previously sought and received ratepayer funding for new CP systems. Failure to act timely does not render the currently proposed expenditures unreasonable. As we noted in the *PSEP Decision*: "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."[451] PG&E's failure to adopt enhanced cathodic protection requirements earlier reflects, at best, poor management judgment and possible non-compliance of federal regulations. Therefore, we adopt PG&E's forecast for Install New CP Systems (MWC 75A).

9.3.3. Coupon Test Stations

A coupon test station is used to measure the effectiveness of cathodic protection. 49 CFR 192.469 requires that "Each pipeline under cathodic

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[450] *TURN Opening Brief* at 183-184.

[451] *PSEP Decision* at 54. Pub. Util. Code § 463 states in pertinent part: "For purposes of establishing rates for any electrical or gas corporation, the commission shall disallow expenses reflecting the direct or indirect costs resulting from any unreasonable error or omission relating to the planning, construction, or operation of any portion of the corporation's plant which cost, or is estimated to have cost, more than fifty million dollars ($50,000,000), including any expenses resulting from delays caused by any unreasonable error or omission."

protection … must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection." PG&E had previously interpreted this requirement to mean that a coupon station (or contact point) should be monitored approximately every mile along the transmission system. However, as part of its efforts to move towards industry best practices, PG&E adopted a more stringent standard in 2014 to require a monitoring point at least every mile. In 2015, a five-year implementation period was adopted to achieve this increased standard.[452]

PG&E plans to install over 900 new coupon test stations during the Rate Case Period. It notes that the increased number of coupon test stations will also impact the forecasts for CP monitoring, as the additional coupon test stations will require routine maintenance. PG&E forecasts installing 262 coupon test stations in 2015, 367 stations in 2016 and 367 stations in 2017. PG&E forecasts a unit cost of $18,348 per installation, for forecast capital expenditures of $5.136 million in 2015, $6.582 million in 2016 and $6.756 million in 2017.[453]

Although TURN believes a disallowance of all corrosion control costs is warranted, it notes that if this recommendation is not adopted, the Commission should at a minimum reduce the scope and cost of Coupon Test Stations by 50%. TURN notes that in direct testimony, PG&E stated that the company has 1,400 coupon test stations, and is proposing to install almost 1,000 new test stations during the Rate Case Period, or an increase of 70%, due to a new standard of having a test station "at least every mile."[454] TURN contends that PG&E has not

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[452] Exh. PG&E-1 at 7-23.

[453] Exh. PG&E-1 at 7-224.

[454] *TURN Opening Brief* at 185.

presented any credible evidence to support this significant increase. It argues that this new standard is overly restrictive and not required by federal regulations, and that there are less expensive alternatives to installing test stations that would provide the same risk benefit.[455] Therefore, TURN recommends that the pace of work be increased to 10 years, thus decreasing the costs in half.[456]

We find TURN's arguments to have merit. PG&E currently has approximately 4,000 contact points, of which 1,400 are coupon test stations, to monitor the 6,750 miles of pipe in its transmission system.[457] To achieve PG&E's new standard, it will need to add approximately 2,700 more monitoring points. Based on PG&E's testimony, it appears it will only use coupon test stations for the additional monitoring points.[458]

PG&E's more "prescriptive" standard was presented as requiring a monitoring point at least every mile.[459] This standard was subsequently clarified during hearings to add: "Monitoring points may be reduced less than 1 mile if 1 mile intervals are not adequate to determine cathodic protection effectiveness, and conversely monitoring points may be at intervals greater than 1 mile with written approval from corrosion engineering."[460] PG&E contends that this

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[455] Exh. TURN-1 at 19.

[456] *TURN Opening Brief* at 186-188.

[457] Exh. PG&E-1 at 7-24; Exh. PG&E-9 at WP 7-63.

[458] *See*, e.g., Exh. PG&E-39 at 2C-28 (Answer 70); Exh. PG&E-40 at 7-78 – 7-79 (Answers 148 and 149).

[459] Exh. PG&E-1 at 2-23.

[460] 21 RT at 2447:6-16 (PG&E/Armato); *see* also, Exh. PG&E-62.

subsequent revision was needed because it became apparent during TURN's cross-examination of another PG&E witness that TURN interpreted PG&E's initial testimony to install a monitoring point at literally every mile. PG&E's witness therefore corrected his testimony to "clear up the apparent confusion."[461] However, PG&E's "clarification" sounds very much like its original interpretation that there be a monitoring station "approximately every mile."

PG&E also cites to PHMSA enforcement actions against two transmission pipeline operators to support its request for the additional coupon test stations.[462] While it is true that PHMSA cited both Spectra Energy Transmission (CPF-3-2013-1005) and Florida Gas Transmission (CPF-4-2013-1019) for failing to have "sufficient test stations to measure the adequacy of cathodic protection" on certain pipelines, there is nothing in either of these enforcement actions to conclude that either of these pipeline operators interpreted and implemented 49 CFR 192.469 as requiring a monitoring station "approximately every mile." Thus, we find PG&E's reliance on these enforcement actions misplaced.

Moreover, we are concerned that PG&E focuses only on the installation of coupon test stations to meet the requirements of 49 CFR 192.469, when it is clear that the majority of its current contact points are trailing wire or some other type of contact point. As such, it is surprising that alternatives to coupon test stations were not considered.

In sum, we find that PG&E's "new" interpretation of the requirements of 49 CFR 192.469 is simply new words to describe the existing interpretation. As

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[461] *PG&E Reply Brief* at 10-48 - 10-49.

[462] Exh. PG&E-39 at 2C-28.

such, it would be unreasonable to authorize a 70% increase in the number of coupon test stations during the Rate Case Period. Even if the "new" interpretation did adopt a more prescriptive standard, PG&E has not demonstrated that it must install only coupon test stations, especially when there are other alternatives already used as monitoring points on PG&E's system.

PG&E's recorded 2011 and 2012 capital expenditures for coupon test stations equate to approximately 52 coupon test stations installed each year. Based on this, we find that it would be more reasonable to authorize PG&E to install 60 coupon test stations each year, or a total of 180 coupon test stations during the Rate Case Period. This number represents a modest increase in the number of coupon test stations to be installed in light of PG&E's historical spending. Accordingly, PG&E is authorized to recover capital expenditures to install 60 coupon test stations each year of the Rate Case Period. This results in 2015 capital expenditures of $1.76 million.

9.3.4. Corrosion Investigations

Corrosion Investigations work is similar to the Troubleshooting and Corrective Maintenance work generated from routine CP Monitoring. This work is identified when non-routine testing conducted during transmission leak repairs, direct examinations, ECDA and Close Interval Surveys identifies low pipe-to-soil reads.[463]

PG&E forecasts conducting corrosion investigations on 58 miles per year during the Rate Case Period. PG&E forecasts expenses of $5.455 million in 2015.

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[463] Exh. PG&E-1 at 7-24.

PG&E notes that this amount excludes costs to perform corrective work associated with remediating past compliance issues.[464]

Although TURN believes a disallowance of all corrosion control costs is warranted, it notes that if this recommendation is not adopted, the Commission should still impose a full disallowance of expenses for corrosion investigations.[465] TURN notes that this is one of the activities in which PG&E has admitted to significant deficiencies and has self-determined exclusions. TURN notes that in light of PG&E's internal findings of low CP readings and inadequate cathodic protection, the Commission should find that PG&E's operations have been deficient with respect to corrosion investigations. Accordingly, TURN asserts that PG&E has failed to justify the exclusion amount selected and all costs should be disallowed.

PG&E concedes that its Corrosion Investigations Program had not previously been compliant with federal regulations. However, it had also not requested ratepayer funding for Corrosion Investigations in the past.[466] As discussed above, we will not disallow reasonable costs simply because PG&E should have made the expenditures at an earlier time. Here, PG&E has explained the reason for the significant ramp up in Corrosion Investigations expenses.[467] We find PG&E has met it burden and adopt its 2015 forecast expenditures of $5.455 million for Corrosion Investigations.

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[464] Exh. PG&E-1 at 7-25.

[465] *TURN Opening Brief* at 190.

[466] Exh. PG&E-40 at 7-92.

[467] Exh. PG&E-40 at 7-94.

9.4. Close Interval Survey

Close Interval Survey is a method for determining the adequacy of cathodic protection between the coupon test stations. It involves walking the pipeline and taking pipe-to-soil readings on a set interval. Pursuant to 49 CFR Subpart O (Gas Transmission Pipeline Integrity Management), PG&E currently uses Close Interval Survey techniques when ECDA is utilized as the assessment method for High Consequence Areas.[468] In this application, PG&E plans to initiate Close Interval Survey as a new program and to perform pipe-to-soil reads at 10-foot intervals, consistent with industry best practices.[469]

PG&E states that the Close Interval Survey program will be a complementary program with PG&E's "make piggable" program for all pipeline segments that are not assessed by ECDA. PG&E plans to perform the Close Interval Survey on a 15-year cycle, which equate to approximately 400 miles of pipe to be inspected each year. PG&E states that it considered other timeframes, but determined that the 15-year timeframe "balances an appropriate risk reduction pace with resource constraints."[470] PG&E's forecast is based on unit costs derived from like projects for asphalt and ground conditions. PG&E forecasts expenses of $8.759 million in 2015.

Both Indicated Shippers and TURN have recommended full disallowance of all expenses for Close Interval Survey. We decline to adopt this recommendation, as PG&E has fully explained the basis for its forecast costs and

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[468] Exh. PG&E-1 at 7-26.

[469] Exh. PG&E-40 at 7-94.

[470] Exh. PG&E-1 at 7-26.

the scope of work to be performed. Therefore, we adopt PG&E's forecast for Close Interval Survey.

9.5. AC Interference

9.5.1. PG&E's Request

PG&E states that it had previously addressed AC interference-related issues as they occurred, but is now developing a formal program to address the threat more holistically. The AC Interference program would include assessment of PG&E's system where there is a possibility of AC interference, in the form of either AC Coupling or Induced AC, and mitigation where appropriate.[471]

Since 1971, 49 CFR 192.467(f) and 192.473(a) have required PG&E to provide protection and to have in effect "a continuing program" against damage from stray electrical currents. PG&E states that it has identified approximately 7,000 possible AC Coupling interference locations. Approximately half of these locations (3,500) were installed prior to enactment of the federal regulations.[472] PG&E's forecasts include the inspection and estimated mitigation of locations installed prior to 1971; it has excluded costs to inspect and remediate locations installed after 1971.[473]

PG&E plans to evaluate all 7,000 locations with AC Coupling interference over a 10-year period starting in 2013. Approximately 30% of the pre-1971

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[471] Exh. PG&E-1 at 7-28. AC Coupling occurs where gas transmission lines are in close proximity to electrical tower footings or substations and have the potential for arc strikes. Induced AC can occur where overhead electrical lines parallel gas transmission lines and electrical lines with high current can transfer alternating electrical current through magnetic fields to the underground pipeline.

[472] Exh. PG&E-1 at 7-29.

[473] Exh. PG&E-1 at 7-29.

locations would be investigated during the Rate Case Period, and PG&E projects that 18% of these locations will require mitigation. Mitigation for AC Coupling interference can include moving the electric tower or the pipe to increase separation distance or placing high resistance media between the two facilities.

PG&E proposes that until specific Induced AC interference program procedures are developed, it will integrate diagnostic measurements into the routine CP Monitoring. PG&E has identified four specific Induced AC interference projects requiring mitigation during the Rate Case Period.[474] Mitigation for Induced AC interference could include installing a ground system for the affected pipeline or changing the phasing of the electric transmission system.

PG&E's forecast 2015-2017 capital expenditures are based on general design and mitigation work, installation of 110 AC coupon test stations for monitoring, as well as the four specific Induced AC mitigation projects, while the forecast 2015 expenses include the investigation to identify the locations with a possible AC interference threat and to perform the risk ranking of inspection data. PG&E forecasts capital expenditures of $10.350 million in 2015, $16.518 million in 2016 and $15.051 million in 2017. It forecasts 2015 expenses of $0.528 million.[475]

Finally, in connection with the requirements of 49 CFR 192.473, PG&E had submitted a self-report on transmission pipeline segments that were found to be in close proximity of an electric transmission tower without proper protection on

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[474] Exh. PG&E-1 at 7-30 – 7-31.

[475] Exh. PG&E-1 at 7-32.

December 19, 2012. PG&E is performing corrective work associated with this self-report, but is not seeking ratepayer funding for it.

9.5.2. Intervenors' Positions

ORA

ORA notes that due to PG&E's claim that it had performed AC Interference mitigation on an *ad hoc* basis and the 2012 redesign of major work categories, it is unclear the extent to which PG&E's forecast consists of incremental spending. However, ORA notes that PG&E reported that it only performed one AC interference mitigation project between 2005 and 2012, at a cost of $362,424.[476]

ORA recommends disallowance of all of PG&E's 2015 forecast expense mitigation because PG&E has failed to provide workpapers to substantiate that the forecast expenses result in just and reasonable rates.[477] ORA also recommends a disallowance of capital expenditures for AC Interference mitigation, arguing

> PHMSA regulations require that gas pipeline operators monitor for and mitigate stray currents. PG&E does not appear to have performed work in accordance with this nearly 40 year-old regulation.[478]

As support, ORA notes that a 2014 consultant's report stated "at present, PG&E does not have a written plan to identify, test for, and minimize the detrimental effects of stray currents per 49 CFR 192.437(a) and PHMSA part 192

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[476] *ORA Opening Brief* at 144.

[477] *ORA Opening Brief* at 145.

[478] Exh. ORA-40 at 15.

Guidance."[479] Based on its analysis of PG&E's testimony regarding AC mitigation along Line 401, ORA concludes that PG&E had failed to initiate a study into the condition of the mitigation measures until half of the AC mitigations along the line had presumably failed.[480] Accordingly, it recommends that the Commission place a 50% cost cap on funds for mitigation to reflect PG&E's contribution to the need for these projects, for capital expenditures of $5,750,497.

TURN

Although TURN believes a disallowance of all corrosion control costs is warranted, it notes that if the Commission does not adopt this recommendation it should still disallow all costs for AC Interference inspection and mitigation.[481] In addition to its previous arguments, TURN notes that despite the requirements of 49 CFR 192.467(f) and 192.473(a), the Exponent Phase 2 report found that PG&E's processes for identifying and mitigating AC interference provided little guidance, and there was a lack of knowledge in the field regarding AC interference inspection and mitigation. Further, the Exponent Phase 2 report stated that PG&E does not have a written plan to identify, test for, and minimize stray currents. Based on these additional arguments, TURN recommends that PG&E's forecast amounts for expense and capital for AC Interference should be disallowed in full.

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[479] Exh. ORA-40 at 13 (citation omitted).

[480] Exh. ORA-40 at 15.

[481] *TURN Opening Brief* at 178.

9.5.3. Discussion

Both ORA and TURN's recommended disallowances are based primarily on the Exponent Phase 2 report. However, a review of the relevant portion of the Exponent report reveals that the federal code and PHMSA documents do not provide specific requirements. Rather the deficiencies identified in the Exponent report are in comparison to industry best practices.[482] PG&E has demonstrated that it now has a written plan, guidance document O-16, concerning corrosion control and states that it will be developing additional written plans for AC Interference.[483] Further, PG&E's proposed work to be recovered from ratepayers has not previously been recovered in rates. Consequently, we find PG&E's proposed scope of work and forecast costs for AC Interference are reasonable. We therefore adopt PG&E's forecast 2015 capital expenditures of $10.350 million and forecast 2015 expenses of $0.528 million. We expect PG&E to demonstrate in its next GT&S application that it now follows industry best practices.

9.6. DC Interference

9.6.1. PG&E's Request

DC interference occurs when a metallic structure, such as a pipeline, picks up stray current that is leaked by an external DC power source into the soil. These interfering stray currents can have detrimental effects on PG&E's natural gas pipelines and can lead to some of the highest corrosion rates as compared to other corrosion mechanisms. Sources of stray DC currents include transit systems (such as BART and MUNI) and foreign cathodically protected systems.

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[482] *See*, Exh. PG&E-45 at A-558 – A-562.

[483] Exh. PG&E-40 at 7-49.

Pursuant to the requirements of 49 CFR 192.473, PG&E is expanding and formalizing its current program to better address DC Interference.[484]

PG&E's DC Interference program includes collecting information to identify the location of stray currents, investigating the source and severity of interference and determining the mitigation work needed. PG&E bases the number of investigations on ECDA historical findings extrapolated to PG&E's entire transmission system. Mitigation forecasts are based on 2013 findings, and assume that half of the mitigation costs are expense mitigation work and the other half capital mitigation work. PG&E forecasts capital expenditures of $0.802 million in 2015, $0.822 million in 2016 and $0.844 million in 2017. PG&E forecasts 2015 expenses of $2.552 million.[485]

9.6.2. Intervenors' Positions

ORA's testimony and analysis for DC Interference mitigation is similar to AC Interference mitigation.[486] ORA recommends that the Commission accept PG&E's forecast for inspection, but place a 50% cost cap on funds for mitigation. This would result in recovery of $2,023,231 of forecast 2015 expenses and $400,893 of forecast 2015 capital expenditures from ratepayers.[487]

Although TURN believes a disallowance of all corrosion control costs is warranted, it notes that if the Commission does not adopt this recommendation it should still disallow all costs for DC Interference inspection and mitigation.[488]

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[484] Exh. PG&E-1 at 7-33.

[485] Exh. PG&E-1 at 7-34 – 7-35.

[486] Exh. ORA-40 at 16-19.

[487] *ORA Opening Brief* at 147.

[488] *TURN Opening Brief* at 179.

As an initial matter, TURN notes that PG&E had originally made significant self-disallowances in this activity, but subsequently changed its mind and decided not to exclude any amounts for DC Interference even though PG&E had known problems in this area.[489]

TURN further notes that the Exponent Phase 1 report found that there was little guidance for identifying and mitigating DC interference and standards and work procedures were lacking, even though 49 CFR 192.473(a) required PG&E to have in effect a continuing program to minimize the detrimental effects of stray electrical currents.[490] Additionally, the Exponent Phase 2 report found that, similar to AC Interference, PG&E did not have a written plan to identify, test for, and minimize the detrimental effects of stray currents for DC interference. Based on these additional arguments, TURN recommends that PG&E's forecast amounts for expense and capital for DC Interference should be disallowed in full.

9.6.3. Discussion

Similar to its findings concerning PG&E's AC Interference program, the Exponent report does not find PG&E's DC Interference program has failed to comply with the federal code and PHMSA documents, but rather that PG&E's activities again fall short of industry best practices.[491] PG&E has demonstrated that its proposed scope of work and forecast costs are reasonable. We therefore adopt PG&E forecast 2015 capital expenditures of $0.802 million and forecast

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[489] *TURN Opening Brief* at 180; *see* also, *TURN Opening Brief* at 163-165.

[490] *TURN Opening Brief* at 180.

[491] Exh. PG&E-40 at A-564 – A-567.

2015 expenses of $2.552 million. We expect PG&E to demonstrate in its next GT&S application that it now follows industry best practices.

9.7. Casings

9.7.1. PG&E's Request

Historically, casings were placed around pipelines installed under roads, railroads or canals. However, this practice has been phased out, because pipe cannot be externally inspected when it is housed in a casing, and the casing and pipe can come in contact with one another, causing corrosion concerns at or near the point of contact. Pipeline casings may develop one of two types of contacts:

- Metallic ("hard") contact – Develops as the result of differential settlement between the casing and the pipeline transporting the natural gas
- Electrolyte contact – Develops when liquids (such as water) enter the casing through an end seal failure or leaks in the casing.[492]

In 2013, PG&E developed a risk-based four-year plan to remediate all known contacted casings. PG&E has identified approximately 335 casings as contacted and in need of mitigation. It plans to mitigate a total of 94 capital casings identified in the plan during the Rate Case Period (36 casing locations mitigations in 2015 and in 2016, and 22 casing mitigation locations in 2017). Four of these will be locations based on routine annual casing testing results. PG&E also plans to mitigate 117 expense casings in 2015.

PG&E forecasts capital expenditures of $21.039 million in 2015, $21.141 million in 2016 and $13.068 million in 2017, based on a unit cost per

[492] Exh. PG&E-1 at 7-35 – 7-36.

capital casing mitigation location of $540,000.[493] PG&E forecasts 2015 expenses of $48.504 million, which consists of expense casing mitigation expenses of $47.302 million and $1.202 million for casing testing (without test facilities).[494]

9.7.2. Intervenors' Positions

ORA

ORA agrees with PG&E that the work to mitigate contacted casings is needed. However, it believes that the majority of the costs to perform this work should be borne by PG&E shareholders. ORA states:

> PG&E had not just recently discovered the 335 contacted casings included in the mitigation plan at the time the application was filed in December, 2013, but had known of numerous contacted casings dating as far back as 2005 that had never since been mitigated. During this same time period PG&E was mitigating far fewer contacted casings each year than it was discovering each year and developing a growing backlog of contacted casings that have remained unmitigated until PG&E's current plan is implemented.[495]

As support ORA notes that the requirements regarding electrical isolation of transmission pipeline (49 CFR 192.467(c)) were adopted in 1968, and last amended in 1978. Further, PHMSA Interpretation #PI-86-004, states that upon discovery of a contacted pipe, "an operator should determine a course of action intended to correct or negate the adverse effects of shorted casings. The operator's plan of action should be initiated within six months of completion of

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[493] Exh. PG&E-9 at WP 7-95.

[494] Exh. PG&E-9 at WP 7-28.

[495] *ORA Opening Brief* at 134-135 (citations omitted).

the [cathodic protection] survey."[496] The PHMSA Interpretation lists three options that may be pursued, including monitoring the short with leak detection instruments until clearing the contact or minimizing the possibility of the contact is practical, or corrosion or a leak is detected, or other conditions render the monitoring inadequate to minimize the risk.

ORA questions why PG&E found that monitoring under its prior corrosion control program satisfied the requirements of 49 CFR 192.467(c), but now believes it is necessary to mitigate contacted casings to satisfy the requirements of the statute. Among other things, ORA contends that PG&E lacks records demonstrating when PG&E initiated a plan of corrective action upon discovery of a contacted casing, even though 49 CFR 192.491 requires that operators maintain records to demonstrate the adequacy of corrosion control measures or that a corrosion condition does not exist.[497]

ORA further argues that even if PG&E did have a robust program for monitoring casings, it did not have a robust program to initiate mitigation of contacted casings within six months of identification. It notes that PG&E was aware of 335 unmitigated casings as of 2013, but had not yet initiated remediation of these casings within six months, as required by 49 CFR 192.467(c).[498] Moreover, ORA notes that PG&E mitigated only 30 contacted casings in the past 10 years, with nine casings mitigated in 2013, and is now proposing to mitigate 117 expense casings and 36 capital casings in 2015 alone.[499]

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[496] Exh. ORA-69, Attachment 2 at 4.

[497] *ORA Opening Brief* at 139-140.

[498] Exh. ORA-40 at 7.

[499] Exh. ORA-40 at 8.

ORA argues that most of forecast casing mitigation costs are due to PG&E's failure to mitigate the impacts of contacted casings as required by the PHMSA regulations and Pub. Util. Code § 451.[500] In light of "the severity of PG&E's deferral of maintenance of contacted casings," ORA argues that ratepayers only fund the amount for ongoing mitigations of newly discovered contacted casings, and not contacted casings which PG&E has been aware of for longer than the six months allowed by PHMSA regulations. It therefore recommends ratepayers fund $4,895,618, to perform 12.75 expense casing mitigation and $1,937,137 to perform 3.58 capitalized casing mitigations per year. ORA contends that the remaining mitigations contained in PG&E's forecast should be funded by PG&E shareholders.[501]

TURN

Although TURN believes a disallowance of all corrosion control costs is warranted, it notes that if the Commission does not adopt this recommendation it should still disallow 95% of PG&E's forecast 2015 expenses and 96% of forecast 2015 capital expenditures.[502] Similar to ORA, TURN notes that 49 CFR 192.467 has required that pipelines be electrically isolated from metallic casings since 1970. Therefore, TURN concludes the 335 casings in need of remediation did not suddenly occur, but rather, constitute a backlog that PG&E failed to previously correct.[503] Consequently, TURN recommends that PG&E should only recover from ratepayers costs associated with mitigations required by annual casings

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[500] *ORA Opening Brief* at 143-144.

[501] Exh. ORA-40 at 10-11.

[502] *TURN Opening Brief* at 175.

[503] Exh. TURN-1 at 21.

surveys, as all other work would be to remediate PG&E's past failure to comply with 49 CFR 192.467.[504]

TURN argues that even if the Commission does not conclude that PG&E failed to comply with federal regulations, it should still find that PG&E's practice of allowing a large backlog of unremediated contacted casings is imprudent. TURN notes that PG&E does not track the date when it initiates a corrective action plan, or when it has completed remediation of contacted casings. Additionally, TURN notes that PG&E has stated that it does not have internal standards for when contacted casings must be remediated.[505] Finally, TURN points out that PG&E's claim, that the accelerated priority given to contacted casings, is the result of recent industry incidents is misplaced, as the incidents in question occurred in 2007 and 2009.

In light of the above, TURN argues that PG&E should be allowed to recover from ratepayers only work to correct newly determined contacted casings, or $2.5 million in 2015 for casing expense mitigation (a disallowance of $46.0 million) and $0.939 million in 2015 for casing capital expenditures (a disallowance of $20.1 million).[506]

9.7.3. Discussion

ORA, Indicated Shippers and TURN all raise the same general argument – that all costs associated with Casings should be disallowed because PG&E should have performed this work sooner. However, as we have discussed

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504 *TURN Opening Brief* at 175-176.

505 *TURN Opening Brief* at 177.

506 *TURN Opening Brief* at 178.

elsewhere in this Decision, forecast costs are not subject to disallowances simply because utility management imprudently delayed work. Rather, a disallowance is warranted when the forecast work is necessary because: (1) PG&E had not originally performed the work properly, or (2) PG&E had failed to comply with regulatory requirements that it was previously funded to satisfy.

Here, the record does not demonstrate that PG&E had previously received funding to perform mitigation of the contacted casings, but failed to do so. Further, there is no testimony to conclude that the corrosion problems with the 335 contacted casings would have been smaller if PG&E had remediated them sooner. However, we find there is sufficient record evidence to conclude that some of the proposed mitigation work is the result of PG&E's failure to originally perform the work properly.

PG&E's QA audit Non Conformance Report, dated September 2, 2010, found that upon review of 156 A-Forms, "19% of pipe inspections made during corrosion leak repairs were performed by individuals who were not Operator Qualified for the task."[507] According to the report, the potential impact is:

> If an employee is not OQ'd [Operator Qualified] for the task which they are performing, PG&E is out of compliance and at risk. A pipe inspector without proper OQ for the task may misidentify or misinterpret details regarding the condition of the pipe. Finally, having non-qualified inspectors may cause PG&E to have to re-inspect the repair at additional expense to our company.[508]

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[507] Exh. TURN-14, Report Number NCR06 (the pages in this exhibit are unnumbered).

[508] Exh. TURN-14, NCR06 at 2.

During cross-examination, PG&E's witness explained that leak repair was normally done by a multi-person crew. However, only one individual's LAN ID would be included on the A-Form, and that this person may not be OQ'd. According to the witness, while the pipe may not have been inspected by an individual who was OQ'd, the crew could include at least one OQ'd individual.[509] While the witness testified "And so my understanding of OQ is that you are either qualified to do the task or you are overseen by someone that is qualified to do the task"[510] he could not affirm that there was in fact the case.

A review of the A-Form shows that there are multiple spaces where a LAN ID is to be entered, including "Readings", "Repaired By", "Field Reviewed By", "Mapping Reviewed By", and "Inspected By".[511] This would imply that even if there were a multi-person crew, the intent was to identify the specific individuals performing the leak survey, repair and inspection work.

Based on PG&E's witness' testimony that one individual completed the A-Form, the spaces for "Repaired By" and "Inspected By" would contain the same LAN ID. We do not find this testimony credible based on the format of the A-Form. Further, the witness' testimony raises concerns that a PG&E crew could consist of all non-OQ'd individuals.

Based on this evidence, we conclude that a portion of the 335 contacted casings to be mitigated are due to PG&E's failure to properly inspect prior casing mitigations. Since PG&E would have already received ratepayer funding to

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[509] 22 RT at 2519:17 – 2520:25 (PG&E/Armato).

[510] 22 RT 2521:10-13 (PG&E/Armato).

[511] Exh. TURN-14, NCR06, Attachment 2.

perform these mitigations, ratepayers should not fund the costs for additional mitigation due to improper inspections.

Based on the percentage of non-compliance found in NCR06, we find that 19% of the proposed capital and expense casing mitigation projects for the Rate Case Period, or 17 capital casing mitigations and 22 expense casing mitigations, should be funded by PG&E shareholders to correct prior work that was performed improperly. The remaining 81% of the proposed capital and expense casing mitigation projects, or 73 capital casing mitigation projects and 95 expense casing mitigation projects, will be funded by ratepayers.

For 2015, of the 36 capital casing mitigation projects, ratepayers shall fund 29 of the projects and PG&E shareholders shall fund seven of the projects. Of the 117 expense casing mitigation projects, PG&E shareholders shall fund 22 of the projects and ratepayers shall fund 95 of the projects. This represents a disallowance of $4.074 million in capital expenditures and $8.911 million in expenses in for casing mitigations in 2015, resulting in authorized 2015 capital expenditures of $16.991 million and 2015 expenses of $38.390 million.[512] PG&E's 2015 expense forecast of $1.202 million for casing testing (without test facilities) is approved.

9.8. Internal Corrosion

9.8.1. PG&E's Request

49 CFR 192.475-477 sets forth internal corrosion control requirements. PG&E states that it historically considered internal corrosion a relatively low threat since most of its gas is received from interstate transmission pipelines and

[512] There will be corresponding disallowances in 2016 and 2017. (*See* Appendix H, Table H-1, Line 19.)

the contracts with these interstate operators mandate dry gas that is free of liquids that could create an environment for internal corrosion to develop. PG&E notes that its historical internal corrosion control program was compliant with code requirements, but once again did not meet industry best practices. It therefore plans to adopt more prescriptive standards and procedures for Internal Corrosion, which will include the development of site-specific Internal Metal Loss Action Plans (IMLAPS,) broadening the use of gas quality monitoring at all gas receipt points and installing filter separators upstream of sites where liquid is most likely to accumulate.[513]

PG&E's 2015 expense forecast consists of specific inspection and mitigation projects for each of the three gas storage facilities in PG&E's system, and non-site specific inspection and mitigation projects for other transmission assets. The capital forecast includes installation of three types of internal corrosion monitoring and mitigation systems: chemical injection pumps, Electron Microscopy coupon mounting devices and permanently mounted Ultrasound Thickness sensors.

PG&E forecasts capital expenditures of $0.535 million in 2015, $0.658 million in 2016 and $0.845 million in 2017. PG&E forecasts 2015 expenses of $8.784 million.

9.8.2. Intervenors' Positions

Although TURN believes a disallowance of all corrosion control costs is warranted, it notes that if the Commission does not adopt this recommendation

[513] Exh. PG&E-1 at 7-40 – 7-41.

it should still disallow all of PG&E's forecast expenses for Internal Corrosion.[514] TURN contends that PG&E was inspecting for and mitigating internal corrosion deficiently, in violation of 49 CFR 192.475-192.477. As support, TURN cites to the Exponent Phase 1 report findings, which identified numerous deficiencies, including the absence of procedures for identifying, monitoring and evaluating for internal corrosion and the process for evaluating internal corrosion mitigation measures. Further, TURN notes that the Exponent Phase 2 report specifically states that a formal program for internal corrosion control is requirement by ASME B.31.8.

TURN also notes that although PG&E submitted to SED a document summarizing its self reports on corrosion issues and stated that any remedial work to comply with regulations would be funded separately by shareholders, it has "made no effort in its case-in-chief to explain how, if at all, it excluded remedial work from this violation in its forecast."[515] Based on its previous arguments, and supplemented here, TURN recommends that PG&E's forecast amounts for expense should be disallowed in full.

9.8.3. Discussion

We have considered TURN's assertions and find that no disallowances are warranted. The Exponent Phase 1 report does not find that PG&E was in violation of 49 CFR 192.475-192.477, but rather that "select issues indicate that internal and external challenges persist in the corrosion organization at PG&E which, if left unresolved, may hinder PG&E's ability to mitigate and prevent

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514 *TURN Opening Brief* at 188.

515 *TURN Opening Brief* at 189.

corrosion related failures."[516] Similarly, the Exponent Phase 2 report does not find any violations of federal regulations, but rather deficiencies in PG&E's documentation and guidelines for internal corrosion control inspection, monitoring and mitigation. In many instances, the report notes that PG&E's proposed Internal Corrosion manual will address these deficiencies.[517] Accordingly, we do not find TURN's assertions to be supported by the record.

We therefore find PG&E's forecast expenses and capital expenditures reasonable and adopt PG&E's forecasts.

9.9. Atmospheric Corrosion

9.9.1. PG&E's Request

Atmospheric corrosion is a form of external corrosion that occurs when natural gas transmission pipelines are exposed to air or pollutants. Exposed piping is dependent on its coating to inhibit corrosion by preventing water intrusion to the pipe surface. PG&E's atmospheric corrosion program includes both the inspection for and mitigation of atmospheric corrosion as required by 49 CFR 192.479-481. PG&E states that while its inspection program meets code compliance requirements, benchmarking had shown that other operators were going above and beyond compliance with their atmospheric corrosion programs.[518]

PG&E's atmospheric corrosion inspections were performed as a secondary activity, so no costs were recorded in 2011-2013. However, PG&E plans to enhance the scope of the inspection program by initiating more comprehensive

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[516] Exh. TURN-52 at 58.

[517] Exh. PG&E-45 at A-576 – A-579.

[518] *PG&E Opening Brief* at 10-56.

procedures starting in 2015. Therefore, no costs were forecast in 2014 because the expanded inspection process would be under development.[519] PG&E is planning a significant ramp up in 2015 expenses to move the atmospheric corrosion program towards industry best practices. It forecasts $20.437 million in expenses in 2015.[520]

The 2015 atmospheric corrosion inspection expense forecast is based on cost quotes from vendors of the unit cost to perform new inspection process, multiplied by the number of units to be inspected. The new atmospheric corrosion inspection procedures increase the frequency and scope of inspections, and include a requirement that all atmospheric corrosion necessitating mitigation to be addressed within three years. PG&E has excluded from its forecast approximately $29 million that it anticipates spending in 2014-2017 to remediate previously identified atmospheric corrosion locations that where not addressed within the three-year timeframe.[521]

9.9.2. Intervenors' Positions

Similar to its arguments concerning AC Interference and DC Interference mitigation, ORA believes that PG&E's Atmospheric Corrosion forecast is partly the result of deferred corrosion control maintenance. As such, it argues that ratepayers should only be responsible for half of the forecast expenses for mitigation. Based on its calculation of inspection to mitigation, ORA

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[519] Exh. PG&E-1 at 7-43.

[520] Exh. PG&E-1 at 7-45.

[521] Exh. PG&E-1 at 7-44.

recommends recovery of $16,143,948 of 2015 forecast expenses for Atmospheric Corrosion from ratepayers.[522]

Although TURN believes a disallowance of all corrosion control costs is warranted, it notes that if the Commission does not adopt this recommendation it should still disallow PG&E's forecast amounts for Atmospheric Corrosion.[523] TURN notes that Atmospheric Corrosion is one of the activities in which PG&E admits to significant deficiencies and has self-determined significant disallowances. TURN states that notwithstanding the requirements of 49 CFR 192.479 and 192.481 that PG&E have programs to inspect and mitigate the adverse effects of atmospheric corrosion, both PG&E's internal 2011 audit and the Exponent Phase 1 report identified numerous deficiencies in PG&E's inspections. TURN contends that these findings support a conclusion that most of the forecast inspection and remediation work proposed would be unnecessary if PG&E had inspected for atmospheric corrosion correctly. Moreover, TURN states that PG&E has acknowledged that some of the remediation work has not be completed within the timeframe specified by 49 CFR 192.481. TURN concludes "If PG&E took its compliance obligations seriously, one would expect the company to mitigate out-of-compliance corrosion as quickly as possible."[524] In light of these additional arguments, TURN recommends that the Commission disallow all of PG&E's forecast amounts for Atmospheric Corrosion expense.

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[522] Exh. ORA-40 at 19-20.

[523] *TURN Opening Brief* at 181.

[524] *TURN Opening Brief* at 182.

9.9.3. Discussion

Based on the evidence presented, we do not find that PG&E's proposed scope of work for Atmospheric Corrosion is to remediate past work that was originally performed incorrectly. While the Exponent Phase 2 report did find that PG&E was non-compliant with federal regulations in certain instances,[525] PG&E has excluded costs associated with non-compliance. As we have previously discussed, we will not disallow reasonable costs simply because PG&E should have made the expenditures at an earlier time. Here, PG&E has explained that the proposed increase in the scope of work is to move the Atmospheric Corrosion program toward industry best practices. We find PG&E has met its burden of proof and adopt PG&E's forecast 2015 expenses of $20.437 million.

10. Gas Transmission System Operations and Maintenance Activities

10.1. Overview

Gas Transmission Operations and Maintenance activities include tasks prescribed by regulation ("compliance tasks"), tasks necessary to increase the useful life of the assets and reduce the likelihood of the assets becoming inoperative, breaking or failing ("preventative tasks"), and repair or replacement tasks that become necessary when Gas Transmission assets become inoperative, break or fail, but do not rise to the level of requiring a specified project ("repair tasks" or "corrective tasks").[526] The transmission assets include transmission

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[525] *See*, e.g., Exh. PG&E-45 at A-582 (noting PG&E had no existing or planned atmospheric corrosion inspection requirements for customer meters).

[526] Exh. PG&E-1 at 8-2.

pipelines, compressor stations, storage fields, relator stations and metering stations. PG&E states that its forecast will allow it to continue to meet or exceed all regulatory compliance requirements. It notes that its 2015 forecast is higher than in prior years because it plans to expand the scope of activity in the following areas:

- Aerial patrols and ground patrols
- Increased regulatory and valve maintenance
- Increased compressor station and storage field compressor preventive maintenance and corrective maintenance programs
- Transmission expense projects that include unplanned pipe repairs.

PG&E's forecast for the various tasks are summarized below:

Table 27
Gas Transmission System Operations and Maintenance Expense
Forecast 2015 Expenses
($ Thousands of Nominal Dollars)

Locate and Mark	$ 8,986
Pipeline Maintenance	30,182
Station Maintenance	27,310
Transmission Expense Projects	36,960
Stanpac	652
Total Expenses	**$104,090**

PG&E notes that Gas Transmission Operations and Maintenance is also conducting the Pipeline Centerline Survey project, a multi-year project to reclaim and clear the existing Gas Transmission rights-of-way. However, PG&E is not requesting cost recovery for this project, nor for cost recovery to address the

encroachments that are being documented through the Pipeline Centerline Survey.[527]

10.2. Locate and Mark

The Locate and Mark Program part of the PG&E Damage Prevention Program is intended to prevent excavation damages by third party contractors, PG&E construction crews, or others from causing damage to the PG&E transmission pipeline assets by accurately locating and marking transmission assets.[528] In addition, work crews monitor the "811 – Call Before you Dig" system and are present at the excavation site when the PG&E transmission pipelines are being exposed by the excavation contractors. Work performed under this program is required under 49 CFR 192.614 and Govt. Code § 4216.

PG&E forecasts $9 million in expenses for this program in 2015. It notes that the large increase in program activity is due to significant construction projects throughout its service territory and increased public awareness of the "811 – Call Before you Dig" campaign.[529] No party raised specific objections to PG&E's forecast expenditures. We find the forecast reasonable and adopt PG&E's forecast for this program.

10.3. Pipeline Maintenance

The Pipeline Maintenance Program consists of the following activities:

- Leak Management – This work is done to comply with 49 CFR 192.703, 192.706 and 192.717. Activities include

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[527] *PG&E Opening Brief* at 8-6.

[528] Exh. PG&E-1 at 8-11 – 8-12.

[529] *PG&E Opening Brief* at 11-3.

leak surveys, leak repairs, leak rechecks and grading and monitoring of leaks.[530]

- Pipeline Patrols – This work is required to meet the requirements of 49 CFR 192.705. Activities include ground patrols by foot or vehicle, and aerial patrols by fixed-wing aircraft or helicopter.[531]

- Pipeline Preventative Maintenance and Corrective Maintenance – This work is done in support of 49 CFR 192.605, 192.739, and 192.745. Activities include inspections to verify operation, identification, location of regulator station equipment, pipeline valves, and gas holders, routine preventative and corrective maintenance, and repair of failed or inoperable equipment. PG&E notes that work in this area is increasing as PG&E adds more automated valves to its system, which requires maintenance more frequently than manual valves.[532]

- Operating Transmission Pipeline and Stations – This work is covered by several sections of 49 CFR 192.701 and 192.703. Activities include operating valves as required, taking odometer readings, operating SCADA and other equipment, calibrating test gauges and portable pressure recorders, monitoring pressures and removing pipeline liquids. PG&E notes that the increase in expenses for activity is due to the growing maintenance and operating tasks associated with the SCADA system.[533]

- Right-of-Way Support – Activities include pipeline marker maintenance (required by 49 CFR 192.702), vegetation

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[530] Exh. PG&E-1 at 8-13.

[531] Exh. PG&E-1 at 8-15.

[532] Exh. PG&E-1 at 8-17 – 8-18.

[533] Exh. PG&E-1 at 8-19.

management (covered by 49 CFR 192.613, 192.705 and 192.706) and class location activities.

PG&E forecasts 2015 expenses for the Pipeline Maintenance Program as follows:

Table 28
Pipeline Maintenance
Forecast 2015 Expenses
($ Thousands of Nominal Dollars)

Leak Management	
Leak Survey	$4,184
Corrective Maintenance Gas Main Leak	1,586
Leak Rechecks	359
Total Expenses	**$6,129**
Pipeline Patrols	
Pipeline Ground Patrol	$1,982
Pipeline Aerial Patrol	6,571
Total Expenses	**$8,553**
Pipeline Maintenance and Repair	
Pipeline preventative Maintenance	$5,464
Pipeline Corrective Maintenance and Repairs	5,736
Total Expenses	**$11,200**
Operating Transmission Pipeline and Stations	
Operate Transmission Pipeline	$2,767
Operate Transmission Regulator Station	639
Total Expense	**$3,406**
Right-of-Way Support	

Pipeline Markers for Gas Transmission Pipeline	$498
Vegetation Management	396
Total Expenses	**$895**

No party recommended any changes to these forecast amounts in their briefs. We find the forecast reasonable and adopt PG&E's forecast for this program.

10.4. Station Maintenance

This program includes both preventative and corrective maintenance activities. Preventative maintenance activities include work performed on drive units, control systems, safety systems, and auxiliary systems and equipment. The work performed on gas transmission pipeline compressor stations, storage compressor stations and terminals will meet the requirements of 49 CFR 192.605 and 192.703, environmental regulations, and PG&E internal standards and work procedures.[534]

Corrective maintenance activities include work on gas transmission pipeline compressor stations, storage field compressor stations and terminals will meet Federal requirements and GO 112-E. The work includes inspection, testing, troubleshooting and repair or replacement of equipment and components.[535]

PG&E forecasts $27.3 million in 2015 for Station Preventive and Corrective Maintenance. No party recommended any changes to these forecast amounts in

[534] Exh. PG&E-1 at 8-23.

[535] Exh. PG&E-1 at 8-24.

their briefs. We find the forecast reasonable and adopt PG&E's forecast for this program.

10.5. Transmission Expense Projects

Transmission Expense Projects are associated with the following programs:

- Pipeline Projects – These projects arise from continuing surveillance and patrol activities, leak surveys, valve and regulator maintenance and inspection activities and pipeline repairs as a result of other activities.
- Permits & Fees Projects – These include McDonald Island Reclamation Fees, Gas Lease Fees, Department of Transportation Fees and Lease Payments.[536]

PG&E forecasts $36.9 million in 2015 for Transmission Expense - $30.6 for Pipeline Projects and $6.3 million for Permits and Fees Projects. No party recommended any changes to these forecast amounts in their briefs. We find the forecast reasonable and adopt PG&E's forecast for this program

10.6. Stanpac

PG&E Gas Transmission Operations and Maintenance operates the Stanpac transmission pipeline system that delivers natural gas from the gathering system near Rio Vista, California to various local transmission systems and customers in the East Bay region. The Stanpac pipeline miles represent 0.82% of the total transmission miles owned and operated by PG&E; PG&E owns 6/7 of Stanpac. PG&E's forecast includes an allocation of O&M costs from the

[536] Exh. PG&E-1 at 8-26.

total Gas Transmission costs in Major Work Categories DF, JO and JP and forecast pipeline expense projects for the Stanpac pipeline.[537]

PG&E forecasts $0.65 in 2015 for Stanpac. No party recommended any changes to these forecast amounts in their briefs. We find the forecast reasonable and adopt PG&E's forecast for this program

11. Other GT&S Support Plans

11.1. Overview

PG&E forecasts capital and expense to support the work performed across all asset families. This includes the following:

- Maintain the building facilities used by the PG&E employees who operate and support the gas transmission and storage system.
- Continue to develop a Process Safety organization to establish a Process Safety Management (PSM) system.
- Comply with environmental laws and regulations, protect sensitive species and natural resources, and properly dispose of hazardous waste.
- Research and develop innovations to enhance the operation and control of PG&E's gas transmission and storage system.
- Provide customer-related services to noncore gas customers on PG&E's backbone and local transmission systems.
- Provide tools and equipment required by PG&E employees to operate, replace, and repair its gas transmission and storage assets.

[537] Exh. PG&E-1 at 8-28.

- Build new building facilities that support the business operations of PG&E's gas transmission and storage system.[538]

PG&E forecasts $20.3 million in expenses for 2015. PG&E forecasts capital expenditures of $24.2 million in 2015, $13.7 million in 2016 and $14.3 million in 2017.

11.2. Expense Forecast

PG&E's expense forecast by Major Work Category is summarized below:

Table 29
Other GT&S Support Plans
Forecast 2015 Expenses

MWC	Program	
AB	Buildings and Process Safety	$ 4,642,000
AK	Environmental	11,077,500
AR	Read & Investigate Meters	592,547
AY	Habitat and Species Protections	211,000
CR	Hazardous Waste Disposal and Transportation Costs	211,000
EZ	Manage Various Customer Care Processes	865,704
GZ	Research and Development Costs	2,215,500
HY	Change/Maintain Used Gas Meters	438,456
	Total Expenses	**$20,253,706**

[538] Exh. PG&E-2 at 12-1.

11.2.1. Buildings and Process Safety Organization

In its application, PG&E forecasted $4.6 million in expense for support expenses for Buildings and the Process Safety Organization Support (MWC AB). Building expenses consist of ongoing building operating costs and the expense portion of new building projects.[539] PG&E's building forecast includes the expense portion of three incremental building projects that support PG&E's GT&S operational work (a mirror Control Center, the consolidated headquarters for Gas Operations in San Ramon, and a new Roseville Service Center), smaller expected incremental projects, and forecasts of ongoing maintenance. The Process Safety Organization provides a comprehensive risk-based approach to enhance safety by identifying, understanding, and mitigating risk to minimize the possibility of incidents that have high consequences.[540] No parties opposed this forecast.

On August 14, 2014, the Commission issued *Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2014-2016* (*2014 GRC Decision)* [D.14-08-032]. In that decision, the Commission adopted an allocation of costs between transmission and distribution for the new Gas Operations headquarters that differed from PG&E's proposal in this application. Pursuant to the *2014 GRC Decision*, 60% of PG&E's Gas Operations headquarters cost would be allocated to transmission.[541] Based on this adopted allocation, PG&E's 2015 forecast expense for Buildings and Process Safety Organization

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[539] Exh PG&E-2 at 12-2.

[540] Exh. PG&E-2 at 12-3.

[541] *2014 GRC Decision* [D.14-08-032] at 122.

Support is revised $5,479,692. We adopt PG&E's forecast for this program, as revised.

11.2.2. Environmental Operational Costs

Environmental Operational Costs (MWC AK) consists of costs to coordinate PG&E's management of hazardous materials, including remediation. The work encompassed in this work category include:

- Hazardous Material Management
- Air Quality Management
- Water Quality Management
- Other Environmental Expenses – includes work to obtain permits and work with other agencies regarding endangered species, habitat conservation plans, bird nesting, and archeological artifacts.
- Remediation[542]

PG&E forecasts expenses of $11.1 million in 2015. PG&E explains that the increase over historical spending is due to increased regulatory requirements (California's Aboveground Petroleum Storage Act and the California Air Resources Board's Enhanced Vapor Recovery Program), environmental remediation for hexavalent chromium at the Hinkey and Topock Compressor Stations, expanded remediation of gas facilities where mercury manometers and other equipment were used and repaired, and expanded remediation for pipeline assessment and cleanup.[543] We adopt PG&E's forecast.

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[542] Exh. PG&E-2 at 12-4 – 12-6.

[543] Exh. PG&E-2 at 12-6 and 12-7.

11.2.3. Habitat and Species Protections

Habitat and Species Protection Costs (MWC AY) includes costs to comply with regulations that protect endangered species and sensitive habitats. The work includes:

- Providing technical support for field projects to comply with endangered species and sensitive habitat regulations.
- Continuing to develop habitat conservation plans for several geographic areas in PG&E's service territory.
- Mitigating the impact of major projects on threatened and endangered species.[544]

PG&E assumes that the scope of the habitat and species protection activities will not change materially from its 2013 forecasted work level. It therefore forecasts 2015 expenses of $0.2 million. We adopt PG&E's forecasted amount.

11.2.4. Hazardous Waste Disposal and Transportation Costs

Hazardous Waste Disposal and Transportation (MWC CR) includes costs of disposing hazardous waste, universal waste, and other materials regulated as industrial wastes.

PG&E assumes that the scope of activities will not change materially from the 2012 level. PG&E forecasts 2015 expenses of $0.2 million. We adopt PG&E's forecasted amount.

11.2.5. Research and Development Costs

Research and Development Costs (MWC GZ) includes costs for PG&E's Research and Development and Innovation Program, directly relevant to the

[544] Exh. PG&E-2 at 12-7.

GT&S activities. Work in this area will include collaborative R&D efforts with industry organizations on new technologies and better integrity assessment tools to maximize and enhance public safety.

PG&E forecasts 2015 expenses of $2.2 million, which would include collaborative R&D efforts, tests, pilots, deployment and R&D management. We adopt PG&E's forecast.

11.2.6. Customer Access Charge Costs

Customer Access Charge Costs (MWCs AR, HY and EZ) include the cost of activities related to the Customer Access Charge (CAC). The CAC is used to recover the cost to provide the following services to noncore gas customers on PG&E's backbone and transmission systems:

- Reading the customer meters (MWC AR)
- Maintaining the customer meters (MWC HY)
- Providing direct customer service through account managers in PG&E's Customer Care organization (MWC EZ)[545]

PG&E's 2015 forecast reflects recorded 2012 costs. PG&E forecasts total Customer Access Charge Costs of $1.9 million, consisting of $0.6 million for MWC AR, $0.9 million for MWC EZ and $0.4 million for MWC HY. We adopt PG&E's forecast.

11.3. Capital Expenditures

PG&E's capital expenditure forecast by Major Work Category is summarized below:

Table 30
Other GT&S Support Plans

[545] Exh. PG&E-2 at 12-10.

Forecast 2015 Capital Expenditures

MWC	Program	
05	Tools and Equipment	$10,700,000
78	Manage Buildings	13,537,569
	Total Capital Expenditures	**$24,236,569**

11.3.2. Tools and Equipment

Tools and Equipment (MWC 05) includes all capital expenditures to purchase new tools, fleet, and equipment for GT&S employees. PG&E's forecast is based on a five-year average of recorded and forecasted capital expenditures, which was then increased to support PG&E's plan to hire incremental maintenance and construction crews and field personnel to execute the increased work forecasted for 2015-2017.[546] PG&E's forecast capital expenditures are $10.7 million in 2015, $4.3 million in 2016 and $3.6 million in 2017.[547]

ORA opposes PG&E's forecast, noting that PG&E underspent in 2013 recorded year compared to its forecast. ORA therefore recommends using 2013 recorded spending levels, which would result in a 2015 forecast of $8.991 million.[548]

On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 12 – Other GT&S Support Costs* (Exh. Joint-3 at 13-15),

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[546] Exh. PG&E-2 at 12-11.

[547] Exh. PG&E-2 at 12-10.

[548] Exh. ORA-42 at 8.

regarding tools and equipment, was entered into the record. PG&E stipulated to ORA's 2015 forecast for tools and equipment capital expenditure. Tools and Equipment capital expenditures for 2016 and 2017 would be subject to post test year escalation, as included in the PG&E-ORA joint stipulation for Chapter 18, Post Test Year Ratemaking.[549]

We find the joint stipulation on Tools and Equipment capital expenditures to be reasonable and adopt the 2015 capital expenditure forecast of $8,991,000. Tools and Equipment capital expenditures for 2016 and 2017 will be subject to post test year escalation, as included in adopted joint stipulation between PG&E and ORA for Chapter 18, Post Test Year Ratemaking.[550]

11.3.3. Building Management Expenditures

Building Management Expenditures (MWC 78) includes capital expenditures for buildings and office facilities not funded through PG&E's GRC. These expenditures include replacements and improvements for buildings and structures required to support the GT&S activities, office buildings, trailers and other real property. PG&E's 2015 forecast capital expenditures of $13.5 million includes Gas Transmission's proportionate share of the facilities supporting both the gas transmission and gas distribution functions.

As noted in Buildings and the Process Safety Organization Support (MWC AB) above, the *2014 GRC Decision* adopted an allocation of costs between transmission and distribution for the new Gas Operations headquarters that differed from PG&E's proposal in its application. Based on the adopted

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[549] Exh. Joint-3 at 14.

[550] *See* Exh. Joint-3 at 23-28.

allocation, PG&E's capital forecast for Building Management Expenditures is revised to $18,492,258.[551] We adopt PG&E's forecast, as revised.

12. Gas System Operations

12.1. Overview

Gas System Operations oversees the gas transmission and storage system day to day to maintain continuous availability of gas to customers. It includes the GTCC, Gas Distribution Control Center, Gas System Planning (GSP), Wholesale Marketing and Business Development Department (WM&BD) and Gas Scheduling and Accounting (GS&A).

PG&E's forecast 2015 expenses and capital expenditures are summarized below:

Table 31
Gas System Operations
Forecast 2015 Expenses

Gas System Operations (GTCC)	$17,935,000
Marketing/Sales Strategy (WM&BD)	7,490,000
Compressor Fuel and Power	19,124,000
Greenhouse Gas Compliance Instruments	3,191,375
Total Expenses	**$47,740,375**

[551] *PG&E Opening Brief* at 12-10.

Table 32
Gas System Operations
Forecast 2015 Capital Expenditures

New Business	$ 8,560,000
Meter Sets – Power Plants	1,617,840
Capacity	66,993,000
Total Capital Expenditures	**$77,170,840**

12.2. Expenses

12.2.1. Gas System Operations Staff

The GTCC operates the gas transmission and storage system in real time to route gas for ultimate consumption by customers. Its activities include proactively monitoring the entire system to detect and respond to abnormal conditions early in their development and coordinating and monitoring pipeline inspections, maintenance, and construction. GTCC is staffed 24 hours a day, 365 days a year.[552] PG&E forecasts $17.935 million in 2015 for labor, material, consulting, contract and other costs associated with the operation and maintenance of the GTCC (MWC CM), including costs for Gas Control, Gas Control Strategy and Support, GSP, and the GS&A departments.

In addition, PG&E forecasts $7.490 million in expense for 2015 associated with wholesale commercial activity of the WM&BD Department (MWC CX). The WM&BD Department contracts for capacity on the backbone to transport customer-owned gas, contracts for seasonal storage, and offers related activities

[552] Exh. PG&E-2 at 10-5 – 10-6.

such as balancing customer pipeline accounts and the parking and lending of gas.[553] PG&E's forecast expenses are primarily for labor.[554]

We adopt PG&E's forecast for Gas Operations Staff (Major Work Categories CM and CX).

12.2.2. Electricity Costs for Gas Compressor Operations

PG&E has electric-powered gas compressors at Bethany, Delevan, and McDonald Island, and incurs costs for the electricity to operate them. PG&E is currently authorized to recover its actual recorded costs, and estimates Electricity Costs for Gas Compressor Operations (MWC JT) expenses of $18.5 million for 2015. This forecast is comprised of costs for: (1) the natural gas compressor station fuel and power costs for McDonald Island and, (2) electricity powered compressors in the system.[555]

ORA challenges PG&E's 3% escalation rate, arguing that the US inflation rate should be applied instead. Applying this lower rate, ORA recommends 2015 expenses of $18.241 million for Gas Compressor Operations.[556]

On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 10 – Gas Operations* (Exh. Joint-3 at 9-12) was entered into the record. PG&E stipulated to ORA's 2015 forecast of $18.241 million for Electricity Costs for Gas Compressor Operations, which would reduce PG&E's forecast for compressor fuel by $88,748. Electricity Costs for Gas Compressor

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[553] Exh. PG&E-2 at 10-6.

[554] Exh. ORA-56 at 16.

[555] Exh. PG&E-2 at 10-31.

[556] E xh. ORA-56 at 18-19.

Operations expenses for 2016 and 2017 would be subject to post test year escalation, as included in the PG&E-ORA joint stipulation for Chapter 18, Post Test Year Ratemaking.[557]

We find the joint stipulation on Electricity Costs for Gas Compressor Operations (MWC JT) expenses to be reasonable and adopt the 2015 expense forecast of $18,241,000. Electricity Costs for Gas Compressor Operations expenses for 2016 and 2017 will subject to post test year escalation, as included in adopted joint stipulation between PG&E and ORA for Chapter 18, Post Test Year Ratemaking.

12.2.3. Greenhouse Gas Compliance Instrument Costs

PG&E requests authorization to recover the cost of greenhouse gas (GHG) compliance instruments (allowances and offsets) it procures for gas compressors on the backbone transmission system and at storage facilities, and for any other gas transmission and storage equipment that may incur an obligation, to comply with the requirements of AB 32, the California Global Warming Solutions Act of 2006.[558] PG&E states that since these obligations are incidental to operating the gas transmission and storage system for the benefit of customers and mandated by AB 32, these costs should be recovered from ratepayers.

PG&E notes that it was authorized by D.13-03-017 to recover the costs of GHG compliance instruments for the six compressor stations for which it anticipated incurring compliance costs – Topock, Hinkley, Kettleman, Delevan, Gerber and Burney. However, it now forecasts that Tionesta Compressor Station

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[557] Exh. Joint-3 at 10.

[558] Exh. PG&E-2 at 10-32.

will incur compliance costs and that other gas transmission and storage facilities may incur an obligation in the future if their GHG emissions exceed the annual emissions threshold set by the California Air Resources Board. PG&E forecasts 2015 expenses of $3.191 million for Greenhouse Gas Compliance Instrument Costs (MWC JT).

ORA questions the GHG compliance forecasts, noting discrepancies between prepared testimony and workpapers.[559] It recommends that a 2.1% escalation rate, rather than the 3% rate applied by PG&E, be used to calculate the 2015 forecast. Based on this recommendation, ORA recommends a forecast of $3.088 million for 2015.

On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 10 – Gas Operations* (Exh. Joint-3 at 9-12) was entered into the record. PG&E stipulated to ORA's 2015 forecast of $3.088 million for Greenhouse Gas Compliance Instruments. Greenhouse Gas Compliance Instruments expenses for 2016 and 2017 would be subject to post test year escalation, as included in the PG&E-ORA joint stipulation for Chapter 18, Post Test Year Ratemaking.[560]

On October 22, 2015, the Commission adopted *Decision Adopting Procedures Necessary for Natural Gas Corporations to Comply With the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (Cap-and-Trade Program* [D.15-10-032.]. Among other things, D.15-10-032 authorized each utility to forecast and reconcile its natural gas GHG compliance costs and allowance proceeds as part of the existing true-up advice letter process and revised the

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[559] Exh. ORA-56 at 19-21.

[560] Exh. Joint-3 at 11.

annual advice letters to contain a new section related to GHG costs and allowance proceeds.[561] The utilities were therefore directed to "file a one-time Tier 1 Advice Letter no later than April 1, 2016 to include forecast 2015 and 2016 GHG costs approved in this decision into rates."[562]

Based on the directives in D.15-10-032, PG&E's recovery of expenses for GHG compliance instruments will now be recovered as part of the annual true-up process. As such, allowing recovery of these expenses as part of the GT&S application would result in double recovery. Accordingly, PG&E and ORA's *Joint Stipulation Comparison Exhibit Chapter 10 – Gas Operations* (Exh. Joint-3 at 9-12) is denied, and PG&E's request to recover expenses for GHG compliance instruments is removed, as these costs will be recovered elsewhere.

12.3. Capital Expenditures

12.3.1. New Business

New Business (MWC 26) covers the costs of gas transmission facilities extended from the existing gas transmission system to provide service to localized large new customer loads. PG&E states that the majority of new business relates to new natural gas-fired plants or large residential developments. According to PG&E, the four main factors that drive New Business capacity expenditures are: (1) location of the new customer(s) in relation to PG&E's gas system; (2) projected gas demand or load; (3) duty cycle, time of year, and hours of the day that the new customer will operate; and (4) existing planned investments to serve customer load growth.

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[561] D.15-10-032 at 18-19 and Appendix A.

[562] D.15-10-032 at 20.

PG&E's forecast assumes: (1) an expenditure of $4.0 million (2013 dollars) in each of the three years for small residential new business; and (2) two large projects during 2015-2017 totaling $8.0 million. PG&E notes that this forecast accounts for the uncertainty regarding when and if new large projects will come on line. Further, it states that while the exact projects that it forecasted at the time of its application may not go forward, its past experience has been that an emerging new business project that was not anticipated will replace it. PG&E forecasts $8.56 million in New Business (MWC 26) in 2015.[563]

PG&E also forecasts $4.366 million to install new meter sets (meter stations and other supporting facilities) for new transmission level customers.[564] PG&E's forecast is based on projects it expects to occur based on based on past experience. PG&E notes that generally requests to install new meter sets have short notice and brief schedules.[565]

We adopt PG&E's forecast capital expenditures for New Business (MWC 26) and Meter Sets – Power Plants (MWC 26) are reasonable and are adopted.

12.4. Capacity Projects

Capacity Projects cover the costs of installing gas transmission facilities to increase capacity to meet non-customer-specific demand growth. PG&E's forecast of capital expenditures for capacity projects during the Rate Case Period are summarized below.

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563 Exh. PG&E-2 10-22 – 10-23.

564 Exh. PG&E-2 at 10-22.

565 Exh. PG&E-40 at 10-9.

Table 33
Capacity Projects
Summary of Capital Expenditures
($ in Thousands)

Description	2015	2016	2017
NOP Reductions	$10,337	$ 28,355	$ 36,866
Pipe Betterment	6,095	6,249	6,414
Customer Demand Growth	41,661	14,059	45,659
Line 407	8,900	58,800	89,300
Total Capital Expenditures	**$66,993**	**$107,473**	**$178,239**

12.4.1. Normal Operating Pressure Reductions

PG&E has instituted a policy to reduce the normal operating pressure (NOP) of the transmission system so that both NOP and overpressure protection are below MAOP at all times. PG&E states that reduction of NOP is a multi-year process that will extend beyond the Rate Case Period.

PG&E notes that it has already implemented this new NOP policy on the backbone system, with only minor effect on backbone capacity. However, it states that NOP reductions on the local transmission system will tend to reduce design day capacity (Cold Winter Day or Abnormal Peak Day). Consequently, some of the proposed capacity investments are to retain service design capacity standards.[566]

PG&E plans to install pipe to support programmatic reductions of the normal operating pressures of the transmission system so that pipeline pressures are kept below MAOP at all times, while maintaining levels of pipeline capacity to support customer service at the appropriate design standard. PG&E has

[566] Exh. PG&E-2 at 10-12 and 10-27.

identified fourteen capacity reinforcement projects in relation to the NOP reduction policy during the Rate Case Period.

TURN maintains that the Commission should disallow recovery of capital costs resulting from reducing normal operating pressure. It contends that the need to lower the set points of regulators to give a greater safety margin to compensate for operational errors should not exist if PG&E kept better records, trained its employees better and properly maintained its equipment.[567] TURN believes that this work is remedial in nature and should be disallowed in full. TURN further notes that at the same time PG&E is reducing NOP, it is also proposing to address other operational deficiencies with new and expanded programs at great cost to ratepayers. It believes that reducing NOP, and thus capacity, is "treating the symptom, but not the cause" of past operational shortcomings.

We are not persuaded by TURN's arguments that PG&E's NOP reduction policy is the result of past operational deficiencies. PG&E has stated that its past practice was to set NOP close to MAOP, and to set overpressure protection at or slightly above MAOP. However, it has now changed this practice in response to SB 705 (Stats. 2011, ch. 522), setting both the NOP and overpressure protection setpoints below MAOP.[568] PG&E further notes that this policy allows for a greater margin of safety and creates a larger interval between alarms, which provides an operator more time to assess and take appropriate action before the next level alarm is reached.

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[567] Exh. TURN-1 at 24.

[568] Exh. PG&E-40 at 10-10.

We find PG&E's forecast of $75.6 million over the Rate Case Period to be supported by the record. PG&E's forecast is adopted.

12.4.2. Pipe Betterment

Pipe betterment projects increase capacity by leveraging a planned "like-for-like" replacement of an existing pipeline. In these instances, PG&E will upsize the diameter or length of the planned replacement to reduce the risk of having to perform an incremental capacity project in the future. PG&E notes that upsizing is less costly over the long term and that betterment of an existing project results in cost savings compared to the total costs of a like-for-like replacement project plus a future incremental project.[569]

Based on past experience, PG&E estimates betterment costs at 4.8% of pipeline replacement costs. PG&E forecasts betterment costs of $18.9 million over the Rate Case Period.

We adopt PG&E's forecast for Pipeline Betterment.

12.4.3. Customer Demand Growth (New Capacity)

The need for new capacity projects is the result of increasing population, increased commercial and industrial loads, and other factors such as modeling of new homegrowth. When enough customer load growth has accumulated in a certain area, transmission capacity in that area becomes constrained, resulting in the need to reinforce the transmission system with new capacity before the design day conditions occur.

PG&E's modeling program indicates that a number of local transmission systems barely meet Abnormal Peak Day (APD) or Cold Winter Day (CWD)

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[569] Exh. PG&E-2 at 10-27-10-28.

design standards due to recent growth, and others will approach design standard limits in the near future. Areas experiencing significant load growth include certain locations of Stockton and Yosemite Divisions, which are projected to become constrained within the Rate Case Period. Excluding its proposed Line 407 project, PG&E forecasts capital expenditures of $101.4 million for Capacity Projects during the Rate Case Period.

We adopt PG&E's forecast for Customer Demand Growth (New Capacity).

12.4.4. Line 407

Line 407 is a major new transmission line to expand the Sacramento Valley Local Transmission (SVLT) system. Construction of a new line on the SVLT system had been agreed upon in both Gas Accord IV and Gas Accord V settlements. However, in each instance construction was deferred due to failure of demand growth to materialize as forecast. PG&E now expects to require this new line in 2017 to avoid capacity constraints and meet service design standards.

In Gas Accord V, PG&E agreed to meet and confer with the parties and to file an advice letter prior to constructing Line 407 Phase 2. However, PG&E now propose that Line 407 be built during the current Rate Case Period.

PG&E argues that Line 407 is needed to meet growth rates between now and 2035. PG&E forecasts an average annual increase of 9,800 new residential and 700 new commercial gas customers this 20-year period, resulting in an increase in gas demand under APD conditions.[570] PG&E further notes that its Board of Directors authorized full funding for Line 407 in June 2014, and the

[570] Exh. PG&E-2 at 10-29.

project is anticipated to be operational by the end of 2017.[571] Finally, PG&E notes that the stipulation between PG&E and ORA regarding the Post Test Year Cost Recovery Mechanism includes a provision for a balancing account of up to $7 million in revenue requirements for Line 407, if the project is completed in 2017.[572] Thus, PG&E concludes that there is no uncertainty and Line 407 will be going into operation in 2017.

Indicated Shippers and Calpine oppose PG&E's request to include the Line 407 project in rates. Indicated Shippers maintains that PG&E has provided limited evidence to support its forecast of new demand. Further, it notes that while PG&E's forecast expects 10,000 connections per year for the next 20 years, the actual increase in connections in 2013 over 2012 was only 1,000.[573] Calpine also notes that PG&E's demand forecast in support of the project has been wrong in the past, and the current forecast is likely incorrect as well.[574] Calpine provides further support for this argument, noting that PG&E's actual connections between 2012 and 2014 were "off by 30% and are trending away from PG&E's estimated growth expectations."[575] Calpine additionally maintains that PG&E's reliance on the December 2013 noncore curtailments experienced in the Sacramento Valley is misplaced.

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[571] Exh. PG&E-40 at 10-25.

[572] *PG&E Opening Brief* at 13-16. This stipulation is consistent with ORA's proposal. (*See* Exh. seeORA-25 at 19.)

[573] *Indicated Shippers Opening Brief* at 208-209.

[574] *Calpine Opening Brief* at 17.

[575] *Calpine Opening Brief* at 18.

Based on the history and uncertainty of the Line 407 project, Indicated Shippers and Calpine argue that, similar to the Gas Accord IV and V settlements, the Line 407 project should be treated as an adder project. Accordingly, Indicated Shippers and Calpine urge that the PG&E's proposal be rejected.

We find that PG&E has provided sufficient evidence to conclude that the Line 407 project is needed and likely to be completed within the Rate Case Period. As such, we do not agree with Indicated Shippers that Line 407 should be treated as an adder project. Further, we note that the stipulation between PG&E and ORA regarding the Post Test Year Cost Recovery Mechanism includes a provision for a balancing account of up to $7 million in revenue requirements for Line 407, if the project is completed in 2017. This will provide ratepayer protection, as ratepayers will not pay for this project until it is used and useful. In light of these considerations, PG&E's forecast capital expenditures for the Line 407 project is adopted, with recovery of these costs subject to the stipulation between PG&E and ORA (Exh. Joint-3 at 26.)

12.5. Network Investment Plans

PG&E proposes to develop a comprehensive portfolio of risk-based, long-term integrated network investment plans for system capacity. PG&E states that it intends to create 12 long-term "living" network investment plans based on integrated hydraulic models, one for each of the 12 major local transmission systems.[576]

PG&E states that its funding request for system capacity in this application is based on its best assessment of work that appears to be required to avoid

[576] Exh. PG&E-2 at 10-12 – 10-13.

capacity risks in the Rate Case Period. However, it expects that the network investment plan approach will yield "as yet unidentified but significant savings compared to approaching each safety and growth-related project on a discrete basis."[577] PG&E identifies additional benefits that would result from the Network Investment Plans.[578] No party opposed PG&E's proposed use of Network Investment Plans. PG&E's proposal is adopted.

12.6. Allocation of Storage Assets to Pipeline Load Balancing

PG&E had proposed to allocate additional storage injection and withdrawal capacity to load balancing.[579] On March 6, 2015, Calpine filed *Motion of Calpine Corporation to Strike Portions of Pacific Gas and Electric Company's Testimony (Calpine Motion to Strike)* to strike from the record the following:

1. Page 10-48, line 24 through page 10-50, Table 10-10 of Chapter 10 (Gas System Operations) of PG&E's opening testimony, marked as Exhibit PG&E-2.

2. Page 10-26, line 1 through page 10-29, line 17 of Chapter 10 (Gas System Operations) of PG&E's rebuttal testimony, marked as Exhibit PG&E-43; and

3. Page 2753, line 9, through page 2754, line 17, and page 2755, line 21, through page 2776, line 28, of Volume 23 of the Reporter's Transcript in this proceeding, dated February 18, 2015.[580]

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[577] Exh. PG&E-2 at 10-15.

[578] Exh. PG&E-2 at 10-15 – 10-16.

[579] Exh. PG&E-2 at 10-48 – 10-50.

[580] *Calpine Motion to Strike* at 1-2.

Calpine filed this motion after cross-examination of PG&E's witness Christopher, arguing that PG&E's direct and rebuttal testimony on allocation of storage assets was "fundamentally inconsistent, and PG&E's response to Calpine's clarifying data request on the issue of reallocating storage assets to load balancing is, at best, inaccurate incomplete, and misleading."[581] Calpine argues that as a result, it did not have a fair opportunity to conduct further discovery or prepare cross examination on this issue to the detriment of Calpine's position and the Commission's process. PG&E filed a response to the *Calpine Motion to Strike*. With the ALJ's permission, Wild Goose filed a reply to PG&E's response.

The ALJ granted the *Calpine Motion to Strike* by oral ruling on March 18, 2015.[582] We hereby confirm the ALJ ruling that the following testimony is struck from the record:

1. Page 10-48, line 24 through page 10-50, Table 10-10 of Chapter 10 (Gas System Operations) of PG&E's opening testimony, marked as Exhibit PG&E-2.

2. Page 10-26, line 1 through page 10-29, line 17 of Chapter 10 (Gas System Operations) of PG&E's rebuttal testimony, marked as Exhibit PG&E-43; and

3. Page 2753, line 9, through page 2754, line 17, and page 2755, line 21, through page 2776, line 28, of Volume 23 of the Reporter's Transcript in this proceeding, dated February 18, 2015.

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[581] *Calpine Motion to Strike* at 8.

[582] 33 RT at 4642:9 – 4643:2 (ALJ Yip-Kikugawa)

Our determination does not prejudice future consideration of this issue. PG&E may propose to reallocate storage assets for load balancing in a future proceeding, where a full and complete record can be developed

12.7. Daily Balancing (Gill Ranch Proposal)

Gill Ranch Storage LLC (Gill Ranch) supports PG&E's proposal for a Fifth Nomination Cycle and the Customer Nomination Redirect Project.[583] In addition, Gill Ranch recommends that daily balancing should be required in place of the current monthly balancing system. Gill Ranch asserts that requiring daily balancing and implementing the Fifth Nomination Cycle will increase the effective capacity of PG&E's system to meet sharp fluctuations in gas demand, thus potentially allowing PG&E to avoid or defer some of the proposed infrastructure expenditures. Further, Gill Ranch maintains that daily balancing could avoid ratepayer subsidy issues, as under the current balancing system, ratepayers are potentially subsidizing PG&E's transportation customers.[584]

Gill Ranch's proposal is opposed by PG&E, and Calpine. PG&E states that daily balancing has commercial implications, as it would require customers to balance every day. Further, PG&E states that its computer systems would need to be changed internally to accommodate daily balancing, that the cost of this change is unknown, and that this change would likely not be well received by its customers, as they would need to balance every day.[585]

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[583] Exh. Gill Ranch-1 at 4.

[584] Exh. Gill Ranch-1 at 5.

[585] 25 RT at 3177:1-15 (PG&E/Christopher).

Calpine raises similar objections. It notes that Gill Ranch has not provided any data to support its assertion that daily balancing is needed. Further, Calpine asserts that since load balancing costs are included in backbone transmission rates, backbone shippers who benefit from monthly balancing are the ones who pay for that service, and are not subsidized by other ratepayers. Additionally, "customers who balance on a daily basis can avoid paying for monthly balancing through the existing "self-balancing credit" that PG&E offers under Schedule G-IMB."[586] Consequently, according to Calpine, implementation of daily load balancing will not solve the competition problem alleged by Gill Ranch.[587]

We agree with PG&E and Calpine that Gill Ranch has not demonstrated a need for daily balancing. Accordingly, Gill Ranch's proposal is denied.

13. Information Technology

PG&E proposes various technology projects that support Transmission Pipeline, Gas Storage, Gas Transmission, Operations and Maintenance, and Gas Systems Operations. The Information Technology projects proposed for the Rate Case Period focus on making information about the gas transmission system easily accessible and widely available and to enhance PG&E's ability to operate the gas transmission system safely.[588]

PG&E notes that, pursuant to the *PSEP Decision*, it is not seeking recovery for costs associated with the Gas Transmission Asset Management program (now known as the Mariner Program). However, it notes that this application includes

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[586] Exh. Calpine-1 at 29-30.

[587] *Calpine Opening Brief* at 22.

[588] Exh. PG&E-2 at 11-1.

some projects that involve areas of technology similar to the tools and applications that were included in the Mariner Program. PG&E states these programs are distinguishable and include enhancements to or replacements for existing technology.[589] PG&E forecasts 2015 expenses of $16.34 million and capital expenditures of $24,47 million in 2015, $31.34 million in 2016 and $14.14 million in 2017.

PG&E's proposed technology projects for the Rate Case Period, and the associated capital expenditures and 2015 expenses are summarized below:

Table 34
Information Technology Project Costs
Forecast Capital Expenditures and Expenses[590]
($ Thousands of Nominal Dollars)

Project	2015 – 2017 Capital Expenditures	2015 Expense
Gas Storage Database		$528
Pipeline Patrol Mobile	$3,985	211
Mobile Inspection Reports	268	
Gas Transmission Work Management	987	211
Field As-Built Modifications	8,248	
Supervisory Control and Data Acquisition (SCADA) Replacement	3,938	
Leak Rupture Detection Implementation	7,998	
Advanced Control Room Applications	5,277	211
Collaborative Technology with Field	1,017	
Fifth Nomination Cycle	974	285
Customer Nominations Redirect		844

[589] Exh. PG&E-2 at 11-2 – 11-3.

[590] Exh. PG&E-2 at 11-5, Table 11-3.

Gas Transaction System (GTS) Replacement	13,755	528
Artificial Intelligence (AI) System	12,828	
Cyber Security Evaluation and Corrective Measures	5,992	1,160
Enterprise Primavera P6 and SAP Integration	1,498	2,342
Leak Survey Mobile Device Replacement	667	
Automated Upload Design Pipeline Feature Lists (PFL)	2,523	422
Ongoing System O&M Enhancements		
		9,600
Total	**$69,955**	**$16,342**

ORA recommends that a five-year (2009-2013) trend be used to forecast PG&E's 2015 Information Technology expense. It argues "A five-year trend relies on PG&E's past actions, its actual commitment to IT spending, removes questions on the various assumptions used, and removes any assumptions linked to the capital projects."[591] Using a five-year trend would result in a 2015 expense forecast of $10.459 million. ORA further recommends that PG&E's 2015 capital expenditures forecast be reduced by 14%. ORA notes that this reduction reflects the actual-to-forecast difference of IT project costs that used PG&E's Concept Cost Estimating Tool (the Tool) and is consistent with ORA's recommendation in PG&E's 2014 GRC.[592]

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[591] Exh. ORA-15 at 5-6.

[592] Exh. ORA-15 at 8.

TURN recommends that the forecast expense and capital expenditures associated with the Automated Upload of Design Pipeline Features List Project be disallowed. TURN asserts that its analysis finds that this project would not be cost effective and that the manual process that it intends to replace is adequate.[593] TURN therefore recommends that PG&E's 2015 expense forecast be reduced by $422,000 and that PG&E's 2016 capital expenditure forecast be reduced by $2,523,000.[594]

On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 11 – Information Technology* (Exh. Joint-4), was entered into the record. ORA, TURN and PG&E stipulate to 2015 expense forecast of $14.66 million, which reflects a 10.3% reduction to PG&E's 2015 expense forecast, to implement the IT programs and projects as described in PG&E's 2015 GT&S Application. With respect to capital expenditures, ORA, TURN and PG&E stipulate to an 8% reduction to PG&E's 2015 capital forecast, resulting in 2015 capital expenditure forecast of $22.515 million. Escalation of Information Technology expenses and capital expenditures for 2016 and 2017 would be subject to the joint stipulation on post test year ratemaking. We find the joint stipulation for Information Technology is a reasonable compromise of the disputed issues and reasonable in light of the record. Accordingly, the ORA, TURN and PG&E *Joint Stipulation Comparison Exhibit Chapter 11 – Information Technology* (Exh. Joint-4) is adopted.

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[593] Exh. TURN-4 at 12.

[594] Exh. TURN-4 at 13.

14. Reporting Requirements and Program Management

14.1. Reporting Requirements

PG&E currently prepares various reports as directed by the Commission. The reports fall into four categories:

- Commission decisions and Resolutions
- Code requirements and advisories
- GO 112-E
- Informal agreements with the Commission[595]

PG&E proposes to replace various reports with a gas operations performance report, which would focus on safety and risk management and provide the Commission with information needed to develop effective safety performance metrics, as mandated by Pub. Util. Code § 955 et seq. PG&E proposes to work with Commission staff in Commission-led workshops to develop a list of metrics and information that would be reported in a gas operations performance report, and the reporting intervals. PG&E also recommends implementing quarterly meetings with the Commission and interested parties to discuss the information in the reports.

14.1.1. PG&E/ORA Joint Stipulation

ORA generally agrees with PG&E's proposal. However, it notes that a different process may be necessary to address requirements established by statute or to meet federal requirements. Therefore, it proposes that upon the conclusion of the Commission-led workshops that PG&E should be required to submit a Tier 2 Advice letter containing: 1) a matrix aligning past reporting

[595] Exh. PG&E-2 at 13-3. The various reports that PG&E must address are identified in Attachment A of Chapter 13 (Exh. PG&E-2).

requirements with the proposed reporting requirements; and 2) the new reporting templates.[596]

On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 13 – Reporting and Communications* (Exh. Joint-3 at 16-18), was entered into the record. PG&E and ORA stipulate to supporting a Commission-led workshop to consider changes to reporting requirements as broadly as possible once the other issues in this case have been resolved. PG&E and ORA further stipulate that this workshop should address reporting templates that will apply following this GT&S rate case proceeding and should align with reporting templates contemplated in Commission R.13-11-006 (Rate Case Plan) and other proceedings as appropriate. To the extent possible, the workshop should be coordinated with the requirements of those other proceedings. This workshop should also consider reporting issues raised over the course of this application.

We find the PG&E-ORA joint stipulation for Reporting and Communications reasonable in light of the record. Accordingly, PG&E and ORA *Joint Stipulation Comparison Exhibit Chapter 13 – Reporting and Communications* (Exh. Joint-3 at 16-18) is adopted.

14.1.2. PG&E/Calpine Joint Stipulation

Calpine and Indicated Shippers note that prior to Gas Accord V, GT&S rates for noncore customers were not subject to changes at the end of each year due to balancing account true-ups related to differences between PG&E's expected and actual recovery of GT&S costs. However, Gas Accord V

[596] Exh. ORA-17 at 2.

implemented provisions to share GT&S noncore revenues between ratepayers and shareholders, which required year-end true-ups of balancing accounts for GT&S revenues. Calpine/Indicated Shippers contend that PG&E's practice of proposing year-end GT&S rate changes on or about November 1 is too late for customers' planning purposes, as many noncore customers operate on an annual budgeting cycle that needs to be in place by the end of the third quarter of each year. Therefore, Calpine/Indicated Shippers proposed that PG&E file an informational advice letter on or about August 1 of each year that includes its forecast at that time of the year-end true-ups of the noncore balancing accounts for GT&S revenues, of the expected year-end changes in GT&S revenue requirements that impact noncore customers, and of the resulting noncore GT&S rate changes expected at the end of the year.[597]

PG&E opposes this proposal. It argues that it currently provides updated rate forecasts on its website, along with related information, as the data becomes available. PG&E maintains that this information is more than adequate, and that Calpine/Indicated Shipper's recommendation would add an undue compliance burden on PG&E.[598]

On February 26, 2015, PG&E and Calpine reached the following stipulation, which was read into the record:

> Between August 1st and August 10th of each year, PG&E will post on its website in a location readily accessible to noncore customers best efforts forecast of the year-end true-ups of the noncore balancing accounts for GT&S revenues of the expected year-end changes in GT&S revenues that impact noncore

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[597] Exh. Calpine/Indicated Shippers-1 at 26-28.

[598] Exh. PG&E-43 at 18-7.

> customers and of the resulting GT&S rate changes expected at the end of the year. PG&E will factor into its forecasts actual and anticipated filings by PG&E and Commission decisions, resolutions and dispositions among other factors that could impact rates.[599]

We find the PG&E/Calpine joint stipulation reasonable in light of the record. Accordingly, the joint stipulation is adopted.

14.2. Program Management Office

PG&E's Program Management Office was formed in 2011 as part of the *PSEP Decision*. It manages a broad array of project and program activities set forth in PSEP and has been instrumental in setting priorities, planning, scheduling, forecasting, and managing the day-to-day activities that enable complex program execution for PG&E's PSEP program. PG&E proposes to continue utilizing the Program Management Office and extend its processes, procedures, and controls to manage the implementation of all the major gas transmission projects and programs.[600]

PG&E forecasts 2015 expenses of $6.33 million and 2015 capital expenditures of $6.42 million for Projects Controls organization staff (employees and contractors). The actual costs incurred by the Projects Controls staff would be allocated between expense and capital based on the type of work approved in this proceeding and subsequently managed by the PMO.[601] The transmission pipeline and station project areas to be coordinated through the Project Management Office during the Rate Case Period are summarize below:

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[599] 29 RT at 4067:22 – 4068:7 (PG&E/Hoglund).

[600] Exh. PG&E-1 at 9-2 – 9-4.

[601] Exh. PG&E-1 at 9-14 – 9-15.

Table 35
Project Areas Coordinated Through Project Management Office[602]

Current	To Be Added
Hydrostatic Strength Testing	Additional Pipeline Replacement Including Work Required by Others (WRO)
Pipeline Replacement	Station Reliability Projects
In-Line Inspections (ILI)	ILI Upgrade Projects
Valve Automation	Corrosion Inspection Digs Integrity Management (IM) Inspections

ORA does not oppose PG&E's forecast for 2015-2017.

On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 9 – Program Management Office* (Exh. Joint-3 at 6-8), was entered into the record. ORA stipulates to PG&E's 2015 expense forecast of $6.33 million and 2015 capital expenditure forecast of $6.42 million. Program Management Office expenses and capital expenses for 2016 and 2017 are subject to the joint stipulation on post test year escalation (Chapter 18). We find the joint stipulation for Program Management Office is a reasonable in light of the record. Accordingly the PG&E and ORA *Joint Stipulation Comparison Exhibit Chapter 9 – Program Management Office* (Exh. Joint-3 at 6-8) is adopted.

15. Results of Operations (RO)

PG&E's GT&S cost of service, as expressed in revenue requirement, is calculated based on: (1) PG&E's planned capital and expense expenditures; (2) the Gas Accord methodology, most recently reflected in the Gas Accord V settlement adopted in D.11-04-031; (3) the Pipeline Safety Enhancement Plan

[602] Exh. PG&E-1 at 9-15 (Table 9-1).

approved in the *PSEP Decision*; (4) *2014 GRC Decision*; (5) D.09-09-020 approving the all-party Settlement Agreement on a Pension Cost Recovery Mechanism; and (6) maintaining the existing embedded cost structure.

To derive the adopted revenue requirements for 2015, we utilize the RO computer model. Revenue requirements in 2016 and 2017 are based on the methodology adopted in Section 16.4, Post Test-Year Ratemaking. The RO model incorporates the adjustments and amounts adopted in this Decision. Appendix C presents PG&E's adopted 2015 base revenue requirement.

15.1. Operating and Maintenance Expenses

Operating and Maintenance (O&M) expense includes labor, materials, supplies, contracts and other expenses related to operating and maintaining the GT&S facilities and providing customer service. PG&E provides the estimated O&M expenses in Exh. PG&E-1 and PG&E-2, Chapters 4 through 12.[603]

Franchise fees and uncollectibles are also included in O&M expenses. PG&E applied a franchise fee factor of 0.9653% and an uncollectibles factor of 0.3788%.[604] In the *2014 GRC Decision*, the Commission adopted a revised methodology to determine PG&E's uncollectibles factor, which is based on a 10-year rolling average using uncollectible data. Pursuant to Advice Letter 3535-G/4540-E, PG&E's uncollectibles factor is 0.3325% effective January 1, 2015. Pursuant to Advice Letter 3612-G/4675-E, PG&E's uncollectibles factor is 0.3347% effective January 1, 2016. We apply the uncollectibles factor in Advice Letter 3612-G/4675-E to both 2016 and 2017.

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[603] Exh. PG&E-2 at 16-4.

[604] Exh. PG&E-2 at 16-4 – 16-5.

No party disputed PG&E's methodology for computing O&M expenses.

15.2. Administrative and General Expenses

Administrative and General (A&G) expenses include the salaries and expenses of personnel not engaged in directly supporting specific utility functions, and such items as insurance, workers compensation payments, consultant fees, and employee benefits. Since these expenses are of a general nature and not chargeable to any specific function, A&G expenses are first estimated in total and then allocated among PG&E's UCCs, using O&M expense labor ratios.[605]

The amount of A&G expenses to be allocated to the GT&S UCCs are based on the *2014 GRC Decision* and any subsequent filings that may alter the allocation. PG&E's application, which was filed before this decision was issued, included a placeholder for A&G expenses. The final RO model will include the updated A&G expense in accordance with the *2014 GRC Decision*.

PG&E further notes that the pension forecast associated with 2015, 2016 and 2017 will be added as a separate line item in Gas Preliminary Statement Part C and implemented as part of the Annual Gas True-Up filing and by advice letter, as appropriate.[606]

No party disputed PG&E's methodology for computing A&G expenses.

15.3. Capital Related Inputs

The primary capital-related inputs to the cost of service calculation are plant, depreciation and rate base.

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[605] Exh. PG&E-2 at 16-5.

[606] Exh. PG&E-2 at 16-6.

15.3.1. Plant

PG&E's investment in utility plant is presented in terms of recorded plant as of December 31, 2012, and forecast net plant additions for 2013, 2014 and 2015. Plant includes the cost of gas transmission and storage assets such as gas transmission mains, compressor stations and storage wells.[607] PG&E's forecasted weighted average plant for recorded year 2012, forecast years 2013, 2014 and 2015 are revised as discussed in this Decision.

No party disputes PG&E's methodology for computing forecast plant additions, forecast plant retirements or allocation of common, general and intangible plant.

15.3.2. Depreciation

PG&E's depreciation expense and depreciation reserve are based on a Depreciation Study performed in 2013. This study is presented in Exh. PG&E-2, Chapter 15A. The depreciation study determined the service life and survivor curve that best describes each plant account and/or subaccount and estimates the net salvage percent associated with each of the plant accounts.[608] Plant accounts are based on the plant chart of accounts prescribed in the FERC Uniform System of Accounts in Title 18 of the CFR.

The depreciation rates for the gas transmission and storage accounts are developed by incorporating 2015 proposed depreciation parameters and 2012 year-end plant and reserve amounts. Based on the Depreciation Study, PG&E's annual depreciation accrual rate is 2.37%.

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[607] Exh. PG&E-2 at 15-2.

[608] Exh. PG&E-2 at 15A-1.

TURN recommends a longer average service life and corresponding dispersion curve for Federal Energy Regulatory Commission (FERC) Accounts 367 (Transmission Mains) and 369 (Transmission Measuring and Regulating Station Equipment). It further recommends a -25% net salvage, rather than PG&E's proposal to increase negative net salvage to a -50% level for Account 367 (Transmission Mains).[609] Adoption of TURN's proposals would have resulted in an annual depreciation accrual rate of 1.93%.

ORA recommends the following changes to net salvage:

Table 36
ORA Net Salvage Recommendations[610]

FERC Account	Current NSR	PG&E Proposed	ORA Proposed
353 (Transmission Lines)	-10	-50	-20
367 (Transmission Mains)	-15	-50	-25
369 (Station Equipment)	0 or -1	-20	-10

Adoption of ORA's depreciation recommendation would result in an annual depreciation accrual rate of 2.00%.

On February 24, 2015, a stipulation between PG&E, TURN and ORA, *Joint Depreciation Stipulation* (Exh. Joint-1), was entered into the record. PG&E, TURN and ORA stipulated to jointly supporting a depreciation schedule for contested accounts that produces and overall depreciation rate of 2.15%. This amount is

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609 Exh. TURN-6 at 6.

610 Exh. ORA-19 at 3 (Table 15-1).

roughly midway between the overall rate PG&E sound and the combined impact of TURN's and ORA's proposals.

The joint stipulation includes three supporting tables. PG&E, TURN and ORA stipulate that the account-specific parameters set forth in the column labeled "settled parameters" in Table 15A-2 should be adopted.

We find that the joint stipulation on depreciation to be a reasonable compromise of disputed issues regarding treatment of depreciation expense and reasonable in light of the record. Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, the adopted stipulated figures are binding in this proceeding, but are not precedential in any future proceedings. Accordingly, *Joint Depreciation Stipulation* (Exh. Joint-1) is adopted.

15.3.3. Rate Base

Rate base represents the investment PG&E has made in utility plant. The rate base amount is used to determine the return component in the revenue requirement calculation. PG&E's forecasted weighted average rate base (excluding PSEP investments for 2011-2014) for recorded year 2012, forecast years 2013, 2014 and 2015 are revised as discussed in this Decision.

No party disputes PG&E's methodology for computing GT&S rate base.

15.3.4. PSEP Recovery 2011-2014

PG&E's application had included a placeholder for PSEP cost recovery based on the PSEP Update Application RO model extended out to 2017. PG&E proposed to revise the placeholder amount based on a final decision in the PSEP Update Application (A.13-10-017).[611] On November 20, 2014, the Commission

[611] Exh. PG&E-2 at 16-7.

issued *Decision Adopting Settlement Decision*]D.14-11-023], which adopted a settlement agreement between PG&E, ORA and TURN, which lowered the revenue requirement from that requested in the PSEP Update Application. The Results of Operations model in the Decision incorporates the PSEP update to actual costs.

15.4. Income Taxes

PG&E's calculation of the Federal Income Tax and California Corporation Franchise Tax expenses and associated deferred taxes for each UCC is summarized in Table 16-6 of Exh. PG&E-2. Except for one exception discussed below, no party disputed PG&E's proposed methodology to compute income taxes.

15.4.1. Net Operating Loss and Bonus Depreciation

PG&E has a Net Operating Loss (NOL) situation for Gas Transmission for 2011-2014. Pursuant to D.12-11-051, PG&E included a reduction in the Test Year to deferred taxes due to an NOL carry forward. PG&E notes that to the extent that capital-related expenses (i.e., bonus depreciation) gives rise to a regulatory NOL carry forward (NOLC), "the deductions are not generating full current tax savings."[612] Therefore, consistent with the normalization requirements in Section 168(f)(2) of the Internal Revenue Code, PG&E proposes to delay the offset to rate base until the deferred tax is actually realized.

[612] Exh. PG&E-2 at 16-9 – 16-10.

ORA opposes this proposal, arguing that it serves no other purpose than to increase PG&E's rate base. Accordingly, ORA recommends no adjustment to the forecast of deferred taxes for a NOL carry forward.[613]

In rebuttal testimony, PG&E agreed that if the bonus depreciation extension for 2014 was adopted before a decision in this proceeding was issued, it should be reflected in the decision. Otherwise, PG&E recommended a continuation of the Tax Act Memorandum Account mechanism and a means to reflect bonus depreciation.[614]

On February 24, 2015, a stipulation between PG&E and ORA, *Joint Stipulation on Treatment of NOLC and Bonus Depreciation* (Exh. Joint-2), was entered into the record. PG&E and ORA agreed to a fixed increase to the test year revenue requirement computation of $34 million, to reflect NOLCs. The test year increase would be reduced by a dynamic computation of the benefits of the 2014 bonus depreciation extension, based on the adopted capital forecast. The stipulation further describes the mechanics of the revenue requirement computations. Finally, PG&E and ORA stipulated that any further extension of bonus depreciation should be addressed as part of a TAMA balancing account mechanism for GT&S, which PG&E would retain for the term of this rate case.

We find that the joint stipulation on treatment of NOLC and bonus depreciation to be a reasonable compromise of disputed issues and reasonable in light of the record. Accordingly, *Joint Stipulation on Treatment of NOLC and Bonus Depreciation* (Exh. Joint-2) is adopted.

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[613] Exh. ORA-44 at 6.

[614] Exh. PG&E-43 at 16A-12.

15.5. Taxes Other than Income

Taxes Other than Income include property taxes, payroll taxes, business taxes and other taxes (business and state and federal highway use tax). No party disputes PG&E's methodology for computing these taxes.

16. Cost Recovery Issues

16.1. Transmission Revenue Balancing Account

PG&E's GT&S revenue requirements are allocated between core and noncore customers. The current revenue structure provides for two-way balancing for 100% of most core revenues. Revenue requirements allocated to noncore customers and to core backbone customers are currently subject to a GT&S Revenue Sharing Mechanism (GTSRSM), whereby these customers and PG&E shareholders share a portion of the differences between the adopted revenue requirement and billed revenues from noncore customers.[615] Currently, the amount "at risk" is 50% of noncore backbone revenues and 25% of noncore local transmission revenues.[616] The GTSRSM was negotiated as part of the Gas Accord V Settlement Agreement.

PG&E proposes to discontinue the GTSRSM and replace it with a two-way balancing account revenue structure (except for Gill Ranch storage revenues). PG&E notes that this change would align revenue recovery for PG&E's GT&S noncore revenues with revenue recovery for PG&E's other lines of business, PG&E's core revenues and the other Commission-regulated investor owned utilities.[617] Further, PG&E contends that its proposed change is "consistent with

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[615] Exh. PG&E-2 at 18-2.

[616] Exh. PG&E-2 at 10-19; *see* also, Exh. PG&E-40 at 10-30.

[617] *PG&E Opening Brief* at 16-5; Exh. PG&E-2 at 10-18 – 10-19.

a singular focus on safety" by providing revenue certainty and eliminating any incentive to improve earnings by increasing throughput on the system.[618]

PG&E's proposal is opposed by NCGC, Calpine and SMUD.

NCGC states that PG&E's adopted revenue requirement has historically been more than recorded expenditure, and it is questionable whether PG&E would be able to complete the authorized work within the Rate Case Period. NCGC argues that "this proposed balancing account treatment would allow PG&E to retain any authorized revenue requirements collected during the rate period, even if they are not expended on the proposed safety improvements and risk mitigation measures for which they were intended."[619] Thus, it contends that if PG&E's proposal is adopted, "the balancing account should be structured so PG&E would be required to refund that portion of any revenue requirement relating to any and all amounts authorized but not spent."[620]

Calpine argues that full balancing account protection for GT&S revenues would not necessarily improve safety. It contends "in order to improve safety, PG&E must spend money on identifying and mitigating the most serious risks. The proposed revenue balancing account will not have an impact on PG&E's ability or incentives to identify and mitigate risks."[621] Calpine further believes that PG&E management would continue to have a market-based incentive to improve earnings even if there is revenue certainty, since the company has an

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[618] *PG&E Opening Brief* at 16-3 – 16-4.

[619] *NCGC Opening Brief* at 16.

[620] *NCGC Opening Brief* at 17.

[621] *Calpine Opening Brief* at 26.

obligation to enhance shareholder value and PG&E management's compensation is tied to PG&E's financial performance.

Calpine recommends that PG&E should continue to be at risk for 50% of its noncore backbone revenues and for 100% of its market storage revenues. Calpine notes that PG&E competes against other operators who provide similar services with respect to backbone transmission and market storage. As such, PG&E should have the proper incentive to remain competitive by reducing costs.[622]

SMUD supports Calpine's position.

We are persuaded by intervenors' arguments that the GTSRSM should remain in place. We agree that PG&E should continue to have incentives to earn its forecasted revenues, especially in markets where it competes with its customers. A two-way balancing account would not provide these incentives. Accordingly, PG&E's request to discontinue the GTSRSM and replace it with a two-way balancing account revenue structure is denied.

16.2. Transmission Integrity Management Program Balancing Account

PG&E proposes to change the one-way Transmission Integrity Management Program Balancing Account (TIMPBA) adopted in Gas Accord V to a two-way balancing account. PG&E states that the two-way TIMP balancing account would track all expenses and capital revenue requirements incurred in managing and implementing its TIMP programs. At the end of 2017, any unspent amounts would be returned to customers. At the same time, if PG&E anticipates incurring costs above the total adopted expenses and capital revenue

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[622] *Calpine Opening Brief* at 28.

requirements, it would file a Tier 3 advice letter seeking recovery of these additional costs.[623]

PG&E presents various arguments in support of a two-way TIMP balancing account. First, it notes that Pub. Util. Code § 969, addressing TIMP balancing accounts, was enacted to increase safety spending transparency "by requiring that funds authorized for that use stay in one account and only be used for that purpose."[624] Pub. Util. Code § 969 also specifically stated that this was not to interfere with the Commission's ability to establish two-way balancing accounts. PG&E next notes that the Commission adopted San Diego Gas & Electric Company's (SDG&E) two-way TIMP balancing account proposal, with recovery of any costs in excess of the authorized O&M costs and capital expenditures subject to recovery through a Tier 3 advice letter.[625] Additionally, it notes that the Report of the Independent Review Panel on the San Bruno Explosion, as well as the Independent Review on Gas Distribution prepared by Cycla Corporation for the Safety and Enforcement Division expressed support for two-way balancing accounts.[626]

PG&E further argues that a two-way balancing account is necessary because "PG&E does not know whether there will be new rules or new findings that require greater transmission integrity management costs than forecast. Additionally, PG&E (or the industry) may identify new areas requiring PG&E to

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[623] Exh. PG&E-2 at 18-4 – 18-5.

[624] Exh. PG&E-2 at 18-4.

[625] *PG&E Opening Brief* at 16-7 (citing D.13-05-010).

[626] *PG&E Opening Brief* at 16-8.

incur additional, prudent costs."[627] PG&E argues that a one-way balancing account would not provide the company with funding flexibility to respond to these new requirements.

Intervenors oppose PG&E's proposal. Both Indicated Shippers and TURN contend that PG&E's proposed TIMP balancing account constitutes an expansion of the scope of, and a material departure from, the balancing account agreed to in Gas Accord V and approved in the *Gas Accord V Decision*. Indicated Shippers notes that the categories of expense and capital encompassed in PG&E's request is much broader than PG&E's prior TIMP balancing account.[628] Indicated Shippers further argues that PG&E has not explained the harm that resulted from the use of a one-way TIMP balancing account or demonstrated that the one-way TIMP balancing account actually impaired safety.[629] Indicated Shippers therefore recommends that PG&E's request be rejected.

TURN notes that the expanded scope means that the total amount of expenses subject to the balancing account would be approximately $96 million and the forecast 2015 capital expenditures subject to the balancing account would be approximately $74.3 million. By way of comparison, TURN notes that the TIMP balancing account adopted in the *Gas Accord V Decision* only applied to expenses, which were forecast at $22 million for the test year.[630]

TURN further opposes PG&E's proposal to be able to seek rate recovery for cost overruns via a Tier 3 Advice Letter. It argues that since cost recovery

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[627] *PG&E Opening Brief* at 16-8 – 16-9.

[628] *Indicated Shippers Opening Brief* at 216.

[629] *Indicated Shippers Opening Brief* at 218.

[630] *TURN Opening Brief* at 196-197.

through the advice letter process would be subject to a lower degree of scrutiny, PG&E would have little incentive to control its costs.[631] In addition, TURN raises concerns regarding cost containment and the ability of PG&E and its contractors to perform the work efficiently and at a reasonable cost. For these reasons, TURN recommends that the Commission reject PG&E's proposal. Alternatively, TURN states that if the Commission does adopt PG&E's proposal for a two-way TIMP balancing account, PG&E should be required to seek additional funding through an application, not a Tier 3 advice letter.[632]

Similar to its arguments opposing elimination of the GTSRSM, Calpine argues that "it is important that PG&E have a strong incentive to complete TIMP-related projects at or below the approved budgets and not to seek to reduce the scope of TIMP related work if it experiences cost overruns."[633] NCGC also opposes establishment of a two-way TIMP Balancing Account on the grounds as it opposes elimination of the GTSRSM.[634]

We reject PG&E's proposal to change the TIMP balancing account to a two-way balancing account. While we agree a two-way balancing account would allow any savings to be passed on to ratepayers, it also subjects ratepayers to the risk of higher rates in the event PG&E's costs exceed authorized amounts. Further, PG&E is proposing to seek additional funding when it anticipates incurring costs above the total adopted expenses and capital revenue

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631 *TURN Opening Brief* at 197.

632 *TURN Opening Brief* at 198.

633 *Calpine Opening Brief* at 29.

634 *NCGC Opening Brief* at 17.

requirements. We agree with TURN that this could allow PG&E to seek recovery for cost overruns and does not encourage PG&E to seek reasonable costs.

PG&E presents the Tier 3 advice letter as providing customer protection in the form of review before PG&E is authorized to recover its costs in rates. While a Tier 3 advice letter provides the most stringent level of review among the various informal processes, it does not provide the same level of scrutiny and review as a formal application. Further, Advice Letters are ministerial in nature, where the Commission has identified specific parameters and requirements for approval. Here, PG&E envisions seeking recovery of costs to implement new rules or "new areas" requiring additional costs. Neither of these types of activities is ministerial in nature, and should not be delegated to Energy Division staff. Further, the expanded scope of the balancing account to include both expenses and capital expenditures as well as the need to ensure that hydrotest costs are properly identified as being performed as part of integrity management or as part of compliance with D.11-06-017 require a higher level of review by the Commission. While PG&E has argued that discovery and hearings can be included as part of the Advice Letter process, we find that these activities are more appropriately addressed and resolved by an Administrative Law Judge as part of a formal proceeding.

For the reasons discussed above, PG&E's request to change the one-way TIMPBA to a two-way balancing account is denied. The programs and amounts to be tracked in the TIMPBA are presented in Appendix I, Tables I-1 and I-2.

We are, however, sympathetic to PG&E's need to ensure that it will be able to obtain funding to comply with new transmission integrity management statutes or rules. Accordingly, PG&E is authorized to establish a new Transmission Integrity Management Program Memorandum Account to track

costs associated with any new transmission integrity management statutes or rules. We allow PG&E to track these costs in a memorandum account so that it will preserve the opportunity to seek recovery of these costs at a later date.[635]

Accordingly, within 15 days after the effective date of this Decision, PG&E shall file a Tier 2 Advice Letter to establish a new Transmission Integrity Management Program Memorandum Account to track costs associated with any new transmission integrity management statutes or rules. Pursuant to Pub. Util. Code § 969, costs incurred in the following programs shall be tracked in the memorandum account:

Table 37
Programs Included In
Transmission Integrity Management Program
Memorandum Accounts

Description	Category
Traditional In-Line Inspections (ILI)	Expense/Capital
Non-Traditional ILI	Expense/Capital
ILI Casings	Expense
Traditional ILI - Direct Examinations and Repairs	Expense
Non-Traditional ILI - Direct Examinations and Repairs	Expense
External Corrosion Direct Assessments	Expense
Internal Corrosion Direct Assessments	Expense
Stress Corrosion Cracking Direct Assessments	Expense
TIMP Pressure Tests	Expense
Geological Hazard Monitoring	Expense

[635] Authorization of a memorandum account does not necessarily mean that the Commission has decided that the types of costs to be recorded in the account should be recoverable in addition to rates that have been otherwise authorized, e.g., in a general rate case. Instead, the utility shall bear the burden when it requests recovery of the recorded costs, to show that separate recovery of the types of costs recorded in the account is appropriate, that the utility acted prudently when it incurred these costs and that the level of costs is reasonable. Thus, PG&E is reminded that just because the Commission has authorized this memorandum account, it does not mean that recovery of costs in the memorandum accounts from ratepayers is appropriate.

Root Cause Analyses	Expense
Risk Analysis Process Improvements	Expense

PG&E shall seek recovery of costs in this memorandum account through the filing of a formal application.

16.3. Z-Factor Mechanism

PG&E proposes to continue its existing Z-Factor mechanism, which has been in place since the first Gas Accord Settlement Agreement.[636] Application of the Z-Factor mechanism has been addressed as part of the stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year Mechanism* (Exh. Joint-3 at 26, line 6), which has been approved.

16.3.1. Adjustment Mechanism for Costs Determined in Other Proceedings Beyond 2014

PG&E proposes continuing the Adjustment Mechanism for Costs Determined in Other Proceedings tracking account, which was adopted as part of the Gas Accord V Settlement.[637] No party has opposed this proposal. PG&E's proposal is adopted.

16.3.2. Recovery of Line 407 Costs

PG&E had proposed a methodology for recovering costs for Line 407. However, recovery of Line 407 Costs has been addressed as part of the stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year Mechanism* (Exh. Joint-3 at 26, line 5).

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[636] Exh. PG&E-2 at 18-5.

[637] Exh. PG&E-2 at 18-6.

16.3.3. Actual Costs for Electricity Used to Provide GT&S Services, and GHG Compliance Costs Incurred for Natural Gas Compressor Stations

PG&E proposes continuing its currently-authorized recovery of all actual costs incurred for electricity used to provide gas compression and GHG compliance costs incurred for natural gas compressor stations. PG&E's recovery of GHG compliance costs has been addressed in D.15-10-032. As such, the accounting process for recovering these costs should be included as part of PG&E's existing Annual Gas True-Up advice letter process.

16.3.4. Tax Act Memorandum Account

PG&E had proposed to terminate the Tax Act Memorandum Account (TAMA) balancing account.[638] However, as part of *Joint Stipulation on Treatment of NOLC and Bonus Depreciation* (Exh. Joint-2), PG&E and ORA stipulated that any further extension of bonus depreciation should be addressed as part of a TAMA balancing account mechanism for GT&S. Given the adoption of *Joint Stipulation on Treatment of NOLC and Bonus Depreciation*, we will not be terminating the TAMA balancing account.

16.4. Post Test Year Ratemaking

PG&E's proposed Post Test Year (PTY) ratemaking mechanism is the same as the mechanism used in PG&E's 2011 GT&S application, with the exception of expense adjustments to three programs. ORA notes that based on PG&E's revenue forecasts, "PG&E is requesting attrition increases of $63.2 million (or 5.32%) in 2016 and $170.6 million (or 13.64%) in 2017 for its base revenue

[638] Exh. PG&E-2 at 18-7 18-8.

requirement without the PSEP Update, or increases of $61.1 million (or 4.75%) in 2016 and $167.5 million (or 12.43%) in 2017 with the PSEP Update figures included."[639]

ORA contends that PG&E's forecasts are excessive. It recommends PTY revenue increases of 3.0% per year for 2016 and 2017, plus $35 million of additional revenues to cover certain incremental costs. This would result in effective post test-year increases of 3.66% in 2016 and 5.56% in 2018.[640] Alternatively, ORA proposes a cost-of-service-based approach that computes separate expense and capital attrition year adjustments. This proposal is similar to PG&E's, but the escalation rates for expenses are lower than what had been proposed by PG&E and the attrition year capital additions would be based on test year additions, escalated using capital cost indices.[641]

On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year Mechanism* (Exh. Joint-3 at 23-28), was entered into the record. PG&E and ORA stipulated to jointly proposing a post-test year mechanism. The proposal is based primarily on ORA's Alternative Proposal (Exh. ORA-22 at 32-43), with some modifications. The stipulated joint recommendation is presented in Exh. Joint-3 at 25-27.

CUE strongly supports the stipulation, noting that it "achieves a dramatically superior outcome for PG&E's employees compared to ORA's

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[639] Exh. ORA-22 at 22.

[640] Exh. ORA-22 at 27.

[641] Exh. ORA-22 at 32-43.

original proposals and ensures a capital escalation rate necessary to support safety goals."[642] No parties opposed the joint stipulation.

We find the joint stipulation to be reasonable. However, we believe that there is an error with respect to the stipulated amounts for Incremental Specific Expense Adjustments, which is Line 3 of the stipulation.[643] The specific expense adjustments are from Table 18-5 in Exh. PG&E-2.[644] This table, however, did not incorporate corrections to External Corrosion Direct Assessment.[645] We assume that PG&E and ORA had intended to use these updated figures in their joint stipulation. Using the corrected figures in Exh. PG&E-46, Table 18-5 (with Errata), footnote 2 on page 26 of Exh. Joint-3 would be:

Table 18-5 (Errata Adjusted)		Millions ($)		
Line No.	Program	2015 Forecast	2016 Forecast	2017 Forecast
1	Traditional ILI, including Direct Exam & Repair	28	28	53
2	External and Internal Corrosion Direct Assessment (Errata - PG&E-46)	44	51	65
3	Hydrostatic Testing Station Facility M&C	5	11	23
4	Total	77	91	141

642 *CUE Opening Brief* at 2.

643 Exh. Joint-3 at 26.

644 Exh. Joint-3 at 26, Footnote 2.

645 Exh. PG&E-46 at Errata-55, line 7.

The impact of this change on PG&E's recommendation is to increase 2016 and 2017 amounts by $1 million each year – to $14 million in 2016 and $50 million in 2017.

We adopt the *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year Mechanism* (Exh. Joint-3 at 23-28), as revised above.

17. Other Revenue Requirement and Cost Recovery Issues

17.1. 2011-2014 Capital Expenditures

17.1.1. PG&E's Position

PG&E states that its 2011 GT&S Rate Case Application had forecasted $853.2 million in capital expenditures during the 2011-2014 Rate Case Period. In the *Gas Accord V Decision*, the Commission adopted a settlement agreement between PG&E and all but two parties, which approved capital expenditures of $497.3 million.[646] PG&E argues that due to events after the issuance of Gas Accord V, PG&E spent amounts far in excess of the adopted amounts to meet new and heightened safety requirements adopted following the San Bruno fire and explosion.[647] Consequently, PG&E seeks to roll into rate base $696.4 million in capital expenditures.[648]

PG&E witness Stavropoulos testified that based on his review, the spending levels under Gas Accord V were insufficient to fund the work that PG&E needed to meet the new regulatory requirements. Consequently, PG&E

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[646] *PG&E Opening Brief* at 6-2.

[647] *PG&E Opening Brief* at 6-2 – 6-3. These included five new gas safety bills enacted by the Legislature in 2011 and the Commission's Natural Gas Safety Action Plan issued in 2013.

[648] We adjust PG&E's requested amount of $698.4 million to reflect a mathematical error in PG&E's calculations.

significantly increased its spending levels since 2011.[649] Mr. Stavropoulos notes that this increased spending has allowed PG&E to move towards its goal of becoming the safest, most reliable gas company, and contends that the programs proposed in this proceeding will place it in a good position relative to its peers.[650]

PG&E notes that typically, "capital additions that have gone into rate base during the years since the last rate case routinely become a part of a utility's rate base without any analysis or discussion by the Commission."[651] However, in response to challenges by intervenors, PG&E submitted supplemental testimony and detailed work papers to support its expenditures.

PG&E's capital expenditures above the $500 million adopted in the *Gas Accord V Decision* are presented below:

Table 38
Capital Expenditures Above Adopted 2011-2014
($ Thousands of Nominal Dollars)

Projects and Programs included in Exh. PG&E-22	$496,890[652]
Programs	
Tools and Equipment	34,422
Buildings	36,855
Pipeline Reliability/Safety	31,672
Corrosion	15,690
	118,639

[649] 13 Reporter's Transcript (RT) at 1010:24 – 1011:3 (PG&E/ Stavropoulos).

[650] 13 RT at 1019:8 – 1020:19, 1027:23 – 1028:27 (PG&E/ Stavropoulos).

[651] *PG&E Opening Brief* at 6-4.

[652] PG&E's testimony and Exh. PG&E-22 had indicated spending of $498.890 million. However, when the numbers contained in Appendix A are added up, the total is $496,890,468. We use this amount in this Decision. We further correct the total capital expenditures above the amount adopted in Gas Accord V to $696.4 million.

Projects and Programs where increase less than $1 million	80,871
Total Capital Expenditures	**$696,400**

PG&E's supplemental testimony provides detailed information for $496.890 million of the expenditures.[653] PG&E explains that it provided detailed information only for: (1) projects or programs that were forecast in the 2011 Rate Case for which the expenditures exceeded or are forecast to exceed $1 million above the adopted amount and (2) projects or programs that were not originally filed in the 2011 Rate Case that were greater than $1 million.[654] PG&E asserts that the information provided in its supplemental testimony more than meets PG&E's burden that these capital expenditures were prudently incurred and should be recovered from ratepayers.

PG&E notes that, as ordered in the *Gas Accord V Decision*, it has included in its semi-annual GT&S Safety Reports information regarding all additional spending above showing the difference between adopted and actual capital expenditures.[655] It contends that since it provided this information to the Commission and parties to Gas Accord V, they were aware of the difference between adopted and actual capital expenditures. Moreover, PG&E argues that the Commission "anticipated PG&E spending significant funds on its gas

[653] Exh. PG&E-22, Appendix A.

[654] Exh. PG&E-22 at 3S-3.

[655] *PG&E Opening Brief* at 6-8.

transmission and storage system during the 2011-2014 period" since it conferred oversight authority for Gas Accord V projects and spending to the SED.[656]

PG&E next contends that $125 million of the approximately $700 million in spending was explicitly authorized in Resolution L-411A.[657] PG&E asserts that this resolution "allowed PG&E to incur capital costs during the period 2011-2014 up to the revenue requirement benefits resulting from bonus depreciation in a tax act memorandum account (TAMA)."[658] PG&E notes that the Gas Accord V settlement included an express provision for bonus tax depreciation. As such, PG&E believes that the amount in spending above the amount authorized in the *Gas Accord V Decision* is actually only $575 million.[659]

PG&E further argues that denying recovery of these expenditures would allow ratepayers to receive the benefit of a used and useful asset for free. Relying on the *PSEP Decision*, PG&E asserts that it would be "fundamentally unfair for customers not to pay for necessary capital investments during the useful life of the assets."[660]

Additionally, PG&E contends that the work performed between 2011-2014 was absolutely necessary and was performed efficiently. As support, PG&E notes:

> PG&E loses approximately 15 percent in revenues for each full year that a capital addition is in service and is above adopted rate base. This is a substantial loss of revenues that would cause PG&E, even if

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656 *PG&E Opening Brief* at 6-8.

657 *PG&E Opening Brief* at 6-9; *PG&E Reply Brief* at 6-2.

658 *PG&E Opening Brief* at 6-9.

659 *PG&E Reply Brief* at 6-2.

660 *PG&E Opening Brief* at 6-5.

> it were otherwise earning its authorized return, to earn less than authorized. PG&E has every incentive to minimize such costs by doing the work efficiently and only doing the work that it believed to be absolutely essential.[661]

Finally, PG&E urges the Commission to reject TURN's proposal that PG&E must demonstrate that the costs PG&E seeks to recover are not the result of imprudence. PG&E argues: "Once a utility has made a prima facie showing that an investment was prudent, the Commission should require evidence of imprudence, not a mere list of possibilities to show that a project was imprudent."[662] PG&E contends that while it has provided detailed work papers to demonstrate that "the vast majority of the capital spending in excess of adopted was necessary and prudent to comply with new regulatory investments," no party has demonstrated that PG&E acted imprudently.[663] To adopt TURN's position (that PG&E must prove it did not act imprudently) would, in PG&E's mind, create a new untenable legal standard.

17.1.2. TURN's Position

TURN opposes rolling the 2011-2014 expenditures into rate base absent further review. It notes that the proposed $700 million increase in rate base associated with these expenditures would result in an annual revenue requirement increase of approximately $105 million per year.[664] TURN further disputes PG&E's argument that this is a "typical" rate case, noting that PG&E's witness Smith had characterized this proceeding as "the first opportunity for the

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[661] *PG&E Opening Brief* at 6-9 (citations omitted).

[662] *PG&E Opening Brief* at 6-10.

[663] *PG&E Opening Brief* at 6-11.

[664] *Opening Brief of The Utility Reform Network* (*TURN Opening Brief*), filed April 29, 2015, at 40.

Commission to review the 2011-14 capital expenditures to the extent they vary from the forecast included in the Gas Accord V decision."[665]

TURN argues that PG&E's application and direct testimony provided no explanation of the reasonableness of the 2011-2014 expenditures, but rather "simply list[s] the capital expenditures (recorded for 2011-12 and forecasted for 2013-14 in workpaper tables)."[666] TURN asserts that, notwithstanding PG&E's assertions that the additional $700 million in 2011-2014 capital expenditures was necessary due to new regulatory requirements, PG&E still must demonstrate that the underlying projects and their associated costs are "prudent (and not the product of or inextricably tied to past imprudence), and the associated costs must be reasonable."[667] TURN contends there is no "presumption of prudence" for PG&E's 2011-2014 capital expenditures in excess of the amounts set forth in the Gas Accord V settlement. Rather, "PG&E must demonstrate the prudence of the projects that resulted in $700 million of capital expenditures in excess of the $500 million from the [Gas Accord] V settlement, whether attributed to spending more than forecast on projects included in the [Gas Accord] V showing, or spending on projects not included in that showing."[668]

TURN witness Finkelstein questions whether the spending above the authorized 2011-2014 levels should be presumed reasonable.

> The projects and cost estimates underlying PG&E's 2011 GT&S application reflected 2009 forecasts of 2011-2014 activities. After

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[665] *Reply Brief of The Utility Reform Network (TURN Reply Brief)*, filed May 20, 2015, at 37.

[666] *TURN Opening Brief* at 40.

[667] *TURN Opening Brief* at 42.

[668] *TURN Opening Brief* at 43-44.

> the September 9, 2010 San Bruno catastrophe, it is likely that for at least some of the projects and programs with forecasts included in the "adopted amounts," PG&E chose not to pursue the project due to changed priorities. There is also concern that projects or costs that should be deemed part of the PSEP-related efforts (and subject to PSEP-related rate recovery restrictions) are instead designated as GT&S projects. Under these circumstances, there is reason to review the entirety of PG&E's GT&S spending during 2011-14, whether or not the reported amount is part of the "adopted amounts" from the 2011 GT&S decision.[669]

TURN contends that PG&E has failed to demonstrate that its 2011-2014 capital expenditures in excess of the amount authorized in Gas Accord V are reasonable. It notes that due to PG&E's selection criteria, PG&E has provided no showing to support $80.871 million of capital expenditures.[670] TURN further notes that while PG&E's supplemental testimony states that the utility will cumulatively spend $118.639 million above the amount adopted in Gas Accord V for four programs (Tools and Equipment, Buildings, Pipeline Reliability/Safety, and Corrosion), PG&E provides only a summary description of the reason for the significant increases in these programs.[671]

TURN next challenges the adequacy of PG&E's showing with regard to the 104 projects and programs contained in PG&E's supplemental testimony. TURN presents numerous examples to support its assertions that PG&E has failed to provide sufficient documentation and information to explain the significant cost increases and demonstrate the reasonableness of the costs associated with the

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669 Exh. TURN-16 at 4.

670 *TURN Opening Brief* at 53.

671 *TURN Opening Brief* at 54-55.

projects and programs.[672] TURN argues that the information provided by PG&E is insufficient to permit rate recovery because:

- PG&E does not explain how a requested cost figure is derived or why the cost figure represents a reasonable cost for the underlying project.
- There is no showing of the actions leading to the need for the project.
- PG&E has failed to identify the factors that caused some projects, originally identified in the Gas Accord V materials, to now have significantly higher costs.
- For some of the projects there is a very large discrepancy between the cost figures set forth in the supplemental materials and the cost that PG&E now proposes to add to rate base for the same project.[673]

TURN further disputes PG&E's argument that the *Gas Accord V Decision* "anticipated PG&E spending significant funds on PG&E's GT&S facilities" and delegated to SED and the Energy Division the authority to determine the reasonableness of 2011-2014 expenditures in excess of $500 million approved in the Gas Accord V settlement. It contends that the statements in the *Gas Accord V Decision* relied upon by PG&E refer to the agreed-upon revenue requirements adopted in the settlement for PG&E's planned pipeline safety, reliability and integrity efforts. TURN argues: "If the Commission had understood PG&E as likely to record GT&S-related capital expenditures in 2011-14 in an amount

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672 *TURN Opening Brief* at 56-66.

673 *TURN Opening Brief* at 58-59.

substantially greater than the $500 million subsumed in the [Gas Accord] V settlement approved in [the *Gas Accord V Decision*], it would have said so."[674]

TURN recommends that the Commission should disallow rate recovery of the 2011-2014 capital expenditures during the 2015-2017 Rate Case Period and conduct a third party audit to assess whether these costs were reasonable and prudent. TURN also asserts that PG&E shareholders should bear the cost of the audit.[675]

17.1.3. Discussion

PG&E acknowledges that it carries the burden of proof in this proceeding.[676] PG&E witness Stavropoulos testified that the requested 2015-2017 revenue requirement is "an unprecedented increase; but it is a necessary one because we are in unprecedented times."[677] Yet, despite this statement, PG&E would like us to simply approve 2011-2014 capital expenditures of almost $700 million above the $500 million authorized in the *Gas Accord V Decision* without further review. While it is possible that the additional capital expenditures during this time period were necessary to comply with new safety regulations and requirements put in place after the issuance of the *Gas Accord V Decision*,[678] we cannot agree that the costs associated with these projects should be presumed to be reasonable. Rather, as noted by TURN: "If the 2011-14 above-forecast spending of $700 million were truly the product of 'heightened

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674 *TURN Opening Brief* at 68-69.

675 *TURN Opening Brief* at 80-81.

676 *PG&E Reply Brief* at 6-14.

677 Exh. PG&E-1 at 1-1:23-24.

678 *Reply Brief of Pacific Gas and Electric Company (PG&E Reply Brief)*, filed May 20, 2015, at 6-1.

expectations,' the utility should have reasonably understood there to be a need for a heightened showing in support of that spending."[679]

We disagree with PG&E's belated suggestion that its authorization to spend $125 million through the TAMA has been found to be reasonable, thus making its 2011-2014 above-forecast spending only $575 million. Resolution L-411A specifically notes

> The establishment of a memorandum account does not change rates, nor guarantee that rates will be changed in the future. This mechanism simply allows the Commission to determine at a future date whether rates should be changed, without having to be concerned with issues of retroactive ratemaking.[680]

Resolution L-411A goes on further to note that while the utility would not be required to seek pre-approval of the spending of bonus depreciation, the reasonableness of these expenditures would still be subject to review in a subsequent GRC.[681] Thus, contrary to PG&E's assertions, no portion of the $700 million above forecast spending has already been authorized or found to be reasonable by the Commission. Moreover, even if this were the case, PG&E has provided no documentation to identify which project(s) were funded by the TAMA.

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[679] *TURN Reply Brief* at 38.

[680] Revised Resolution on the Commission's Own Motion Establishing a Memorandum Account for all Cost-Of-Service Rate-Regulated Utilities, Except for: Class C and D Water and Sewer Utilities, Mountain Utilities, Alpine Natural Gas, NRG Energy Center, Small Local Exchange Carrier Telephone Corporations and Those Energy and Water Utilities that will be Addressing the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act Of 2010 in a 2011 Or 2012 Test Year General Rate Case, to Allow the Commission to Consider Revising Rates to Reflect the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Resolution L-411A), issued June 23, 2011, at 2.

[681] Resolution L-411A at 6

PG&E argues that 2009 forecasted capital expenditures should not serve as the basis for assessing the reasonableness of the 2011-2014 expenditures above the authorized amount. Rather, the Commission should consider these additional expenditures in light of the "new legal requirements and heightened stakeholder expectations for safety and reliability" and in comparison to the forecast for 2015-2017.[682] We find this argument somewhat circular. PG&E is essentially arguing that the reasonableness of the 2011-2014 capital expenditures is due to the reasonableness of the 2015-2017 forecasts. However, in determining whether the 2015-2017 forecasts are reasonable, we would consider past expenditures, including those made in 2011-2014.

PG&E next argues that the Commission and parties to Gas Accord V were provided semi-annual reports showing the difference between adopted and actual capital expenditures, regardless of size. PG&E additionally contends that the Commission tasked SED with reviewing these reports and tracking that PG&E was spending the allocated funds on storage and pipeline-related safety, reliability and integrity activities.[683] Based on these arguments, PG&E seeks to have us find these expenditures reasonable.

We do not find PG&E's arguments to be persuasive. While the *Gas Accord V* Decision tasked SED with reviewing the semi-annual reports to ensure that PG&E was spending its allocated funds on these storage and pipeline-related safety, reliability, and integrity activities, there is nothing to suggest that this review included a reasonableness review. Indeed, PG&E's response to TURN Data Request 37, Question 1 specifically states "PG&E does not contend that

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[682] *PG&E Reply Brief* at 6-3.

[683] *PG&E Opening Brief* at 6-8; *PG&E Reply Brief* at 6-14.

SED's review was intended to constitute a review to determine the reasonableness of PG&E's 2011-2014 capital expenditures for purposes of rate recovery."[684] Additionally, PG&E witness Howe stated he had no knowledge whether SED or Energy Division had made any recommendations or findings on the reasonableness of PG&E's 2011-2014 capital expenditures.[685] Thus, we do not find that the record supports a conclusion that SED or Energy Division were tasked with performing a reasonableness review or had made any determinations with respect to the reasonableness of PG&E's 2011-2014 capital expenditures. Further, the Commission has never transferred the burden of making a prima facia case from the utility to its staff. No matter what we may direct the staff to examine for us, that analysis, if any, is merely supplemental, and not a replacement for the utility meeting its burden of proof.

Accordingly, as we explain below, we are removing PG&E's entire request from this GT&S application. The request is addressed in the following manner:

1. The $80.871 million for small projects is disallowed.
2. The $118.639 million for four projects – Tools and Equipment; Buildings; Pipeline Reliability/Safety; and Corrosion – shall be subject to further review by a third-party auditor for reasonableness. PG&E may seek recovery of those amounts found reasonable at a later time.
3. Of the $496.890 million for 104 projects, detailed in Exh. PG&E_22:

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[684] Exh. TURN-68, Answer 1c.

[685] 26 RT at 3437:3-20 (PG&E/Howe).

a. $18,106,206 associated with six projects in MWC-98 that were included in Gas Accord V, where the expenditures were above the funded amount is disallowed.

b. $21,432,557 associated with three projects in MWC-75 that were included in Gas Accord V, where the expenditures were above the funded amount is disallowed.

c. $457,351,706 associated with the 95 projects that were not disallowed in (a) and (b) above is subject to further review by a third-party auditor for reasonableness. PG&E may seek recovery of those amounts found reasonable at a later time.

17.1.3.1. Expenditures Under $1 Million

PG&E provides no testimony or supporting documentation to support the $80.871 million associated with projects with expenditures of less than $1 million over what was adopted in Gas Accord V.[686] Rather, PG&E states that it generally uses a $1 million threshold, under which it does not provide specific details for a project.[687] While this may be the case, the amount of this category in aggregate is significant. Without supporting documentation, there is no basis for us to conclude that these expenditures are reasonable. Moreover, it is unclear whether the increases in this category are associated with projects included in Gas Accord V or new projects (both the number of projects within each category and in total). Consequently, we conclude that the $80.871 million in expenditures are unreasonable and should not be recovered in rates. This amount is therefore disallowed. Consistent with the *Penalties Decision*, the disallowance for these capital expenditures shall be permanently removed from rate base.

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[686] Exh. PG&E-22 at 3S-1, footnote 1.

[687] *PG&E Reply Brief* at 6-14.

17.1.3.2. Expenditures for Four Projects

With respect to the $118.639 million for four projects – Tools and Equipment; Buildings; Pipeline Reliability/Safety; and Corrosion – we find that there is no evidence to support the reasonableness of these expenditures. Exhibit PG&E-22, supplemented by comments in PG&E's Opening and Reply briefs, provide minimal discussion regarding the reasons for these expenditures.[688] A review of PG&E's testimony finds that, aside from listing the 2011 and 2012 recorded costs and the 2013 and 2014 forecast costs for MWC-78 (Manage Buildings) and MWC-05 (Tools and Equipment), there is no explanation how the 2011-2014 costs were determined.[689] Further, although PG&E contends that the programmatic costs for Pipeline Reliability Safety and Corrosion are supported "through its testimony and workpapers in its initial showing," it fails to provide any citation to any supporting documents.[690] Absent this information, there is no basis for the Commission to determine what work was performed in these projects and whether the level of spending was reasonable. Nonetheless, we agree that these projects may have been warranted, such as the determination to build a consolidated Gas Operations headquarters in light of the significant increase in gas operations personnel.

Based on these considerations, we agree with TURN that rate recovery of $118.639 million for the four projects should be excluded from this Rate Case Period and be subject to a third party review to determine the appropriate

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[688] Exh. PG&E-22 at 3S-5 – 3S-6; *PG&E Opening Brief* at 6-4 – 6-5; *PG&E Reply Brief* at 6-15 – 6-16.

[689] Exh. PG&E-2 at 12-16, Table 12-2.

[690] *PG&E Reply Brief* at 6-16.

amount to be recovered from ratepayers. The process and context of this third party review is discussed below.

17.1.3.3. Expenditures for 104 Projects Detailed in Exh. PG&E-22

We next turn to the 104 projects identified by PG&E in Exh. PG&E-22. Of the $498.890 million of spending over forecast Gas Accord V spending, approximately $173 million is associated with 21 projects for Gas Accord V work.[691] In the *Gas Accord V Decision*, the settling parties were asked whether the settlement would provide "the necessary funds for PG&E to carry out the capital expenditures and O&M activities that are required by Subpart O and related regulations" in light of the San Bruno fire and explosion. In response,

> The settlement parties commented that the Gas Accord V Settlement provides 92% of the monies that PG&E had requested for O&M pipeline integrity, 100% of the capital investment requested for pipeline integrity management in MWC-98, and 98% of the monies that PG&E had requested for pipeline safety and reliability efforts in MWC-75.[692]

Based on this response, the Commission found that there were sufficient monies during the four-year rate cycle to fund the pipeline-related safety, integrity and reliability projects and maintenance activities. Despite the settling parties', including PG&E's, representation that the Gas Accord V settlement amounts could fund all the work in MWC-98, PG&E now seeks to recover an additional $50,057,074 work performed in 2011-2014. This request, however, is not supported by Exh. PG&E-22 nor the supporting workpapers. For example,

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[691] Exh. PG&E-22, Attachment A.

[692] D.11-04-013 at 27.

costs for the Line 300B MP256.64-299.00 ILI upgrade project increased from $4,775,000 to $7,054,727.[693] The advance authorizations for this project increase the cost estimates in each revision, yet provide no explanation for the increase.[694] In light of the fact that MWC-98 was fully funded and the lack of sufficient evidence to support the reasonableness of expenditures above the funded amount, we disallow the portion of 2011-2014 expenditures that exceeded the Gas Accord Settlement amounts for the following projects for MWC-98[695]:

Table 39
Disallowance of 2011-2014 Capital Expenditures Associated with Work Included in Gas Accord V, MWC-98

Project Name	PSRS ID Number	Job Number	SAP Planning Order	Amount Above Gas Accord V Settlement Amount[696]
L-300A MP256.21-299.01 ILI UPGRADE	17149	30603915	5723873	$3,663,038
L-210C MP 19.46-32.11 ILI UPGRADE	17150	30603914	5723872	$1,456,283
L-300B MP256.64-299.00 ILI UPGRADE	17151	30603916	5723874	$2,279,727
L-101 MP 0.00-11.62 ILI UPGRADE SOUTH	19837	30712995	5748018	$1,449,156
L-101 MP 11.62 - 32.57 ILI UPGRADE NORTH	19838	30712993	5747997	$5,477,235
L-105N ILI MP 7.75 to 22.85 Upgrade Proj	23206	P.03638	5723868	$3,780,767

[693] Exh. PG&E-22, Attachment A, at A-1 line 6. This project is in MWC-98.

[694] Exh. PG&E-23 at SWP 4A-116 – SWP 4A-136.

[695] Two other projects in MWC-98, the Line 109 MP 14.62-36.96 ILI Upgrade (PSRS ID 17140) and Line 57A MP 9.29-16.68 ILI Upgrade (PSRS ID 17146) did not have costs included in the Gas Accord V settlement for 2011-2014. These projects consist of total of $6,780,868, in expenditures. As discussed in this Section, due to insufficient information to determine the reasonableness of these expenditures, these costs are excluded from the 2015-2017 rate cycle and subject to an audit for reasonableness.

[696] Exh. PG&E-22, Attachment A, Column M.

Total Disallowance	$18,106,206

With respect to MWC-75, which was 98% funded in Gas Accord V, we find there is no basis to conclude the increased 2011-2014 expenditures for three projects associated with work in Gas Accord V are reasonable. In one case, the increases are because PG&E amended the scope of the project from emergency repair of 30" pipeline on Line 132, MP 42.95 – 43-63 (installed in 1948) to replacement with 9,162 feet of new 30" pipeline.[697] This amendment was made after the replacement project was completed. As a result, the cost for this project increased from $4,923,134 to $17,884,899.[698] In two other cases, PG&E supports increasing project costs by $8,470,792 (from the Gas Accord V amount of $2,889,328) using job estimates and Business Cases.[699] Accordingly, we disallow the portion of 2011-2014 expenditures that exceeded the Gas Accord Settlement amounts for the following projects for MWC 75:

Table 40
Disallowance of 2011-2014 Capital Expenditures
Associated with Work Included in Gas Accord V, MWC-75

Project Name	PSRS ID Number	Job Number	SAP Planning Order	Amount Above Gas Accord V Settlement Amount
L-132 MP 42.95-43.63 REPLACE - SOUTH SF	18036	30604188	5726804	$12,961,765
105 B MP 10.44 - 10.78 REPL. FAULT XING	20425	30716295	5735703	$1,190,369
DFM-7221-15 REPL 1.60MI MP 0.04-1.69 PH1	18039	30841616	5726808	$7,280,423

[697] Exh. PG&E-23 at SWP 4A-150 – SWP 4A-162.

[698] Exh. PG&E-22, Attachment A at A-1, line 8.

[699] Exh. PG&E-22, Attachment A at A-2, line 11 and A-14, line 96.

Total Disallowance	$21,432,557

Consistent with the *Penalties Decision*, the costs for these nine capital projects identified in Tables 39 and 40 above are permanently removed from rate base.

We find that the remaining projects identified in Exhibit PG&E-22 are equally lacking in information to support the reasonableness of the expenditures. PG&E appears to believe that so long as it has documented that costs were incurred, the Commission should find the costs to be reasonable. That is not the case. As we have noted above, we do not disagree with PG&E's assertions that the additional capital expenditures during 2011-2014 were necessary. However, we cannot agree that the costs are considered reasonable.

As discussed above, PG&E's initial and supplemental testimonies do not support a finding of reasonableness. Further, PG&E argues that the proxy for determining the reasonableness for capital spending from 2011-2014 should be PG&E's forecast of capital spending for 2015-2017.[700] However, as discussed above, this comparison requires a finding that the forecast 2015-2017 capital spending is reasonable. PG&E should not be attempting to bootstrap the 2011-2014 capital spending. Rather, it should demonstrate that the costs were incurred prudently and that it made best efforts to contain costs (e.g., that there were competitive bids for contracts, that that the pace of any work performed did not result in unwarranted upward cost pressures, that cost overruns were explained and reasonable).

[700] *PG&E Reply Brief* at 6-3.

In light of these considerations, we adopt TURN's recommendation that an audit should be conducted. The audit shall be performed by Commission staff or a third party and shall examine all costs not approved or disallowed here. We further agree with TURN that the cost of the audit should be paid for by PG&E shareholders.

17.1.3.4. Disposition of 2011-2014 Capital Expenditures

As discussed above, we have removed $696.4 million, associated with PG&E's 2011-2014 capital expenditures above the amounts authorized in Gas Accord V, from PG&E's request in this GT&S application. Removal of these expenditures results in a reduction in a 2015 revenue requirement of $81.178 million. Appendix F summarizes the disposition of these expenditures and its impact on 2015 revenue requirement. Of the amount removed, $120.409 million is permanently disallowed, and PG&E cannot seek future recovery of these amounts in rates. The remaining $575.991 million shall be subject to an audit by Commission staff or a third party.

Consistent with TURN's recommendation, the audit shall include, at a minimum:

1) an assessment of whether the project is PSEP-related rather than GT&S-related;
2) a determination of the extent to which the project costs were inflated by factors such as the accelerated nature of PG&E's gas transmission system remediation work during that time period; and
3) a determination of the extent to which any project is necessary due to prior work that had not be performed correctly or had previously been funded in rates but never performed.

Because the capital expenditures subject to review are safety-related, the audit shall be overseen jointly by the Energy Division and the Safety and Enforcement Division (SED) and shall be completed as soon as practicable. Energy Division and SED shall provide a status update to the Executive Director every six months until the audit is completed. A copy of the audit report will be provided to the Energy Division, SED and PG&E. PG&E may file an application to seek recovery of its 2011-2014 capital expenditures that have not been otherwise disallowed after the audit has been completed. This application shall not include any other requests, and PG&E shall not combine this application with any other applications. The audit report shall be part of the record, and be sponsored by SED.

17.2. Disallowance Associated with Delay

In the *Ex Parte Sanctions Decision*, the Commission adopted a ratemaking remedy to address a five-month delay caused by PG&E's improper ex parte communications in this proceeding. The Commission ordered:

> PG&E's shareholders will be required to fund a disallowance of a portion of revenues no larger than would be amortized over the five-month period of the original scheduled final decision in this proceeding (March 2015) and the modified schedule (August 2015) contained within a revised scoping memo issued November 13, 2014.[701]

[701] *Ex Parte Sanctions Decision* [D.14-11-041] at 34, Ordering Paragraph 3 (*slip op.*).

The *Ex Parte Sanctions Decision* further noted that "[t]he exact amount of this ratemaking remedy for ratepayer reparations will be calculated at the time a final decision is rendered in this case."[702]

PG&E puts forth three reasons why there should be no additional disallowance associated with the delay. First, PG&E states that the only consequence associated with the delay is that there will be a shorter amount of time to recover its authorized revenue requirement from customers.[703] PG&E argues that this delay, however, does not harm ratepayers since "on a rate impact basis, the impact of the lower than otherwise rates that ratepayers will experience from May [through] September 2015 ... approximately offsets the impact of the higher than otherwise 2016 and 2017 rates that will result from the amortization of the delayed amount."[704] Further, PG&E notes that those parties who have raised claims of customer harm due to the delay caused by PG&E have, themselves, requested delays in this proceeding.[705]

Indicated Shippers, on the other hand, argues that the delay caused by PG&E "exacerbates regulatory uncertainty and the potential for rate shock" especially since its members cannot plan effectively for the future.[706] Indicated Shippers does concede that the impact of the delay, and the severity of the rate shock, will depend on the outcome of this proceeding.

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[702] *Ex Parte Sanctions Decision* [D.14-11-041] at 32, Conclusion of Law 6 (*slip op.*).

[703] *PG&E Opening Brief* at 5-3.

[704] *Comments of PG&E on Potential Remedies to be Imposed as a Result of Delay Caused by PG&E*, filed December 19, 2014, Exh. A at 3-4 ¶ 5.

[705] *PG&E Opening Brief* at 5-4.

[706] *Indicated Shippers Opening Brief* at 87.

Next, PG&E contends that although rate implementation will be delayed, the Commission can adopt an appropriate amortization period in order to avoid rate volatility.[707] It notes that the Commission has in the past approved "tailored amortization solutions that take into consideration the timing and extent of competing gas and electric rate changes and the relative impacts on combined gas and electric bills."[708]

Finally, PG&E asserts that any additional disallowance would constitute a penalty and would violate the Public Utilities Code, state and federal law.[709] In particular, PG&E contends that any additional disallowance attributed to the delay would exceed the maximum fine under Pub. Util. Code § 2107. We disagree. The $1.050 million fine adopted in the *Ex Parte Sanctions Decision* directly addressed PG&E's violation of the Commission's ex parte rules and Rule 1.1.[710] The disallowance, on the other hand, is an equitable remedy to address the impact of PG&E's violation, and the corresponding five-month delay in this proceeding, on ratepayers.

PG&E raised these same arguments in its application for rehearing of the *Ex Parte Sanctions Decision*. These arguments have been considered and rejected by the Commission on rehearing in D.15-06-035. As noted in D.15-06-035: "It is well established that regulatory lag and/or shortened amortization periods associated with delayed decisions and implementation periods translate into

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[707] *PG&E Opening Brief* at 5-5.

[708] *PG&E Opening Brief* at 5-5.

[709] *PG&E Opening Brief* at 5-6.

[710] *Ex Parte Sanctions Decision* at 30-31 (FOF 9) & 31 (COL 1).

negative economic consequences for ratepayers."[711] Moreover, unlike delay that is the result of unintentional or unavoidable events, the five-month delay in this instance is directly attributable to PG&E's unlawful conduct. Having already addressed this issue, we need not address it again here.

Based on the revenue requirement adopted in this Decision, the amount of the disallowance is $164.003 million, which represents the incremental amount of revenues that would be amortized over a five month period.

17.3. Adjustment for Overlapping Work

Pursuant to the *Second Amended Scoping Memo*, this Decision addresses which remedies adopted in the *Penalties Decision* (and are to be paid by PG&E shareholders) overlap with work forecast in this proceeding that PG&E proposes to be paid by ratepayers.

17.3.1. Overview of Parties' Positions

PG&E proposes reductions relative to its original revenue requirements forecast in this proceeding of the following: $1.775 million (for 2015), $1.99 million (for 2016), and $1.25 million (for 2017) for a three-year total reduction of $4.224 million based on $5.1576 million in remedy costs. PG&E identifies these costs as overlapping with amounts in its original revenue requirements GT&S forecast.[712]

The overlap of costs identified by PG&E includes capital expenditures of $1,398,400 ($908,500 recorded from 2011 to 2014 and $489,900 of forecasted spending from 2015 to 2017), and $3,759,200 in forecast expenses covering 2015 to

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[711] *Order Denying Rehearing of Decision (D.) 14-11-041* [D.15-06-035] at 13 (*slip op.*).

[712] Exh. PG&E-137, Table 24-1.

2017. Expenses incurred on or before December 31, 2014 are not overlapping with PG&E's GT&S forward-looking revenue requirement forecast since they were expensed at the time.

For capital costs incurred during 2011-2014 to implement the remedies, PG&E proposes to charge its shareholders for $0.909 million and to reduce the plant component of rate base by the same amount. For costs to be incurred during 2015-2017, PG&E proposes to direct charge orders set up for the remaining remedies based on the actual time spent to implement each remedy. These orders will charge the costs to a below-the-line account, so that shareholders absorb the remedy-related costs. PG&E reflects the remedies revenue adjustment in the Results of Operations model summary under the category labeled "Other Adjustments."[713]

TURN was the only party to challenge PG&E with respect to the amount of overlapping remedy costs to be removed from the GT&S revenue requirement to comply with the *Penalties Decision*. TURN claims that PG&E understates the amount to be removed from the GT&S revenue requirement. TURN challenges PG&E on two points: (1) whether the total remedy costs charged to common overhead should be allocated 100% to transmission rather than allocated, in part, to distribution functions; and (2) whether PG&E's total estimate is reasonable, or if a larger amount should be removed from the GT&S revenue requirement.

TURN's proposals results in $5.47 million in expense and $6.49 million in capital to be removed from the GT&S revenue requirements, which exceeds

[713] Exh. PG&E-137 at. 25-3.

PG&E's figures by $6.8 million – (i.e., $4.1 million capital and $2.7 million in expense).

17.3.2. Allocation of Common Overhead Applicable to the Transmission Function

PG&E identifies 80 out of the 143 remedies adopted in the *Penalties Decision* attributable to pipeline safety enhancements for which implementation costs overlap with costs included in its GT&S rate case. For seven of the identified remedies, PG&E directly charged costs to a GT&S order, Major Work Category, or included the related expenditures as specific line items in the 2015-2017 GT&S forecasts. In compliance with the *Penalties Decision*, PG&E identified these expenditures for removal from the GT&S Rate Case forecast.[714]

For the remaining overlapping remedies, actions to address implementation entailed shared support-type work within PG&E's Gas Operations. The costs to perform that shared support work are assigned to Provider Cost Centers (PCCs). The accumulated PCC costs represent departments that do not bill directly to a work order, but that spend time on both transmission and distribution work.

As noted by PG&E, gas operations costs are recovered through two different types of proceedings: (a) the GT&S Rate Case for gas transmission and storage costs, and (b) the General Rate Case for gas distribution costs. Accordingly, given the dual procedural tracks to recover these different categories of gas operations costs, PG&E undertook to allocate a share of the PCC overhead costs between gas transmission and distribution functions. At the time the remedies were adopted in the *Penalties Decision*, however, PG&E had no

[714] *See* Exh. PG&E-137, Amended Appendix A, lines 10, 16, 17, 19, 21, 22 and 68.

accounting mechanism yet in place to track the detailed costs for shared support work associated with each remedy allocated between transmission and distribution.

As a result, to identify the overlapping costs associated with the shared support work functions to be removed from the GT&S revenue requirement, PG&E developed a method to allocate the PCC costs between distribution and transmission functions. For this purpose, PG&E relied on the mix of 2015 total gas transmission and distribution expenditures as the basis to allocate PCC costs. The resulting allocation factors were approximately 75% distribution and 25% transmission. PG&E applied these percentage shares to assign PCC costs between transmission and distribution functions.

TURN disagrees with PG&E's approach to quantify gas transmission costs in allocating the majority of the PCC common overhead costs to distribution. TURN claims that PG&E understates overlapping remedy costs by allocating only approximately 25% of common PCC overhead costs to the transmission function, rather than 100%. TURN argues that PG&E stands to benefit by limiting the transmission related costs removed from the GT&S Rate Case.

TURN argues that the remedies ordered in the *Penalties Decision* arose out of enforcement cases solely focused on PG&E's transmission system and targeted at remedying violations solely related to transmission. In light of the transmission focus of the remedies in the *Penalties Decision*, TURN argues that all of the costs should, by definition, be recognized as transmission-related. As such, TURN opposes PG&E's allocation methodology and argues instead that all of the PCC overhead costs should be treated as transmission-related to be removed from the GT&S revenue requirement.

17.3.2.1. Discussion

We accept as reasonable PG&E's methodology to identify revenue requirements reductions associated with the overlapping costs of remedies adopted in the *Penalties Decision*. We are not persuaded by TURN's arguments that 100% of PCC common costs should be treated as transmission-related. To carry out the directives of the *Penalties Decision*, the objective is to identify and exclude GT&S revenue requirements attributable to implementing the remedies adopted in the *Penalties Decision*—no more and no less. The relevant data for this purpose is the cost of implementing the remedies that PG&E included in its original forecast of GT&S revenue requirements.

A reduction in the GT&S revenue requirements based on allocation of 100% of common PCC costs to transmission would accomplish the intent of the *Penalties Decision* only if PG&E had used such an allocation to develop its original forecast of GT&S revenue requirements. TURN, however, provides no evidence that PG&E did, in fact, allocate 100% of PCC costs to transmission as the basis for its original GT&S revenue requirement. There is no evidence that PG&E included costs in its GT&S revenue requirement that would typically be accounted for as distribution. We find no basis to conclude that PCCs involved in implementing the remedies adopted in the *Penalties Decision* are focused entirely on transmission to the exclusion of distribution functions.

As long as any remedy implementation costs allocated to distribution are excluded from the revenue requirements paid for by ratepayers, PG&E does not realize any unfair advantage. In this case, even though PG&E has not reduced its GT&S revenue requirements for PCC costs allocated to distribution, PG&E is not now recovering distribution costs from ratepayers for implementation of remedies ordered in the *Penalties Decision*. Retail rates now in effect are based on

distribution costs adopted in the 2014 GRC, adjusted to reflect 2015 and 2016 attrition allowances. Although PG&E has filed an application for a 2017 GRC test year, that proceeding is still in process. Accordingly, existing retail rates do not include any increases currently pending review in PG&E's 2017 GRC. Such increases, if any, won't be subject to recovery until the Commission acts on PG&E's 2017 GRC proposal.

PG&E proposes to use a similar cost allocation approach as used in this GT&S proceeding to remove any overlapping distribution-related costs relating to remedies adopted in the *Penalties Decision* as part of its 2017 GRC. As a result, PG&E proposes to use the same PCC allocation methodology to identify common overhead costs allocated to distribution, and to reduce its 2017 GRC revenue requirement accordingly. PG&E is in the process of identifying the overlap between the remedies and PG&E's Enterprise Records Information Management (ERIM) forecast in its 2017 GRC. We find PG&E's proposed approach reasonable as a basis to remove relevant distribution-related costs from its 2017 GRC so as to ensure that ratepayers do not pay for any costs relating to implementing the remedies adopted in the *Penalties Decision*.

17.3.3. Sufficiency of Rigor Applied in Quantifying Revenue Requirement Reductions

TURN claims that PG&E underestimates total overlapping costs to be removed from the GT&S revenue requirement pursuant to the *Penalties Decision* by failing to apply a demonstrably rigorous methodology. As a result, TURN claims that PG&E's forecast results were skewed in PG&E's favor. TURN claims that PG&E did not create any documents or show the final instructions given to employees to identify (a) GT&S activities which overlap with the remedies in the *Penalties Decision* and (b) the costs of those activities. TURN claims PG&E left no

audit trail by which to verify that it used an appropriately rigorous process and executed that process fairly and accurately. In order to overcome what TURN characterizes as a lack of rigor in PG&E's methodology, TURN proposes that a 200% multiplier be applied to PG&E's forecast to calculate the amount to be removed from the GT&S revenue requirement to comply with the *Penalties Decision*.

PG&E disputes TURN's claims that its methodology to identify overlapping costs lacked rigor. PG&E states that it is unclear how TURN arrived at the 200% multiplier, and nothing in TURN's testimony specifically supports the proposed 200% multiplier figure. PG&E contends that it has demonstrated that its process and methodology is sufficiently rigorous and reliable, and reflects a five-step process to identify the overlapping remedies and their associated costs.

17.3.3.1. Discussion

We conclude that PG&E employed a sufficiently rigorous process to identify the costs that required removal from the GT&S revenue requirement in compliance with the *Penalties Decision*. For each overlapping remedy, PG&E submitted a work paper that describes the remedy, provides the compliance action and schedule, and describes how the cost overlap with the GT&S Revenue Requirement was determined. PG&E explains the process it used to identify overlapping costs, which included 79 formal meetings in addition to informal meetings, in which remedy owners, subject matter experts, and witnesses in the

GT&S Rate Case went through each remedy and compared it to the work forecast in the case.[715]

Although PG&E did not issue a single set of "final instructions," as TURN expected, PG&E went through many discussions with the relevant individuals, and conveyed the criteria for determining overlapping costs. PG&E's process was iterative rather than being mechanistic. As explained by PG&E, producing a single document conveying instructions and criteria to be mechanically applied would have resulted in a *less* rigorous process. We find no sound basis to support TURN's proposal to reject PG&E's results, or to apply a 200% multiplier to PG&E's calculation of the overlap amounts. Accordingly, we adopt PG&E's forecast of the amount of overlap costs to be removed from the GT&S revenue requirement for purposes of this proceeding.

18. Rate Issues

18.1. Throughput Forecasts

Chapter 14 of PG&E's direct testimony presents PG&E's forecasts for gas demand and throughput, off-system revenue, Silverado path flow, forecast of backbone transmission firm contract volumes, and forecasted discounted transmission contracts. With the exception of ORA's proposed changes to the residential sector and the industrial transmission sector, no party commented on PG&E's throughput forecast.

PG&E proposes to revise gas transmission rates effective January 1, 2015, incorporating the current throughput projection for 2015. PG&E relies upon econometric and non-econometric methods to generate its throughput forecasts

[715] 37 RT at 5483:17-24 (PG&E/Gibson).

over the Rate Case Period for the following market segments: core (residential and commercial customers), noncore, industrial (large manufacturing as well a non-manufacturing customers), noncore Electric Generation (generators and cogeneration facilities using natural gas as fuel), and wholesale (municipal and private entities purchasing transportation-only services from PG&E for their resale of gas through non-PG&E distribution systems).

PG&E's demand forecasts for residential, small commercial, large commercial and Noncore industrial are based on econometric models, which develop the relationships between gas demand and factors such as economic and demographic activity, prices, temperature and seasonal-use patterns based on historical data. Forecasts for wholesale customers, on the other hand, are based on customer-specific information obtained from the customers when possible. PG&E states that its current forecast methodology is consistent with prior gas proceedings, including the 2011 GT&S proceeding and the 2009 Biennial Cost Allocation Proceeding.[716] PG&E's average weather gas demand forecast is presented in Table 14-1 of Exh. PG&E-2 at 14-3. The cold year gas demand forecast (1-35 years) is presented in Table 14-2 of Exh. PG&E-2 at 14-9.

ORA's econometric models are similar to PG&E's and result in throughput forecasts that are very close to PG&E's except for two sectors.[717] ORA forecasts lower throughputs in the residential sector than PG&E and higher throughputs to the industrial transmission sector. ORA presents a comparison of its average weather gas demand forecast with PG&E in Table 14-1 of Exh. ORA-43 at 6-8,

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[716] Exh. PG&E-2 at 14-4.

[717] Exh. ORA-43 at 12-23.

and a comparison of its cold year gas demand forecast in Table 14-2 of Exh. ORA-43 at 9-11.

On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 14 – Throughput Forecast* (Exh. Joint-3 at 19-22), was entered into the record. PG&E stated that it did not object to ORA's proposed changes to the throughput forecast. Accordingly, PG&E and ORA stipulated to the following gas demand forecasts:

Table 41
Average-Weather Gas Demand Forecast[718]
(MDTH/D)

Description	2015 Forecast	2016 Forecast	2017 Forecast
Core			
Residential	519	515	514
Commercial	232	233	233
Small Commercial	211	212	212
Large Commercial	21	21	21
Interdepartmental	0.4	0.4	0.4
Core Natural Gas Vehicles	7	7	7
Total Core	**758**	**755**	**754**
Noncore			
Industrial	507	501	507
Industrial Distribution	68	68	68
Industrial Transmission	434	428	434

[718] Exh. Joint-3 at 21.

Industrial Backbone	4.8	4.8	4.9
Noncore Natural Gas Vehicles	1	1	1
Non-market-responsive Electric Generation	178	178	178
Market-responsive Electric Generation	506	505	497
Total Noncore	**1,192**	**1,185**	**1,183**
Wholesale	10	10	10
Total Gas Demand	**1,960**	**1,950**	**1,947**

Table 42
Cold-Weather Gas Demand Forecast[719]
(MDTH/D)

Description	2015 Forecast	2016 Forecast	2017 Forecast
Core			
Residential	582	578	589
Commercial	248	248	249
Small Commercial	227	227	228
Large Commercial	21	21	21
Interdepartmental	0.4	0.4	0.4
Core Natural Gas Vehicles	7	7	7
Total Core	**837**	**833**	**845**
Noncore			

[719] Exh. Joint-3 at 22.

Industrial	509	503	510
Industrial Distribution	70	70	71
Industrial Transmission	434	428	434
Industrial Backbone	4.8	4.8	4.9
Noncore Natural Gas Vehicles	1	1	1
Non-market-responsive Electric Generation	178	178	178
Market-responsive Electric Generation	512	511	502
Total Noncore	**1,200**	**1,193**	**1,191**
Wholesale	**10**	**10**	**10**
Total Gas Demand	**2,047**	**2,036**	**2,046**

No party opposed the stipulation. We find the joint stipulation to be reasonable and adopt the joint stipulation on Throughput Forecast. Additionally, we adopt PG&E's forecasts for off-system revenue, Silverado path flow, forecast of backbone transmission from contract volumes, as presented in Chapter 14 of Exh. PG&E-2, Table 14-4 (Redwood Off-System Uncommitted Revenue Forecast for Summer Months 2015-2017), Table 14-7 (Non-GXF Revenue Forecast 2015-2017), and Table 14-8 (Firm Backbone Contracts). Finally, we adopt PG&E's forecast for the continuation of existing discounted contracts, as discussed in Exhibit PG&E-2 at 14-25 – 14-26.

18.2. Backbone Rate Design

18.2.1. Equalization of Baja and Redwood Path Rates for Core and Noncore

PG&E seeks authority to modify its existing backbone transmission service rate structure to equalize the currently separate rates for the Redwood and Baja paths for Core customers for Noncore customers.

18.2.1.1. Background

In *Re Applications to Unbundle Rates and Components* [D.97-08-055], the Commission adopted the original Gas Accord settlement to unbundle PG&E's backbone transmission revenue requirement and to create separate rates for backbone transmission service. This unbundling created a new market, the PG&E Citygate, at the virtual point downstream from each path wherever gas moved from a backbone pipeline into PG&E's local transmission system.

The Gas Accord unbundled PG&E's backbone system into four geographic transmission paths. Separate rates were adopted for four backbone transmission paths: Redwood (Lines 400 and 401), Baja (Line 300), Silverado (California Gas), and Mission (On-System Storage).[720] The two primary paths were: (a) the Redwood Path which transports gas from northern receipt points to the PG&E Citygate; and (b) the Baja Path which transports gas from southern receipt points to the PG&E Citygate. Gas flows from Topock onto the Redwood Path and from Malin onto the Baja Path, as system operators respond to the market's preferred sources of gas.

Under the original Gas Accord, the Redwood path rate for core customers was based entirely on Line 400 costs, while the Redwood path rate for noncore

[720] D.97-08-055, slip op. at 18, Appendix B at 4.

customers was based on a mixture of Line 400 and 401 costs.[721] The Gas Accord structure continued through Gas Accords II through V with limited modifications. The current backbone rate structure reflects the Gas Accord V adopted in the *Gas Accord V Decision* which retained distinct rates for each backbone path.

PG&E has traditionally designed backbone rates based on a system average backbone load factor. Thus instead of allocating costs to each backbone path and dividing these costs by a forecast of path demand, PG&E divides allocated path costs by the product of the path capacity and the system average load factor.

18.2.1.2. Parties' Proposals

PG&E proposes a change in the current rate structure for backbone rates for the Redwood and Baja paths. Under PG&E's proposal, Redwood and Baja path costs would be rolled-in together into a single rate. Backbone rates for Core and Noncore customers would remain distinct from each other, but Redwood and Baja path rates would be the same within each class (i.e., core and noncore). PG&E thus proposes to combine the core's share of Redwood path revenue requirement with the core's share of Baja path revenue requirement into a single core Redwood/Baja revenue requirement. Core rates would recover the single core Redwood/Baja revenue requirement plus allocated common costs.

Under PG&E's proposal to equalize rates in this manner, the revenue requirement associated with Line 401 would be rolled into noncore rates only. Equalized path rates for core customers would contain only revenue requirement

[721] *Id.* at 16, Appendix B at 37.

associated with Lines 400 and 300. The core's share of the Redwood path revenue requirement would not contain any revenue requirement for Line 401. Core rates would include a discount to reflect the core's preferential use of highly depreciated capacity on Line 400. PG&E expects Line 400 costs to increase, however, as a result of safety-related work and replacement of aging equipment on this line.

PG&E also proposes to combine the noncore's share of the Redwood path revenue requirement with the noncore's share of the Baja path revenue requirement into a single noncore Redwood/Baja revenue requirement. For a given type of service, the same noncore rate would apply to transportation on either the Redwood path or the Baja path.

PG&E claims its rate equalization proposal will benefit all of its customers by applying downward pressure to the price of gas at the PG&E Citygate.[722] Absent rate equalization, the Baja transportation rate would be higher than the Redwood rate for both core and noncore shippers, because Baja's revenue requirement is higher than Redwood's. PG&E claims that as a result, PG&E Citygate prices would move upward relative to what equalized rates would produce.

The testimony of Catherine Yap prepared on behalf of SCGC, CMTA, Kern River Gas Transmission Company, and Questar Southern Trails Company, also offers support for PG&E's proposal.[723] In her testimony, Yap concluded that equalizing Baja and Redwood transportation rates would reduce Baja path rates

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[722] Exh. PG&E-2, at 10-21, lines 8-10.

[723] Exh. CMTA/SCGC/KRGTC/QSTC-1 at 2,.

from what they would be under path differentiation, leading to lower Citygate prices for both core and noncore customers.

Yap calculates that the difference between the gas price at the PG&E Citygate under path rate differentiation versus path rate equalization will generally equal the difference between the Baja As-Available rate under path rate differentiation versus under path rate equalization. Yap claims that path rate differentiation would cost noncore customers $303 million more during 2015-2017, under PG&E's forecast and $204 million under ORA's forecast.

Yap calculates that based on the PG&E forecast, under path differentiated rates, the Baja As-Available path rates would increase by 1.9 times from 2014 to 2015 and by more than 2.5 times from 2014 to 2017. Assuming the ORA forecast, the As-Available Baja path rates would increase by 1.4 times from 2014 to 2015 and more than double from 2014 to 2017. The Baja path differentiated As-Available rate would be over 75% ($0.362/dth) higher than the Redwood path differentiated As-Available rate under the ORA forecast in year 2017 and over 85% ($0.480/dth) higher under the PG&E forecast.

Yap argues that the efficiency of the PG&E Citygate market and secondary markets does not depend upon having separate rates for separate paths. Instead, Yap argues, the unbundling of backbone costs is what has enabled the Gas Accord to operate efficiently. Yap notes that the Gas Accord has functioned well during the last two settlement periods that have incorporated path rates close to equalization.[724]

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[724] Gas Accord IV Baja path rates were $0.025/dth higher than the Redwood path rates. Gas Accord V Baja path rates were between $0.025 and $0.040/dth higher than the Redwood path rates.

For much of the recent past, gas at the receipt points on the Redwood Path has been significantly less expensive than at the southern receipt points. Demand for Malin gas is high, and the Redwood path has generally run full, being fully contracted at firm rates. Meanwhile, gas demand from the Baja path has been lower. As a result, Baja has been subscribed at lower firm volumes than Redwood. Since upstream supplies on the Redwood Path are less expensive, the Baja Path is the non-preferred path and marginal supply source.[725] PG&E claims that Citygate prices tend to be influenced by the highest incremental cost of transportation for the marginal source of gas supply, currently the Baja As-Available rate, plus the border price for gas.[726] Assuming Baja is on the margin, PG&E claims that the Baja as-available rate would be much higher than an equalized as-available rate.[727] PG&E claims that Citygate price increases under non-equalized backbone rates would be substantial.

PG&E claims that based on its revenue requirement and throughput forecast for 2015, rate differentials would contribute $0.26 per Dth to the Citygate price in non-winter months, when the Baja as-available transportation rate is typically at the margin. In non-winter months of 2016 and 2017, as the Baja as-available rate increases, PG&E calculates this figure would grow to $0.33 and $0.54 per Dth, respectively.

PG&E further argues that equalizing Redwood and Baja path rates for Core and Noncore customers, respectively, recognizes the contractual and operational realities of the backbone system. Irrespective of which path initially

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[725] Exh. PG&E-2, at 10-21.

[726] Exh. PG&E-2, at 10-21.

[727] Exh. PG&E-40 at 10-36.

receives the gas, PG&E's shippers are contractually entitled to deliver gas anywhere on PG&E's system, at the receiving path's rate. Redwood shippers can deliver gas as far south as Topock, and Baja shippers can deliver gas as far north as Malin.[728]

PG&E characterizes its Redwood and Baja rate equalization proposal as consistent with the rate structure of its previous two GT&S Rate Cases (Gas Accords IV and V). For 2015-2017, PG&E proposes to fully average the respective Core and Noncore Redwood/Baja rates and eliminate the $0.025 to $0.040 rate differential that has existed for seven years.

Calpine/Canadian Association of Petroleum Producers (CAPP)/GTN)/City of Palo Alto oppose PG&E's proposal for equalized rates. They argue that PG&E offers no valid basis to change the Gas Accord rate structure, noting that the Commission has previously rejected similar rate equalization proposals.[729] These parties propose continuation of path-specific rates based upon the adopted revenue requirement for each path.

ORA also opposes equalization of the Redwood and Baja backbone transmission rates for Core and Noncore customers. ORA supports the current rate design for the Redwood and Baja backbone transmission paths based on continuation of the existing Gas Accord cost allocation and rate design methodologies. ORA recommendation results in a $0.1843 per Dth cost-based

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[728] Exh. PG&E-2 at 10-21.

[729] *See* CAPP-1 at 8-10. In 2003, in the last fully-litigated Gas Accord case, the Commission considered both a proposal for a rolled-in, postage-stamp rate design, similar to PG&E's proposal in this case, and a proposal to use path-specific load factors. The Commission rejected both of those proposals in *Opinion Regarding the Gas Structure and Rates for Pacific Gas and Electric Company for 2004 (2004 GT&S Decision)* [D.03-12-061].

price differential between Core Redwood and Baja transmission rates in TY 2015 while an estimated $0.1162 per Dth cost-based price differential will exist between the Noncore Redwood and Baja transmission rates.

ORA argues that PG&E's proposal to equalize the Baja and Redwood Path Rates would increase costs to core customers who buy long-term capacity rather than gas at PG&E Citygate. ORA compares the backbone transmission rates under PG&E's proposal with the traditional rate design using PG&E's Proposed Revenue Requirements and throughput forecast. ORA contends that PG&E's proposal, in fact, may lead to market distortions by creating an incentive for shippers to bring gas in from the cheapest source, while abandoning cost-causation principals for transporting that gas within California.[730]

PG&E claims that the backbone rate treatment proposed by Calpine/CAPP/GTN/City of Palo Alto and ORA would result in a sizeable Baja-Redwood as-available rate differential, and could increase the gas price at the PG&E Citygate. PG&E argues that the proponents of path-differentiated rates are primarily market participants advocating their own agenda, and that as a result, such proponents' arguments should be viewed with skepticism.

PG&E denies that equalized rates would set market participant groups against each other. For such market inequities to occur, PG&E argues, the rosters of Redwood and Baja shippers would have had to remain distinct, mutually exclusive, and static through time. Of the 97 shippers with contracts on the Redwood path between 1998 and 2007, only 13 hold Redwood path capacity today. Firm capacity contracts are typically less than two year commitments, leaving shippers free to exercise strategic, free-market judgment on a periodic

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[730] Exh. ORA-41 at 62.

basis. Shippers are free to commit to the Redwood path, the Baja path, both, or neither.

18.2.1.3. Discussion

We decline to adopt PG&E's proposed change to equalize the backbone rates for the Redwood and Baja paths. We are not persuaded that such a change in status quo with respect to the existing backbone rate structure is warranted. Instead, we shall continue to apply the existing differential backbone rate structure. We recognize that continuation of path-differentiated rates means that some customers and shippers will face higher costs than they would under equalized rates while others will realize lower costs. We find, on balance however, that any purported arguments in favor of eliminating rate differentials are outweighed by potential negative consequences of doing so.

The existing rate structure is based on the costs of the respective paths and recognizes that the Redwood and Baja paths each provide access to a distinct market: Redwood to Malin on the Oregon border and Baja to Topock on the Arizona border. PG&E receives gas supplies from these two different, well-defined, competing markets at either end of its backbone system. The mixes of supply sources serving these distinct markets are different, as are the pipelines and markets upstream from these border points. PG&E's Line 401 represented a major incremental, market-driven expansion of the PG&E backbone system south of Malin that only provided incremental access to supplies at Malin. In recognition of these facts, path-specific Redwood and Baja backbone rates on the PG&E system have been the status quo for some time. The current rate structure creates a fair and reasonable differential between PG&E's two primary transmission paths.

PG&E's proposal could undermine the Gas Accord's vintage rate protections for core customers. The partial roll-in that PG&E has proposed in

this case could increase costs for core customers, by an estimated $1.1 million over the next three years, because PG&E is expected to use the Redwood path in preference to Baja capacity to serve core customers.[731]

Equalization of the rates, however, would not be cost based, and would create unfair cross subsidies. The Baja Path currently has a higher revenue requirement than does the Redwood Path. Upstream supplies on the Redwood Path are generally cheaper at present, thus making the Baja Path the non-preferred path and marginal supply source. PG&E's proposal would effectively shift Baja path costs to Redwood shippers.[732] Since Redwood Path costs are below those of the Baja Path, Redwood Path, customers would essentially be subsidizing Baja Path customers.[733]

When the Gas Accord market structure was implemented in 1998, under the adopted backbone rate design methodology, noncore shippers using the Redwood Path paid higher rates than those using the Baja Path due to the higher costs associated with the newer Line 401. In more recent years, however, Line 401 costs have fallen, particularly as the result of accumulated depreciation over time. Meanwhile, Line 300 costs are increasing due in part to higher capital needs.

The Gas Accord rate structure provides transparency in the relative costs on the Redwood and Baja paths as to why Redwood and Baja rates are different. This clarity and certainty would be lost if the path-specific rate framework was abandoned. Some Redwood shippers have made long-term capacity

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[731] Beach Direct Testimony at 4.

[732] Exh. Calpine/CAPP/GTN/Palo Alto-1 at 4.

[733] Exh. ORA-41 at 58-62.

commitments and have borne the higher costs of the Redwood path for many years. It would be unfair to force them to subsidize the now-higher costs of the Baja path through rate equalization. Path-specific rates prevent Baja shippers from unfairly benefiting from low-cost Redwood capacity.

Redwood Path shippers have exclusively paid the past higher capital costs associated with using the newer Line 401 facilities. Under PG&E's proposal, those shippers would now also pay a share of the higher Baja Path costs as the older Line 300 facilities are upgraded. In particular, noncore Redwood Path shippers seeking to transport Western Canadian and Rocky Mountain gas to Californian markets could be penalized by the equalization of backbone rates This cost shift would be unfair to noncore Redwood Path shippers, particularly since they faced paying for service on what was, at that time, the higher cost route. Where shippers faced relatively higher transportation charges in the past as a result of the traditional method, they should not be penalized now by changing the rate structure.

Witness Yap argues that PG&E's proposed equalization of core backbone rates does not violate the Commission's prohibition against rolling the cost of Line 401 into core rates. Yap, however, ignores the applicability of this policy to noncore rates. The *2004 GT&S Decision* addressed rolling the costs of Line 401 into noncore as well as core rates. This policy was never an issue for the core, because the core has never used Line 401 capacity nor been allocated any Line 401 costs. Commission policy, however, was to maintain segregated Line 401 costs for both the core and noncore unless the affected customers agreed to such a combination in the context of a settlement. In the Gas Accord I settlement, PG&E noncore shippers agreed to a partial roll-in of Lines 400 and 401 to form the Redwood noncore rate. No such agreement has been reached in this case,

however, to allow roll-in of costs of Lines 300, 400, and 401 for all noncore shippers.

We are also not convinced that Redwood and Baja rate equalization will apply downward pressure to reduce the price of gas at the PG&E Citygate. Gas moving over the Baja path is currently the marginal source of supply at the PG&E Citygate. If Baja rates are set higher than Redwood rates, PG&E argues that prices at the PG&E Citygate will be higher than if rates on the paths are equalized. PG&E also claims the contractual integration of its system allows any PG&E customer, at any location, to receive gas regardless of the path into which the customer's gas is received,

PG&E has not adequately shown that equalizing rates would generate downward pressures on the price of gas at the PG&E Citygate. We are also not persuaded by Witness Yap's claim that PG&E Citygate prices would be lower on PG&E's equalization proposal. Yap's analysis represents a short-run cost perspective. From a long-term perspective, however, shifting costs from the marginal Baja path to the more fully-utilized Redwood path could raise total costs for gas customers in northern California. In the long run, it is not in customers' interest if market participants lose certainty, clarity, and confidence in how the Commission regulates the cost of transportation to the PG&E Citygate market. Regulatory stability and fairness is important for California to remain attractive, particularly to Canadian gas producers which supply a significant portion of PG&E's gas needs for Northern California.

Even if reducing Baja rates and increasing Redwood rates were to reduce PG&E Citygate prices today, the long-term result could be to raise PG&E Citygate prices over time. Yap concedes the possibility that the Redwood path could once again becomes the marginal path, but argues that during the period,

2015-2017, the cost associated with increased Citygate prices associated with this hypothetical change would be relatively low.

Faced with equalized backbone transmission rates, the shippers would likely use the path resulting in the lowest overall delivered cost of gas. Shippers will choose the gas basin that offers the most attractive price and the transmission path with the least cost. A shipper must have a capacity contract with PG&E and pay the transportation charge to bring gas to the Citygate. It is uncertain as to whether gas shippers taken together would necessarily bring in more gas on both the Redwood and Baja paths so as to cause downward pressures on the PG&E Citygate price. It is uncertain as to whether the benefits to Redwood customers from rolling-in Redwood and Baja rates would exceed the costs for those shippers.

Witness Tom Beach presented a backcast analysis to assess potential long-term impacts of a policy of equalized rates, and whether PG&E Citygate prices would have declined if such a policy had been in place since the Gas Accord was implemented in 1998.[734] Beach presented historical data as to the market value of Redwood and Baja capacity over 2002-2014, in terms of the benefits (positive) or costs (negative) for a shipper holding firm capacity on either path and selling gas at the PG&E Citygate. Generally, the marginal source of gas on PG&E's system has changed a number of times and has repeatedly switched between Malin to Topock in recent years. The path with the higher value has been more heavily used, with higher load factors than on the lower-valued, marginal path.

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[734] Exh. Calpine/CAPP/GTN/Palo Alto-2 at 5.

Beach's backcast shows that over the period studied, equalized rates would have resulted in slightly *higher* PG&E Citygate prices by about $0.003 per Dth compared to path-specific rates. Considering Beach's analysis, we conclude that a path equalization policy would not necessarily lead to lower Citygate prices over the long term.

Moreover, not all customers purchase gas at the PG&E Citygate. Some, like the PG&E core, purchase the large majority of their supplies in the producing regions. Others buy gas in the California border markets at Malin or Topock. Some shippers have made long-term commitments to Redwood capacity in reliance on the longstanding Gas Accord backbone rate design, and would be significantly harmed by a change to rate equalization.

Our adopted outcome is generally consistent with proper regulatory practice by assigning costs to the sources that generate the costs. Maintaining a path-specific rate design provides more accurate price signals to shippers who would bring future incremental supplies to northern California. Equalized backbone rates could discourage new suppliers from seeking access to the PG&E Citygate market. Shippers may be discouraged from making such commitments if, as the result of rate equalization, they were to pay higher costs from a competing path which they would not use.

We are also not persuaded by the argument that rate equalization is appropriate for PG&E based on a presumed analogy to the rate treatment for SoCalGas. The fact that SoCalGas's circumstances are suited to postage-stamp backbone rates does not mean that path-specific backbone rates are appropriate in PG&E's service territory. The PG&E system is much different from that of SoCalGas. PG&E receives supplies from two different, well-defined, competing markets at either end of its backbone system, at Malin and Topock. The mixes of

supply sources serving these distinct markets are different, as are the pipelines and markets upstream from these border points. PG&E's Line 401 represented a major incremental, market-driven expansion of the PG&E backbone system south of Malin.

In consideration of all of the above factors, we decline to adopt PG&E's proposed change in the backbone rate design, and instead adopt a policy which continues the existing separate path-specific rates. Accordingly, we retain the rate design for the Redwood and Baja backbone transmission paths adopted in Gas Accord V Settlement. The fixed differential established for the last year of that settlement was $0.040/Dth.[735] We adopt this amount.

18.2.2. Backbone Load Factor Calculation

PG&E provides backbone service on four backbone paths – Redwood, Baja, Silverado and Mission. Since the beginning of the Gas Accord Structure, PG&E has employed a system average load factor to design backbone transmission rates.[736] The system average load factor is calculated as total backbone throughput (on all paths) divided by total backbone capacity (on all paths) plus the following adjustments:

- Baja on-system discounts
- G-AA, G-SFT and G-NFT premiums
- Reservation charges for unused firm contracts

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[735] *Gas Accord V Decision* [D.11-04-031], Appendix A at 12.

[736] Exh. PG&E-2 at 17A-1 17A-2.

- Disproportionate use of backbone paths[737]

The load factors proposed by PG&E in its opening testimony assumed adoption of equalized rates for the Redwood and Baja backbone transmission lines.[738] However, because we are denying this proposal, PG&E's backbone load factors presented in its direct testimony are also denied.

In its rebuttal testimony, PG&E calculated a system average load factor for non-equalized backbone rates. The system average load factors for non-equalized rates are 65.31% in 2015, 63.61% in 2016 and 60.48% in 2017.[739] PG&E's calculation of the non-equalized backbone load factor for 2015 through 2017 is summarized on Table 17A-2 of Exhibit PG&E-43. PG&E's calculation of the throughput adjustments for backbone load factor is summarized on Table 17A-3 of Exhibit PG&E-43.

PG&E explains how it calculated the system average load factors for non-equalized rates.[740] We find this explanation reasonable and adopt the methodology employed by PG&E for calculating the non-equalized rates presented in Chapter 17A of Exhibit PG&E-43. However, because the system average load factor depends on several inputs that we are modifying in this Decision, including throughput levels, shrinkage rates and backbone rate levels, it is necessary to recalculate the system average load factors presented by PG&E in Exhibit PG&E-43. The recalculated system average load factors are 69.95% in

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[737] Exh. PG&E-2 at 17A-5 – 17A-12.

[738] Exh. PG&E-2 at Table 17A-4.

[739] Exh. PG&E-43 at 17A-11.

[740] Exh. PG&E-43 at 17A-14 – 17A-15.

2015, 68.77% in 2016 and 67.34% in 2017. We adopt these system average load factors.

18.2.3. Backbone Capacity for the Baja and the Redwood Path

For the Rate Case Period, PG&E forecasts firm annual delivery capacity for the Baja Path at 1,026 MMDth/d; and firm annual capacity for the Redwood Path at 2,016 MMDth/d in 2015, 2,036 MMDth/d in 2016, and 2,082 MMDth-day in 2017.[741] No party disputed the forecast capacity for the backbone paths. PG&E's forecast capacity is adopted, with modifications consistent with the updated backbone shrinkage rates discussed in Section 18.8.2. Thus the new firm capacity is 1,025 MMDth/d for the Baja Path, and firm annual capacity for the Redwood Path is 2,015 MMDth/d in 2015; 2,035 MMDth/d in 2016; and 2,080 MMDth/d in 2017.

18.3. Local Transmission Cost Allocation and Rate Design

18.3.1. PG&E Proposal

PG&E proposes to continue the exiting cost allocation and single average local transmission rate design for core and a single average local transmission rate for noncore and wholesale customers. Further, it proposal local transmission rates will continue to be non-bypassable for all customers not qualifying for backbone level end-user service.[742]

Local transmission costs are allocated to core and noncore customer classes based on cold year forecast coincident peak month demands, as established in *Re*

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[741] Exh. PG&E-2 at 10-47.

[742] Exh. PG&E-2 at 17-7.

Investigation on the Commission's Own Motion into Implementing a Rate Design for Unbundling Gas Utility Services Consistent With Policies Adopted in Decision 86-03-057; and Related Matters [D.92-12-058] (1992) 47 Cal. PUC 438. Rates are calculated by dividing the costs allocated to each class by the adopted throughput forecast.[743] PG&E's proposed local transmission rates for core and noncore customers are presented in Exhibit PG&E-2 at 17-7 (Table 17-2).

18.3.2. Proposed Change in PG&E's Allocator for Local Transmission Costs

Calpine/Indicated Shippers state that the local transmission cost component is most affected by safety spending. They note that given the significant increase in safety spending proposed by PG&E in this Rate Case, noncore local transmission rates would increase from $0.33 per Dth in 2014 (including PSEP costs) to $1.06 per Dth in 2017 under the current cost allocation methodology.[744] Calpine states "In light of the significant rate increases proposed by PG&E in this proceeding, and the potential that cross-subsidies present in PG&E's existing rates will grow materially, adherence to cost causation is crucial going forward."[745]

Calpine/Indicated Shippers propose that PG&E's allocator for local transmission costs be changed from the current cold year peak winter month throughput to cold winter day (CWD) throughput. Calpine/Indicated Shippers note that local transmission costs are currently allocated on the basis of each customer class's peak month (December or January) throughput in a cold year,

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[743] Exh. PG&E-2 at 17-6.

[744] Exh. Calpine/Indicated Shippers-1 at 8.

[745] *Calpine Opening Brief* at 32.

but that PG&E designs its local transmission facilities to meet the higher of either (1) core and noncore demand on a Cold Winter Day (CWD), or (2) core demand on an Abnormal Peak Day (APD).[746] Since the current allocator is not based on design criteria for local transmission, Calpine/Indicated Shippers maintain that a too-large share of local transmission costs is allocated to noncore customers, forcing noncore customers to subsidize the core. They therefore propose that the demand measure for allocating local transmission service in rates be changed to reflect PG&E's actual design criteria.

Calpine/Indicated Shippers recommend that the CWD throughput be used as the allocator for local transmission costs, even though the more the most accurate allocation would be the alternative of APD throughput for the core and CWD demand for the noncore. Indicated Shippers notes that modifying the allocator to CWD would increase core allocation from 67% to 74%, while an allocation based on APD would increase the core share from 67% to 80%.[747] Thus, Calpine/Indicated Shippers assert that the use of a CWD allocation of local transmission costs is fair to core customers based on this more conservative approach. Further, they contend that this allocation properly reflects the benefits, including the safety benefits, which core ratepayers will receive from improvements to the local transmission system.[748] Moreover, Calpine/Indicated Shippers note that using a CWD allocation factor for local transmission costs

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[746] Exh. Calpine/Indicated Shippers-1 at 8.

[747] *Indicated Shippers Opening Brief* at 221.

[748] Exh. Calpine/Indicated Shippers-1 at 10.

would be more consistent with the capacity-based allocation of other GT&S costs for backbone transmission and storage.[749]

Calpine/Indicated Shippers do not dispute that their proposed allocation will reduce noncore transmission rates and increase core transmission rates in comparison to the rates under PG&E's proposal. However, Indicated Shippers notes "the question is whether the cost allocation methodology in question most accurately reflects cost causation on the local transmission system."[750]

Calpine/Indicated Shippers' proposal is opposed by PG&E, ORA and TURN. PG&E notes that allocation based on Cold Year Peak Month had been adopted in D.92-12-058 because "local transmission falls between backbone transmission (which uses Cold Year Winter Season as the allocator) and gas distribution (which uses peak day allocator)."[751] PG&E asserts that this rationale still holds true. Moreover, PG&E asserts allocating local transmission costs based on CWD does not comport with cost causation principles, noting

> While the peak day planning criteria may determine the size of the pipe necessary to meet core demand on a very cold day, the cost of meeting that demand does not increase proportionately to the change in the demand or the differential in demand between serving a perfectly flat load shape and serving an incremental demand that is peaky.[752]

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[749] Exh. Calpine/Indicated Shippers-1 at 11.

[750] *Indicated Shippers Opening Brief* at 221.

[751] *PG&E Opening Brief* at 17-11.

[752] Exh. PG&E-43 at 17-17.

Finally, PG&E notes that the proposed allocation would substantially increase the cost burden borne by core customers. Consequently, PG&E advocates that the current local transmission rate design be retained.

ORA and TURN both dispute the notion that improved pipeline safety disproportionately benefits core customers. They note that the Commission has considered this issue in the *Sempra PSEP Decision* and concluded that safety costs benefit customer classes equally and did not justify a change in cost allocation.[753] TURN asserts that Calpine/Indicated Shippers have not provided any new evidence or analysis to warrant a change to this prior determination.

ORA further argues out that since "noncore customers generally purchase gas independently from suppliers other than PG&E, local transmission costs are a bigger proportion of noncore customers' PG&E cost than they are for core customers."[754] Consequently, ORA believes that the increase in noncore customer rates is not comparable to the increase in rates for core customers.

Finally, TURN refutes Calpine/Indicated Shippers' argument that the "design criterion" used for sizing transmission pipelines is directly related to the cost drivers for pipeline installation. It asserts that the record demonstrates that the cost of installing pipelines does not increase proportionately to the size, and thus the capacity, of the pipeline.[755] Consequently, TURN contends that there is no factual basis to conclude that meeting peak day load is a primary driver of

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[753] *TURN Opening Brief* at 155-156; *ORA Opening Brief* at 201-202.

[754] *ORA Opening Brief* at 156.

[755] *TURN Opening Brief* at 204-211.

local transmission pipeline costs. ORA adds "cost allocation is not solely about adherence to any one aspect of cost causation, including design criteria."[756]

TURN does believe that data in this proceeding suggests that "flatter" allocation factors for local transmission costs may actually more accurately reflect marginal costs. Consequently, while it supports maintaining the existing allocation method for this rate case, TURN recommends that the Commission "order PG&E to provide an analysis in the next GT&S rate case demonstrating whether local transmission costs should be allocated more equitably by accounting for the actual relationships between pipeline capacity, throughput and costs."[757]

18.3.3. Proposed Allocation of Local Transmission Costs Based on Public Safety

NCGC express similar concerns as Calpine/Indicated Shippers and also urges that the current allocation methodology be revised. NCGC states that the driving factor for PG&E's revenue requirements increases in this GT&S application is public safety, not peak demand. As such, it asserts "the expenditures provide a societal benefit rather than a benefit specific to customers."[758] As the cause of the public safety expenditures is closely related to the populating living and working closest to PG&E's transmission pipelines, NCGC asserts that the costs for increased safety and risk mitigation should be allocated on the basis of the total number of customers in the customer class.[759]

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[756] *ORA Reply Brief* at 91.

[757] *TURN Opening Brief* at 211.

[758] Exh. NCGC-1 at 12.

[759] Exh. NCGC-1 at 12.

NCGC refutes PG&E's arguments that the increased expenditures are to provide increased reliability, noting that PG&E witnesses have testified that PG&E has a very high level of reliability. Therefore, NCGC asserts that noncore customers will not see any difference in the reliability of their current service as the result of the proposed spending.[760] Further, NCGC argues that since PG&E's facilities are not designated in the same manner as Sempra's, the Commission cannot rely on the *Sempra PSEP Decision* as the basis for rejecting its proposal.[761] Moreover, NCGC states that there is no record evidence that its allocation proposal could result in a significant rate increase to core customers.

TURN also opposes NCGC's recommendation that PG&E's pipeline expenditures be allocated based on the number of customers in a class. TURN argues that expenditures on the local transmission system are to improve public safety, an issue that has been fully addressed by the Commission in the *Sempra PSEP Decision*.[762] Further, TURN notes that while PG&E uses population as a tool to prioritize certain projects, population density around pipelines is not the cause for the spending. Thus, it asserts that NCGC's argument is factually inaccurate.

18.3.4. Discussion

We have considered the arguments concerning whether to change the method by which local transmission costs are allocated to core and noncore customer classes and find that both Calpine/Indicated Shippers' and NCGC's

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[760] *NCGC Opening Brief* at 22.

[761] *NCGC Opening Brief* at 22.

[762] *TURN Opening Brief* at 202.

proposals should be rejected. We disagree with Calpine/Indicated Shippers and NCGC that costs to enhance the safety of transmission pipelines do not enhance system reliability. As we stated in the *Sempra PSEP Decision*, "An un-ruptured pipeline (properly constructed and tested) can usually be expected to deliver gas in a reliable fashion to businesses or individuals."[763] This conclusion applies whether the customer is located 20 yards or 20 miles from the transmission pipeline. Thus, considering population density when prioritizing safety improvements in pipes does not provide more benefits to core customers than noncore customers. This is true regardless of how a utility's facilities are designated.

We also decline to adopt Calpine/Indicated Shippers' recommendation to base the allocation method on CWD. As PG&E has testified, its local transmission system is a shared resource between core and noncore customers. Thus, while CWD may reflect the design criteria used by PG&E to construct the local transmission system, it does not reasonably reflect the costs imposed by core and noncore customers for this shared resource.

In light of these considerations, we decline to change the current allocation of local transmission costs between core and noncore customer classes. However, we are persuaded by TURN's arguments that "flatter" allocation factors for local transmission costs may actually more accurately reflect marginal costs. Therefore, PG&E shall provide an analysis as part of its next GT&S application demonstrating whether local transmission costs should be allocated

[763] *Sempra PSEP Decision* [D.14-06-007] at 47.

more equitably by accounting for the actual relationships between pipeline capacity, throughput and costs.

18.4. Storage Rate Design

18.4.1. Storage Capacity

PG&E forecasts lower firm injection and withdrawal capacities for the system and lower inventory capacity than in the 2011 GT&S Rate Case application.[764] These changes are due to: (1) the expiration of PG&E's lease for the four oldest of the seven compressor units at McDonald Island and their removal in 2014 and (2) reduced well deliverability at the McDonald Island storage field, because the current market for storage services does not support the continued costs of maintaining high well capacities.[765] Total firm injection capacity at minimum system inventory is 422 MDth/d. Total firm withdrawal capacity at minimum system inventory is 1,331 MDth/d.

Central Valley Gas Storage, Gill Ranch Storage and Wild Goose Storage support PG&E's proposal to reduce storage capacity with the removal of compressors and the reduction of maximum withdrawal capacities at McDonald Island.[766] No party opposed PG&E's proposed firm injection and withdrawal capacities and minimum system inventory. PG&E's proposal is adopted.

18.4.2. Allocation of Storage Costs

PG&E does not propose any changes to the existing cost allocation and rate design methodology for: (1) core firm storage; (2) monthly balancing, and

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[764] Exh. PG&E-2 at 10-48.

[765] Exh. PG&E-2 at 10-45 – 10-46.

[766] *Joint Opening Brief of Central Valley Gas Storage, Gill Ranch Storage and Wild Goose Storage* at 5.

(3) market storage services.[767] In Table 17-1 of its Opening Brief, PG&E presents the storage units for cost allocation. This Table, however, has not been adjusted to reflect that PG&E's proposal to allocate 130 MMcf/d (133 MDth/d) of injection capacity and 200 MMcf/d (204 MDth/d) of withdrawal capacity to balancing, along with the associated revenues had been struck from the record in this proceeding in its entirety.[768] Therefore, Table 17-1 in PG&E's Opening Brief should reflect the current amount of storage units allocated to load balancing, 27,922 Mdth, and should not have increased the amount to 48,399 MDth for injection and 74,460 Mdth for withdrawal.

PG&E states that the proposed allocation table in its direct testimony was not struck from the record, suggesting that it is still applicable. However, Calpine correctly notes that PG&E now attempts to "sneak its original, rejected, proposal in via a table that was inadvertently not referenced in Calpine's motion to strike."[769] According to Calpine

> Had PG&E followed the ALJ's ruling and not allocated additional storage costs to load balancing, Table 17-1 would have reflected the existing 75 MMcf/day or 27,922.50 MDth/year of storage costs for both load balancing injection and withdrawal (i.e., 75 MMcf/day x 1.02 x 365 days = 27,922.50 MDth/year), rather than increasing these amounts, as proposed by Mr. Christopher, by 55 MMcf/day or 20,476.5 MDth/day for injection (55 MMcf/day x 1.02 x 365 = 20,476.5 MDth/year) and by 125 MMcf/day or 46,537.5 MDth/year for withdrawal (125 MMcf/day x 1.02 x 365 = 46,537.5 MDth/year) (27,922 MDth + 20,476.5 MDth = 48399 MDth as shown on Table 17-1 for

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[767] Exh. PG&E-2 at 17-7.

[768] 33 RT at 4642:9 – 4643:2 (ALJ Yip-Kikugawa)

[769] *Calpine Reply Brief* at 17.

injection and 27,922 MDth + 46,537.5 Mdth = 74,460 Mdth as shown on Table 17-1 for withdrawal).[770]

Based on Calpine's calculations, the storage units for cost allocation should be as follows:

Table 43
Storage Units for Cost Allocation for Traditional Storage Assets (MDth)

Storage Services	Injection Inventory	Inventory	Withdrawal Inventory	Total Storage Units
G-CFS	41,074.37	33,477.70	175,963.00	250,515.07
System Balancing	27,922.00	4,100.00	27,922.00	59,944.00
G-SFS	12,353.21	308.91	2188.12	14,850.24
Traditional Asset	81,349.58	37,886.61	206,073.12	325,309.31

We adopt the above storage units in Table 43. PG&E shall allocate costs for traditional storage assets to the three firm storage services based on the storage units adopted above.

18.4.3. Core Injection and Withdrawal

PG&E proposes two changes to core's injection and withdrawal rights. First, PG&E proposes to change the winter withdrawal profile for the G-CFS service by an increase in the withdrawal rights in December and January, and a decrease in withdrawal rights in February and March. PG&E maintains that this proposal will "reshape the core Winter Firm Withdrawal Rights Curve to better fit Core winter supply requirements and improve winter reliability."[771]

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[770] *Calpine Reply Brief* at 17.

[771] Exh. PG&E-2 at 10-51.

Second, PG&E proposes to eliminate the annual inventory threshold that determines the method by which injection and withdrawal rights for Core Procurement Groups (CPG) (Core Transport Agents (CTAs) and Core Gas Supply (CGS)) are determined. PG&E proposes to eliminate the fixed-rights method and use the variable method exclusively. PG&E states that without the proposed change, the service will become less reliable for all CPGs as the number of CTAs that have fixed rights increase.[772]

No party opposed PG&E's proposal. PG&E's proposal is adopted.

18.5. Transmission Level Customer Access Charges

PG&E proposes to continue to scale the currently adopted customer access charges multiplied by the forecast of customers by tier, such that the resulting revenues match the customer access charge revenue requirement. The proposed customer access charges are presented in Exhibit PG&E-2, Table 17-2.

No party challenged the proposed Transmission Level Customer Access Charges. PG&E's proposal is adopted.

18.6. Electric Generation Rate Design

18.6.1. Overview

Parties disagree concerning the gas transmission rate structure to apply to electric generator (EG) shippers on PG&E's system for purposes of this proceeding. Under current tariffs, PG&E offers two separate gas transmission rates for EG shippers:

[772] Exh. PG&E-2 at 10-52.

(1) EG shippers that connect directly to the PG&E backbone system pay the Electric Generation Backbone ("G-EG/BB") transmission rate, and

(2) EG shippers that connect to the local transmission system pay the Electric Generation Local Transmission ("G-EG/LT") rate (also referred to as the "All Other Customers" [AOC] rate).

The backbone transmission system transports gas from PG&E's interconnection with interstate pipelines, other local distribution companies, and California gas fields to PG&E's local transmission system and distribution system. The local transmission system accepts gas from the backbone and transports it to the distribution system only. The EG-LT transmission rate covers the additional service to connect electric generation located more remotely from the Backbone system. The G-EG/BB rate does not include local transmission costs while the G-EG/LT rate does include local transmission costs.

18.6.2. Parties' Positions

PG&E proposes continuation of the existing rate structure whereby separately stated EG-BB rates and EG- LT –i.e., All Other Customers (EG-AOC) rates apply. PG&E's proposal for continuation of separate rates for Electric Generators is supported by SMUD and Calpine. Dynegy and NCGC oppose the continuation of the separate G-EG/BB and G-EG/LT rate structures, and instead propose that a single EG Rate apply to all electric generators in PG&E's service territory. Based on its forecasted revenue requirements, PG&E's proposed allocation among EG customers would result in a slight decrease in EG-BB rates and a significant increase in EG-AOC rates.

PG&E argues that maintaining separate rate schedules reflects the inherent cost differences between electric generators served from PG&E's backbone, and electric generators served from PG&E's local transmission system. PG&E notes

that electric generators directly connected to the backbone system take a different kind of service than those connected to local transmission, which is reflected in the separation between EG-BB backbone and EG-AOC local transmission rates.

SMUD supports the PG&E proposal for continuation of the separate rate structures for EG shippers and opposes the Dynegy and NCGC proposal for the gas transportation rate structure. SMUD is a municipal utility district engaged in the generation, purchase, and sale of electric power to retail customers mainly within Sacramento County. SMUD owns gas-fired generation used to serve load and pays PG&E for gas transportation service to ship gas over the PG&E system.

Calpine also supports the PG&E rate structure proposal for continuation of separate rate, and opposes the change to a single rate, as proposed by Dynegy and NCGC. Calpine has EG facilities connected to PG&E's local transmission system and backbone system.

Dynegy and NCGC argue that all electric generation customers should pay the same EG transportation rate, regardless of whether the electric generator is connected to PG&E's system at the backbone level or at the local transmission level. Dynegy and NCGC argue that a single rate for all EG customers would promote fair competition in the electric market by placing all customers on a level playing field. They claim that the two-level rate structure combined with PG&E's proposed rate increases creates a loss of revenues to cover the costs of the local transmission system: (1) when local transmission generators cannot compete in electricity markets and are not dispatched, requiring no gas transportation services and producing no contribution toward the local transmission revenue requirement, and (2) when backbone-level EG customers are dispatched instead of local generation units (because of their rate advantage). Although backbone-level EG customers require gas transportation service, they

make no contribution toward the costs of the local transmission system under PG&E's proposals.

NCGC argues that imposing separate rates for backbone and local transmission for noncore customers is based on an arbitrary division between local transmission and backbone facilities, and is not consistent with the practices utilized by SDG&E, SoCalGas and other gas utilities on the West Coast.

NCGC also claims that the current backbone vs. local distinction for EG rates is based on differences in location. A BB-connected EG customer can take advantage of its location. However, an LT-connected EG customer has no similar opportunity to take advantage of its location, either on the basis of mileage of facilities used or ability to interconnect to the BB.

Dynegy and NCGC each own EG facilities that take service from PG&E's local transmission system and pay the G-EG/LT rate schedule. Dynegy owns the Moss Landing power plant, which has four generation units, Units 1, 2, 6 and 7.[773] NCGC members are public agencies that own and operate gas-fired generation facilities for the benefit of their residential, commercial, and industrial customers.[774]

Dynegy and NCGC claim that PG&E's rate proposals will adversely impact the cost of electric generation from their units and thus reduce the competitiveness of these plants, eventually driving existing electric generators served by the local transmission system out of business. Dynegy claims that as a result, any new gas-fired plants would only be located near the backbone system. More immediately, if EG customers served by the local transmission system are

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[773] Exh. Dynegy-1 at 6: 3-4.

[774] Exh. NCGC-1 at 1:25-30 and 2:23, fn. 1.

required to pay more than EG customers connected to the backbone system, backbone-level units will be dispatched more often than comparable (or more efficient) units on the local transmission system.

The rate differential between the G-EB/BB and G-EG/LT tariffs is significant, and PG&E's proposed spending on public safety programs would increase this differential. Because the G-EG/BB rate is significantly lower than the G-EG/LT rate, Dynegy and NCGC claim that electric generators on the E-EG/BB rate realize a competitive advantage. PG&E's proposed capital spending would result in large increases in local transmission costs. As a result, the differential between the G-EG/LT rate and the G-EG/BB rate will increase.

NCGC likewise argues that the differential in rates for electric generation customers will adversely affect the economic viability of G-EG/LT connected generation facilities. NCGC also claims that impact the wholesale electricity market will produce a multiplier effect that will increase the cost of electricity disproportionately to the increase in gas transportation costs to electric generators. The transportation rate difference between the G-EG/BB and G-EG/LT customer classes results in a difference in the marginal costs of similar generators.

Dynegy and NCGC argue that, with the large increase in local transmission costs proposed in this proceeding, it is unfair for them to pay for local transmission service while customers connected directly to the backbone system do not pay for local transmission service. Implementing a single rate for all EG customers would have the effect of lowering local transmission rates and raising rates for backbone-connected customers. Dynegy and NCGC thus seek to end the rate differential by equalizing the rates paid by all EG customers.

PG&E argues that the proposal for a single EG rate is based on insufficient analysis, noting that neither Dynegy nor NCGC analyzed the effect a single EG rate on the dispatch of electric generation in the California Independent System Operator Corporation (CAISO) market.[775] PG&E argues that no basis has been established by opposing parties to change the Gas Accord rate design for electric generators.

SMUD also opposes the proposal for a single EG rate applicable to all electric generators. SMUD argues that imposing a single rate would shift of local transmission costs from local transmission customers to backbone customers. SMUD submits that such a proposal ignores long-held cost causation principles that the Commission has followed in prior rate cases.

SMUD believes that such a proposal would be fundamentally unfair to charge Backbone-only customers for costs associated with local transmission service where Backbone shippers do not utilize local transmission service. SMUC argues that imposing a single rate would severely diminish the value of SMUD's prior investments in its own local transmission system,[776] and negate the value of SMUD's $90 million investment to a modern, safe and reliable local gas transmission infrastructure, and the millions it spends annually to maintain it.

SMUD disputes the Dynegy and NCGC claims of unfairness regarding the lower EG rates paid by backbone-connected customers. SMUD notes that along with other EG-BB generation facilities, SMUD has substantial, additional gas transport costs that Dynegy does not incur. SMUD bears the cost of building and

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[775] 31 RT at 4363:6-18; 36 RT at 5364:25 - 5365:2 (NCGC/Falcon).

[776] Exh. SMUD-1 at 13; Exh. PG&E- 43 at 17-3 and 17-4; Exh. Calpine/Indicated Shippers-1 at 13.

maintaining a 76-mile local pipeline system. Such non-PG&E gas costs directly impact the competitiveness of these plants relative to Moss Landing and other market participants. SMUD thus argues that if it also had to pay the PG&E local gas transmission component, SMUD would be in effect be paying twice for local gas transmission, resulting in SMUD being the one with the commercial disadvantage, not Dynegy.

Aside from rate differential impacts, moreover, SMUD argues that many other sources of revenue are available to Dynegy that impact competitiveness, including congestion payments and capacity/reliability payments. Dynegy received $6.6 million from the CAISO in late 2014 to be available as a capacity resource to support grid reliability for 60 days. Such payments also impact on individual plant economics and competitiveness.

Calpine also disputes Dynegy's claims that continuing the separate rate elements for EG gas shippers would be unfair. Calpine likewise argues that its own EG facilities that receive local transmission service will be impacted in the same way as Dynegy's and NCGC's facilities as a result of PG&E's proposed rates. Unlike Dynegy and NCGC, however, Calpine argues, it is willing to pay for the services that it receives and does not expect to be subsidized by other gas customers just to be more competitive.

Calpine argues that when Dynegy acquired the Moss Landing plant, it took a calculated risk concerning future natural gas transportation rates, among other factors that could affect its competitive position. Likewise, the plants that consume most of the NCGC members' gas today were built *after* the existing rate structure was already adopted. Calpine argues that the Commission should not bail out such competitors from a risk they assumed, particularly where costs of the bailout would be paid by the very customers with whom they compete.

18.6.3. Discussion

We conclude that the existing rate structure based on separate costs assigned to rate schedules for EG-BB and EG- LT, i.e., All Other Customers (EG-AOC) is just and reasonable. Accordingly, for purposes of rates adopted in this proceeding, we shall maintain this existing rate structure. The EG-BB and EG-AOC services are distinct, and form the basis for separate EG rate schedules.[777] As stated in PG&E's Gas Rule No. 1, the backbone transmission system transports gas from PG&E's interconnection with interstate pipelines, other local distribution companies, and California gas fields to PG&E's local transmission and distribution systems.[778]

We thus find that the separation of backbone and local transmission rates is consistent with principles of cost causation, and provides an incentive for new gas-fired generation plants to interconnect directly to the backbone system where PG&E can more easily manage changes in the flow of gas.[779]

We decline to adopt proposals for a single EG transportation rate, as proposed by Dynegy and NCGC. All else being equal, a single rate would lower local transmission rates and increase rates for backbone-connected customers. Customers connected to the local transmission system cause PG&E to incur local transmission costs, while customers connected directly to the backbone system do not. The backbone system is actively managed in real time by transmission operators who route gas, control pressure and adjust inventory to compensate for imbalances between nominations and actual deliveries to shippers. The local

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[777] Exh. PG&E-40 at 10-20.

[778] Exh. PG&E-40 at 10-20, lines 5-8.

[779] Exh. PG&E-40 at 10-20, lines 26-30.

transmission system is passive, doesn't use a nomination system, and generally is not managed downstream of the regulators that tie it to the backbone.

It would be unfair to require all EG customers to pay the same transportation rate, however, regardless of whether they connect to PG&E's system at the backbone or at the local transmission level. Imposing a single EG rate for all electric generators would require shippers taking service under the EG-BB rate to pay for PG&E's local transmission system whether they use it or not. Yet, PG&E backbone-level customers do not use the local transmission system, and do not cause local transmission costs to be incurred. Such customers should not be forced to pay the costs of the local transmission system which they do not use, thereby subsidizing EG units located on the local transmission system that are more costly to serve.[780]

Based on cost causation principles, it is reasonable and appropriate to charge these customers a separate backbone-level transportation rate that does not include the costs of the local transmission system which they do not use. Maintaining a rate differential for these different types of service is thus fair and consistent with principles of cost causation.

Dynegy and NCGC are connected to, and take service from PG&E's local transmission system under Rate EG-AOC. They claim that paying this separate rate places them at an unreasonable competitive disadvantage because their gas transportation costs will be higher than those of backbone-connected customers. Yet, backbone-level customers pay, essentially, for local transmission service in the cost that they incur to build, operate and maintain their lateral pipeline

[780] Exh. Calpine-1 at 18.

facilities that connect their plants to the backbone system. Backbone-connected customers bear the equivalent of local transmission costs (via the laterals that connect their plants to the backbone system). Thus, it would not be fair for backbone-level customers to pay both the costs of their own facilities to connect to the backbone plus the costs of PG&E's local transmission facilities.

The backbone-level rate is available to customers, both EG and other noncore customers, that connect directly to the backbone system (and that meet certain other eligibility criteria), irrespective of where they are located. The distinction drawn is based on the type of service received, backbone vs. local transmission, and the costs associated therewith, and not based on customer location.

Given the incremental movement toward unbundling backbone and local transmission service during the 1990's and early 2000's, electric generation developers should have foreseen that unbundling of these services was likely and taken this into account in deciding to construct or purchase gas-fired generation. Calpine witness Beach provided historic background on the unbundling of PG&E's backbone and local transmission services that occurred beginning in the 1990s.[781]

In 1992, PG&E's transportation service was divided into three distinct functions: backbone transmission; local transmission; and distribution. Since then, PG&E has allocated the costs of each of these functions differently among its customer classes. PG&E initially unbundled backbone and local transmission services during the Gas Accord I settlement, implemented in 1998. Although the

[781] Exh. Calpine-1 at 6.

Gas Accord I settlement unbundled backbone and local transmission services, and established separate rates for backbone and local transmission service, most customers paid both backbone and local transmission charges.

In the *2004 GT&S Decision*, in conjunction with bifurcation of the EG rate class, we created a separate rate for customers that connect directly to the backbone system and that never connected to the local transmission system. We concluded that such customers should not have to pay for the local transmission service, stating that: "It is unreasonable to continue with a status quo of a one size fits all local transmission rate that does not properly reflect existing market conditions."[782]

The final unbundling into EG-AOC and EG-BB rates occurred in 2005. Dynegy did not acquire Moss Landing until 2007. Dynegy purchased Moss Landing Units 1 and 2 after the differential between backbone-level and local transmission-level EG rates already existed and thus likely took the differential into account when it purchased the Moss Landing plants.[783] Similarly, a number of NCGC members were also aware of the existing rate structure when they built their gas-fired plants.[784] Given this gradual incremental pace of rate unbundling, we find no basis for claims of unfairness in terms of the impacts of the bifurcated rate structure on competitors' business planning and investments over time.

In any case, we are not persuaded that the current rate design should be changed to protect the ability of certain EG customers to compete. EG rates are

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[782] *2004 GT&S Decision* [D.03-12-061] at 366 and 369.

[783] Exh. Calpine-1 at 14.

[784] Exh. Calpine-1 at 14; Exh. NCGC-8.

not the sole gas transportation cost incurred by EG plants. For some EG plants, PG&E's rates do not apply at all. Other features affect competition, many of which may dilute or offset competitive impacts of transmission costs. As noted by SMUD and Calpine, the drivers of competition in electricity markets are complex and reflect multiple factors in addition to gas transportation rate levels. Dynegy and NCGC have failed to account for such complexities in asserting that transmission rate differentials create impediments to their ability to compete.

Neither Dynegy nor NCGC analyzed how moving to a single EG rate would affect wholesale electric prices in California.[785] Yet, PG&E's analysis showed that continuation of the existing rate design will not affect wholesale electric prices. Using an hourly production simulation model, PG&E compared its proposed transmission rates to a single EG rate structure to determine if either would result in significant increased marginal costs in the wholesale electric market.[786] The model results showed no significant change in the wholesale market as a result of changing from the status quo to a single EG transmission rate.[787]

Dynegy and NCGC argue that an EG unit cannot effectively compete if its gas transmission costs exceed those of other EG plants. The more expensive plant will be dispatched less often, generate less energy, and earn less. PG&E witness Hatton testified that, based on computer simulations of dispatch in spot electricity markets, that Moss Landing Units 1 and 2 will operate only 1% of the

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[785] 31 RT at 4363:19 - 4364:2 (Dynegy/Isemonger); 36 RT at 5365:3-13 (NCGC/Falcon).

[786] Exh. PG&E-43 at 17B-4.

[787] Exh. PG&E-43 at 17B-5.

time if PG&E's proposed local transmission and backbone path rates are adopted and the existing bifurcated structure of EG rates continues.[788] Dynergy claims that the resulting rate differential, if adopted, would make it nearly impossible for Moss Landing Units 1 and 2 to compete against generators who can take advantage of the Backbone-level rate.

These claims, however, rely on PG&E's original assumptions regarding the magnitude of revenue requirement increases. Dynergy doesn't take into account that PG&E's shareholders must absorb a material part of the safety costs that form a large share of PG&E's proposed cost increases.[789] Also, our adopted GT&S revenue requirement in other respects may differ from PG&E's assumptions.

Dynegy claims if the Moss Landing load factor declines substantially, it will be shipping less gas through the PG&E local transmission system resulting in under-collection of local transmission revenues potentially putting the EG-AOC rate class at risk. This seems doubtful, however, given the many miles of local transmission system operated by PG&E and the significant number of customers paying for PG&E local transmission system, above and beyond the EG-AOC customer pool.

In any event, any impacts on *individual* generators would not impair the efficiency of the overall market. Moreover, gas-fired EG plants do not compete solely on the basis of the efficiency with which they produce electricity.[790] Each EG plant makes its own infrastructure choices relative to competitors, many of

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[788] *Dynegy Opening Brief* at 7.

[789] *Penalties Decision* [D.15-04-024] at 93.

[790] Exh. Calpine-1 at 16, lines 24-27.

which are driven by the locations at which plants are sited. EG plants sited favorably with respect to natural gas transportation service may have a cost-based advantage over others sited less favorably. Each EG customer incurs its own costs for lateral and gas system upgrades to connect its plants to the PG&E system. The single EG rate proposal does not extend to the costs of lateral facilities built to connect power plants to PG&E's transmission system.[791]

Moreover, it is not realistic to level the playing field through simply changing the rate design as proposed. A single EG rate would not level the playing field as between generators paying a single EG rate and those connected to interstate pipelines or that reside in SoCalGas' service territory. Fairness is not promoted by altering the playing field in one respect to favor one class of competitors through rate design, while those competitors may enjoy other advantages that are not being addressed. Competition is enhanced when competitors pay cost-based rates for essential utility services. Rates can reasonably reflect differences that result from locational attributes so long as those differences are based on cost causation.[792]

We also find no merit in NCGC's claim that PG&E's proposed rate design violates Pub. Util. Code § 453(c) by maintaining an "unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service." NCGC claims that a single rate violates Pub. Util. Code § 453(c) by discriminating between localities not based on the level of service, and forcing LT-connected electric generators to pay

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[791] 31 RT at 4316:16 – 4317:1.

[792] Exh. Calpine-1 at 20, lines 7-13.

significantly higher rates than those paid by backbone-connected electric generation customers.

We find no violation of Pub. Util. Code § 453(c) based upon the existing gas transportation rate differences between classes of customers. In this case, the question is whether the rate is discriminatory because it does not treat generation facilities similarly. The Section 453(c) prohibition applies to unreasonable differences in rates charged to similarly situated customers. Yet, as noted previously, there are distinct cost-based differences in the respective levels of service for which the differential rates apply. Accordingly, there is nothing arbitrary or discriminatory in recognizing such differences in costs as the basis to justify rate differences. As a result, we find that no violation of Section 453(c) has been established.

18.6.4. Alternatives to the Single-Rate Proposal

As a back-up position, in the event that their proposal to establish a single gas transportation rate is rejected, Dynegy and NCGC put forth various alternative proposals. Dynegy proposes (1) that the Commission extend a bill credit to all customers that qualify for inclusion within a new "Local Generation in the Transmission System" rate class; (2) that the Commission adopt a new, refined bill credit for Moss Landing Units 1 and 2; (3) that Dynergy be allowed to purchase Line 301-G from PG&E; or (4) that PG&E and Dynegy enter into a long-term discounted contract for service to Moss Landing Units 1 and 2.

NCGC proposed (1) removing the restriction in PG&E's Rule 1 that prevents existing customers from constructing laterals to PG&E's backbone system in order to access Rate Schedule G-EG/BB or (2) reclassifying as backbone pipelines certain of PG&E's current local transmission pipelines that serve NCGC members.

We do not find any of these alternative proposals to be appropriate for adoption at this time. We provide the following comments on these alternative proposals, however, as noted below.

We decline to adopt the Dynegy alternative proposal for continuation of some version of the Local Transmission Bill Credits. Dynegy suggests a new Bill Credit, either permanent or just for the next three year Gas Accord period, that results in the same net amount of local transmission costs that the Moss Landing Units paid through 2011.

We are not persuaded by Dynegy's claims that the bill credits included in past Gas Accord settlements reflect a policy of minimizing the differential between G-EG/LT and G-EG/BB rates and of allowing Moss Landing Units 1 and 2 a reasonable opportunity to compete in CAISO electric markets. Witness Isemonger admitted there are no statements in the Gas Accord settlements, the motions presenting them, the comments supporting their adoption, or in Commission decisions indicating the intention of the bill credits, or the reason for adoption.[793]

Certain NCGC members also have received Bill Credits in past Gas Accords. The relative value of the bill credit for Moss Landing versus the NCGC plants differed significantly, however, As witness Falcon explains, the NCGC Bill Credit was "not at any time comparable to the Moss Landing credit, and did not result in the same differential as that explained in Mr. Isemonger's testimony for Moss Landing."[794]

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[793] 31 RT at 4310:16 and 23, 4311:20 and 28, 4312:20 and 26 (Dynegy/Isemonger).

[794] Exh. NCGC-2 at 3, lines 3-4.

The bill credits were a feature of the Gas Accord III, Gas Accord IV, and Gas Accord V Settlement Agreements. These bill credits were funded by Backbone shippers to mitigate, in part, the cost of natural gas transportation for generators connected to the PG&E local transmission system. We previously approved these bill credits as an integrated feature of the previous settlements as part of the compromise of underlying litigation positions of the parties. Nothing in the Gas Accord settlements suggests that the purpose of the bill credits was to address competitive issues in electric markets.

By contrast, the current proposal to incorporate a bill credit is not the product of a settlement, but is a contested issue. The bill credit mechanism results in a shortfall in collection of the Local Transmission revenue requirement, which must be collected from other customers.[795] It would not be fair and equitable for a few parties to continue to benefit from a bill credit at the expense of others that do not.

Dynegy also proposes that a new EG rate class be created called "Local Generation in the Transmission System" which would be higher than the G-EGBB rate by a fixed differential. The new rate class would include "principally Dynegy's Moss Landing Units 1 and 2, as well perhaps as other units that might petition the CPUC for inclusion."[796] The rate applicable to such class would be designed to reflect the same premium above the G-EG/BB rate that was provided in past Gas Accord settlements through the Bill Credit prior to 2012, which witness Isemonger calculated at 5.6 cents per Dth.[797] Dynegy

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[795] Exh. PG&E-43 at 17-12, lines 8-10.

[796] Exh. Dynegy-1 at 39, lines 5-6.

[797] Exh. Dynegy-1 at 39, lines 13-15.

suggests that this rate class could be limited to electric generation plants that have received Local Transmission Bill Credits as a result of previous Gas Accord Settlements, and could sunset as those plants are retired.

We decline to adopt the Dynegy proposal to create the new rate class higher than the G-EGBB rate by a fixed differential. We do not find this proposal to be adequately developed. Dynegy has not sufficiently analyzed the petition process for the new rate class, the criteria for inclusion, how revenue shortfalls associated with the discount given to this customer class would be allocated, or what rates members would pay. Moreover, adopting a rate subsidy to improve the competitive position of certain plants would be unduly discriminatory and violate Pub. Util. Code § 453(a).

We also decline to adopt the NCGC proposal to expand the classification of backbone facilities "to include key transmission mains whose primary purpose is moving gas to various load centers," such as "high pressure mains originating in Milpitas and serving the San Francisco peninsula, mains bringing gas to the Monterey-Santa Cruz area and mains bringing gas to and through the Sacramento, Stockton and Fresno areas."[798] We find this proposal to be inconsistent with the Commission's definition of backbone facilities as pipelines that originate at receipt points with interstate pipelines or other utilities.[799] NCGC does not specify which pipelines would be re-classified from local transmission to backbone transmission, nor analyze cost impacts on remaining local transmission customers.

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[798] Exh. NCGC-1 at 19, lines 7-11.

[799] Exh. Calpine-1 at 20, lines 23-25.

Dynegy suggests, as another alternative, that it could purchase or lease Line 301-G, the local transmission line serving Moss Landing Units 1 and 2. This proceeding is not the proper vehicle to consider a sale or lease of used and useful facilities. An application under Pub. Util. Code § 851 would be required to address such a course of action. PG&E also notes that it has many Core customers either connected to, or downstream of Line 301-G. The sale or lease of local transmission capacity would complicate operations of that facility, especially when curtailments might be required.

As another alternative, Dynegy suggests a long-term contract with payments to PG&E based on Dynegy's hypothetical cost to build a direct connection to PG&E's backbone and bypass the local transmission system. As noted by PG&E, this proposal is akin to a lease and would complicate its ability to operate Line 301-G.[800] Dynegy claims it can build such a lateral for $1 million per mile. However, PG&E's pipeline capacity proposals in this rate case typically range between $3 million and $5 million per mile.[801] Given this disparity, it is doubtful that PG&E and Dynegy could negotiate a long-term contract based on the hypothetical costs to build a lateral to the backbone.

18.7. Modification of Noncore Customer Class

In *Re Rulemaking into Proposed Refinements for New Regulatory Framework for Gas Utilities* [D.86-12-010], 1986 Cal. PUC LEXIS 754, the Commission adopted policies to restructure natural gas regulation in California. Among other things, D.86-12-010 separated the gas market into two classes of customers – core and

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[800] Exh. PG&E-40 at 10-23.

[801] Exh. PG&E-40 at 10-22.

noncore. The noncore customer class consists primarily of large commercial, industrial, and electric generation customers who usually procure their own natural gas supplies. These customers may use the utility's transmission and distribution system and other services on an unbundled basis. The Commission also established a 250 Dth/year minimum size to qualify as a noncore customer.[802]

Commercial Energy proposes that the current 250 Dth/year threshold to qualify for noncore status be lowered to 100 Dth/year to allow small commercial customers with alternate heating capability to choose noncore service. Commercial Energy notes that at the time the Commission adopted its definition of core and noncore markets, the Commission had signaled its openness to re-examing the noncore definition in the future.[803] Commercial Energy argues that given the changes in the natural gas marketplace, such as the growing sophistication of customers to control their energy usage and more available options for alternate heating capability, the floor for becoming a noncore customer should be reduced to 100 Dth/year.[804]

Commercial Energy states that lowering the threshold would not result in a rush of core customers leaving for noncore service, as there are only 662 existing core customers potentially eligible for noncore service if the threshold were lowered to 100 Dth/year. Further, it believes that 50% of the eligible customers would likely opt for changing to noncore service, which it estimates would reduce core gas demand by approximately 2%. Commercial Energy

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802 D.86-12-010, 1986 Cal. PUC LEXIS 754 at *14 - *22.

803 Exh. Commercial Energy-1 at 21-22.

804 Exh. Commercial Energy-1 at 23-26.

argues that some of the benefits of reducing the minimum threshold include "[reducing] the demand for interstate pipeline capacity, storage capacity and intrastate backbone capacity needed by PG&E for core customers" and "[providing] the system with additional 'demand response' capacity in the form of an increased amount of curtailable load."[805]

PG&E opposes Commercial Energy's proposal, arguing that it "could have significant operational and rate impacts on both core and noncore customers."[806] First, based on its experience with a number of grandfathered customers on its noncore tariffs that have annual usage less than 250 Dth/year, PG&E expresses concern that customers with annual usage between 100 Dth/year and 250 Dth/year may not comply with curtailment orders, thus negatively impacting PG&E's ability to operate its gas transmission system. Further, it believes that while the rates for core customers migrating to noncore service would likely decrease, rates for the remaining core customers and noncore customers would likely increase. Additionally, PG&E notes that the load profiles of the newly-eligible noncore customers are "peakier than the existing noncore customers, thus causing the load shapes for noncore to deteriorate, increasing transmission rates for noncore customers."[807]

PG&E therefore advocates that Commercial Energy's proposal be rejected. However, it states that if the Commission were to consider Commercial Energy's proposal, the proposal should be considered on a statewide basis "in which all impacts could be thoroughly examined (particularly because adoption of

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[805] Exh. Commercial Energy-1 at 29.

[806] *PG&E Opening Brief* at 17-23.

[807] *PG&E Opening Brief* at 17-24.

Commercial Energy's proposal could impact gas distribution rates, which are not at issued in this case)."[808]

We decline to adopt Commercial Energy's proposal. There is little analysis concerning the potential impact of adopting a lower threshold on rates, with both Commercial Energy and PG&E speculating on the number of customers who would switch to noncore service, the degree of noncompliance to curtailment requirements, and load shape. We do not find it reasonable to adopt a proposal that could have a significant impact on gas operations and core rates without further analysis. Further, the definition of noncore customer was adopted in a rulemaking that applied to all gas utilities. We do not believe it is appropriate to change this definition on a utility-by-utility basis. Rather, a change to the definition of noncore customer to reduce the minimum threshold to 100 Dth/year should be considered in the context of a rulemaking applicable to all gas utilities, where all potential impacts can be considered together.

18.8. Other System Values that Impact Cost Allocation or Rate Design

18.8.1. British Thermal Unit Value

PG&E used the following British Thermal Unit (Btu) conversion factors for rate design and other purposes:

[808] *PG&E Opening Brief* at 17-25.

Table 44
BTU Conversion Factors for PG&E Pipeline and Storage Systems[809]

System	Btu Conversion Factor (Dth per MMcf)
Transmission (Except CA Production)	1,020
Transmission – CA Production	985
PG&E Storage	1,020

PG&E states that these Btu conversion factors are representative of the actual heating values on the PG&E system for the last several years. No party opposed PG&E's proposal and it is adopted.

18.8.2. Shrinkage

For the purposes of modeling system flows and capacities that are used in calculating proposed rates, PG&E used the existing base shrinkage rates specified in Advice Letter 3236-G, which were in effect at the time PG&E submitted its testimony. In Advice Letter 3513-G, the Commission adopted PG&E's proposed transmission and distribution base allowances effective November 1, 2014, to better match the 2015 shrinkage forecast. On September 11, 2015, PG&E filed Advice Letter 3630-G to adjust the transmission and core seasonal distribution shrinkage allowances to better match the actual shrinkage expected on PG&E's system for 2016. Advice Letter 3630-G was approved on November 1, 2015, with an effective date of November 1, 2015. PG&E's proposed rates shall reflect the revised base shrinkage allowance percentages (exclusive of the adopted adjustment allowances). Additionally, PG&E's proposed rates shall reflect the base shrinkage allowance from Advice Letter

[809] Exh. PG&E-2 at 10-52, Table 10-13.

3630-G during the period beginning November 1, 2016, for which PG&E has not yet filed new shrinkage rates.

18.9. Illustrative Rates

Illustrative rates based on the revenue requirements adopted in this decision are presented in Appendix J. However, final rates cannot be adopted until after the adopted revenue requirements in today's Decision are adjusted to reflect the $850 million of PG&E shareholder-funded safety improvements adopted in the *Penalties Decision*.[810]

19. Core Gas Supply

19.1. Core Capacity Allocations

19.1.1. Core Intrastate Pipeline Capacity

PG&E is proposing a 333,678 Dth/d reduction in the amount of intrastate capacity held for core customers in the winter, and a 169,679 Dth/d reduction in the amount of intrastate capacity held for core customers in the summer.[811] PG&E notes that the proposed intrastate capacity changes are consistent with the interstate capacity ranges proposed in *Application of Pacific Gas and Electric Company to Set New Core Interstate Pipeline Capacity Planning Range* [A.13-06-011], and PG&E's current core interstate capacity contracts. PG&E's proposed changes are summarized below.

Table 45

[810] *See* discussion in Section 22 below.

[811] Exh. PG&E-2 at 19-2.

Proposed Core Intrastate Transmission Capacity Allocation[812]

	Dth/d		
Description	Existing	New	Change
Redwood Path Annual	608,766	605,088	(3,678)
Baja Path Annual	348,000	182,000	(166,000)
Baja Path Seasonal (New: November to March	321,000	157,000	(164,000)
Total – November to March	1,277,766	944,088	(333,678)
Total – April to December	956,766	787,088	(169,678)

PG&E states that holding intrastate capacity to match upstream interstate capacity facilitates the seamless utilization of pipelines.[813] However, it requests that it be allowed to file a Tier 1 Advice Letter to request intrastate (Redwood or Baja Path) contract increases in the event there is a need for "increases to intrastate pipeline capacity corresponding to interstate pipeline approval requests."[814]

No party opposed PG&E's proposed core intrastate pipeline capacity allocation. PG&E's proposed allocation is adopted. Additionally, PG&E is authorized to file a Tier 1 Advice Letter if the need arises for it to increase intrastate pipeline capacity corresponding to interstate pipeline approval requests.

On April 7, 2015, PG&E and the City of Palo Alto (Palo Alto) submitted a joint stipulation, *Joint Redwood and Baja Capacity Allocation Stipulation*

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[812] Exh. PG&E-2 at 19-2, Table 19-1.

[813] Exh. PG&E-43 at 19-4.

[814] Exh. PG&E-2 at 19-7.

(Exh. Joint-5), that states PG&E will continue the allocation of Core Redwood capacity to Palo Alto at the same level adopted in Gas Accord V, or 5.898 MDth/d. Additionally, PG&E will provide Palo Alto with a Baja capacity option for the 2015-2017 Rate Case Period, scaled down consistent with Core Gas Supply's proposed lower Baja contract. The stipulation also provides that Palo Alto's Redwood or Baja capacity option would be adjusted if the Commission adopts a different Redwood or Baja contract quantity for Core Gas Supply than what PG&E proposed in its testimony.[815]

We find the joint stipulation to be reasonable, as it continues an allocation to Palo Alto that is consistent with the allocation Palo Alto received in Gas Accord V. Therefore, the *Joint Redwood and Baja Capacity Allocation Stipulation* between PG&E and Palo Alto (Exh. Joint-5) is adopted.

19.1.2. PG&E Firm Storage Capacity

PG&E's proposes the storage inventory for Core Firm Storage Contract remain unchanged at 33.5 billion cubic foot (Bcf). However, it proposes to adjust the November to March withdrawal rights to fully incorporate existing assets that are available to meet peak load conditions. The proposed changes in PG&E firm storage capacity for its core customers are summarized in Table 19-3 of Exhibit PG&E-2 at 19-8.

No party objects to PG&E's proposed adjustment to the core customers' storage withdrawal rights. PG&E's proposal is adopted.

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[815] Exh. Joint-5 at 1.

19.2. Adjustments to 1-Day-in-10-Year Core Capacity Planning Standard

PG&E proposes to adjust the 1-Day-in-10-Year Core Capacity Planning Standard (Reliability Standard) by explicitly allowing for the assumption of 330 MDth/d of firm gas supply at PG&E's Citygate. PG&E notes that it has proposed a reduction in intrastate Baja Path contracted capacity of 330 MDthd. It states "If the Reliability Standard is not adjusted to reflect this change, it would result in the need to add 330 MDth/d or additional withdrawal capacity to continue meeting the standard."[816] PG&E therefore proposes to modify the Reliability Standard "to assume that 330 MDth/d of reliability gas supply will be available at PG&E's Citygate for the purposes of calculating compliance with the standard."[817]

No party opposes PG&E's proposal. PG&E's proposal to modify the Reliability Standard by explicitly allowing for the assumption of 330 MDth/d of firm gas supply at PG&E's Citygate is adopted.

19.3. Changes to Core Procurement Incentive Mechanism

The Core Procurement Incentive Mechanism (CPIM) is used to measure the reasonableness of PG&E's Procurement function for bundled core customers.[818] PG&E proposes the following changes to the CPIM:

1. Addition of a monthly index component at PG&E's Citygate to reflect baseload purchases made at that point. This change

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[816] Exh. PG&E-2 at 19-12.

[817] Exh. PG&E-2 at 19-13.

[818] Exh. PG&E-2 at 19-14.

is in connection to PG&E's proposed reduction in Baja Path capacity discussed in Section 20.1.1 above.[819]

2. Modify the CPIM benchmark to reflect intrastate capacity holding changes. This change is to reflect the new capacity holdings proposed by PG&E in Section 20.1.1 above.[820]

No party opposes PG&E's proposed changes. PG&E's proposed changes to the CPIM benchmark are adopted.

In addition to the two changes above, PG&E proposes that it be authorized to make certain changes to the CPIM mechanism for determination of PG&E's benchmark upon agreement between PG&E and ORA. PG&E's proposal would cover potential changes in four areas: (1) the method for calculating the benchmark load; (2) the setting of the benchmark sequence; (3) the items to be included in the capacity demand charge benchmark; and (4) the determination of gas index pricing.[821] PG&E states that any changes would be effective immediately upon agreement between PG&E and ORA and be reported by PG&E in the first CPIM Annual Report to which they apply. Changes that could not be agreed upon by PG&E and ORA and any other changes to the CPIM that are not specifically identified above would be considered through the existing application process.

PG&E's proposal is opposed by CTAC. CTAC argues that PG&E's proposal is overly broad and "there is no limit as to the changes to the

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[819] Exh. PG&E-2 at 19-14 – 19-15.

[820] Exh. PG&E-2 at 19-15.

[821] Exh. PG&E-2 at 19-15.

benchmark allowable in these un-reviewed agreements."[822] While CTAC does not question ORA's qualifications to review the proposed changes, it believes that parties "should retain the ability to review and address non-trivial potential changes in the CPIM prior to their implementation."[823] CTAC believes this is particularly true when the changes would materially affect the CPIM outcomes.

PG&E rebuts the concerns raised by CTAC, noting that the proposal is limited to four very discrete proposed changes. Moreover, it notes that CTAs have no identifiable interest in CPIM outcomes, since any cost impacts resulting from changes in the CPIM calculation only impact PG&E's bundled customers, not CTAs or their customers. Additionally, PG&E argues that since CTAs are market participants, "forward or real time knowledge of proposed CPIM changes could provide signals to market participants as to PG&E's purchasing strategies and operations."[824]

ORA supports PG&E's proposal for changes to the CPIM mechanism. It further notes that "if PG&E makes a proposal significant enough to warrant detailed ORA analysis and potential opposition, ORA will do so, consistent with ORA's mandate to represent all core ratepayers taking local transportation services from PG&E."[825]

We find that PG&E's proposal that certain changes to the CPIM mechanism for determination of PG&E's benchmark be effective upon agreement between PG&E and ORA is reasonable. PG&E has identified four specific areas

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[822] Exh. CTAC-1 at 25.

[823] Exh. CTAC-1 at 26.

[824] *PG&E Reply Brief* at 18-6.

[825] *ORA Reply Brief* at 92.

covered by the proposal. Based on the examples provided by PG&E, the proposed areas would allow PG&E to revise its benchmarks in a more timely manner. Further, ORA has affirmed that it would perform detailed analysis if warranted. Finally, as PG&E has acknowledged, any changes that are not agreed upon by PG&E and ORA, as well as any other changes to the CPIM would be considered through the existing application process.

CTAC does raise a valid point that since PG&E proposes that any agreed-upon changes be reported by PG&E in the first CPIM Annual Report to which they apply, there could be a significant delay before parties are aware that the benchmark has been changed. Therefore, we shall require PG&E to notify parties and the Energy Division 15 days after the changes become effective.

Accordingly, we adopt PG&E's proposal that changes to (1) the method for calculating the benchmark load; (2) the setting of the benchmark sequence; (3) the items to be included in the capacity demand charge benchmark; and (4) the determination of gas index pricing shall be effective upon agreement between PG&E and ORA. PG&E shall serve notice of any changes resulting from the agreement between PG&E and ORA within 15 days of the effective date to the Energy Division and parties to PG&E's most recent GT&S rate application.

19.4. Core Aggregation Program Adjustments

19.4.1. Pipeline Capacity Allocation Methodology

19.4.1.1. PG&E's Proposal

In the *Gas Accord V Settlement Decision* (D.11-04-031), the Commission approved, among other things, the Core Transport Agent Settlement Agreement

(CTA Settlement Agreement).[826] Among other things, the CTA Settlement Agreement updated the pipeline allocation process for assigning core intrastate pipeline, interstate pipeline, and storage capacities to CTAs. This process allocates capacity three times a year based on the January Capacity Factor.[827]

PG&E proposes to change from using the January Capacity Factor to using a Seasonal Capacity Factor.[828] PG&E maintains that this change is warranted because "the CTAs' collective share of January core load has historically represented the smallest CTA market share of any month", resulting in an under-allocation of capacity, and associated costs, to CTAs.[829]

Under PG&E's proposed Seasonal Capacity Factor, "the seasonal capacity factor would be based on the aggregation of the most recent historical load for customers during the months being allocated."[830] This would result in one allocation percentage that would be used for each CTA for each four-month offering. After the allocation to all the CTAs, the remaining capacity share would represent the share allocable to Core Gas Supply for the bundled core customers.

PG&E maintains this proposed change in the methodology for allocating pipeline capacity to CTAs will more closely align the allocation with the respective customer loads served by CTAs and Gore Gas Supply during the period covered by the allocation. It further proposes that, pursuant to Section

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826 *Gas Accord V Decision* [D.11-04-031], Appendix B.

827 *Gas Accord V Decision* [D.11-04-031], Appendix B at 1 (Sections A.3 - A.5).

828 Exh. PG&E-2 at 19-17.

829 *PG&E Opening Brief* at 18-7.

830 *PG&E Opening Brief* at 18-8; Exh. PG&E-2 at 19-7.

A.1 of the CTA Settlement Agreement, this modification be made effective on January 1, 2016, for capacity allocations covering April 1, 2016 forward.[831]

19.4.1.2. Commercial Energy's Proposal

Commercial Energy opposes PG&E's proposal, arguing CTAs would be allocated a much higher percentage of stranded capacity costs throughout the year. It notes that unlike past Gas Accords, where PG&E and the CTAs would hold a workshop to discuss cost allocation and customer support issues, PG&E did not discuss its proposal to change to a Seasonal Capacity Factor with any CTA.[832]

According to Commercial Energy, CTA load is more constant across the year than core load. Under the current allocation, CTAs have adequate pipeline capacity in the summer months and need to supplement their pipeline capacity in the winter months with storage. However, under PG&E's proposed allocation, Commercial Energy states the pipeline capacity allocation to CTAs would increase in the summer months when CTA loads are the lowest.[833]

Commercial Energy therefore maintains that PG&E's Seasonal Capacity Factor is inconsistent with cost allocation principles, as it would "reduce the pipeline capacity allocation to customers with high winter peaks and low summer loads even though such customers cause a greater need for backbone capacity on the PG&E system as a whole during peak demand periods."[834] It

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[831] Exh. PG&E-2 at 19-18.

[832] Exh. Commercial Energy-1 at 7.

[833] Exh. Commercial Energy-1 at 9-11.

[834] Exh. Commercial Energy-1 at 13-14.

contends that PG&E's proposed change in capacity allocation would result in a 40% increase in costs to CTAs in comparison to the prior year's rates.[835]

Commercial Energy proposes to revise the current pipeline capacity allocation for CTAs to calculate a capacity factor based on Peak Day usage for all CTAs as a proportion of Peak Day usage for all Core customers, as opposed to peak month (January) consumption. Commercial Energy maintains that its approach would be consistent with how PG&E designs its system and would align capacity with cost causation, as costs would be allocated to customers based on how their demands drive capacity expansion.[836] Commercial Energy proposes that its proposed allocation factor be adopted and made effective April 1, 2016.

19.4.1.3. Other Parties' Comments

Tiger Natural Gas, Inc. (Tiger) opposes PG&E's proposal. It notes that PG&E's pipeline capacity holdings throughout the year are largely dictated by the PG&E core's winter peak demand. Therefore, Tiger maintains that allocating pipeline capacity and the associated costs between PG&E core and CTAs based on their relative shares of the core's total January throughput is consistent with the Commission's cost allocation ratemaking principles.[837] Further, it notes that adoption of PG&E's proposed Seasonal Capacity Factor methodology would result in a significant increase in the capacity costs to be borne by individual CTAs.

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[835] Exh. Commercial Energy-1 at 11.

[836] Exh. Commercial Energy-1 at 16.

[837] *Tiger Natural Gas Inc. Opening Brief* at 5-6.

Tiger maintains that PG&E has alternative ways to reduce the pipeline capacity costs borne by the Core Procurement Group. For example, it asserts that PG&E can adjust its core pipeline capacity over time. Tiger notes that PG&E's Core Gas Supply intrastate pipeline capacity reservations is designed in relationship to PG&E's interstate capacity planning ranges, and that PG&E is exceeding the minimum holdings by 15%. Thus, Tiger believes PG&E could safely reduce its pipeline capacity holdings and the associated costs to obtain the same or greater reduction in pipeline capacity holdings than it would achieve by modifying the pipeline allocation methodology.[838]

Tiger further notes that Commercial Energy's proposed Peak Day methodology is consistent with the methodology used by PG&E for system design and planning purposes. As such, it supports Commercial Energy's proposal, arguing that it is consistent with the Commission's ratemaking principles. Tiger states that if the Commission declines to adopt Commercial Energy's proposal, then the status quo should be maintained.

Finally, Tiger contends that the CTA Settlement Agreement approved in D.11-04-031[839] had provided that the existing pipeline allocation methodology will continue in effect after the end of the Gas Accord V settlement term and that PG&E would consult with the CTAs before proposing to change the existing methodology.[840] Tiger therefore maintains that PG&E should have tried to work out a joint proposal to revise the pipeline allocation methodology prior to filing its GT&S application. Therefore, Tiger urges that the Commission expressly state

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[838] *Tiger Natural Gas Inc. Opening Brief* at 7.

[839] *Decision Regarding the Gas Accord Settlement* [D.11-04-031], Appendix B (Section A.9).

[840] *Tiger Natural Gas Inc. Opening Brief* at 6.

"that no future PG&E proposals to revise the current pipeline allocation methodology or address any other CTA issues or concerns will be entertained by the Commission unless and until PG&E demonstrates it has lived up to it (sic) meet and confer obligations under the CTA settlement."[841]

SPURR supports PG&E's proposal and opposes Commercial Energy's proposal. It argues "PG&E's proposal avoids an $11 million dollar swing in costs that would result from the [Commercial Energy] proposal, repairs the current over-allocation of interstate and intrastate pipeline capacity to the bundled core, and mitigates the incentive for flatter-load customers to depart bundled service and leave peakier customers behind."[842] SPURR highlights its analysis, which compares the impact of costs to bundled customers and CTAs under the two proposals.[843]

SPURR notes that if it is determined in A.13-06-011 that PG&E should only hold interstate capacity on behalf of its core bundled customers, the issue of allocation would be moot as there will be no need for any methodology to allocate intrastate or interstate pipeline capacity to CTAs. However, if pipeline capacity continues to be allocated to CTAs, SPURR supports PG&E's proposed Seasonal Pipeline Capacity proposal.

SPURR maintains that since PG&E holding pipeline capacity benefits all core customers, the costs should be allocated using an equal-cents-per-therm (ECPT) allocator. SPURR cites to various Commission decisions to support this

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[841] *Tiger Natural Gas Inc. Opening Brief* at 7.

[842] *Concurrent Opening Brief of School Project for Utility Rate Reduction (SPURR Opening Brief)* at 4.

[843] *SPURR Opening Brief* at 5-7.

proposition.[844] SPURR asserts that PG&E's proposed seasonal capacity allocation methodology yields a result closer to ECPT than the current allocation methodology.

SPURR further notes that Commercial Energy's proposal covers only allocation of intrastate pipeline capacity, while PG&E's proposal allocates pipeline capacity for both interstate pipelines and PG&E's backbone transmission.[845] Additionally, SPURR asserts that Commercial Energy's proposal is based on factors (peak day) not used to design PG&E's backbone system. Finally, SPURR criticizes Commercial Energy's proposal for using the wrong costs and too small a sample set.[846] As such, SPURR urges that Commercial Energy's proposal be rejected.

TURN also supports PG&E's proposal, arguing that it "represents a more equitable method of allocating backbone pipeline capacity" since it better reflects the way in which pipeline capacity is actually utilized.[847] TURN notes that Commercial Energy's proposal ignores the fact that backbone transmission costs are designed using a cold and dry year allocator, not a peak day allocator. TURN states that given the significant difference between peak day load and cold/dry year load, Commercial Energy's "cost causation" arguments should be given little weight.[848]

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[844] *SPURR Opening Brief* at 7-9.

[845] *SPURR Opening Brief* at 11.

[846] *SPURR Opening Brief* at 15.

[847] *TURN Opening Brief* at 212.

[848] *TURN Opening Brief* at 214.

19.4.1.4. Discussion

It is clear that both PG&E and the CTAs no longer believe that the January Capacity Factor should continue to serve as the pipeline allocation process for assigning core intrastate pipeline, interstate pipeline, and storage capacities to CTAs. However, we are persuaded by the testimony and analysis presented by parties that both proposals, presented by PG&E and by Commercial Energy, are flawed and should not be adopted. As such, we decline to adopt either proposal and continue the January Capacity Factor at this time.

We note that Section A.1 of the CTA Settlement Agreement states

> These new procedures will become effective April 1, 2012. The CTA capacity structure as defined in this settlement will succeed the Gas Accord V Settlement unless changed by the CPUC in a future decision or settlement. No party to this settlement will petition for changes to these terms to be effective any time prior to April 2016, except as noted in A.9.

It is unclear from the above language whether April 2016 referred to the date when proposals to change the allocation methodology could first be presented or the effective date for changes to terms adopted in the CTA Settlement Agreement. We therefore draw no conclusions whether PG&E improperly proposed a change in the allocation methodology as part of its GT&S application. Nonetheless, there is sufficient evidence to conclude that PG&E's failure to discuss this proposed change with the CTAs prior to filing its application was unexpected and a departure from past practice.

On October 22, 2015, the Commission adopted *Decision Regarding the Core Interstate Pipeline Capacity Planning Range for Pacific Gas and Electric Company (Interstate Pipeline Capacity Decision)* [D.15-10-050], which determined, as relevant here, that (1) PG&E should continue its planning for and procurement of

interstate pipeline capacity on behalf of the CTAs' customers and (2) reduced the amount of interstate pipeline capacity that PG&E holds on behalf of the core demand.[849] We believe that this decision could impact how the allocation of capacity (and thus costs) should be changed.

In light of the determinations in D.15-10-050 and an apparent consensus that the existing January Capacity Factor should be changed, we direct PG&E to meet and confer with the CTAs to discuss changes to the capacity factor prior to filing a new proposal.

19.4.2. Incremental Storage Capacity Allocation

In *Opinion Regarding the Proposal for Incremental Core Gas Storage* [D.06-07-010], the Commission adopted a Partial Settlement Agreement which provided, in relevant part

> Until such time that Core Transport Agents' (CTA) load reaches the 10 percent level of the January capacity factor, CTAs' pro-rata share of the core customer storage holdings remains at the current level. Specifically, until their load reaches the 10 percent level: 10 CTAs will not be offered a pro-rata share of any incremental storage capacity held by PG&E on behalf of core customers; and 2) CTAs or their customers will not be required to pay for such incremental storage capacity.
>
> If CTA load approaches the 10 percent level of the January capacity factor, PG&E will make a timely proposal for an appropriate treatment of the incremental capacity vis-à-vis CTAs.[850]

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[849] D.15-10-050 at 2.

[850] *Opinion Regarding the Proposal for Incremental Core Gas Storage* [D.06-07-010], Appendix A at 5 (Section C.2).

PG&E states that the CTAs' load exceeded the 10% threshold in 2010, and currently is over 18%. PG&E proposes that the Commission delay the implementation of assignment (and the corresponding assumption of cost responsibility) of incremental storage capacity to CTAs until: (a) April 1, 2016 or later; and (b) the total incremental core storage withdrawal requirement exceeds 100 MDth/d. Once both conditions occur, PG&E would file an advice letter to implement a core incremental storage capacity allocation mechanism.[851]

No party objected to PG&E's proposal. PG&E shall file a Tier 3 Advice Letter to implement the assignment (and the corresponding assumption of cost responsibility) of incremental storage capacity to CTAs once the following two conditions are met: (a) the date occurs on April 1, 2016 or later; and (b) the total incremental core storage withdrawal requirement exceeds 100 MDth/d. The Advice Letter shall be served on the service list of this proceeding.

20. Core Transport Agent Issues

20.1. Core Load Forecast Model

Under Gas Rule 21, PG&E's Core Gas Supply (CGS) Department and CTAs (collectively, the Core Procurement Groups, or CPG) must match nominated supply to daily usage for the customers for which they are responsible. PG&E's Gas Control provides each CPG with an individualized estimate of its customers' aggregate daily usage (Determined Usage). Each CPG must supply this amount of gas to the system or incur a penalty. Further, each CPG must stay within a monthly balancing target of five percent of actual

[851] Exh. PG&E-2 at 19-18.

aggregate metered usage. Otherwise, tariffs require PG&E to buy or sell volumes on the customer's behalf to correct the imbalance.[852]

In Gas Accord V, PG&E agreed to "re-tune" the Core Load Forecast Model (CLFM) and to explore whether smart meter data could be used to improve forecast accuracy. PG&E states that at this point, data from gas smart meters is not yet practical for daily gas use forecasting, as the data is not collected hourly or daily, but rather records the number of times a meter accumulates 100 cubic feet.[853] However, PG&E proposes to modify the CLFM to use an average of 24 hourly temperature forecasts (one for each hour in the gas day), which it believes will yield greater Determined Usage accuracy, along with a corresponding revision to the CLFM's regression equations.

PG&E further proposes to conduct further analysis on the CLFM and its inputs to continue to improve Determined Usage accuracy. PG&E contends that improvements in the CLFM "would increase customer satisfaction because CGS and CTAs would have more accurate information about their usage, which would increase their ability to manage imbalances and [Operational Flow Orders]."[854]

While Commercial Energy agrees that PG&E's proposal to modify the CLFM by using an average of 24 hourly temperature forecasts will improve the accuracy of the CLFM slightly, it criticizes PG&E's failure to make any attempt to analyze SmartMeter data. It argues "The accuracy of the CLFM has a significant

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[852] Exh. PG&E-2 at 10-42.

[853] Exh. PG&E-2 at 10-43; 25 RT at 2816:10-17 (PG&E/Christopher).

[854] Exh. PG&E-2 at 10-44.

impact on CTAs and their customers; it is crucial that PG&E make meaningful changes to the CLFM using he SmartMeter that are readily available to it."[855]

Commercial Energy highlights the financial risks to CTAs if the CLFM is not accurate, and identifies "several fundamental defects that lead to inaccurate forecasts."[856] Commercial Energy further notes that while PG&E has spent over $2.3 billion on the program, it has no current plans to facilitate incorporation of SmartMeter data into its forecast methodology nor to create a data processing system for transforming SmartMeter data for use in daily forecasting. "Commercial Energy believes this wholesale lack of effort is an irresponsible underutilization of a program on which PG&E has spent nine years and billions of dollars."[857]

Commercial Energy therefore proposes that PG&E should provide the raw meter reads to the CTAs to allow the CTAs to "back-test the CLFM and then work with PG&E to improve it."[858] Commercial Energy notes that in the past, PG&E had routinely met with the CTAs to discuss issues that concerned them, and that these discussions "led to positive outcomes, including the growth of the CTA-served market and improvements in customer service to PG&E's largest core customers – the CTAs themselves."[859]

While we find that PG&E's proposed modification would improve the Determined Usage accuracy, it is clear that incorporating gas SmartMeter data in

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[855] *Commercial Energy Opening Brief* at 59.

[856] *Commercial Energy Opening Brief* at 60.

[857] *Commercial Energy Opening Brief* at 61.

[858] *Commercial Energy Opening Brief* at 62.

[859] *Commercial Energy Opening Brief* at 62.

the CLFM would likely provide even greater accuracy. We agree with Commercial Energy that PG&E should be exploring the possibility of using data from the gas SmartMeters for more than just monthly billing. PG&E states that it would need to accumulate about two years' worth of SmartMeter data and perform significant analysis of that data to determine whether SmartMeter data could be useful for forecasting purposes.[860] By now, PG&E should have sufficient gas SmartMeter data to perform such an analysis, and we encourage PG&E to evaluate whether and how this data could be utilized to improve the accuracy of the Determined Usage.

To ensure that there is full consideration of how the CLFM can be changed to provide greater accuracy, including the use of gas SmartMeter data, we further direct PG&E to meet regularly with the CTAs to explore future changes. We are troubled that the CTAs have mentioned more than once that PG&E has ceased its ongoing dialogue with CTAs on various issues. PG&E and the CTAs should work together to develop joint proposals whenever possible, as it would avoid unnecessary litigation and result in outcomes that are accepted by all parties. PG&E shall submit any proposed changes to the CLFM to incorporate gas SmartMeter data either as part of a GT&S application or through the filing of a Tier 3 Advice Letter.

Finally we find that the CTAs should be provided detailed gas SmartMeter usage data for their customers to the extent this data can be provided without imposing undue operational burden on PG&E. According to CTAC, PG&E had already indicated its willingness to provide detailed usage data generated by the

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[860] *PG&E Opening Brief* at 18-18.

SmartMeters via "EDI 867" files, but does not yet have plans approved to disclose this customer data.[861] Although PG&E has not provided further detail on the reasons, it appears from a data response that it is likely related to PG&E's "internal discussion to consider the appropriateness of permitting CTAs to view their customer's daily gas consumption."[862]

Notwithstanding this data response, PG&E has stated that it is "amenable to exploring the feasibility of providing individual customers' daily SmartMeter gas reads via EDI 867 files, with the appropriate customer authorization and CTAs' reimbursement of implementation and operating costs."[863] Commercial Energy notes that "PG&E already receives daily SmartMeter reads, though not from all customer meters; forwarding this data to CTAs should be a relatively straightforward process, particularly as gas usage data is not confidential information subject to the debate about third-party status and customer consent in this proceeding."[864] We agree that CTAs are entitled to receive gas SmartMeter usage data for their customers, as that data will be used to provide or bill for gas.[865] To ensure there is no confusion, we clarify here that a Core Transport Agent providing gas aggregation service to customers in accordance with the provisions of Schedule G-CT and the Core Gas Aggregation Service Agreement is a "covered entity", as that term is defined in Gas Rule 27.

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[861] *CTAC Opening Brief* at 43.

[862] Exh. CTA-1, Attachment G (Answer 7.a).

[863] *PG&E Opening Brief* at 18-31.

[864] *Commercial Energy Opening Brief* at 89.

[865] *See* Gas Rule 27.

While PG&E has expressed its willingness to pursue the feasibility of providing SmartMeter gas data to CTAs, we want to ensure that this is done without undue delay. Therefore, within 60 days of the effective date of this Decision, PG&E shall hold a workshop to explore how CTA customer usage data generated by gas SmartMeters may be provided to CTAs, including the format for the data, and the timing for when PG&E shall begin providing the data.

20.2. CTA Procurement of Intrastate Pipeline Capacity and Gas Storage Capacity

Under the current core gas aggregation program, PG&E Core Gas Supply procures intrastate backbone capacity and gas storage assets on behalf of the entire core (bundled customers and customers served by CTAs), with CTAs having the ability to either accept and use their allocation of such assets, or reject their allocation and fulfill their gas supply needs with other resources available in the market.

Under the current regulatory framework, capacity that is declined by the CTAs is marketed to others by PG&E, and the CTAs receive a credit from the sale of that pipeline capacity. If PG&E is unable to recover the full cost of the capacity through these sales, the CTAs are then responsible for paying a portion of the unrecovered cost. In the CTA Settlement Agreement, PG&E and the CTAs agreed that there would be a three-year transition period to move CTAs to taking full responsibility for the capacity that is offered to them but not elected. As of April 2015, the CTAs have assumed full cost responsibility in aggregate for all capacity not elected.[866] As a result, and in light of the increase in CTA served

[866] *Gas Accord V Decision*, Appendix B at 2 (Section 7).

load as a percentage of the entire core load, there has been an increasing financial burden on CTAs.

CTAC and Commercial Energy propose that going forward, Core Gas Supply should only procure intrastate backbone capacity and gas storage capacity to serve PG&E's bundled customers and allow CTAs to contract independently for these services at market prices.[867] Both maintain that adopting this proposal will not result in long-term reliability problems for bundled and CTA-served core customers and is necessary to maintain a competitive market.

20.2.1. CTAC

CTAC notes that its proposal to allow CTAs to manage their own intrastate backbone capacity resources and to utilize independent storage providers to meet their firm storage requirements is consistent with PG&E Gas Schedule G-CT. For example, CTAC notes Gas Schedule G-CT already allows CTAs to use certain assets in place of accepting PG&E's allocation of PG&E's intrastate backbone capacity to meet the Reliability Standard. CTAC states its proposal would provide that if a CTA were to use the assets enumerated in the tariff to meet its Firm Winter Capacity Requirement, PG&E Core Gas Supply would not also reserve duplicative PG&E intrastate backbone capacity.[868] Along the same lines, Schedule G-CT permits a CTA to meet its firm storage requirements by either accepting a share of PG&E's firm storage assets, or certifying that it has procured "Alternate Resources" as a substitute.[869] CTAC

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[867] *CTAC Opening Brief* at 11; *Commercial Energy Opening Brief* at 64.

[868] *CTAC Opening Brief* at 13-14.

[869] *CTAC Opening Brief* at 18.

notes that PG&E Core Gas Supply currently utilizes independent third party storage providers to supply incremental storage to meet the Reliability Standard and has never encountered any problem with delivery of gas from them.[870] Consequently, CTA asserts that self-management of backbone capacity and storage resources would not raise reliability concerns.

CTAC further maintains that the current flexibility provided under Schedule G-CT would be rendered obsolete if PG&E continues to procure backbone capacity for the CTAs "as it is not economically feasible to both pay for PG&E's expensive intrastate backbone capacity, and also to pay for an alternate resource."[871] This would force all CTAs "into the same business model and same procurement strategy as PG&E Core Gas Supply."[872] CTAC asserts the CTA self-management of intrastate transmission capacity and storage resources is necessary to promote a competitive core aggregation market.[873]

Finally CTAC notes that its proposal would not result in shifting of costs to bundled core customers. It states that since PG&E would not be procuring intrastate backbone capacity and/or storage capacity for the CTA, there would be no stranded costs.[874] Moreover, CTAC notes that PG&E is already proposing to reduce its legacy storage holdings, and thus "has demonstrated flexibility in adjusting its storage assets without regard to stranded capital costs."[875]

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[870] *CTAC Opening Brief* at 19.

[871] *CTAC Opening Brief* at 15.

[872] *CTAC Opening Brief* at 25.

[873] *CTAC Opening Brief* at 27.

[874] *CTAC Opening Brief* at 27.

[875] *CTAC Opening Brief* at 28.

20.2.2. Commercial Energy

Commercial Energy also advocates that PG&E no longer procure intrastate backbone capacity and storage services on behalf of CTAs. It asserts that PG&E overallocates capacity to CTAs, which "results in the CTAs incurring significant unnecessary costs and prevents the CTAs from meeting their customers' needs in the most effective manner possible."[876]

Commercial Energy notes that the CTAs have rejected between 25% and 40% of their allocated transmission capacity since 2011 and that in January 2012, the CTAs rejected almost 100% of the capacity allocated to them by PG&E. Commercial Energy believes that the CTAs' rejection of transmission capacity demonstrates that PG&E's allocation methodology is "fundamentally flawed."[877] More importantly, Commercial Energy points out that the amount PG&E is able to recover for rejected CTA storage in the open market has decreased sharply, resulting in CTAs paying stranded costs for a significant portion of the rejected core storage capacity.

Commercial Energy also disputes PG&E's claims that allowing CTAs to procure their own storage and backbone capacity would undermine the reliability of PG&E's system. Commercial Energy notes that PG&E's Schedule G-CT requires sufficient safeguards if a CTA chooses the third party storage or Mission Path options to meet their Firm Winter Capacity Requirement. Further, it notes that under the current tariff, CTAs may not use one capacity reservation to meet both backbone and storage capacity.

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[876] *Commercial Energy Opening Brief* at 64.

[877] *Commercial Energy Opening Brief* at 66.

Commercial Energy further points out that although PG&E already relies heavily on third party storage to ensure it has ample flexible capacity. According to Commercial Energy, this means that PG&E is not only entrusting the ISPs to meet their commercial obligations on PG&E's system, but that PG&E also has significant flexibility to adjust its holdings to match the actual needs of its customers.[878]

Commercial Energy contends "If PG&E continues to impose stranded storage costs on CTAs year after year, the Commission could conclude that PG&E has contacted for more storage than it needs for the core, and PG&E should reduce its investment in such storage over time."[879] Therefore, Commercial Energy proposes that CTAs be responsible for a declining share of unsubscribed capacity costs over a nine-year period. This proposal would ultimately allow CTAs to obtain storage and backbone transmission services at market-based rates. Commercial Energy's proposed transition is discussed on pages 43-46 of Exhibit Commercial Energy-1.

Commercial Energy proposes the same transition period proposed for storage capacity also be applied to intrastate capacity. Commercial Energy recognizes that PG&E's interstate and intrastate pipeline systems coordinate capacity. However, it believes that PG&E's concerns regarding the ability to match interstate and intrastate capacity is unfounded under the proposed transition period. Finally, Commercial Energy acknowledges that interstate pipeline capacity is currently under consideration in A.13-06-011. However, it

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[878] *Commercial Energy Opening Brief* at 69-71.

[879] Exh. Commercial Energy-1 at 39.

believes that "if the decision in A.13-06-011 produces a conflicting outcome with respect to mandatory allocation of capacity to CTAs to the decision issued in this proceeding, the outcomes will of course have to be reconciled."[880]

20.2.3. PG&E

PG&E opposes CTAC and Commercial Energy's proposals. First, PG&E notes that it proposes to hold an amount of intrastate capacity that corresponds to the range of interstate capacity it is required to hold for core customers. According to PG&E, any interstate-intrastate capacity mismatches could limit the usefulness of the interstate capacity. It asserts that the proposal that PG&E no longer hold intrastate capacity for CTAs fails to acknowledge the potential mismatch between interstate capacity and intrastate capacity holdings for the core.[881] PG&E further contends that CTAC provides no evidence to support its claim that having PG&E hold intrastate capacity for CTAs adds to the cost and complexity of CTAs doing business.

PG&E also asserts that the current regulatory framework facilitates the movement of core customers from PG&E service to CTA service, since there is a single intrastate capacity reservation for the entire core market. PG&E refutes CTAC's argument that a cross-over rate would maintain the same benefit if CTAs self-procured intrastate capacity, noting that a cross-over rate does not address reliability and would not "ensure that the core market retains access to

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[880] *Commercial Energy Opening Brief* at 73-74.

[881] *PG&E Opening Brief* at 18-19.

capacity even when operational conditions are strained and/or prices are high."[882]

PG&E next argues that PG&E should continue to procure storage capacity for CTAs. It notes that the storage assigned to CTAs is their pro rata share to ensure adequate gas supply for all core customers on a peak day. PG&E argues that even if CTAs were allowed to use ISP storage capacity to satisfy their obligation, "PG&E would still be the de facto provider of last resort if a CTA or ISP were to fail to perform."[883]

PG&E notes that the record shows that the Independent Storage Providers' (ISP) certificated storage capacity is not representative of actual available capacity. Consequently, it argues the ISPs "have failed to show that they are able to meet the reliability needs of core customers every hour of every day of the year."[884] Finally, PG&E notes that while it is not concerned about whether ISPs have appropriate operational and engineering characteristics to be a reliable incremental source of gas to serve core load, it is concerned whether allowing the CTAs to procure storage capacity from ISPs would allow PG&E to meet real-time gas pipeline operational reliability.[885] For this reason, PG&E states that CTAC and Commercial Energy's proposals should be rejected.

20.2.4. TURN

TURN opposes proposals to eliminate CTA responsibility for pipeline transmission capacity. It maintains that Commercial Energy incorrectly

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[882] *PG&E Opening Brief* at 18-22.

[883] *PG&E Opening Brief* at 18-23.

[884] *PG&E Opening Brief* at 18-24.

[885] *PG&E Opening Brief* at 18-24 – 18-25.

concludes that PG&E overprocures capacity, and asserts that PG&E's holdings of intrastate pipeline capacity are designed to match its upstream interstate capacity.[886] TURN further argues "If the Commission finds in A.13-06-011 that CTA should be included in calculating the interstate pipeline procurement range, then a decision in this case that finds PG&E should not hold intrastate pipeline capacity for CTA load would leave PG&E holding excess intrastate pipeline capacity."[887]

TURN further notes that PG&E's 1-in-10 reliability standard ensures that sufficient gas flows into storage during the summer so that there is enough gas to meet "peak demand." Thus "a peak load reliability standard will, by definition, result in 'excess assets' during some of the time", and paying for these excess costs is part of paying for reliability.[888] TURN asserts that adopting CTAC and Commercial Energy's proposals would result in the CTAs not paying for the assets necessary for reliability and shifting all reliability costs to bundled core customers. Thus, TURN urges that the Commission reject these proposals.

20.2.5. Independent Storage Providers

Central Valley Storage LLC, Gill Ranch Storage LLC and Wild Goose Storage LLC (jointly, the "independent storage providers" or "ISPs") support CTAC's proposal that CTAs be allowed flexibility to procure storage resources from either PG&E or from ISPs. They note that ISPs provide reliable storage service as they "maintain storage facilities and related equipment that is

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[886] *TURN Opening Brief* at 215.

[887] *TURN Opening Brief* at 216.

[888] *TURN Opening Brief* at 217.

sufficiently reliable to ensure that the volumes of gas contracted by firm service customers, such as CTAs, can be delivered to and received from PG&E's system under a wide range of circumstances."[889] In addition to discussing the design aspects and maintenance and operation practices to ensure reliable service, the ISPs state that they offer service at market-based rates that are typically lower than the rates offered by PG&E to the CTAs.[890]

The ISPs further note that they are public utilities subject to Commission regulation and their obligation to serve is consistent with the demands of the market. The ISPs argue that similar to PG&E, their obligation to serve "carries with it strict requirements regarding the ability to sell/transfer their facilities, reduce their capacity or exist the storage business." Further, the ISPs assert that PG&E's arguments should be given no weight since its witness "had no basis, legal or otherwise, for his written testimony on this matter."[891]

The ISPs further dispute PG&E's claim that there are reliability issues associated with CTAs' receipt of storage services from ISPs. They note that their certificated storage capacity of 130.5 Bcf exceeds the 33.5 Bcf of working gas capacity PG&E holds to serve the entirety of the core market.[892] Therefore, they argue there is sufficient redundancy in the market to assure that the needs of the core storage are met. Moreover, the ISPs contend that PG&E incorrectly assumes

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[889] *ISP Opening Brief* at 10.

[890] *ISP Opening Brief* at 10-13.

[891] *ISP Opening Brief* at 15.

[892] *ISP Opening Brief* at 16.

that the necessary gas to backstop the failed delivery from one ISP would come from PG&E's own storage.[893]

20.2.6. Discussion

A central consideration in determining whether to grant CTAC and Commercial Energy's proposals is the potential impact on safety and the ability of the CTAs to serve their customers in the event of future price fluctuations or turmoil in the gas market. We considered similar arguments with respect to PG&E's procurement of interstate pipeline capacity on behalf of CTAs and concluded that due to reliability and safety concerns, PG&E should continue to procure interstate capacity for CTAs, reasoning "It is not appropriate at this time to discharge PG&E of its responsibility to hold pipeline capacity on behalf of the customers of the CTAs until there are rules in place for ensuring that the CTAs have sufficient resources to meet their customers' obligations.[894]

We find that the same reasoning articulated in the *Interstate Pipeline Capacity Decision* – the need for system reliability and safety – applies to the procurement of interstate pipeline capacity. Moreover, PG&E has testified to the need for intrastate capacity to correspond to the range of interstate capacity it is required to hold for core customers to ensure efficient operation of its pipeline system. Given the complementary nature of interstate and intrastate pipeline capacity, we decline to adopt CTAC and Commercial Energy's proposals that PG&E no longer procure intrastate capacity on behalf of the CTAs at this time.

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[893] *ISP Opening Brief* at 18.

[894] *Interstate Pipeline Capacity Decision* [D.15-10-050] at 22-27.

We note that in the *Interstate Pipeline Capacity Decision*, we reduced PG&E's interstate pipeline capacity planning range. We expect that this lower range will result in a corresponding decrease in intrastate capacity procured for core customers.

We adopt, however, CTAC and Commercial Energy's proposals that PG&E no longer procure storage services on behalf of the CTAs. The record demonstrates that PG&E already relies on third party storage to meet its winter load. The ISPs are public utilities subject to Commission regulation and have a corresponding obligation to serve; their contracts to provide firm storage services to their customers are no different than PG&E's. As such, we do not find that PG&E's arguments concerning the reliability of ISPs persuasive, especially when PG&E also utilizes their services.

We further do not have the same concerns with respect to reliability of storage as with intrastate capacity. Schedule G-CT requires that CTAs rejecting PG&E's firm storage allocation must certify that they have amounts equivalent to the rejected withdrawal capacity. "Gas in storage, for the purpose of providing core reliability, including gas stored using the Allocated Storage, may not incur encumbrances of any kind."[895] Thus, storage services for purposes of reliability are subject to the same requirements regardless of whether the services are provided by PG&E or a third party.

We further find that allowing CTAs to plan and procure storage services on their own is consistent with the Commission's overall objectives to create a competitive natural gas storage market and to provide utility customers the

[895] Gas Schedule G-CT, Sheet 10.

option to purchase gas supplies directly from CTAs rather than the investor-owned utility. Under the current construct, PG&E is in a position to influence the development of both a third-party storage market and a core aggregation program, due to the potentially significant financial consequences to CTAs if they were to reject PG&E's allocation of storage services. Since PG&E competes with both ISPs and CTAs, we should ensure that its ability to impact the growth of these markets is reduced. Consequently, we conclude that the procurement of storage services for CTAs should transition from PG&E to the CTAs themselves.

We find that this transition should occur over a ten-year period, commencing on January 1, 2018. This transition would have PG&E reduce the amount of storage that it procures and allocates to each CTA by 10% the first year (2018), increasing the amount to be reduced by an additional 10% each subsequent year until PG&E no longer procures any storage services on behalf of the CTA. During this transition period, the CTA may still reject some or all of the PG&E-allocated core firm storage capacity, but will be responsible for those stranded costs. The CTA's procurement of storage capacity for the amount that is not allocated by PG&E may be from PG&E or a Commission-certified independent storage provider. Energy Division shall host a workshop for PG&E, the CTAs and consumer groups to address changes to Schedule G-CT to implement this transition. The workshop shall be held within 90 days after the effective date of this Decision. PG&E file a Tier 2 Advice Letter proposing any changes to Schedule G-CT agreed upon by the parties.

20.3. Modifying the Firm Winter Capacity Requirement

Gas Schedule G-CT provides CTAs with the choice of fulfilling the Firm Winter Capacity Requirement by accepting PG&E's allocation of PG&E intrastate

backbone capacity, or with any combination of the following gas assets specified in the tariff:

1. Under the terms of Schedules G-SFT or G-AFT, contract with PG&E for all or part of the CTA's path-specific proportionate share of firm Backbone pipeline capacity PG&E has reserved for Core End-Use Customers.

2. Contract with a party other than PG&E for guaranteed use of that party's firm Backbone pipeline capacity or for guaranteed use of that party's firm PG&E storage capacity and withdrawal rights in conjunction with Mission Path capacity under Schedules G-AA or G-NAA.

3. Contract with PG&E for firm Backbone pipeline capacity or firm storage capacity and withdrawal rights in conjunction with Mission Path capacity under Schedules G-AA or G-NAA.[896]

CTAC proposes that the second and third options above be modified to permit the use of third-party firm storage capacity for purposes of complying with the Firm Winter Capacity. PG&E does not oppose this proposed modification. We find the proposed modification to the second and third options to comply with Firm Winter Capacity to be reasonable. CTAC's proposal is adopted.

CTAC further proposes that a fourth option be added to permit CTAs to contract with a party other than PG&E demonstrating firm gas delivery to the PG&E Citygate. PG&E opposes this modification. It notes that the current three options "all require holding actual firm backbone pipeline or PG&E storage capacity, or having a firm agreement with a third-party guaranteeing use of their

[896] Gas Schedule G-CT at Sheet 9.

actual firm backbone pipeline or PG&E storage capacity."[897] PG&E maintains that CTAC's proposal does not require firm capacity to be held at PG&E's Citygate and thus, would not provide a similar level of protection to core customers as the existing options.[898] Therefore, PG&E contends that CTAC's proposal should be rejected.

We have considered the arguments and find that CTAC's proposal to add a fourth option is reasonable, subject to a modification in response to a concern raised by PG&E. While we agree that CTAs should be provided additional flexibility in the types of gas assets that can be used to meet their Firm Winter Capacity Requirement, CTAs must meet the reliability needs of core customers. We agree with PG&E that a gas supplier cannot just promise to provide gas at PG&E's Citygate – it must demonstrate that it is able to deliver the gas contracted.

Accordingly, PG&E shall file a Tier 1 Advice letter to modify Gas Schedule G-CT at Sheet 9 to add a fourth option for a CTA to satisfy its Firm Winter Capacity Requirement. This option shall state: "A CTA may meet the Firm Winter Capacity Requirement by contracting with a party other than PG&E demonstrating firm gas delivery to the PG&E Citygate. 'Demonstrating firm gas delivery' cannot be met by providing a letter from the firm gas supplier guaranteeing Citygate delivery. " Additionally, a CTA exercising Option 4 to satisfy the Firm Winter Capacity requirements for any winter month shall be

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[897] *PG&E Opening Brief* at 18-26.

[898] *PG&E Opening Brief* at 18-26.

required to submit, within five days of notification, an executed *Declaration of Alternate Winter Capacity* (Form No. 79-845, Attachment J).

20.4. Billing and Operational Issues

Under existing Commission policies a CTA may choose among three billing service options for each customer: 1) PG&E and the CTA send their own bills and collect their own charges from customers; 2) the CTA handles the billing and collection of its own charges and PG&E's charges associated with gas service; and 3) PG&E handles the billing and collection of its own charges and the CTA's charges. CTAC and Commercial Energy have raised several challenges with respect to PG&E's practices when it handles the billing and collection of its own charges and the CTA's charges (PG&E Consolidated Billing).

20.4.1. Allocation of Partial Payments for Past Due Accounts

PG&E's Gas Rule 23 provides that partial payments shall be allocated "proportionately" among CTA and PG&E charges, unless the account is delinquent as specified in PG&E's Rule 11.[899] Rule 11.D provides that bills are considered past due if payment is not received by PG&E within 19 days after the bill is mailed to the customer. CTAC maintains that notwithstanding the requirements of Gas Rule 23.C.1.c.5.b, "PG&E has implemented a policy whereby all partial customer payments are first applied to pay off PG&E's charges immediately upon the expiration of 21 days from the date PG&E mails a bill to a customer."[900]

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[899] Exh. TURN-81, Sheet 10 (Gas Rule 23.C.1.c.5).

[900] *CTAC Opening Brief* at 32-33.

CTAC argues that because Gas Rule 8 requires various steps (*e.g.*, 15 day mailed notice, 48 hour mailed notice and 24 hour in person or telephone notice), a delinquent customer cannot be considered for disconnection until these (and other) steps are taken.[901] Thus, under CTAC's analysis, payments received before all of these steps are taken must be proportionally allocated. Commercial Energy argues for the same result by asserting that "disconnection is a completely voluntary action by PG&E," that pro-rata allocation of all payments would not violate any provision of Rule 23 or Commission precedent," and that equity favors pro-rata allocation so that PG&E and a CTA are treated the same.[902]

PG&E refutes CTAC's and Commercial Energy's arguments, citing to various Commission decisions adopting measures aimed at minimizing the number of residential service disconnections due to nonpayment.[903] PG&E further disputes CTAC's arguments that PG&E must wait until the account has reached the point of disconnection before applying residential payment allocation. It notes that "the effect of this proposal is to apportion a larger percentage of customers' late payments to CTAs, even though these CTA's charges cannot lead to service disconnection."[904] PG&E believes that such an interpretation is inconsistent with Gas Rule 23 and is not in the customer's best interest.

TURN urges the Commission to reject CTAC's and Commercial Energy's proposal to change the allocation of residential payments between PG&E charges

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901 *CTAC Opening Brief* at 32-36.

902 *Commercial Energy Opening Brief* at 87-89.

903 *PG&E Opening Brief* at 18-31 – 18-32 (citing D.97-10-087 and D.05-12-041).

904 *PG&E Reply Brief* at 18-21.

and CTA charges for past due accounts. It notes that Pub. Util. Code § 779.2 prohibits PG&E from terminating residential service for nonpayment of any delinquent account. Since only delinquent PG&E charges may result in discontinuance of service, PG&E must first allocate a partial payment on a delinquent account to PG&E charges.[905]

United Energy Trading LLC (UET) further accuses PG&E of using at least two other criteria in designating accounts as delinquent – PG&E's accounting system will perform a "look back" to identify accounts which have a history of late payment and will examine whether the CTA carries a balance. UET asserts that in both instances, PG&E's accounting system will flag the customer as delinquent, even if the customer's current payment is in full and on time. Therefore, UET recommends that the Commission "direct PG&E to cease this policy and provide CTAs with a pro rata share of customer payments unless an account is subject to service termination pursuant to Gas Rules 8 and 11."[906]

CTAC and Commercial Energy have suggested that PG&E has acted improperly and/or in violation of Gas Rule 23 by applying partial payments to PG&E charges first because a customer who has not paid its bills to a CTA may continue to receive gas service. However, as TURN notes, this would still be the case if the CTA separately billed the customer for its own charges. The Commission has adopted over the years various measures to protect customers from service disconnections. The provisions in Gas Rule 23 further that policy. As such, we reject CTAC and Commercial Energy's proposal to change Gas Rule

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[905] *TURN Opening Brief* at 219.

[906] *UET Reply Brief* at 5.

23 to allocate partial payments on past due accounts pro rata between PG&E charges and CTA charges.

Finally, we note that, consistent with Gas Rule 23.C.1.c.5.b, a partial payment received by PG&E within 19 days after the bill is mailed to the customer is not considered past due, nor subject to potential service disconnection. In those instances, PG&E shall allocate the partial payment pro rata between PG&E charges and CTA charges. We agree with UET that PG&E should only allocate partial payments to PG&E charges first when the account is subject to service termination pursuant to Gas Rules 8 and 11. PG&E should not be designating accounts as "delinquent" simply based on a CTA customer's history of late payment or because the CTA carries a balance.

20.4.2. Access to Customer Information

PG&E's provides PG&E Consolidated Billing services to CTAs under Gas Rule 23. CTAC states that while this option allows CTA customers to receive one bill from the utility for distribution and commodity service, PG&E has unreasonably limited the amount of basic billing information that it will share with the CTAs.[907] Commercial Energy complains that PG&E considers CTAs to be third parties and thus "claims customer privacy justifies withholding billing and payment information from CTAs regarding their own customers."[908]

PG&E contends that the CTAs are seeking unauthorized disclosure of PG&E-specific information, specifically credit information for customers who agreed to debt repayment plans and payment information for PG&E's electric

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[907] *CTAC Opening Brief* at 36.

[908] *Commercial Energy Opening Brief* at 74.

charges and gas distribution charges.[909] PG&E maintains that consistent with Commission precedent and California law concerning the privacy of customer usage and billing data, this information is confidential and cannot be released without written customer authorization.[910] As support, PG&E cites to *Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company* [D.11-07-056], *Decision Extending Privacy Protections to Customers f Gas corporations and Community Choice Aggregators, and to Residential and Small Commercial Customers of Electric Service Providers* [D.12-08-045] and *Decision Authorizing Provision of Customer Energy Data to Third Parties Upon Customer Request* [D.13-09-025]. PG&E next maintains that the CTAs have failed to prove that the requested disclosures are warranted without customer consent.

Both CTAC and Commercial Energy assert that PG&E incorrectly relies on Rule 23.E.1.h for the proposition that CTAs are third parties that must have separate written authorization in order to receive their own customers' payment and billing information. CTAC cites to Gas Sample Form No. 79-845A, the *Core Gas Aggregation Service Agreement -- ATTACHMENT A - Customer Authorization for Core Gas Aggregation Service* for the proposition that since it authorizes the CTA to obtain natural gas for the customer, it includes authorization to release "current and historical gas usage information."[911] Commercial Energy maintains that since the CTAs have contracted with PG&E for consolidated billing services,

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[909] *PG&E Opening Brief* at 18-29.

[910] *PG&E Opening Brief* at 18-35.

[911] *CTAC Opening Brief* at 39.

"the CTA, PG&E, and the customer have interlocking contractual relationships."[912] Given those three relationships, CTAC disagrees with PG&E's assertion that the CTAs have a third-party relationship with their own customers.[913]

Commercial Energy further notes that while PG&E Consolidated Billing "requires CTAs to delegate billing and collections activities to PG&E, … PG&E uses its agency to justify keeping CTAs completely uninformed as to payment plan and partial payment issues."[914] It notes that in an ALJ Ruling in a separate complaint proceeding, the ALJ found that "so long as UET is seeking only information regarding its own customer accounts, and no provision of law prohibits PG&E from complying with those information requests, PG&E is obligated to turn over to [UET] the customer account information in its possession."[915] UET further notes that there is no actual privacy interest at issue since the CTA "already knows the customer, knows how much he owes, and knows that payment is overdue."[916]

We find PG&E's arguments unconvincing. Form 79-845A, the *Core Gas Aggregation Service Agreement -- ATTACHMENT A - Customer Authorization for Core Gas Aggregation Service* establishes buyer/seller relationship between a CTA and a core customer.[917] This agreement specifically states:

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912 *Commercial Energy Opening Brief* at 76.

913 *Commercial Energy Opening Brief* at 75 – 78.

914 *Commercial Energy Opening Brief* at 78.

915 *Commercial Energy Opening Brief* at 78 (citing Exh. Commercial Energy 29 at 4).

916 *UET Reply Brief* at 7.

917 Exh. TURN-81.

> CTA shall be considered an Agent for the Group, and for individual Group members, who are Core End-Use Customers receiving transportation service and who have selected the CTA as their gas supplier, pursuant to Schedule G-CT.[918]

Under the California Civil Code, "An agent is the one who represents another, called the principal, in dealings with third persons. Such representation is called agency."[919] An agent has authority to "do everything necessary or proper and usual, in the ordinary course of business, for effecting the purpose of his [sic] agency; … ."[920]

Here, Form 79-845 makes clear that a CTA is the agent for the core customer (who is the principal) and thus has the right to all information related to the purpose of the agency, which would include the complete billing information. While Form 79-845A explicitly refers to disclosure of a CTA customer's current and historical gas usage to the CTA, the CTA, as an agent for the core customer, is also entitled to the customer's billing information. As discussed below, we find that Form 79-845A should be revised to make customer consent regarding disclosure of this information more explicit.

We further find that adopting PG&E's interpretation, that CTAs are third parties, would contradict portions of Pub. Util. Code § 985. Section 985(a) requires CTAs to maintain the confidentiality of its customers' information, including "customer-specific billing, credit, or usage information." Further, a CTA is required to "provide on all customer bills a telephone number by which

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[918] Exh. TURN-81, Sample Form No. 79-845.

[919] Civil Code § 2295.

[920] Civil Code § 2319(1).

customers may contact the core transport agent to report and resolve billing inquires and complaints."[921] Adoption of PG&E's position would effectively nullify these legislative directives.

Further, PG&E's argument fails for a more practical reason. As previously discussed, a CTA has three billing options and the issues raised by the CTAs pertain to the option where PG&E bills for the natural gas and the delivery of that gas. If, however, the CTA opts to handle the billing for both PG&E's charges and its own or to bill for its charges separately, it would have access to all of the customer billing information at issue here. We find no reason why a CTA is permitted access to its own customer's information in one billing situation but not another.

In sum, a CTA is an agent of its core customers and, for purposes of billing those core customers; PG&E is an agent of the CTA when it is doing the combined billing on behalf of the CTA. All information available to the core customer, thus, must be made available to the CTA.

20.4.3. Payment Plan Notice and Negotiation

In connection with access to CTA customer billing information, CTAC and Commercial Energy further argue that PG&E should inform the CTAs when joint CTA-PG&E customers have been given payment plans.[922] They believe this information should include amounts billed to the customer, customer payments and PG&E's application of such payments to various components of the bill.

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[921] Pub. Util. Code § 985(e).

[922] *CTAC Opening Brief* at 41; *Commercial Energy Opening Brief* at 80.

Commercial Energy further asserts that this information should be provided on a rolling basis for each billing cycle until the payment plan has been completed.

CTAC maintains that CTAs and customers are harmed by PG&E's practice of not informing the CTA when a customer has made a partial payment or negotiated a payment extension or payment plan with PG&E. It notes that without basic and necessary billing data, CTAs are unable to provide effective service to their customers.[923]

PG&E argues that CTAs are third parties with respect to PG&E. It further notes that release of PG&E Account Information is limited pursuant to Gas Rule 9M and Affiliate Rule IV.[924] Consequently, PG&E asserts that it cannot disclose customer billing information, including any negotiated payment plans, without first obtaining customer consent. PG&E maintains that Form 79-845A cannot be interpreted as authorizing disclosure of credit information, such as payment plans.[925] It further notes that Form 79-1095 – *Authorization to Receive Customer Information or Act Upon a Customer's Behalf* clearly explains the scope of information that will be disclosed a third party and limits a third-party's authority to a three-year period.[926] PG&E further disputes CTAC's claim that it provides no information to the CTAs and lists a variety of reports it provides to the CTAs on a daily or monthly basis.[927]

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[923] *CTAC Opening Brief* at 40.

[924] *PG&E Opening Brief* at 18-36.

[925] *PG&E Opening Brief* at 18-39.

[926] *PG&E Opening Brief* at 18-38.

[927] *PG&E Opening Brief* at 18-41 – 18-42.

TURN believes that the issues raised by the CTAs highlight an apparent lack of communication between the CTAs and PG&E. TURN states "both parties contribute to the problem through their policies and actions, and change is appropriate on both sides."[928] TURN puts forth four recommendations to the customer consent issues. First, TURN contends that because "Form 79-845A does not inform customers that they are giving the CTA access to their credit-related information, that form cannot act as a substitute for Form 79-1095 for CTA customers."[929] TURN therefore recommends that CTAs be required to use Form 79-1095 "unless and until the Commission approves an alternate approach."[930]

Second, TURN recommends that PG&E should work with interested CTAs to redesign Form 79-845A to incorporate the contents of Form 79-1095 pertaining to the types of information of most concern to the CTAs. "This revision to Form 79-845A should be designed to encourage customers who will receive Consolidated PG&E Billing to consent to additional information disclosure, but not necessarily to encourage all CTA customers to give their CTAs access to their PG&E payment and credit information."[931]

Third, TURN recommends that PG&E should be directed to work with interested CTAs to improve its internal policies regarding the provision of

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[928] *TURN Opening Brief* at 226.

[929] *TURN Opening Brief* at 231.

[930] *TURN Opening Brief* at 229

[931] *TURN Opening Brief* at 231-232.

information and data regarding customer payments, when customer consent has been provided.[932]

Finally, TURN recommends that the CTAs educate new customers about the importance of contacting the CTA in the event that the customer has fallen behind on payments but is working with PG&E to catch up.[933]

TURN's recommendations are supported by PG&E.[934] CTAC generally opposes TURN's recommendations. CTAC believes that it is unnecessary to redesign Form 79-845A to include an authorization for the disclosure of negotiated payment plan information. However, if the Commission agrees with TURN on this point, "CTAC requests that the Commission direct PG&E to disclose the information at issue pending any revisions to Gas Form 79-845A."[935] Commercial Energy also supports TURN's recommendation to revise or eliminate Form 79-845A and Form 79-1095. Commercial Energy believes Form 79-845A should be amended to include a release of billing and payment information by the customer to the CTA. "Incorporating this release would help streamline the CTA-Customer-PG&E relationship by removing several barriers to effective communication and eliminating Form 79-1095, which contains conflicting provisions and has been a barrier to some CTAs obtaining customer consent to access billing information."[936] Commercial Energy opposes TURN's

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[932] *TURN Opening Brief* at 232.

[933] *TURN Opening Brief* at 233.

[934] *PG&E Reply Brief* at 18-23.

[935] *CTAC Reply Brief* at 35.

[936] *Commercial Energy Reply Brief* at 52-53.

recommendation that CTAs should educate their customers about the requirement to contact the CTA if the customer falls behind on payments.

We have considered the arguments put forth by the parties and conclude that although Form 79-845A establishes the agency relationship between the CTA and its customer, the form does not explicitly inform customers that they are giving the CTA access to their credit-related information. Therefore, PG&E should work with interested CTAs to redesign Form 79-845A to authorize PG&E to release a CTA customer's billing and payment information, including any negotiated payment plans entered into between the customer and PG&E for payment of past due or delinquent CTA charges, to the CTA. Within 90 days of the effective date of this Decision, PG&E shall file a Tier 2 Advice Letter, which will describe the process it undertook to revise Form 79-845A with interested CTAs and proposing a revised Form 79-845A.

While CTAC has requested that the Commission direct PG&E to disclose the information at issue pending the revision of Form 79-845A, we decline to do so without customers first being informed of and acknowledging that by authorizing a CTA to act on the customer's behalf in obtaining natural gas under the Core Natural Gas Aggregation Service tariffs, the customer has authorized PG&E to provide the CTA with the customer's billing and payment information related to the provision of such service, including information regarding payment plans entered into for the payment of debts owing for such service. Until Form 79-845A is revised, a CTA may obtain an acknowledgement of disclosure of billing information through a letter or other form. Once that acknowledgement is received by PG&E, PG&E shall provide the CTA customer's billing and payment information to the CTA.

As discussed above, given the agency relationship between the CTA and its customer, the CTA is not a "third party." As such, Form 79-1095 is not applicable to CTAs.

Commercial Energy also requests that PG&E include the CTA in any negotiations of payment plans.[937] Commercial Energy argues that by not knowing the details of a payment plan, it is left in the dark when it receives payments on an account do not match the customer's usage. Commercial Energy also posits that including a CTA in the payment plan negotiation process will increase transparency of that process.

We reject this proposal as introducing too many additional burdens on consumers to the late payment negotiation process. Additionally, Gas Rule 23.C.1.c.5.a specifically provides "PG&E is responsible for collecting the unpaid balance of all charges from Customers, sending notices informing Customers of unpaid balances, and taking the appropriate actions to recover the unpaid amounts owed the CTA."[938] We do not believe any change in this provision is necessary, especially in light of our determination above.

Finally, because we have now clarified the information that PG&E should provide to CTAs, PG&E should meet with CTAs to determine whether the various reports identified on page 18-42 of *PG&E Opening Brief* need to be revised. PG&E may propose revisions to these reports in its next GT&S application.

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[937] CEofE Opening Brief at pp. 81-84.

[938] Exh. TURN-81, Gas Rule 23, Sheet 14.

21. Programs Directed Towards Small and Medium Sized Businesses

The California Asian Pacific Chamber of Commerce (CAPCC) put forth various proposals to expand the low income California Alternate Rates for Energy (CARE) program to include the smallest of the small commercial customer class, enhance outreach and program availability relating to energy efficiency incentives, expand the Economic Development Rate to gas, and to consider Demand Response or Time-Varying programs for natural gas customers.[939] PG&E opposed these proposals, arguing they are outside the scope of this proceeding.

On September 3, 2015, CAPCC filed a motion to withdraw as a party from this proceeding. CAPCC states that it is "actively working with PG&E outside of this proceeding to address the issues it has raised in this proceeding" and therefore no longer believes it is necessary to maintain party status.[940] CAPPC's motion is supported by PG&E.

CAPCC's motion is granted.

22. Application of $850 Million Penalty for Future Pipeline Safety Improvements

As discussed above, the *Penalties Decision* required PG&E shareholders to absorb the cost of future transmission pipeline safety enhancements in the amount of $850 million, to apply to pipeline safety enhancements to be approved in this proceeding and any subsequent GT&S proceeding, if necessary. Only costs that PG&E would have been granted rate recovery for in the GT&S, but for

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[939] Exh. CAPCC-1 & Exh. CAPCC-2.

[940] *Motion of California Asian Pacific Chamber of Commerce to Withdraw from Party Status*, filed September 3, 2015, at 1-2.

the *Penalties Decision*, count towards the $850 million. Therefore, any disallowances adopted in this Decision are not to be applied towards the $850 million penalty.

Of the $850 million penalty, up to $161.5 million would be applied against items that are expensed for projects or programs, and a minimum of $688.5 million would be applied to capital expenditures.[941] The amounts to be removed from expenses and capital expenditures would be tracked in a Shareholder Funded Gas Transmission Safety Account, which consists of two subaccounts – one for Expense and one for Capital Expenditures.[942]

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 on December 17, 2015, directed PG&E to make certain revisions through a supplemental advice letter. Advice Letter 3596-G-A was filed on December 31, 2015. The Supplemental Advice Letter was approved on March 7, 2016. With the establishment of the Shareholder Funded Gas Transmission Safety Account and its two subaccounts, PG&E may record costs incurred after on or after January 1, 2015 for designated safety-related programs and projects into these accounts.

The *Penalties Decision* defines "safety related capital expenditures" as "any capital expenditure to replace, repair, or upgrade transmission lines, unless the work is for the purpose of serving new load."[943] "Safety related expenses" is defined as:

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[941] *Penalties Decision* at 94-95 (*slip op.).*

[942] *Penalties Decision* at 96 (*slip op.).*

[943] *Penalties Decision* at 96 (*slip op.).*

> (i) costs for safety inspections and testing of transmission pipeline; (ii) any costs for repairing or replacing transmission lines that are properly expensed, and (iii) projects or programs to improve transmission line record-keeping, including GIS equipment and systems, but excluding any items that shareholders were required to fund by the PSEP Decision (D.12-12-030 in R.11-02-019).[944]

Based on these definitions, PG&E identified the safety-related gas transmission projects and programs in the GT&S rate case forecast that should be recorded in the Shareholder Funded Gas Transmission Safety Account and its two subaccounts.[945]

Appendix E reflects the authorized 2015 expenses and capital expenditures, and 2016 and 2017 expenses and capital additions based on the PTYR escalation rates. Based on the information presented in Appendix E, all of the $850 million penalty adopted in the *Penalties Decision* will be used during this Rate Case Cycle.

In the *Second Amended Scoping Memo*, we noted that parties had asserted that the prioritization of programs and projects cannot be made until a final decision on authorized revenue requirement was issued. It appears, however, that the basis of this concern was to have a discrete list of disallowances for capital projects to ensure that disallowed projects did not get rolled into ratebase. We believe that it would be appropriate to allocate the $850 million as follows:

1. In 2015, all safety-related capital additions ($427.977 million) would be funded by PG&E shareholders.

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[944] *Penalties Decision* at 96 (*slip op.*).

[945] *Response of Pacific Gas and Electric Company to Administrative Law Judge's Ruling Requiring Information to Implement the San Bruno Penalty Decision*, filed June 1, 2015, Appendix B.

2. In 2016, the safety-related capital additions for the following programs would be PG&E shareholders: ILI (PTYR specific adjusted), hydrostatic testing and vintage pipeline replacement ($262.191 million).
3. In 2015, $157.831 million of safety-related expenses would be funded by PG&E shareholders.

Appendix G presents the impact of applying the $850 million penalty on the Results of Operations and Post Test Year Ratemaking models, as well as illustrative rates, based on the above proposed allocation.[946] Pursuant to the *Penalties Decision*, the amounts allocated to the specific programs (and any sub-programs) are the maximum amounts that could be recorded to the Shareholder Funded Gas Transmission Safety Account and its two subaccounts, and PG&E shall not apply underspending in one program or sub-program to offset overspending in another program or sub-program.

If the above allocation is adopted as part of this Decision, a second decision will not be necessary. If this occurs, PG&E's new rates may be implemented upon the filing of a Tier 1 Advice Letter (subject to Energy Division review). If a second decision is needed, it would take at least two months before final rates would be put into effect. Therefore, as part of comments on this proposed decision, we ask parties to respond to the proposed allocation and our proposal to resolve all issues in a single decision. If parties believe a second decision is still necessary, they should include in their comments the specific factual issues that need to be addressed and a proposed schedule.

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[946] This will also result in a change in the system load factor, as presented in Appendix G, Table G-34.

23. Amortization of Revenue Requirement

In *Decision Granting January 1, 2015 Effective Date for Pacific Gas and Electric Company's Test Year 2015 Revenue Requirement* [D.14-06-012], the Commission granted PG&E's motion that its GT&S revenue requirement be effective as of January 1, 2015 and subject to interest based on the Federal Reserve three-month commercial paper rate.[947] On August 29, 2014, the Commission approved PG&E Advice Letter 3496-G, which established a memorandum account to record the differences between PG&E's interim 2015 revenue requirements for its gas transmission and storage operations and services and the revenue requirements ultimately adopted in this Decision.

In its response to PG&E's motion, Shell Energy had expressed concern over the rate shock that may result based on the amount of time to amortize the adopted revenue requirement. Therefore, we determined that our decision authorizing PG&E's revenue requirement would address the amortization period to be used. Based on the revenue requirement adopted in this decision, we find that the difference between the authorized revenue requirements in this decision and the placeholder revenue requirement incorporated in gas rates PG&E has collected in the Gas Transmission and Storage Memorandum Account should be amortized over 18 months.

24. Motions

As expected from a proceeding of this complexity and high level of contention, parties have made numerous requests and filed a large number of motions. The assigned ALJ has issued filed, electronic and oral rulings in

[947] D.14-06-012 at 7-8 (Ordering Paragraphs 2 & 3).

response to these motions. This Decision confirms all rulings issued in response to the motions.

Additionally, PG&E has filed two motions seeking to file certain confidential information contained in notices of communications under seal. The protected materials in the confidential, unredacted version of PG&E's notices are described in the motions. PG&E's motions are unopposed and are granted. Accordingly, the confidential, unredacted version of the following notices of communication shall remain under seal and shall not be made accessible or disclosed to anyone other than the Commission staff except on the further order or filing of the Commission, the assigned ALJ, or the ALJ then designated as Law and Motion Judge:

- *Motion of Pacific Gas and Electric Company for Leave to File Confidential Material in Notice of Communication Under Seal Under Rule 11.4*, filed January 5 2016 [communication with Energy Division Director]
- *Motion of Pacific Gas and Electric Company for Leave to File Confidential Material in Notice of Communication Under Seal Under Rule 11.4*, filed April 14, 2016 [communication with Energy Division Director]

Unless specifically discussed in this section, all outstanding motions filed in this proceeding that have not yet been ruled on are hereby denied.

25. Transcript Corrections

On April 22, 2015, parties submitted proposed corrections to the hearing transcripts. The proposed corrections are contained in Appendix K of this Decision. None of the proposed corrections were opposed. Accordingly, the proposed corrections filed by the following parties are granted:

- PG&E

- TURN
- ORA
- Calpine
- NCGC
- CTAC
- SPURR
- Commercial Energy
- Dynegy

26. Comments on Proposed Decision

The proposed decision of ALJ 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 _____.

27. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Amy Yip-Kikugawa is the assigned ALJ in this proceeding.

Findings of Fact

1. Since PG&E's last GT&S application, there have been significant legislative and regulatory changes mandating a greater priority on safety
2. PG&E's gas assets are divided into asset families.
3. This is the first GT&S case where PG&E is required to develop a revenue requirement explicitly based on risk.
4. PG&E's risk management program is evolving.

5. In D.14-12-025, the Commission established two new procedures, which feed into the GRC applications in which the utilities request funding for such safety-related activities: (1) the filing of a Safety Model Assessment Proceeding (S-MAP) by each of the large energy utilities, which are to be consolidated; and (2) a subsequent Risk Assessment Mitigation Phase.

Transmission Pipe

6. PG&E's use of ILI is significantly lower than the industry.

7. PG&E has adopted a 10-year plan to upgrade the system in order to in-line inspect over 4,273 transmission pipeline miles by the end of 2024.

8. PG&E's ILI program over the rate case period is designed to upgrade 531 miles to accommodate traditional and non-traditional ILI tools and inspect over 885 miles using traditional ILI tools.

9. Under the PSEP program, PG&E's pace for making its pipelines piggable was 48 miles per year.

10. PG&E proposes to convert an average of 162 miles per year to accommodate traditional ILI tools and 15 miles per year to accommodate the use of non-traditional ILI tools during the Rate Case Period.

11. The Gas Transmission Systems' study fully explains the work performed.

12. PG&E has provided sufficient evidence that none of the ILI and Direct Assessment work proposed during this Rate Case Period include costs to address prior violations and findings.

13. Starting in 2015, PG&E defines pipelines using the definition of transmission pipelines in 49 CFR 192.3, resulting in defining an additional 920 miles as transmission, rather than distribution.

14. PG&E's listing of actual January-June 2013 ECDA projects and estimates show an average ratio of 4.5 digs to projects.

15. Because PG&E rounds up partial digs in its forecast, PG&E average ratio is 6.8 digs to projects.

16. PG&E does not separately track immediate indications between those found in the baseline assessments and those found in the reassessments for ECDA.

17. PG&E forecast costs for hydrostatic testing includes approximately 47 miles of pipe installed between 1956 and 1961 that do not have a corresponding pressure test record.

18. PG&E's response to TURN Data Request 30, Question 2, which reflects the correct effective date of GO 112, shows that 98 miles of pipe installed between January 1, 1956-June 30, 1961 do not have pressure test records.

19. PG&E has confirmed ratepayers will not bear the costs of testing the post-1961 miles of pipe for which PG&E does not have strength test records.

20. PG&E proposes to study 98 fault crossings during the Rate Case Period.

21. PG&E proposes to perform 9 mitigations during the Rate Case Period.

22. PG&E's assumed average annual inflation rate of 4.0% to convert recorded 2003-2006 fault crossing mitigation project costs to 2013 dollars.

23. The average inflation rate between 2003 and 2013 using the GDPIPD is 2.1%.

24. PG&E expects to replace 60 miles of vintage pipe during the Rate Case Period, focusing on the areas with the greatest population density.

25. PG&E's forecast unit costs for vintage pipe replacement are based on nine PSEP projects – 1 project for small diameter (<12") pipe, 4 projects for medium diameter (12-16") pipe, and 4 projects for large diameter (24-30") pipe.

26. PG&E's large diameter pipe forecast is based on four projects on Line 109 (located on the Peninsula), while half of the expected large diameter pipe projects are outside of the San Francisco Bay.

27. ORA's recommended unit costs for vintage pipe replacement are based on 42 PSEP projects – 13 projects for small diameter (<12") pipe, 10 projects for medium diameter (12-20") pipe, and 19 projects for large diameter (≥24") pipe.

28. PG&E's definition of "congested" has changed over the course of the Rate Case Period.

29. Betterment costs are included in PSEP project costs.

30. PG&E has separately requested funding for betterment projects as part of its forecast for Gas System Operations, Capacity Projects.

31. PG&E's Unit Cost Analysis identifies Medium Diameter Pipe as pipe between 12" – 20" and Large Diameter Pipe as pipe 24" or greater. However, the Cost Calculator considers Medium Diameter Pipe as pipe between 12" and 24" and Large Diameter Pipe as pipe greater than 24".

32. PG&E used a 7% escalation rate, which assumed all PSEP costs were incurred in 2012.

33. ORA determined that absent any counteracting trends that would reduce project costs, the escalation rate should be approximately 4.4%.

34. Although the Geo-hazard Threat Identification and Mitigation Program and the Vintage Pipeline Replacement Project both address the same interactive threat, the Geo-hazard Threat Identification and Mitigation Program does not consider the nature of the pipe as a factor.

35. PG&E assumes a 3% inflation rate in calculating the average cost for projects in its Geo-hazard Threat Identification and Mitigation Program.

36. PG&E forecasts the cost to replace, automate and upgrade gas shut-off valves in the Valve Automation Program to be $1.34 million per valve, as compared to $0.58 million per valve for the first phase authorized in the *PSEP Decision*.

37. Following the San Bruno explosion and fire and at the request of U.S. Representative Jackie Speier, PG&E will send letters to homeowners and businesses within 2,000 feet of PG&E's transmission pipelines every three years.

38. PG&E has not provided any detail of the amount spent for each of the communication streams and outreach methods identified in its Public Awareness Program.

39. PG&E's forecast includes approximately $5.3 million for mailing the informational letters to home owners and businesses within 2,000 feet of PG&E's transmission pipelines in 2017.

40. PG&E forecasts replacing approximately 99 inoperable or hard-to-operate valves during the Rate Case Period.

41. In 2013, PG&E changed its definition of inoperable valve to include "valves have become so difficult to operate that the best option becomes a capital valve replacement."

42. PG&E's Class Location program is a compliance requirement pursuant to 49 CFR 192.613 to ensure that pipelines are operating within the appropriate class as determined by population density.

43. PG&E's pipeline replacement and strength testing costs are based on costs associated with PSEP.

44. The forecast Class Location Program expense for the planned strength test (MWC HP) is $2.2 million per test mile. However, the broader Hydrotest Program forecast is $0.97 million per test mile.

45. Although the proposed work in the Water and Levee Crossing Program has a lower risk ranking than other programs, PG&E has an obligation to perform this work to meet the requirements under the master lease agreements with the California State Lands Commission.

46. PG&E's jurisdictional levee crossing work is performed in conjunction with the Army Corps of Engineers and the California Department of Water Resources.

47. PG&E's Audit of Gas Damage Prevention Program[948] and Pipeline Centerline Project Audit (Part 2) do not identify any existing errors or find that PG&E is in violation of federal regulations.

48. PG&E's forecast Shallow Pipe Program capital cost of $8 million per mile is based on recent pipeline replacement unit costs from PSEP and includes mobilization and demobilization costs.

49. PG&E includes a 30% increase in total project costs for mobilization and demobilization costs.

50. For the Work Required by Others Program, PG&E projects that approximately 60% of total project costs will be paid by the requesting party and 40% by ratepayers.

51. The California High Speed Rail Act (Pub. Util. Code § 185000 et seq.) provides that the California High Speed Rail Authority shall pay the reasonable and necessary costs for the removal or relocation of utility facilities and shall be entitled to certain credits, such as betterment or salvage value.

Storage

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[948] Exh. TURN-20.

52. On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 5 – Asset Family – Storage* (Exh. Joint-3 at -5), was entered into the record.

Facilities

53. Due to the limited industry experience of ECA type work, there is a limited amount of historical forecasting data on which to base scope and cost for ECA projects.

54. PG&E's hydrostatic station testing forecast is largely based on third-party estimates and preliminary data from the 2013 station records research.

55. On April 22, 2015, a stipulation between PG&E and ORA, *ORA-PG&E Joint Stipulation, Engineering Critical Assessment and Hydrostatic Testing (Chapter 6)* (Exhibit Joint-6) was entered into the record.

56. PG&E's forecast ECA 1, ECA 2 and Hydrostatic Station Testing costs includes costs for assets installed after January 1, 1956.

57. PG&E "does not currently have the ability to identify the amount of funding included in its forecast to perform ECA Phases 1 and 2 and Hydrostatic Station Testing work on stations with post-1961 components or features for which PG&E lacks required traceable, verifiable, and complete records."

58. The *ORA-PG&E Joint Stipulation, Engineering Critical Assessment and Hydrostatic Testing* does not require PG&E to ensure that it has traceable, verifiable and complete records for its C&P and M&P stations and does not address the fact that the stipulated costs include amounts that should be paid by PG&E shareholders.

59. Utility Standard TD 4551S, "Station Critical Documentation", identifies the critical documentation needed to safely and efficiently operate all C&P and M&P facilities.

60. PG&E has identified 500 Measurement & Control facilities and 17 Control & Processing facilities requiring attention under the Critical Documents Program.

61. Although PG&E has stated that vintage stations may be missing certain documents because those documents and diagrams were not required at the time the station was built, it has not specifically addressed whether the existing station document packages are otherwise traceable, verifiable and complete .

62. The intent of the Data Acquisition and Metric Development Program is to capture this data in an automated form that allows for continual update and communication of station health and performance to enable identification of appropriate mitigation actions.

63. PG&E will coordinate both the simple and the complex station rebuild programs and the Critical Documents Program to avoid duplication and optimize efficiencies.

64. Based on PG&E Utility Standard TD-4551S, the definition of transmission station assets does not include distribution stations.

65. Assembly Bill (AB) 1900 (Stats. 2012, ch. 602) establishes a process to promote and facilitate the injection and use of biomethane in to common carrier pipelines.

66. PG&E forecasts $4.8 million in capital expenditures in 2015 for the Biomethane Interconnects Program.

67. On January 16, 2014, the Commission issued D.14-01-034, which adopted monitoring, testing, reporting, and recordkeeping protocols.

68. PG&E's current tariffs require the supplier of gas to the system to pay for interconnection costs, including biomethane gas suppliers.

69. On June 11, 2015, the Commission issued D.15-06-029, which determined that the costs of complying with the standards and protocols adopted by D.14-01-034 should be borne by the biomethane producers and included a five-year monetary incentive program to encourage biomethane producers to design, construct, and to successfully operate biomethane projects that interconnect with the gas utilities' pipeline systems.

Corrosion Control

70. Starting in 2013, PG&E initiated significant improvements to its Corrosion Control Program to bring the program in alignment with industry practices and reduce the risk of corrosion-related incidents.

71. PG&E has excluded $23 million in expenses and $21 million in capital expenditures from its forecast to correct prior non-compliance with regulatory requirements for corrosion control.

72. Both the *PSEP Decision* and the *Penalties Decision* determined that disallowed capital expenditures should be permanently excluded from PG&E's rate base..

73. Intervenors have presented evidence to support their arguments that the amount of PG&E's self-exclusions for corrosion control does not account for all instances of prior imprudence.

74. PG&E has been preparing and filing spending reports every six months that compare recorded spending to adopted funding pursuant to the *Gas Accord V Decision* and proposes to continue providing these reports unless directed otherwise.

75. PG&E currently has approximately 4,000 contact points, of which 1,400 are coupon test stations, to monitor the 6,750 miles of pipe in its transmission system.

76. The majority of PG&E's current contact points are trailing wire or some other type of contact point.

77. PG&E plans to install over 900 new coupon test stations during the Rate Case Period.

78. PG&E had previously interpreted 49 CFR 192.469 to mean a coupon station (or contact point) should be monitored approximately every mile along the transmission system.

79. As part of its efforts to move towards industry best practices, PG&E adopted a more stringent standard which, as clarified during cross-examination, it interprets to mean "monitoring points may be reduced less than 1 mile if 1 mile intervals are not adequate to determine cathodic protection effectiveness, and conversely monitoring points may be at intervals greater than 1 mile with written approval from corrosion engineering."

80. PG&E's recorded 2011 and 2012 capital expenditures for coupon test stations equate to approximately 52 coupon test stations installed each year.

81. PG&E's forecast expenses for its Corrosion Investigation excludes costs to perform corrective work associated with remediating past compliance issues.

82. PG&E's costs to perform corrective work associated with remediating past compliance issues in the Corrosion Investigation Program shall be paid for by PG&E shareholders.

83. PG&E's forecast expenses and capital expenditures for the AC Interference Program include the inspection and estimated mitigation of locations installed prior to 1971; it has excluded costs to inspect and remediate locations installed after 1971.

84. PG&E is not seeking ratepayer funding for expenses and capital expenditures to perform corrective work in the AC Interference Program for non-compliance with of 49 CFR 192.473.

85. The deficiencies in the AC Interference Program identified in the Exponent Phase 2 report are in comparison to industry best practices and are not a failure to comply with 49 CFR 192.467(f) and 192.473(a).

86. The Exponent Phase 1 and Phase 2 reports do not find PG&E's DC Interference program has failed to comply with the federal code and PHMSA documents, but rather that PG&E's activities fall short or industry best practices.

87. PG&E has identified approximately 335 casings as contacted and in need of mitigation and proposes to mitigate 94 capital casings during the Rate Case Period and 117 expense casings in 2015.

88. There is no testimony to conclude that the corrosion problems with the 335 contacted casings would have been smaller if PG&E had remediated them sooner.

89. There is sufficient record evidence to conclude that some of the proposed mitigation work is the result of PG&E's failure to originally perform the work properly.

90. A review of the A-Form shows the intent was to identify the specific individuals performing the leak survey, repair and inspection work.

91. PG&E's NCR06 found that "19% of pipe inspections made during corrosion leak repairs were performed by individuals who were not Operator Qualified for the task."

92. PG&E historically considered internal corrosion a relatively low threat since most of its gas is received from interstate transmission pipelines and the

contracts with these interstate operators mandate dry gas that is free of liquids that could create an environment for internal corrosion to develop.

93. The Exponent Phase 1 and Phase 2 reports do not find any violations of federal regulations, but rather deficiencies in PG&E's documentation and guidelines for internal corrosion control inspection, monitoring and mitigation.

94. Although PG&E's Atmospheric Corrosion program complied with code requirements, benchmarking had shown that other operators were going above and beyond compliance with their atmospheric corrosion programs.

95. PG&E's atmospheric corrosion inspections were performed as a secondary activity, so no costs were recorded in 2011-2013.

96. PG&E's forecast expenses for the Atmospheric Corrosion program excludes costs associated with non-compliance with federal regulations.

Gas Transmission System Operations and Maintenance Activities

97. PG&E is not requesting cost recovery for the Pipeline Centerline Survey project, nor for cost recovery to address the encroachments that are being documented through the Pipeline Centerline Survey.

Other GT&S Support Plans

98. The *2014 GRC Decision* adopted an allocation of costs between transmission and distribution for the new Gas Operations headquarters that differed from PG&E's proposal in this application.

99. Pursuant to the *2014 GRC Decision*, 60% of PG&E's Gas Operations headquarters cost would be allocated to transmission.

100. PG&E's forecast Tools and Equipment capital expenditures are based on a five-year average of recorded and forecasted capital expenditures, which was then increased to support PG&E's plan to hire incremental maintenance and

construction crews and field personnel to execute the increased work forecasted for 2015-2017.

101. On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 12 – Other GT&S Support Costs,* regarding tools and equipment, was entered into the record.

102. Building Management Expenditures includes capital expenditures for buildings and office facilities not funded through PG&E's GRC.

103. Pursuant to the *2014 GRC Decision*, 60% of PG&E's Building Management Expenditures cost would be allocated to transmission.

Gas System Operations

104. On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 10 – Gas Operations,* concerning Electricity Costs for Gas Compressor Operations was entered into the record.

105. PG&E procures greenhouse gas (GHG) compliance instruments (allowances and offsets) for gas compressors on the backbone transmission system and at storage facilities, and for any other gas transmission and storage equipment that may incur an obligation, to comply with the requirements of AB 32.

106. PG&E was authorized by D.13-03-017 to recover the costs of GHG compliance instruments for the six compressor stations for which it anticipated incurring compliance costs – Topock, Hinkley, Kettleman, Delevan, Gerber and Burney.

107. PG&E forecasts that Tionesta Compressor Station will incur compliance costs and that other gas transmission and storage facilities may incur an obligation in the future if their GHG emissions exceed the annual emissions threshold set by the California Air Resources Board.

108. On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 10 – Gas Operations,* concerning Greenhouse Gas Compliance Instruments was entered into the record.

109. On October 22, 2015, the Commission adopted *Decision Adopting Procedures Necessary for Natural Gas Corporations to Comply With the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (Cap-and-Trade Program*, which authorized each utility to forecast and reconcile its natural gas GHG compliance costs and allowance proceeds as part of the existing true-up advice letter process and revised the annual advice letters to contain a new section related to GHG costs and allowance proceeds.

110. PG&E's past practice was to set NOP close to MAOP, and to set overpressure protection at or slightly above MAOP.

111. Pursuant to SB 705 (Stats. 2011, ch. 522), PG&E now sets both the NOP and overpressure protection setpoints below MAOP.

112. The Line 407 project is needed and likely to be completed within the Rate Case Period.

113. The Line 407 project should not be treated as an adder project.

114. The stipulation between PG&E and ORA regarding the Post Test Year Cost Recovery Mechanism includes a provision for a balancing account of up to $7 million in revenue requirements for Line 407, if the project is completed in 2017, and ratepayers will not pay for this project until it is used and useful.

115. On March 6, 2015, Calpine filed *Motion of Calpine Corporation to Strike Portions of Pacific Gas and Electric Company's Testimony (Calpine Motion to Strike)* to strike from the record PG&E's testimony to allocate additional storage injection and withdrawal capacity to load balancing.

116. Calpine's motion to strike was granted by oral ruling on March 18, 2015.

Information Technology

117. Pursuant to the *PSEP Decision*, PG&E is not seeking recovery for costs associated with the Gas Transmission Asset Management program (now known as the Mariner Program).

118. On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 11 – Information Technology,* was entered into the record.

Reporting and Program Management

119. On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 13 – Reporting and Communications*, was entered into the record.

120. On February 26, 2015, PG&E and Calpine reached an oral stipulation that PG&E would post on its website, between August 1st and August 10th of each year, best efforts forecast of the year-end true-ups of the noncore balancing accounts for GT&S revenues, of the expected year-end changes in GT&S revenues that impact noncore customers, and of the resulting GT&S rate changes expected at the end of the year.

121. The February 26, 2015 oral stipulation between PG&E and Calpine was read into the record.

122. On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 9 – Program Management Office*, was entered into the record.

Results of Operations

123. The RO computer model is used to derive the adopted revenue requirements for 2015.

124. In the *2014 GRC Decision*, the Commission adopted a revised methodology to determine PG&E's uncollectibles factor, which is based on a 10-year rolling average using uncollectible data. Pursuant to Advice Letter 3535-G/4540-E, PG&E's uncollectibles factor is 0.3325% effective January 1, 2015. Pursuant to Advice Letter 3612-G/4675-E, PG&E's uncollectibles factor is 0.3347% effective January 1, 2016.

125. Since the amount of A&G expenses to be allocated to the GT&S UCCs are based on the *2014 GRC Decision* and any subsequent filings that may alter the allocation, PG&E's application, which was filed before the *2014 GRC Decision* was issued, included a placeholder for A&G expenses.

126. On February 24, 2015, a stipulation between PG&E, TURN and ORA, *Joint Depreciation Stipulation*, which proposed a depreciation schedule for contested accounts that produces an overall depreciation rate of 2.15%, was entered into the record.

127. PG&E's application had included a placeholder for PSEP cost recovery based on the PSEP Update Application RO model extended out to 2017.

128. On November 20, 2014, the Commission issued D.14-11-023, which adopted a settlement agreement between PG&E, ORA and TURN, which lowered the revenue requirement from that requested in the PSEP Update Application.

129. With the exception of Net Operating Loss and Bonus Depreciation, no party disputed PG&E's proposed methodology to compute income taxes.

130. On February 24, 2015, a stipulation between PG&E and ORA, *Joint Stipulation on Treatment of NOLC and Bonus Depreciation*, was entered into the record.

Cost Recovery Issues

131. Revenue requirements allocated to noncore customers and to core backbone customers are currently subject to a GT&S Revenue Sharing Mechanism (GTSRSM), whereby these customers and PG&E shareholders share a portion of the differences between the adopted revenue requirement and billed revenues from noncore customers

132. Under the GTSRSM, the amount "at risk" is 50% of noncore backbone revenues and 25% of noncore local transmission revenues.

133. PG&E competes against other operators who provide similar services with respect to backbone transmission and market storage.

134. The one-way Transmission Integrity Management Program Balancing Account (TIMPBA) was adopted in Gas Accord V.

135. While a Tier 3 advice letter provides the most stringent level of review among the various informal processes, it does not provide the same level of scrutiny and review as a formal application.

136. Application of the Z-Factor mechanism has been addressed as part of the stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year Mechanism.*

137. On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year*, was entered into the record.

138. The stipulated amounts for Incremental Specific Expense Adjustments, which is Line 3 of the stipulation, does not incorporate corrections to External Corrosion Direct Assessment in PG&E's errata testimony.

Other Revenue Requirement and Cost Recovery Issues

139. Resolution L-411A states that while the utility would not be required to seek pre-approval of the spending of bonus depreciation, the reasonableness of these expenditures would still be subject to review in a subsequent GRC.

140. Although SED was tasked with reviewing the semi-annual reports to ensure that PG&E was spending its allocated funds storage and pipeline-related safety, reliability, and integrity activities authorized in the *Gas Accord V Decision*, SED's review did not include a reasonableness review.

141. PG&E generally uses a $1 million threshold, under which it does not provide specific details for a project.

142. It is unclear whether PG&E's projects under the $1 million threshold are associated with projects included in Gas Accord V or new projects (both the number of projects within each category and in total).

143. There is no evidence to support the reasonableness of PG&E's 2011-2014 capital expenditures of $118.639 million for four projects – Tools and Equipment; Buildings; Pipeline Reliability/Safety; and Corrosion.

144. The Tools and Equipment; Buildings; Pipeline Reliability/Safety; and Corrosion projects may be warranted.

145. Of the $498.890 million of spending over forecast Gas Accord V spending, approximately $173 million is associated with 21 projects for Gas Accord V work.

146. The settling parties, including PG&E, represented that the Gas Accord V settlement amounts could fund all the work in MWC-98.

147. PG&E seeks to recover an additional $18,106,206 for six projects in MWC-98 that were included in the Gas Accord V Settlement Agreement.

148. PG&E has not provided sufficient evidence to support the reasonableness of increased 2011-2014 capital expenditures for the six projects in MWC-98 that were included in the Gas Accord V Settlement Agreement.

149. The Gas Accord V Settlement Agreement settlement amounts could fund 98% of the work in MWC-75.

150. PG&E seeks to recover an additional $21,432,557 for three projects in MWC-75 that were included in the Gas Accord V Settlement Agreement.

151. PG&E has not provided sufficient evidence to support the reasonableness of increased 2011-2014 capital expenditures for the six projects in MWC-75 that were included in the Gas Accord V Settlement Agreement.

152. The *Ex Parte Sanctions Decision* adopted a ratemaking remedy to address a five-month delay caused by PG&E's improper ex parte communications in this proceeding.

153. PG&E proposes to reduce its original revenue requirement forecast to account for costs associated with remedies adopted in the *Penalties Decision* that overlap with work proposed in its GT&S application

154. PG&E proposes reducing capital expenditures by $1,398,400 ($908,500 recorded from 2011 to 2014 and $489,900 of forecasted spending from 2015 to 2017), and $3,759,200 in forecast expenses covering 2015 to 2017 for the overlapping work

155. PG&E identifies 80 out of the 143 remedies adopted in the *Penalties Decision* attributable to pipeline safety enhancements for which implementation costs overlap with costs included in its GT&S rate case.

156. The costs to perform that shared support work are assigned to Provider Cost Centers (PCCs) and are allocated between transmission and distribution functions.

157. There is no evidence that PG&E included costs in its GT&S revenue requirement that would typically be accounted for as distribution.

158. PG&E proposes to use a similar cost allocation approach as used in this GT&S proceeding to remove any overlapping distribution-related costs relating to remedies adopted in the *Penalties Decision* as part of its 2017 GRC.

159. PG&E employed a sufficiently rigorous process to identify the costs that required removal from the GT&S revenue requirement in compliance with the *Penalties Decision*.

Rate Issues

160. On March 23, 2015, a stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 14 – Throughput Forecast*, was entered into the record.

161. PG&E has traditionally designed backbone rates based on a system average backbone load factor.

162. PG&E proposes that Redwood and Baja path costs would be rolled-in together into a single rate.

163. The existing rate structure is based on the costs of the respective paths and recognizes that the Redwood and Baja paths each provide access to a distinct market.

164. The Baja Path currently has a higher revenue requirement than does the Redwood Path.

165. The PG&E system is much different from that of SoCalGas.

166. The load factors proposed by PG&E in its opening testimony assumed adoption of equalized rates for the Redwood and Baja backbone transmission lines.

167. PG&E calculated a system average load factor for non-equalized backbone rates as part of its Rebuttal Testimony.

168. Due to changes in several inputs, such as throughput levels, shrinkage and backbone rate levels, the system average load factors contained in Exhibit PG&E-43 need to be recalculated.

169. PG&E's local transmission costs are allocated to core and noncore customer classes based on cold year forecast coincident peak month demands.

170. Considering population density when prioritizing safety improvements in pipes does not provide more benefits to core customers than noncore customers.

171. PG&E's local transmission system is a shared resource between core and noncore customers.

172. "Flatter" allocation factors for local transmission costs may more accurately reflect marginal costs.

173. Even though PG&E's proposed allocation table in its direct testimony was not struck from the record, the table incorporates PG&E's proposal to allocate additional storage injection and withdrawal capacity to load balancing, which had been struck from the record.

174. PG&E's allocation of storage costs does not reflect that its proposal to allocate 130 MMcf/d (133 MDth/d) of injection capacity and 200 MMcf/d (204 MDth/d) of withdrawal capacity to balancing, along with the associated revenues had been struck from the record in this proceeding in its entirety.

175. Calpine's Opening Brief includes calculations for storage units for allocation of storage costs that exclude PG&E's proposal to allocate additional storage injection and withdrawal capacity to load balancing.

176. The EG-LT transmission rate covers the additional service to connect electric generation located more remotely from the Backbone system. The G-EG/BB rate does not include local transmission costs while the G-EG/LT rate does include local transmission costs

177. The separation of backbone and local transmission rates is consistent with principles of cost causation, and provides an incentive for new gas-fired generation plants to interconnect directly to the backbone system where PG&E can more easily manage changes in the flow of gas.

178. Customers connected to the local transmission system cause PG&E to incur local transmission costs, while customers connected directly to the backbone system do not.

179. PG&E backbone-level customers do not use the local transmission system, and do not cause local transmission costs to be incurred.

180. Backbone-level customers pay, essentially, for local transmission service in the cost that they incur to build, operate and maintain their lateral pipeline facilities that connect their plants to the backbone system.

181. The backbone-level rate is available to customers, both EG and other noncore customers, that connect directly to the backbone system (and that meet certain other eligibility criteria), irrespective of where they are located.

182. EG rates are not the sole gas transportation cost incurred by EG plants.

183. Although bill credits were a feature of the Gas Accord III, Gas Accord IV, and Gas Accord V Settlement Agreements, nothing in the Gas Accord settlements suggest that the purpose of the bill credits was to address competitive issues in electric markets.

184. The current proposal to incorporate a bill credit is not the product of a settlement, but a contested issue.

185. In D.86-12-010, the Commission established a 250 Dth/year minimum size to qualify as a noncore customer.

186. Final rates cannot be adopted until after the revenue requirements adopted in this Decision are adjusted to reflect the $850 million of PG&E shareholder funding for safety improvements adopted in the *Penalties Decision*.

Core Gas Supply

187. On April 7, 2015, PG&E and Palo Alto submitted a joint stipulation, *Joint Redwood and Baja Capacity Allocation Stipulation*, that states PG&E will continue

the allocation of Core Redwood capacity to Palo Alto at the same level adopted in Gas Accord V, or 5.898 MDth/d.

188. PG&E proposes to modify the CPIM to add a monthly index component at PG&E's Citygate to reflect baseload purchases made at that point and to modify the CPIM benchmark to reflect intrastate capacity holding changes.

189. PG&E's proposal that any agreed-upon changes be reported by PG&E in the first CPIM Annual Report to which they apply could result in a significant delay before parties are aware that the benchmark had been changed.

190. Both PG&E and the CTAs no longer believe that the January Capacity Factor should continue to serve as the pipeline allocation process for assigning core intrastate pipeline, interstate pipeline, and storage capacities to CTAs.

191. PG&E's failure to discuss the proposed change with the CTAs prior to filing its application was unexpected and a departure from past practice.

192. In *Opinion Regarding the Proposal for Incremental Core Gas Storage* [D.06-07-010], the Commission adopted a Partial Settlement Agreement which determined the conditions under which the assignment (and the corresponding assumption of cost responsibility) of incremental storage capacity would be borne by CTAs.

Core Transport Agent Issues

193. In Gas Accord V, PG&E agreed to "re-tune" the CLFM and to explore whether smart meter data could be used to improve forecast accuracy.

194. PG&E proposes to modify the CLFM to use an average of 24 hourly temperature forecasts (one for each hour in the gas day), which it believes will yield greater Determined Usage accuracy, along with a corresponding revision to the CLFM's regression equations.

195. PG&E proposes to conduct further analysis on the CLFM and its inputs to continue to improve Determined Usage accuracy.

196. As of April 2015, the CTAs have assumed full cost responsibility in aggregate for all capacity not elected.

197. The ISPs are public utilities subject to Commission regulation and have a corresponding obligation to serve; their contracts to provide firm storage services to their customers are no different than PG&E's.

198. Schedule G-CT requires that CTAs rejecting PG&E's firm storage allocation must certify that they have amounts equivalent to the rejected withdrawal capacity.

199. Gas Rule 23 provides that partial payments shall be allocated "proportionately" among CTA and PG&E charges, unless the account is delinquent as specified in PG&E's Rule 11.

200. Gas Rule 11.D provides that bills are considered past due if payment is not received by PG&E within 19 days after the bill is mailed to the customer.

201. Gas Rule 8 requires various steps (*e.g.*, 15 day mailed notice, 48 hour mailed notice and 24 hour in person or telephone notice) before a delinquent customer can be considered for disconnection.

202. Form 79-845A, the *Core Gas Aggregation Service Agreement -- ATTACHMENT A - Customer Authorization for Core Gas Aggregation Service* establishes buyer/seller relationship between a CTA and a core customer.

203. Form 79-845 makes clear that a CTA is the agent for the core customer (who is the principal) and thus has the right to all information related to the purpose of the agency, which would include the complete billing information.

204. If the CTA opts to handle the billing for both PG&E's charges and its own or to bill for its charges separately, it would have access to all of the customer's billing information.

205. Gas Rule 23.C.1.c.5.a provides that PG&E is responsible for collecting the unpaid balance of all charges from customers and taking the appropriate actions to recover the unpaid amounts owed the CTA.

Administrative Matters

206. The *Penalties Decision* required PG&E shareholders to absorb the cost of future transmission pipeline safety enhancements in the amount of $850 million, to apply to pipeline safety enhancements to be approved in this proceeding and any subsequent GT&S proceeding, if necessary.

207. PG&E may record costs incurred after on or after January 1, 2015 for designated safety-related programs and projects into these accounts in the Shareholder Funded Gas Transmission Safety Account and its two subaccounts,

208. In a filing on June 1, 2015, PG&E identified the safety-related gas transmission projects and programs in the GT&S rate case forecast that should be recorded in the Shareholder Funded Gas Transmission Safety Account and its two subaccounts

209. Based on the information presented in Appendix E, all of the $850 million penalty adopted in the *Penalties Decision* will be used during this Rate Case Cycle.

210. Appendix G presents the impact of applying the $850 million penalty on the Results of Operations and Post Test Year Ratemaking models, as well as illustrative rates, based on the above proposed allocation.

211. *Decision Granting January 1, 2015 Effective Date for Pacific Gas and Electric Company's Test Year 2015 Revenue Requirement* [D.14-06-012] granted PG&E's

motion that its GT&S revenue requirement be effective as of January 1, 2015 and subject to interest based on the Federal Reserve three-month commercial paper rate.

212. D.14-06-012 determined that the decision authorizing PG&E's revenue requirement would address the amortization period to be used.

Conclusions of Law

1. PG&E has the burden to affirmatively establish the reasonableness of all aspects of its application.

2. PG&E's forecast costs are not unreasonable and subject to ratemaking disallowance simply because its management imprudently delayed or deferred work.

3. Disallowances are warranted when the forecast work is necessary because: (1) PG&E had not originally performed the work properly, or (2) PG&E had failed to comply with regulatory requirements that it was previously funded to satisfy.

4. PG&E's risk management process provides a framework for purposes of evaluating the reasonableness of PG&E's forecast revenue requirement in this GT&S proceeding

5. PG&E's proposed risk management approach and asset family categories are reasonable.

6. Customer affordability must be considered in determining the reasonableness of PG&E's requested revenue requirement.

Transmission Pipe

7. PG&E's proposed pace to make pipeline piggable could impose additional costs on ratepayers due to the higher demand for limited construction resources.

8. The pace of work to make pipelines piggable should be reduced and this work shall be performed over a 12-year period, rather than a 10-year period.

9. PG&E's forecast 2015 expenses for in-line inspection work is reasonable and should be adopted.

10. Gas Transmission Systems performed an independent evaluation, even though some of the individuals performing the study were current or former PG&E employees.

11. If PG&E cannot determine whether the immediate indications were from the baseline assessment or from the second run of an assessment, it would not be able to understand frequency trends or determine what actions would need to be taken.

12. PG&E's shareholders should be responsible for 50% of the ICDA expenses.

13. There is no evidence that PG&E received funding in its 2104 GRC to perform transmission integrity management activities.

14. PG&E's proposed reclassification of 920 miles of distribution pipeline should be adopted.

15. PG&E has provided no persuasive explanation why rounding up to the nearest whole number is warranted in its forecast expenses.

16. PG&E's forecast ECDA expenses should be reduced to reflect a digs-to-project ratio of 6.02.

17. PG&E shareholders should be responsible for 50% of the ECDA expenses.

18. PG&E's forecast SCCDA expenses should be adopted.

19. PG&E's 2015 forecast hydrotest capital expense of $0.97 million per mile is reasonable and should be adopted.

20. PG&E should not recover costs for hydrostatic testing of pipe installed between January 1, 1956 and June 30, 1961 for which it has no records from ratepayers.

21. PG&E has consistently represented that between 1956-1961 it pressure tested and retained records for all transmission pipe.

22. PG&E has provided no evidence that the transmission pipes for which there are no pressure test records were in fact not required to have pressure testing or, if pressure testing were required, that that there was no requirement that the records be retained.

23. Based on PG&E's representations and GO-112, PG&E should have pressure test records for all pipeline segments installed after January 1, 1956.

24. PG&E's forecast hydrotest expenses for transmission pipeline should be reduced by 19.2%.

25. The absence of pressure test records for transmission pipeline does not necessarily mean PG&E failed to perform prior capital improvements.

26. PG&E should not recover from ratepayers the costs to pressure test post-1961 miles of pipe for which PG&E does not have strength test records.

27. PG&E's forecast hydrotest capital expenditures for transmission pipeline should be adopted.

28. PG&E should be required to hydrotest 510 miles of pipe during the Rate Case Period plus up to 50 miles of pipe installed after 1961 for which it has no pressure test records.

29. PG&E should be required to file quarterly compliance reports of its transmission pipeline hydrotest work. The reports shall follow the format in Attachment D of the *PSEP Decision*, revised to reflect the projects proposed for the Rate Case Period. PG&E's first compliance filing shall cover the period

between January 1, 2015 and the quarter in which this Decision is issued, and shall be due no later than 30 days after the end of the quarter.

30. PG&E's pace of work to conduct earthquake fault crossing studies should be reduced to 49 studies during the Rate Case Period, which will more closely match the number of mitigations that would be performed.

31. PG&E's proposed unit cost to conduct fault crossing studies is reasonable and should be adopted.

32. PG&E provides no explanation why a 4.0% inflation rate is warranted.

33. The assumed annual inflation used to calculate the forecast unit costs to perform fault crossing mitigations should be reduced from 4.0% to 2.1%.

34. PG&E's assertion that Line 109 is representative of all expected VPR projects is unconvincing.

35. Pipe diameter size, does not appear to be a screen for selecting projects, but rather the method for grouping costs.

36. Although projects with shorter pipe segments will increase unit costs because fixed costs will be spread over fewer miles in the unit cost calculation, it is unreasonable to conclude that that the shorter pipe segments associated with the VPR projects would result in unit prices per mile that are double that of PSEP projects.

37. It is unreasonable to adopt a forecast based on nine PSEP projects, especially when it appears that a larger number of PSEP projects would have met the selection criteria.

38. PG&E's selection of a small number of projects in congested areas has resulted in unit costs that are not representative of the work to be performed in the VPR Program during the Rate Case Period.

39. Unit costs for vintage pipeline replacement should be based on the overlapping (common) projects used by both PG&E and ORA in their analyses, as identified in Exhibit ORA-131.

40. Any betterment costs included in the PSEP project costs should be removed from the forecast unit costs for vintage pipeline replacement.

41. Given the discrepancy between PG&E's definition of Medium Diameter Pipe in the Unit Cost Analysis and the Cost Calculator, and the large number of projects that involve 24" pipe, there is a risk that if separate unit costs were adopted for Medium Diameter and Large Diameter pipe, the costs would not properly reflect the work to be performed.

42. It would be reasonable to average the unit costs for Medium Diameter and Large Diameter pipe and adopt a unit price of $7.985 million/mile for all pipe 12" or greater.

43. The unit prices for vintage pipeline replacement should be $4.51 million per mile for all pipe with diameter less than 12" and $7.985 million per mile for all pipe with diameter of 12" or greater.

44. The escalation rate to be applied to the adopted unit costs for vintage pipeline replacement should be 4.4%, as proposed by ORA.

45. PG&E's forecast 2015 expenses of $0.211 million for the Geo-hazard Threat Identification and Mitigation Program is reasonable and should be adopted.

46. PG&E's forecast 2015 expenses of $1.052 million for Root Cause Analysis and $6.263 million for Risk Analysis Process Improvement are reasonable and should be adopted.

47. PG&E's forecast capital expenditures for the Valve Automation Program are reasonable and should be adopted.

48. It is unknown whether any portion of the work to send out the informational letters in 2014 represented one-time expenses.

49. PG&E's forecast expenses for the Public Awareness Program should be reduced by $3.558 million.

50. The Inoperable and Hard-to-Operate Valves Program should look at not only inoperable valves, but also hard-to-operate valves that are trending to becoming inoperable.

51. PG&E's forecast 2015 expense of $0.242 million for the Inoperable and Hard-to-Operate Valves Program is reasonable and should be adopted.

52. PG&E's forecast capital expenditures of $22.188 million for the Inoperable and Hard-to-Operate Valves Program should be adopted as the maximum amount that PG&E may recover from ratepayers to replace 99 inoperable or hard-to-operate valves during the Rate Case Period.

53. PG&E has not provided persuasive justification why the unit costs for strength testing mitigation in the Class Location Program are more than double the unit costs for the activity in the Hydrotest Program

54. The unit cost for strength testing in the Class Location Program should be reduced to $1.1 million per test mile, resulting in forecast 2015 expenses of $3.985 million.

55. PG&E's forecast capital expenditures for the Class Location Program are reasonable and should be adopted.

56. PG&E's proposed scope of work in the Class Location Program is not to address prior non-compliance.

57. PG&E's forecast expenses and capital expenditures for the Water and Levee Crossing Program are reasonable and should be adopted.

58. PG&E's expense mitigation forecasts in the Shallow Pipe Program are reasonable and should be adopted.

59. PG&E's inclusion of a 30% increase in total project costs for mobilization and demobilization costs are not supported by the record and are unreasonable.

60. PG&E's capital expenditures forecast in the Shallow Pipe Program should be adjusted to disallow the 30% Mobilization/Demobilization adder.

61. PG&E's 15% Shallow Pipe Construction Risk Adder is reasonable.

62. PG&E's forecast capital expenditures for the Gas Gathering Program is reasonable and should be adopted.

63. PG&E's forecast unit cost and the average length of each project is reasonable.

64. PG&E's forecast 2015 expenses of $.739 million for Work Required by Others is reasonable and should be adopted.

65. To the extent that the California High Speed Rail Authority finds any costs are not reasonable (and thus does not reimburse PG&E for those amounts), it does not follow that PG&E should be allowed to recover the "unreasonable" portion of the costs in rates.

66. Given the mandates of Pub. Util. Code §§ 185501(a), 185502(c) and 185503, and the specific credits that the California High Speed Rail Authority could receive under Pub. Util. Code § 185504(a), it is unreasonable to assume that PG&E will only recover 60% of project costs from the California High Speed Rail Authority.

67. PG&E's capital budget for WRO should be reduced by $7.3 million, resulting in forecasted capital expenditures of $17.3 million.

68. Because the forecasted capital expenditures for WRO may still be too high, given the large number of High Speed Rail projects included in the forecast and

the fact that no master agreement has yet been approved by the Commission, PG&E should file a Tier 2 Advice Letter to establish a one-way balancing account to track the difference between amounts adopted in this decision and the portion of costs assigned to customers over the 2015 GT&S rate cycle.

Storage

69. The *Joint Stipulation Comparison Exhibit Chapter 5 – Asset Family – Storage* (Exh. Joint-3 at -5) is reasonable and should be adopted.

Facilities

70. The 1955 ASA standard applicable between 1956 and 1961 requires all records of transmission pipe and transmission stations pressure tests to be maintained.

71. The *ORA-PG&E Joint Stipulation, Engineering Critical Assessment and Hydrostatic Testing* is not in the public interest and should be rejected.

72. Authorizing PG&E's requested funding will allow PG&E to perform the scope of work contemplated to ensure that records for its C&P and M&P Stations are traceable, verifiable and complete.

73. PG&E's proposed methodology to proportion cost responsibility between shareholders and ratepayers to perform Hydrotest Station Testing work should be adopted except that, PG&E shall recover from shareholders all costs to address station components installed on or after January 1, 1956 that do not have but were required to have traceable, verifiable and complete records.

74. PG&E should file a Tier 2 Advice Letter to establish a one-way balancing account to track the difference between amounts adopted in this decision and the actual costs to perform Hydrostatic Station Testing work during the Rate Case Period on stations installed on or before January 1, 1956.

75. In light of PG&E's testimony in other areas, such as ECA Phase 1, and the recordkeeping shortcomings found in the San Bruno Investigations, it would be reasonable to conclude that some of the missing documents at PG&E's C&P and M&P stations are due to deficient records management practices.

76. Existing station documentation packages should be updated to reflect the requirements of TD-4551S (for example, including piping and instrumentation diagrams for vintage stations) and the associated costs should be recovered from ratepayers.

77. PG&E's forecast expenses for the Critical Documents Program should be adopted, costs to be recovered, subject to certain requirements to ensure that the Critical Documents Program is not used to correct past records management deficiencies.

78. PG&E should be allowed to recover from ratepayers costs to update existing station documentation or create new documentation to meet the standard set in Utility Standard TD-4551S for all Measurement & Control facilities and Control & Processing facilities built before January 1, 1956.

79. For all Measurement & Control facilities and Control & Processing facilities built on or after January 1, 1956, PG&E shareholders should bear the costs to update existing station documentation or create new documentation to meet the standard set in Utility Standard TD-4551S if those documents were required to be created and maintained at the time of or post-installation.

80. PG&E should file a Tier 2 Advice Letter to establish a one-way balancing account to track the difference between amounts adopted in this decision and the actual costs of Critical Documents Program work for facilities built before January 1, 1956.

81. PG&E's forecast expenses for the Data Acquisition and Metric Development Program are reasonable and should be adopted.

82. PG&E's forecast expenses and capital expenditures for the Physical Security Program are reasonable and should be adopted.

83. PG&E's forecast capital expenditures for the Becker System Upgrades Program are reasonable and should be adopted.

84. PG&E's forecast expenses for the Gas Quality Practice Assessment Program are reasonable and should be adopted.

85. PG&E's forecast operating and maintenance expenses for the operation of the Gill Ranch Storage Facility are reasonable and should be adopted.

86. PG&E's forecast routine expenses are reasonable and should be adopted.

87. PG&E's forecast capital expenditures to replace the compressor unit at Burney Compressor Station are reasonable and should be adopted.

88. PG&E's forecast capital expenditures to replace the compressor unit at the Los Medanos Underground Storage Facility are reasonable and should be adopted.

89. PG&E's forecast capital expenditures for the Compressor Unit Control Replacement Program are reasonable and should be adopted.

90. PG&E's forecast capital expenditures for the Upgrade Station Controls Program are reasonable and should be adopted.

91. PG&E's forecast capital expenditures for upgrades to the Emergency Shutdown System are reasonable and should be adopted.

92. PG&E's forecast capital expenditures to replace the electrical system at the Santa Rosa Compressor Station are reasonable and should be adopted.

93. PG&E's forecast capital expenditures to upgrade the processing equipment at the Pleasant Creek facility are reasonable and should be adopted.

94. PG&E's forecast capital expenditures to update the switch gear sections (SWGR) and Motor Control Centers (MCC) located within station fences at the Hinkley and Topock Compressor Stations are reasonable and should be adopted.

95. PG&E's forecast capital expenditures to replace up to four switch gear sections (SWGR) and four Motor Control Centers (MCC) sections located at the Hinkley, Topock or Santa Rosa Compressor Stations are reasonable and should be adopted.

96. PG&E's forecast capital expenditures for the Hinkley Compressor Unit Retrofit Project are is reasonable and should be adopted.

97. PG&E's forecast capital expenditures to install active, fixed fire suppression systems at gas transmission and processing compression facilities are reasonable and should be adopted.

98. PG&E's forecast capital expenditures to perform simple station rebuilds are reasonable and should be adopted.

99. PG&E's forecast capital expenditures to perform complex station rebuilds are reasonable and should be adopted.

100. PG&E's forecast capital expenditures to upgrade three transmission terminals are reasonable and should be adopted.

101. PG&E's forecast capital expenditures for the SCADA Visibility Program are reasonable and should be adopted.

102. PG&E's forecast capital expenditures to replace obsolete valve control equipment manufactured by Bristol Controls are reasonable and should be adopted.

103. PG&E's forecast capital expenditures to replace valve actuators manufactured by Limitorque are reasonable and should be adopted.

104. PG&E's forecast capital expenditures for the Electrical Upgrade Program are reasonable and should be adopted.

105. Since D.15-06-029 addressed how PG&E may recover funds from ratepayers for biomethane interconnections, PG&E's forecast capital expenditures for the Biomethane Interconnect Program should be denied.

106. PG&E's forecast capital expenditures for the Routine Capital Spending Program are reasonable and should be adopted.

Corrosion Control

107. Disallowances of costs for work that had previously not been funded by ratepayers are not penalties, but rather the consequence of imprudent actions by the utility.

108. It would be unreasonable to conclude that none of PG&E's past corrosion control work had been performed properly and that if it had been, no future ongoing corrosion control work would be needed.

109. Indicated Shippers' recommendation for an independent third-party financial audit and a separate engineering audit of the corrosion control program should be denied.

110. PG&E should continue preparing and filing spending reports every six months that compare recorded spending to adopted funding, consistent with the requirements in the *Gas Accord V Decision*.

111. PG&E's self-identified exclusions and any disallowances for capital expenditures for corrosion control adopted in this decision should be permanently excluded from rate base.

112. Based on the scope and type of work, there is no basis to conclude that any of the ongoing maintenance work proposed for Routine Cathodic Protection

Maintenance is to correct prior work that had been performed improperly or for work that had previously been included in rates but never performed.

113. PG&E's forecast 2015 expenses for Routine Cathodic Protection Maintenance are reasonable and should be adopted.

114. There is no evidence that any of the CP stations PG&E proposes to replace are due to prior improper operation or maintenance or operation.

115. PG&E's forecast capital expenditures for Replace CP Systems Programare reasonable and should be adopted.

116. PG&E's new interpretation of Monitoring points may be reduced to less than 1 mile, if 1 mile intervals are not adequate to determine cathodic protection effectiveness, and conversely monitoring points may be at intervals greater than 1 mile with written approval from corrosion engineering

117. There is no evidence to support a conclusion that PG&E's adoption of enhanced requirements for cathodic protection was to remediate prior improper work or that PG&E had previously sought and received ratepayer funding for new CP systems.

118. Failure to act timely does not render PG&E's currently proposed expenditures for Install New CP Systems unreasonable.

119. PG&E's forecast capital expenditures for Install New CP Systems are reasonable and should be adopted.

120. PG&E's new interpretation of 49 CFR 192.469 sounds very much like its original interpretation.

121. There is no evidence that the PHMSA enforcement actions against Spectra Energy Transmission (CPF-3-2013-1005) and Florida Gas Transmission (CPF-4-2013-1019) for failing to have "sufficient test stations to measure the adequacy of cathodic protection" on certain pipelines was because these pipeline operators

had interpreted and implemented 49 CFR 192.469 as requiring a monitoring station "approximately every mile."

122. It would be unreasonable to authorize a 70% increase in the number of coupon test stations during the Rate Case Period.

123. PG&E has not demonstrated that it must install only coupon test stations, especially when there are other alternatives already used as monitoring points on PG&E's system.

124. It would be reasonable to authorize PG&E to install 60 coupon test stations each year, or a total of 180 coupon test stations during the Rate Case Period.

125. PG&E should be authorized to recover capital expenditures to install 60 coupon test stations each year of the Rate Case Period.

126. PG&E's forecast 2015 expenses for its Corrosion Investigation Program are reasonable and should be adopted.

127. PG&E's forecast 2015 expenses for its Close Interval Survey Program are reasonable and should be adopted.

128. PG&E's forecast capital expenditures and 2015 expenses for the AC Interference Program are reasonable and should be adopted.

129. PG&E's forecast capital expenditures and 2015 expenses for the DC Interference Program are reasonable and should be adopted.

130. It is reasonable to conclude that a portion of the 335 contacted casings to be mitigated are due to PG&E's failure to properly inspect prior casing mitigations.

131. Since PG&E would have already received ratepayer funding to perform these casing mitigations, ratepayers should not fund the costs for additional mitigation due to improper inspections.

132. Based on the percentage of non-compliance found in NCR06, 19% of the proposed capital and expense casing mitigation projects for the Rate Case Period

should be funded by PG&E shareholders to correct prior work that was performed improperly.

133. PG&E should mitigate 94 capital casings during the Rate Case Period and 117 expense casings in 2015, but should only recover the costs for 29 of the capital mitigation projects and 95 of the expense casing mitigation projects from ratepayers.

134. PG&E's 2015 expense forecast of $1.202 million for casing testing (without test facilities) is reasonable and should be approved.

135. PG&E's forecast expenses and capital expenditures for the Internal Corrosion program are reasonable and should be adopted.

136. PG&E's forecast expenses for the Atmospheric Corrosion program are reasonable and should be adopted.

Gas Transmission System Operations and Maintenance Activities

137. PG&E's forecast 2015 expenses for the Locate and Mark Program are reasonable and should be adopted.

138. PG&E's forecast 2015 expenses for the Pipeline Maintenance Program are reasonable and should be adopted.

139. PG&E's forecast 2015 expenses for the Station Maintenance Program are reasonable and should be adopted.

140. PG&E's forecast transmission expense projects for the Pipeline Projects Program and the Permits & Fees Projects Program are reasonable and should be adopted.

141. PG&E's forecast 2015 expenses for the Stanpac transmission pipeline system are reasonable and should be adopted.

Other GT&S Support Plans

142. PG&E's allocation of building expenses should be revised to reflect the 60% of PG&E's Gas Operations headquarters cost allocated to transmission pursuant to the *2014 GRC Decision*.

143. PG&E's 2015 forecast expense for Buildings and Process Safety Organization Support should be revised $5,479,692 and adopted.

144. PG&E's forecast 2015 expenses for Environmental Operational Costs are reasonable and should be adopted.

145. PG&E's forecast 2015 expenses for the Habitat and Species Protection Program are reasonable and should be adopted.

146. PG&E's forecast 2015 expenses for Hazardous Waste Disposal and Transportation Costs are reasonable and should be adopted.

147. PG&E's forecast 2015 expenses for Research and Development Costs are reasonable and should be adopted.

148. PG&E's forecast 2015 expenses for Customer Access Charge Costs are reasonable and should be adopted.

149. The stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 12 – Other GT&S Support Costs* (Exh. Joint-3 at 13-15), regarding tools and equipment, is reasonable and should be adopted.

150. PG&E's capital forecast for Building Management Expenditures should be revised to $18,492,258 to reflect the 60% allocation adopted in the *2014 GRC Decision.*

151. PG&E's revised capital forecast for Building Management Expenditures is reasonable and should be adopted.

Gas System Operations

152. PG&E's forecast 2015 expenses for Gas Operations Staff are reasonable and should be adopted.

153. The stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 10 – Gas Operations*, concerning Electricity Costs for Gas Compressor Operations is reasonable and should be adopted.

154. Based on the directives in D.15-10-032, PG&E's recovery of expenses for GHG compliance instruments will be recovered as part of the annual true-up process, and allowing recovery of these expenses as part of the GT&S application would result in double recovery.

155. PG&E's request to recover expenses for GHG compliance instruments should be removed from the GT&S forecast.

156. The stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 10 – Gas Operations*, concerning Greenhouse Gas Compliance Instruments should be rejected.

157. PG&E's forecast 2015 expenses for Research and Development Costs are reasonable and should be adopted.

158. PG&E's forecast capital expenditures for New Business and Meter Sets – Power Plants are reasonable and should be adopted.

159. PG&E's forecast capital expenditures for Normal Operating Pressure Reductions are reasonable and should be adopted.

160. PG&E's forecast capital expenditures for Pipe Betterments are reasonable and should be adopted.

161. PG&E's forecast capital expenditures for Customer Demand Growth (New Capacity) are reasonable and should be adopted.

162. PG&E's forecast capital expenditures for the Line 407 project is reasonable and should be adopted, with recovery of costs subject to the stipulation between PG&E and ORA regarding the Post Test Year Cost Recovery Mechanism.

163. PG&E's proposed use of Network Investment Plans is unopposed and should be adopted.

164. PG&E's direct and rebuttal testimony on allocation of storage assets was inconsistent with its responses to Calpine's data request and did not provide Calpine a fair opportunity to conduct further discovery or prepare cross examination on this issue.

165. The ALJ's oral ruling granting Calpine's motion to strike from the record PG&E's testimony to allocate additional storage injection and withdrawal capacity to load balancing should be affirmed.

166. PG&E should be allowed to propose to reallocate storage assets for load balancing in a future proceeding, where a full and complete record can be developed.

167. Gill Ranch has not demonstrated a need for daily balancing and its proposal that daily balancing should be required in place of the current monthly balancing system is rejected.

Information Technology

168. The stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 11 – Information Technology*, is reasonable and should be adopted.

Reporting and Program Management

169. The stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 13 – Reporting and Communications*, is reasonable and should be adopted.

170. The February 26, 2015 oral stipulation between PG&E and Calpine is reasonable and should be adopted.

171. The stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 9 – Program Management Office*, is reasonable and should be adopted.

172. The stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 9 – Program Management Office* (Exh. Joint-3 at 6-8), is reasonable and should be adopted.

Results of Operations

173. PG&E's uncollectibles factor for this Rate Case Period should be based on Advice Letter 3535-G/4540-E and Advice Letter 3612-G/4675-E

174. The uncollectibles factor in Advice Letter 3612-G/4675-E should be applied for both 2016 and 2017.

175. PG&E's methodology for computing O&M expenses is unopposed and should be adopted.

176. The final RO model should include the updated A&G expense in accordance with the 2014 GRC Decision.

177. PG&E's methodology for computing A&G expenses is unopposed and should be adopted.

178. PG&E's methodology for computing forecast plant additions, forecast plant retirements and allocation of common, general and intangible plant is unopposed and should be adopted.

179. The stipulation between PG&E, TURN and ORA, *Joint Depreciation Stipulation*, is reasonable and should be adopted.

180. PG&E's methodology for computing GT&S rate base is unopposed and should be adopted.

181. The Results of Operations model in the Decision incorporates the PSEP update to actual costs.

182. The stipulation between PG&E and ORA, *Joint Stipulation on Treatment of NOLC and Bonus Depreciation* is reasonable and should be adopted.

183. PG&E's proposed methodology to compute income taxes, with the exception of NOLC and bonus depreciation, should be adopted.

184. PG&E's methodology for computing Taxes Other than Income is unopposed and should be adopted.

Cost Recovery Issues

185. There is no evidence that a two-way balancing account revenue structure would have an impact on PG&E's ability or incentives to identify and mitigate risks.

186. PG&E's proposal to discontinue the GTSRSM and replace it with a two-way balancing account revenue structure is denied.

187. Pub. Util. Code § 969 does not require the adoption of a two-way TIMP balancing account.

188. While a two-way balancing account would allow any savings to be passed on to ratepayers, it also subjects ratepayers to the risk of higher rates in the event PG&E's costs exceed authorized amounts.

189. A two-way balancing account could allow PG&E to seek recovery for cost overruns and does not encourage PG&E to seek reasonable costs.

190. Recovery of costs to implement new rules or "new areas" requiring additional costs are more appropriately addressed and resolved by an Administrative Law Judge as part of a formal proceeding.

191. PG&E should be authorized to establish a new Transmission Integrity Management Program Memorandum Account to track costs associated with any new transmission integrity management statutes or rules.

192. PG&E should seek recovery of costs in the Transmission Integrity Management Program Memorandum Account through the filing of a formal application.

193. PG&E's proposal to continue the Adjustment Mechanism for Costs Determined in Other Proceedings tracking account should be adopted.

194. Pursuant to D.15-10-032, the accounting process for recovering PG&E's GHG compliance costs should be included as part of PG&E's existing true-up advice letter process.

195. Given the adoption of *Joint Stipulation on Treatment of NOLC and Bonus Depreciation*, the TAMA balancing account should not be terminated.

196. The *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year Mechanism* should be revised include the errata figures contained in Exh. PG&E-46, Table 18-5 (with Errata).

197. The *Joint Stipulation Comparison Exhibit Chapter 18 – Post Test Year Mechanism* is reasonable and should be adopted as revised.

Other Revenue Requirement and Cost Recovery Issues

198. The record does not support a conclusion that SED or Energy Division were tasked with performing a reasonableness review or had made any determinations with respect to the reasonableness of PG&E's 2011-2014 capital expenditures.

199. The $80.871 million associated with small projects in PG&E's 2011-2014 capital expenditures are unreasonable and should not be recovered in rates.

200. Rate recovery of $118.639 million for the four projects in PG&E's 2011-2014 capital expenditures should be excluded from this Rate Case Period and be subject to a third party review to determine the appropriate amount to be recovered from ratepayers.

201. The $18,106,206 increase in 2011-2014 capital expenditures for six projects in MWC-98 that were represented to have been fully funded in the Gas Accord V Settlement Agreement are not reasonable and should be disallowed.

202. The $21,432,557 increase in 2011-2014 capital expenditures for three projects in MWC-75 that were represented to have been 98% funded in the Gas Accord V Settlement Agreement are not reasonable and should be disallowed.

203. Although capital expenditures during 2011-2014 above the amount authorized in the *Gas Accord V Decision* may have been necessary, PG&E's initial and supplemental testimonies do not support a finding of reasonableness.

204. PG&E bears the burden to demonstrate that the 2011-2014 capital expenditures above the amount authorized in the *Gas Accord V Decision* were incurred prudently and that it made best efforts to contain costs (e.g., that there were competitive bids for contracts, that that the pace of any work performed did not result in unwarranted upward cost pressures, that cost overruns were explained and reasonable).

205. A third party audit should be conducted to examine all 2011-2014 capital expenditures above the amount authorized in the *Gas Accord V Decision* not approved or disallowed in this decision. The cost of the third party audit should be paid for by PG&E shareholders.

206. The third party audit should be overseen jointly by the Energy Division and the Safety and Enforcement Division.

207. PG&E's unlawful conduct directly attributed to a five-month delay in this proceeding.

208. Adopting a ratemaking remedy to address a five-month delay caused by PG&E's improper ex parte communications adopted in the *Ex Parte Sanctions Decision* does not exceed the maximum fine under Pub. Util. Code § 2107.

209. PG&E shareholders should be responsible for the incremental amount of 2015 revenues that would be amortized over a five month period, or $164.003 million associated with the delay caused by PG&E's violation of the ex parte rules.

210. PG&E's method to allocate the PCC costs between distribution and transmission functions is reasonable and should be adopted.

211. A reduction in the GT&S revenue requirements based on allocation of 100% of common PCC costs to transmission would accomplish the intent of the *Penalties Decision* only if PG&E had used such an allocation to develop its original forecast of GT&S revenue requirements.

212. As long as any remedy regarding implementation costs allocated to distribution are excluded from the revenue requirements paid for by ratepayers, PG&E does not realize any unfair advantage.

213. PG&E's proposed approach to remove relevant distribution-related costs from its 2017 GRC so as to ensure that ratepayers do not pay for any costs relating to implementing the remedies adopted in the *Penalties Decision* is reasonable and should be adopted.

Rate Issues

214. The stipulation between PG&E and ORA, *Joint Stipulation Comparison Exhibit Chapter 14 – Throughput Forecast*, is reasonable and should be adopted.

215. PG&E's forecasts for off-system revenue, Silverado path flow, forecast of backbone transmission from contract volumes, as presented in Chapter 14 of Exh. PG&E-2, Table 14-4 (Redwood Off-System Uncommitted Revenue Forecast for Summer Months 2015-2017), Table 14-7 (Non-GXF Revenue Forecast 2015-2015), and Table 14-8 (Firm Backbone Contracts) are reasonable and should be adopted.

216. PG&E's forecast for the continuation of existing discounted contracts, as discussed in Exh. PG&E-2 at 14-25 – 14-26, are reasonable and should be adopted.

217. PG&E's proposal to equalize the backbone rates for the Redwood and Baja paths should be denied and the existing differential backbone rate structure should continue to apply.

218. The current rate structure creates a fair and reasonable differential between PG&E's two primary transmission paths.

219. PG&E's proposal to equalize rates could undermine the Gas Accord's vintage rate protections for core customers.

220. Equalization of the rates would not be cost based and would create unfair cross subsidies.

221. Some Redwood shippers have borne the higher costs of the Redwood path for many years and it would be unfair to force them to subsidize the now-higher costs of the Baja path through rate equalization.

222. Maintaining a path-specific rate design provides more accurate price signals to shippers who would bring future incremental supplies to northern California.

223. The fact that SoCalGas's circumstances are suited to postage-stamp backbone rates does not mean that path-specific backbone rates are appropriate in PG&E's service territory.

224. The fixed differential between the Redwood and the Baja paths established for the last year of the Gas Accord V settlement was $0.040/Dth and should be adopted for this Rate Case Period.

225. PG&E's methodology for calculating the system average load factors for non-equalized rates is reasonable and should be adopted.

226. PG&E's forecast firm annual delivery capacity for the Baja and Redwood Paths are unopposed and should be adopted.

227. Expenditures to enhance the safety of transmission pipelines benefit core and noncore customers equally.

228. While CWD may reflect the design criteria used by PG&E to construct the local transmission system, it does not reasonably reflect the costs imposed by core and noncore customers for this shared resource.

229. Calpine/Indicated Shippers' recommendation to allocate local transmission costs based on CWD should be denied.

230. PG&E should provide an analysis as part of its next GT&S application demonstrating whether local transmission costs should be allocated more equitably by accounting for the actual relationships between pipeline capacity, throughput and costs.

231. PG&E's proposed firm injection and withdrawal capacities for the system and lower inventory capacity for storage are unopposed and should be adopted.

232. Table 17-1 in Exhibit PG&E-2 should be revised to reflect that PG&E's proposal to allocate 130 MMcf/d (133 MDth/d) of injection capacity and 200 MMcf/d (204 MDth/d) of withdrawal capacity to balancing, along with the

associated revenues had been struck from the record in this proceeding in its entirety.

233. The allocation of storage costs should be based on the storage units contained in Table 43 of this Decision.

234. PG&E's proposed changes to Core's injection and withdrawal rights are unopposed and should be adopted.

235. PG&E's proposed Transmission Level Customer Access Charges are unopposed and should be adopted.

236. The existing rate structure based on separate costs assigned to rate schedules for EG-BB and EG- LT, i.e., All Other Customers (EG-AOC) is just and reasonable.

237. Dynegy's and NCGC's proposals for a single EG transportation rate should be denied.

238. It would be unfair to require all EG customers to pay the same transportation rate, regardless of whether they connect to PG&E's system at the backbone or at the local transmission level.

239. Dynegy purchased Moss Landing Units 1 and 2 after the differential between backbone-level and local transmission-level EG rates already existed and thus likely took the differential into account when it purchased the Moss Landing plants.

240. Rates can reasonably reflect differences that result from locational attributes so long as those differences are based on cost causation.

241. PG&E's proposal for the continuation of separate rates for Electric Generators (i.e., separately stated EG-BB and EG-LT rate structures) does not violate Pub. Util. Code § 453(c).

242. Dynegy's proposal for continuation of some version of the Local Transmission Bill Credits should be denied.

243. Dynegy's proposal to create a new rate class higher than the G-EGBB rate is not adequately developed and should be denied.

244. NCGC's proposal to expand the classification of backbone facilities should be denied and it is inconsistent with the Commission's definition of backbone facilities as pipelines that originate at receipt points with interstate pipelines or other utilities.

245. Dynegy's proposal to purchase or lease Line 301-G, the local transmission line serving Moss Landing Units 1 and 2 should be considered in the context of an application under Pub. Util. Code § 851 and is outside the scope of this proceeding.

246. Dynegy's proposal that it enter into a long-term contract with payments to PG&E based on Dynegy's hypothetical cost to build a direct connection to PG&E's backbone and bypass the local transmission system should be denied.

247. Commercial Energy's proposal to lower the current 250 Dth/year threshold to qualify for noncore status to 100 Dth/year should be denied.

248. Since the definition of noncore customer, including the minimum threshold, was adopted in a rulemaking that applied to all gas utilities, it is not appropriate to change this definition on a utility-by-utility basis.

249. PG&E's proposed British Thermal Unit (Btu) conversion factors for rate design and other purposes is unopposed and should be adopted.

250. PG&E's proposed rates should reflect the revised base shrinkage allowance percentages (exclusive of the adopted adjustment allowances) adopted in Advice Letter 3513-G (for rates effective November 1, 2014) and Advice Letter 3630-G (for rates effective November 1, 2015). Additionally, PG&E's proposed

rates shall reflect the base shrinkage allowance from Advice Letter 3630-G during the period beginning November 1, 2016, for which PG&E has not yet filed new shrinkage rates.

Core Gas Supply

251. PG&E's proposed changes to core intrastate pipeline capacity allocation are unopposed and should be adopted.

252. PG&E should be authorized to file a Tier 1 Advice Letter if the need arises for it to increase intrastate pipeline capacity corresponding to interstate pipeline approval requests.

253. The joint stipulation between PG&E and Palo Alto, *Joint Redwood and Baja Capacity Allocation Stipulation*, is reasonable and should be adopted.

254. PG&E's proposed storage inventory for Core Storage Contract and its proposal to adjust the November to March withdrawal rights to fully incorporate existing assets that are available to meet peak load conditions are unopposed and should be adopted.

255. PG&E's proposal to adjust the 1-Day-in-10-Year Core Capacity Planning Standard (Reliability Standard) by explicitly allowing for the assumption of 330 MDth/d of firm gas supply at PG&E's Citygate is unopposed and should be adopted.

256. PG&E's proposed changes to the CPIM are unopposed and should be adopted.

257. PG&E's proposal that it be authorized to make certain changes to the CPIM mechanism for determination of PG&E's benchmark upon agreement between PG&E and ORA is reasonable and should be adopted.

258. PG&E should notify parties and Energy Division of any changes to the CPIM mechanism upon agreement between PG&E and ORA within 15 days after the changes become effective.

259. The determinations in D.15-10-050 could impact how the allocation of capacity (and thus costs) should be changed.

260. PG&E's proposal to change the pipeline capacity allocation methodology from a January Capacity Factor to a Seasonal Capacity Factor should be denied.

261. Commercial Energy's proposal to change the pipeline capacity allocation methodology from a January Capacity Factor to a Peak Day Usage Factor should be denied.

262. PG&E should meet and confer with the CTAs to discuss changes to the capacity factor prior to filing a new proposal.

263. PG&E's proposal to delay the implementation of assignment (and the corresponding assumption of cost responsibility) of incremental storage capacity to CTAs is unopposed and should be adopted.

Core Transport Agent Issues

264. Incorporating gas SmartMeter data in the CLFM would likely provide even greater Determined Usage accuracy.

265. PG&E should be exploring the possibility of using data from the gas SmartMeters for more than just monthly billing.

266. PG&E should meet regularly with the CTAs to explore future changes to the CLFM.

267. The CTAs should be provided detailed gas SmartMeter usage data for their customers to the extent this data can be provided without imposing undue operational burden on PG&E.

268. A Core Transport Agent providing gas aggregation service to customers in accordance with the provisions of Schedule G-CT and the Core Gas Aggregation Service Agreement is a "covered entity", as that term is defined in Gas Rule 27, and are entitled to receive gas SmartMeter usage data for their customers.

269. PG&E should hold a workshop within 60 days of the effective date of this Decision to explore how TA customer usage data generated by gas SmartMeters may be provided to CTAs.

270. Due to the need for system reliability and safety, CTAC and Commercial Energy's proposals that PG&E no longer procure intrastate capacity on behalf of the CTAs should be denied.

271. CTAC and Commercial Energy's proposals that PG&E no longer procure storage services on behalf of the CTAs should be granted.

272. Allowing CTAs to procure storage services on their own does not present the same reliability concerns as with CTA procurement of intrastate capacity.

273. Allowing CTAs to plan and procure storage services on their own is consistent with the Commission's overall objectives to create a competitive natural gas storage market and to provide utility customers the option to purchase gas supplies directly from CTAs rather than the investor-owned utility.

274. Procurement of storage services for CTAs should transition from PG&E to the CTAs themselves over a 10-year period commencing on January 1, 2018.

275. Within 90 days of the effective date of this Decision, Energy Division should host a workshop for PG&E, the CTAs and consumer groups to address changes to Schedule G-CT to implement the transition to CTA self-procurement of storage services.

276. PG&E should include proposed changes to Schedule G-CT as part of its 2018-2020 GT&S application.

277. CTAC's proposal to modify the second and third options for complying with the Firm Winter Capacity to permit the use of third-party firm storage capacity is unopposed and should be adopted.

278. CTAs should be provided additional flexibility in the types of gas assets that can be used to meet their Firm Winter Capacity Requirement.

279. The Firm Winter Capacity Requirement cannot be met through a promise to provide gas at PG&E's Citygate.

280. CTAC's proposal to add a fourth option to comply with the Firm Winter Capacity Requirement is granted.

281. Gas Schedule G-CT should be modified to give CTAs the option to meet their Firm Winter Capacity Requirement by contracting with a party other than PG&E demonstrating firm gas delivery to the PG&E Citygate.

282. Gas Rule 23 furthers the Commission's policy to protect customers from service disconnections.

283. CTAC and Commercial Energy's proposal to change Gas Rule 23 to allocate partial payments on past due accounts pro rata between PG&E charges and CTA charges should be denied.

284. PG&E should only allocate partial payments to PG&E charges first when the account is subject to service termination pursuant to Gas Rules 8 and 11.

285. PG&E should not designate accounts as "delinquent" simply based on a CTA customer's history of late payment or because the CTA carries a balance.

286. Form 79-845A should be revised to explicitly state that customer billing information will be disclosed to the CTA.

287. Adopting PG&E's interpretation that CTAs are third parties would contradict portions of Pub. Util. Code § 985.

288. A CTA is an agent of its core customers and, for purposes of billing those core customers; PG&E is an agent of the CTA when it is doing the combined billing on behalf of the CTA.

289. PG&E should work with interested CTAs to redesign Form 79-845A to authorize PG&E to release a CTA customer's billing and payment information, including any negotiated payment plans entered into between the customer and PG&E for payment of past due or delinquent CTA charges, to the CTA.

290. Within 90 days of the effective date of this Decision, PG&E should file a Tier 2 Advice Letter, which will describe the process it undertook to revise Form 79-845A with interested CTAs and proposing a revised Form 79-845A.

291. Until Form 79-845A is revised, PG&E should provide the CTA customer's billing and payment information to the CTA upon receipt of an acknowledgement for disclosure of billing information through a letter or other form.

292. Given the agency relationship between the CTA and its customer, the CTA is not a "third party" and Form 79-1095 is not applicable to CTAs.

293. Commercial Energy's proposal to include the CTA in any negotiations of payment plans should be denied.

294. PG&E should meet with CTAs to determine whether the various reports currently provided to CTAs should be revised and propose those revisions in its next GT&S application.

Administrative Matters

295. The California Asian Pacific Chamber of Commerce's motion to withdraw as a party should be granted.

296. If the proposal for allocation of the $850 million penalty adopted in the *Penalties Decision* contained in Appendix G were adopted, there would not be a

need for a second decision to address this allocation and PG&E's rates could go into effect upon the filing of a Tier 1 Advice Letter.

297. Parties should comment on the proposal to allocate the $850 million disallowance as part of their comments on the Proposed Decision.

298. Parties advocating for a second decision should include in their comments the specific factual issues that need to be addressed and a proposed schedule.

299. The difference between the authorized revenue requirements in this decision and the placeholder revenue requirement incorporated in gas rates PG&E has collected in the Gas Transmission and Storage Memorandum Account should be amortized over 18 months.

300. All rulings issued by the ALJ in response to the motions should be confirmed.

301. The proposed transcript corrections filed by PG&E, TURN, ORA, Calpine, NCGC, CTAC, SPURR, Commercial Energy and Dynegy should be adopted.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is authorized to collect, through rates and authorized ratemaking accounting mechanisms, over the remainder of this gas transmission and storage rate case cycle through December 31, 2017 the (i) test year revenue requirement set forth in Appendix C of this decision, less (ii) the amount collected by PG&E base rates since January 1, 2015, and prior to the implementation of the revenue requirement authorized by this decision, plus (iii) interest on the difference between (i) and (ii), with said interest based on the

rate for prime, three-month commercial paper reported in Federal Reserve Statistical Release H-15. This difference shall be amortized over 18 months.

2. Pacific Gas and Electric Company's proposed risk management approach and asset family categories are adopted for use in this gas transmission and storage application.

3. Pacific Gas and Electric Company's proposal to reclassify 920 miles of distribution pipe to transmission pipe is granted.

4. Pacific Gas and Electric Company shall file quarterly compliance reports of its hydrotest work. The reports shall follow the format in Attachment D of Decision 12-12-030, revised to reflect the projects proposed for the Rate Case Period. PG&E's first compliance filing shall cover the period between January 1, 2015 and the quarter in which this Decision is issued, and shall be due no later than 30 days after the end of the quarter.

5. Pacific Gas and Electric Company shall replace 99 inoperable or hard-to-operate valves during the 2015-2017 Rate Case Period. The maximum amount PG&E may recover from ratepayers for this work is $22.188 million. Any costs above this amount shall be paid for by shareholders.

6. Pacific Gas and Electric Company shall file a Tier 2 Advice Letter within 15 days of the effective date of this decision to establish a one-way balancing account to track the difference between amounts adopted for the Work Required by Others Program in this decision and the portion of costs assigned to customers over the 2015 Gas Transmission and Storage (GT&S) rate cycle. At the end of the 2015 GT&S rate case cycle, any unspent funds in the balancing account shall be returned to customers as part of the Annual Gas True-Up filing. The amounts to be tracked are: $17.3 million in 2015, $17.697 million in 2016 and $18.158 million in 2017.

7. Pacific Gas and Electric Company shall file a Tier 2 Advice Letter within 15 days of the effective date of this decision to establish a one-way balancing account to track the difference between amounts adopted in this decision and the actual costs to perform Hydrostatic Station Testing work during the Rate Case Period on stations installed on or before January 1, 1956. This difference reflects costs for Hydrostatic Station Testing work on stations installed on or after January 1, 1956 which should be borne by shareholders. Therefore, at the end of the 2015 GT&S rate case cycle, any unspent funds in the balancing account shall be returned to customers. The 2015 amounts to be tracked in the balancing account are: $15.633 million for ECA Phase 1, $8.682 million for ECA Phase 2, $455,403 for hydrostatic station testing (C&P) and $5.470 million for hydrostatic station testing (M&C). The 2016 amounts to be tracked are: $16.008 million for ECA Phase 1, $8.890 million for ECA Phase 2, $466,318 for hydrostatic station testing (C&P) and $11.200 million for hydrostatic station testing (M&C). The 2017 amounts to be tracked are: $16.383 million for ECA Phase 1, $9.098 million for ECA Phase 2, $477,263 for hydrostatic station testing (C&P) and $22.940 million for hydrostatic station testing (M&C).

8. Pacific Gas and Electric Company shall file a Tier 2 Advice Letter within 15 days of the effective date of this decision to track the difference between amounts adopted in this decision and the actual costs of Critical Documents Program work for facilities built on or before December 31, 1955. At the end of the rate case cycle, the difference between the amount authorized and the actual costs of Critical documents Program work for facilities built on or before December 31, 1955 shall be returned to ratepayers, in keeping with our mandate that shareholders bear the cost of Critical Documents Program work on facilities built on or after January 1, 1956. The amounts to be tracked in the balancing

account are: $11.573 million in 2015, $11.850 million in 2016 and $12.129 million in 2017.

9. Gill Ranch Storage LLC's proposal for daily balancing is denied.

10. Pacific Gas and Electric Company's proposal to discontinue the GT&S Revenue Sharing Mechanism (GTSRSM) and replace it with a two-way balancing account revenue structure is denied. The GTSRSM negotiated as part of the Gas Accord V Settlement Agreement and adopted in Decision 11-04-031 remains in place.

11. Pacific Gas and Electric Company's proposal to change the one-way Transmission Integrity Management Program Balancing Account adopted in Decision 11-04-031 to a two-way balancing account is denied.

12. The one-way Transmission Integrity Management Program Balancing Account adopted in Decision 11-04-031 remains in effect. The amounts to be tracked, by program, are in Appendix I, Tables I-1 and I-2.

13. Pacific Gas and Electric Company shall file a Tier 2 Advice Letter within 15 days after the effective date of this Decision to establish a new Transmission Integrity Management Program Memorandum Account to track costs associated with any new transmission integrity management statutes or rules effective after January 1, 2015. Pursuant to Pub. Util. Code § 969, costs incurred in the following programs shall be tracked in the memorandum account:

Description	Category
Traditional In-Line Inspections (ILI)	Expense/Capital
Non-Traditional ILI	Expense/Capital
ILI Casings	Expense
Traditional ILI - Direct Examinations and Repairs	Expense
Non-Traditional ILI - Direct Examinations and Repairs	Expense
External Corrosion Direct Assessments	Expense
Internal Corrosion Direct Assessments	Expense

Stress Corrosion Cracking Direct Assessments	Expense
TIMP Pressure Tests	Expense
Geological Hazard Monitoring	Expense
Root Cause Analyses	Expense
Risk Analysis Process Improvements	Expense

PG&E shall seek recovery of costs in this memorandum account through the filing of a formal application.

14. Pacific Gas and Electric Company (PG&E) must limit the amounts recorded in the balancing accounts authorized in this Decision to the adopted expense and capital amounts set forth in Appendix I. 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. PG&E is authorized to collect from ratepayers only the revenue requirements associate with actual expenses and capital costs recorded in the balancing account.

15. Pacific Gas and Electric Company's proposal to terminate the Tax Act Memorandum Account balancing account is denied.

16. Pacific Gas and Electric Company's (PG&E) request to recover as part of this Gas Transmission and Storage application $696.4 million associated with 2011-2014 capital expenditures in excess of the amount authorized in Decision 11-04-031 is denied and shall be removed from PG&E's request. Of the amount removed, $120.409 million is permanently disallowed and shall not be recovered by PG&E in future rates. The remaining $575.991 million shall be subject to an audit by Commission staff or a third party, and may be recovered in a future application. The Commission's Energy Division and Safety and

Enforcement Division (SED) shall oversee the audit which shall include, at a minimum:

> a. an assessment of whether the project is related to the Pipeline Safety Enhancement program rather than to Gas Transmission and Storage;
>
> b. a determination of the extent to which the project costs were inflated by factors such as the accelerated nature of PG&E's gas transmission system remediation work during that time period; and
>
> c. a determination of the extent to which any project is necessary due to prior work that had not be performed correctly or had previously been funded in rates but never performed.

The audit shall be completed as soon as practicable. Energy Division and SED shall provide a status update to the Executive Director every six months until the audit is completed. A copy of the audit report will be provided to the Energy Division, SED and PG&E.

17. Pacific Gas and Electric Company (PG&E) may file an application to seek recovery of the $575.991 million in 2011-2014 capital expenditures that have not been disallowed after it has received the third-party audit report. This application shall not include any other requests, and PG&E shall not combine this application with any other applications. The audit report shall be part of the record, and be sponsored by the Commission's Safety and Enforcement Division.

18. Pacific Gas and Electric Company's proposed allocation of storage costs is denied.

19. Pacific Gas and Electric Company's proposal to equalize the backbone rates for the Redwood and Baja paths is denied and the existing differential backbone rate structure of $0.40/Dth continues to apply.

20. Dynegy Inc.'s and Northern California Generation Coalition's proposals for a single EG transportation rate are denied. Dynegy Inc.'s alternate proposals to a single EG transportation rate are also denied.

21. Commercial Energy of California's proposal to lower the current 250 Dth/year threshold to qualify for noncore status to 100 Dth/year is denied.

22. Pacific Gas and Electric Company's (PG&E) proposed changes to the Core Procurement Incentive Mechanism (CPIM) are adopted. PG&E shall serve notice of any changes to the CPIM as the result of an agreement between PG&E and the Office of Ratepayer Advocates within 15 days of the effective date to the Energy Division, and parties to PG&E's most recent Gas Transmission and Storage application.

23. Pacific Gas and Electric Company's (PG&E) proposal to change the pipeline capacity allocation methodology from a January Capacity Factor to a Seasonal Capacity Factor is denied. PG&E shall meet with interested Core Transport Agents to discuss changes to the capacity factor prior to filing a new proposal.

24. Commercial Energy of California's proposal to change the pipeline capacity allocation methodology from a January Capacity Factor to a Peak Day Usage Factor is denied.

25. Pacific Gas and Electric Company's (PG&E) proposed modifications to the Core Load Forecasting Model (CLFM) are adopted. Additionally, PG&E shall meet regularly with the Core Transport Agents to explore future changes to the CLFM and to consider how to incorporate gas SmartMeter data to improve the accuracy of Determined Usage.

26. Pacific Gas and Electric Company shall provide the Core Transport Agents (CTA) detailed gas SmartMeter usage data for their customers to the extent this

data can be provided without imposing undue operational burden on PG&E. Additionally, PG&E shall hold a workshop within 60 days of the effective date of this decision to explore how CTA customer usage data generated by gas SmartMeters may be provided to CTAs, including the format for the data, and the timing for when PG&E shall begin providing the data.

27. Pacific Gas and Electric Company shall provide an analysis as part of its next gas transmission and storage application demonstrating whether local transmission costs should be allocated more equitably by accounting for the actual relationships between pipeline capacity, throughput and costs.

28. The Core Transport Agent Consortium's and Commercial Energy of California's proposals that Pacific Gas and Electric Company no longer procure intrastate capacity on behalf of the Core Transport Agents are denied.

29. The Core Transport Agent Consortium's and Commercial Energy of California's proposals that Pacific Gas and Electric Company (PG&E) no longer procure storage services on behalf of the Core Transport Agents (CTA) are granted. There will be a ten-year transition period, commencing on January 1, 2018. During this transition PG&E will reduce the amount of storage that it procures and allocates to each CTA by 10% the first year (2018), increasing the amount to be reduced by an additional 10% each subsequent year until PG&E no longer procures any storage services on behalf of the CTA. During this transition period, CTAs may still reject some or all of the PG&E-allocated core firm storage capacity, but will be responsible for those stranded costs. The CTA's procurement of storage capacity for the amount that is not allocated by PG&E may be from PG&E or a Commission-certified independent storage provider.

30. The Energy Division shall host a workshop for Pacific Gas and Electric Company (PG&E), the Core Transport Agents (CTAs), and consumer groups to

address changes to Gas Schedule G-CT to implement the transition from PG&E's procurement of storage services on behalf of the CTAs to the CTAs self-procuring storage services. The workshop shall be held within 90 days after the effective date of this Decision. PG&E shall file a Tier 2 Advice Letter proposing any changes agreed upon by the parties.

31. Pacific Gas and Electric Company's proposal that it file a Tier 3 Advice Letter to implement the assignment (and the corresponding assumption of cost responsibility) of incremental storage capacity to Core Transport Agents once the following two conditions are met: (a) the date occurs on April 1, 2016 or later; and (b) the total incremental core storage withdrawal requirement exceeds 100 MDth/d is granted. The Advice Letter shall be served on the service list of this proceeding.

32. The Core Transport Agent Consortium's proposal to modify the second and third options for complying with the Firm Winter Capacity and to add a fourth option for complying with the Firm Winter Capacity is granted.

33. Within 15 days of the effective date of this Decision, Pacific Gas and Electric Company shall file a Tier 2 Advice Letter to modify Sheet 9 of Gas Schedule G-CT as follows (new language underlined):

> The CTA may satisfy such Firm Winter Capacity Requirement in any combination of the following:
>
> 1. Under the terms of Schedules G-SFT or G-AFT, contract with PG&E for all or part of the CTA's path-specific proportionate share of firm Backbone pipeline capacity PG&E has reserved for Core End-Use Customers.
>
> 2. Contract with a party other than PG&E for guaranteed use of that party's firm Backbone pipeline capacity or for guaranteed use of that party's firm PG&E storage capacity and withdrawal rights in conjunction with Mission Path capacity

under Schedules G-AA or G-NAA or use of third-party firm storage capacity.

3. Contract with PG&E for firm Backbone pipeline capacity or firm storage capacity and withdrawal rights in conjunction with Mission Path capacity under Schedules G-AA or G-NAA or use of third-party firm storage capacity.

4. A CTA may meet the Firm Winter Capacity Requirement by contracting with a party other than PG&E demonstrating firm gas delivery to the PG&E Citygate. 'Demonstrating firm gas delivery' cannot be met by providing a letter from the firm gas supplier guaranteeing Citygate delivery.

34. Pacific Gas and Electric Company (PG&E) shall work with interested Core Transport Agents (CTA) to redesign Form 79-845A to clarify that PG&E is authorized to release a CTA customer's billing and payment information, including any negotiated payment plans entered into between the customer and PG&E for payment of past due or delinquent CTA charges, to the CTA. Within 90 days of the effective date of this Decision, PG&E shall file a Tier 2 Advice Letter, which will describe the process it undertook to revise Form 79-845A with interested CTAs and proposing a revised Form 79-845A.

35. Until Form 79-845A is revised Pacific Gas and Electric Company shall provide the Core Transport Agent (CTA) customer's billing and payment information to the CTA upon receipt of an acknowledgement through a letter or other form from the CTA customer for disclosure of billing information.

36. The stipulation between Pacific Gas and Electric Company, The Utility Reform Network and the Office of Ratepayer Advocates, *Joint Depreciation Stipulation* (Exhibit Joint-1), is adopted.

37. The stipulation between Pacific Gas and Electric Company and the Office of Ratepayer Advocates, *Joint Stipulation on Treatment of NOLC and Bonus Depreciation* (Exhibit Joint-2), is adopted.

38. The stipulation between Pacific Gas and Electric Company and the Office of Ratepayer Advocates, *Joint Stipulation Comparison Exhibit Chapter 5 – Asset Family – Storage* (Exhibit Joint-3 at 3-5) is adopted.

39. The stipulation between Pacific Gas and Electric Company and the Office of Ratepayer Advocates, *ORA-PG&E Joint Stipulation, Engineering Critical Assessment and Hydrostatic Testing (Chapter 6)* (Exhibit Joint-6) is denied.

40. The stipulation between Pacific Gas and Electric Company and the Office of Ratepayer Advocates, *Joint Stipulation Comparison Exhibit Chapter 9 – Program Management Office* (Exhibit Joint-3 at 6-8), is adopted.

41. The stipulation between Pacific Gas and Electric Company and the Office of Ratepayer Advocates, *Joint Stipulation Comparison Exhibit Chapter 10 – Gas Operations* (Exhibit Joint-3 at 9-12) is adopted in part, and denied in part. Those portions of the joint stipulation concerning Electricity Costs for Gas Compressor Operations are adopted and those portions concerning Greenhouse Gas Compliance Instruments are denied.

42. The stipulation between Pacific Gas and Electric Company and the Office of Ratepayer Advocates, *Joint Stipulation Comparison Exhibit Chapter 11 – Information Technology* (Exhibit Joint-4), concerning information programs and projects is adopted

43. The stipulation between Pacific Gas and Electric Company and the Office of Ratepayer Advocates, *Joint Stipulation Comparison Exhibit Chapter 12 – Other GT&S Support Costs* (Exhibit Joint-3 at 13-15), regarding tools and equipment is adopted.

44. The stipulation between Pacific Gas and Electric Company and the Office of Ratepayer Advocates, *Joint Stipulation Comparison Exhibit Chapter 13 – Reporting and Communications* (Exhibit Joint-3 at 16-18), is adopted.

45. The February 26, 2015 oral stipulation between Pacific Gas and Electric Company (PG&E) and Calpine Corporation is adopted. The stipulation, as read into the record states:

> Between August 1st and August 10th of each year, PG&E will post on its website in a location readily accessible to noncore customers best efforts forecast of the year-end true-ups of the noncore balancing accounts for Gas Transmission and Storage (GT&S) revenues of the expected year-end changes in GT&S revenues that impact noncore customers and of the resulting GT&S rate changes expected at the end of the year. PG&E will factor into its forecasts actual and anticipated filings by PG&E and Commission decisions, resolutions and dispositions among other factors that could impact rates.

46. The stipulation between Pacific Gas and Electric Company and the Office of Ratepayer Advocates, *Joint Stipulation Comparison Exhibit Chapter 9 – Program Management Office* (Exhibit Joint-3 at 6-8), is adopted, with footnote 2 on page 26 corrected as follows:

Table 18-5 (Errata Adjusted)		Millions ($)		
Line No.	Program	2015 Forecast	2016 Forecast	2017 Forecast
1	Traditional ILI, including Direct Exam & Repair	28	28	53
2	External and Internal Corrosion Direct Assessment (Errata - PG&E-46)	44	51	65
3	Hydrostatic Testing Station Facility M&C	5	11	23
4	Total	77	91	141

47. The stipulation between Pacific Gas and Electric Company and the Office of Ratepayer Advocates, *Joint Stipulation Comparison Exhibit Chapter 14 – Throughput Forecast* (Exhibit Joint-3 at 19-22), is adopted.

48. The stipulation between Pacific Gas and Electric Company and the city of Palo Alto, Joint Redwood and Baja Capacity Allocation Stipulation (Exhibit Joint-5) is adopted

49. All advice letters filed by Pacific Gas and Electric Company pursuant to this Order shall comply with General Order 96-B and are subject to a finding of compliance by the Energy Division or its successor.

50. The California Asian Pacific Chamber of Commerce's motion to withdraw as a party from this proceeding is granted.

51. All rulings issued by the Administrative Law Judge in response to motions are confirmed.

52. Pacific Gas and Electric Company's motions seeking to file certain confidential information contained in notices of communications under seal are granted. The confidential, unredacted version of the following notices of communication shall remain under seal and shall not be made accessible or disclosed to anyone other than the Commission staff except on the further order or filing of the Commission, the assigned Administrative Law Judge (ALJ), or the ALJ then designated as Law and Motion Judge:

- *Motion of Pacific Gas and Electric Company for Leave to File Confidential Material in Notice of Communication Under Seal Under Rule 11.4*, filed January 5 2016 [communication with Energy Division Director]

- *Motion of Pacific Gas and Electric Company for Leave to File Confidential Material in Notice of Communication Under Seal Under Rule 11.4*, filed April 14, 2016 [communication with Energy Division Director]

53. All outstanding motions filed in this proceeding that have not yet been ruled on are hereby denied.

54. The proposed transcript corrections by the following parties are adopted. The corrections are contained in Appendix K of this Decision.

- Pacific Gas and Electric Company
- The Utility Reform Network
- Office of Ratepayer Advocates
- Calpine Corporation
- Northern California Generation Coalition
- Core Transport Agent Consortium
- School Project for Utility Rate Reduction
- Commercial Energy of California
- Dynegy Inc.

55. The Energy Division workpapers supporting the modeling used to produce the Results of Operations Tables in the appendices of this Decision, in support of the adopted revenue requirements for 2015 through 2017, are received into the record of this proceeding, and identified as Exhibit ALJ-1. Upon the issuance of this decision, the Energy Division will provide a copy of these workpapers 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 workpapers shall contact Energy Division to arrange to receive a copy.

56. The Energy Division results of operations model and rates model, as well as the workpapers supporting the modeling used to produce the Illustrative Rates in the appendices of this Decision, are received into the record of this proceeding, and identified as Exhibit ALJ-2. Upon the issuance of this decision, the Energy Division will provide a copy of the results of operations and rates models, as well as the workpapers supporting the modeling used to produce the Illustrative Rates to Pacific Gas and Electric Company (PG&E) and the Office of

Raepayer 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.

57. All capital expenditure disallowances adopted in this Decision and summarized in Appendix H of this Decision, as well as all self-disallowances identified by Pacific Gas and Electric Company as part of Application 13-12-012 shall be permanently excluded from ratebase, and PG&E shall not earn a rate of return on these assets.

58. Application 13-12-012 and Investigation 14-06-016 remain open.

This order is effective today.

Dated _____, at San Francisco, California.