Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2012.	A.10-12-005 (Filed December 15, 2010)
Application of Southern California Gas Company (U904G) for authority to update its gas revenue requirement and base rates effective on January 1, 2012.	A.10-12-006 (Filed December 15, 2010)

Application: A.10-12-006
Exhibit No.: SCG-205

PREPARED REBUTTAL TESTIMONY OF
RAYMOND K. STANFORD
ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

OCTOBER 2011

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PREPARED REBUTTAL TESTIMONY OF

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I. INTRODUCTION

The following rebuttal testimony regarding Gas Engineering addresses the intervenor testimony dated September 2011 of:

- Division of Ratepayer Advocates (DRA); DRA Exhibits 44 & 45
- Southern California Generation Coalition (SCGC); Catherine Yap, Pages 13-15
- The Utility Reform Network (TURN)/UCAN; Garrick. Jones

Addressed herein are the differences between the Gas Engineering Operating and Maintenance (O&M) and Capital forecasts in my revised direct testimony (Exhibit SCG-05-R), and the direct testimony of each interested party. This rebuttal testimony consolidates the issues raised by DRA, TURN and UCAN, and SCGC since similar issues were addressed by each party. Other activities are addressed separately for DRA.

My rebuttal testimony is organized as follows:

- Section I - Introduction
- Section II – Gas Engineering O&M;
- Section III – Pipeline Integrity – Transmission O&M;
- Section IV – Pipeline Integrity – Distribution O&M;
- Section V – Public Awareness;
- Section VI – Capital Expenditures;
- Section VII - Summary and Conclusion; and
- ATTACHMENTS A through D

In total, SoCalGas is requesting the Commission adopt its 2012 Test Year (TY2012) forecast of $94,452,000 for total Gas Engineering O&M expenses, composed of $78,399,000 for non-shared service (NSS) activities and $16,053,000 (booked expense) for shared service (USS) activities. SoCalGas is also requesting the Commission adopt its forecast of capital expenditures for 2010, 2011, and 2012 of $94,790,000, $114,333,000, and $158,306,000, respectively. The interested parties have each recommended significant reductions to SoCalGas' O&M non-shared services and Capital expenditure requests. There were no objections to the request of $16,053,000 for shared service expenses for TY2012.

The table below summarizes SoCalGas' Gas Engineering request and DRA's recommended funding.

Table RKS-1
Summary of SoCalGas and DRA TY 2012 Recommended Funding
(Thousands of 2009 Dollars)

Gas Engineering	SoCalGas Forecast	DRA Forecast
NSS O&M	$78,399	$29,049
USS O&M	$16,053	$16,053
Total Capital	$158,306	$115,524

The responsibility of Gas Engineering is to provide technical support and policy guidance for compliance with pipeline safety regulations, especially new ones such as the Distribution Integrity Management Program (DIMP) for distribution, transmission and underground storage operations. Southern California Gas Company (SoCalGas) presents this rebuttal testimony to the analysis and conclusions of the above intervenors as it pertains to SoCalGas' Test Year 2012 (TY2012) expense forecast for capital and Operations and Maintenance (O&M), including shared and non-shared services. In this rebuttal testimony, SoCalGas will address both.

First, DRA recommends that the Commission approve SoCalGas' entire Shared-Services (USS), booked expense, proposal. DRA also accepts certain aspects of SoCalGas' Gas Engineering proposals that DRA did not protest. This is also true of certain pipeline integrity program aspects. SoCalGas objects to DRA's recommendations to reduce SoCalGas' funding for key pipeline safety programs. DRA's faulty conclusions, if adopted, is completely contrary to other initiatives being pursued by the state and will inhibit SoCalGas' pipeline safety efforts by cutting needed funding. DRA's testimony claims that SoCalGas did not provide any engineering support. This is absolutely untrue. The fact is that DRA ignored a great volume of engineering analysis provided to it by SoCalGas. DRA also employed selective and inconsistent use of historical data to develop its forecast. The following is a summation of SoCalGas' position on DRA's recommendations per Category of Work for its non-shared services (NSS) and for its shared services (USS) for Operations and Maintenance (O&M) unless otherwise noted in my testimony. In addition, and where applicable, I have discussed the positions of other intervenors.

- Shared Services, USS: DRA did not seek changes to the shared services costs for SoCalGas of $16,053,000 for Gas Engineering.
- Gas Engineering, NSS – DRA has proposed to reduce Gas Engineering's request to fund its core duties. Under Gas Engineering, DRA completely rejects the requests to meet state-mandated environmental regulations under the guise that the rules are not in effect. SoCalGas will rebut this notion with hard evidence.
- Transmission Integrity Management Program (TIMP), NSS – DRA has greatly reduced the funding based on the misconception that SoCalGas has completed its TIMP work. Further, DRA applies a historical trend to make its flawed forecast which further reduces SoCalGas' request. SoCalGas will show that it is on track

to complete its baseline assessment plan by 2012, and used a zero-based, project-specific approach for its forecast.

- Distribution Integrity Management Program (DIMP), NSS – DRA proposes to greatly reduce SoCalGas' funding request based on its perception that SoCalGas did not provide adequate justification or any engineering support. This is untrue and SoCalGas will demonstrate otherwise. DRA did not take exception to the efficacy of the programs proposed but to the rate of mitigation. Under DIMP, it is in the interest of public safety to eradicate known threats, as SoCalGas continues to analyze, identify, and address new ones. DRA's recommended funding would just keep the status quo and not enhance safety as PHMSA intended.
- Public Awareness (PA), NSS – DRA challenged SoCalGas' request and proposes to greatly reduce the funding because DRA alleges that SoCalGas did not provide any support. Again this is incorrect. DRA seems to believe that the status quo is acceptable and ignores the rapidly changing landscape of pipeline safety. The landscape is requiring more be done to improve public awareness from current levels. Again, DRA's proposed funding on pipeline safety activities such as PA would merely maintain the status quo and not support the required public awareness enhancement activities.
- One-Way Balancing Treatment – DRA along with TURN and UCAN argue that SoCalGas should have its Transmission Integrity Management Program funds placed in a one-way balancing account. SoCalGas disagrees and is proposing two-way balancing in response. In addition, SoCalGas is also proposing two-way balancing for DIMP. SoCalGas has also proposed the New Environmental

Regulatory Balancing Account (NERBA) for identified environmental costs in this testimony.

- Reporting – Although TURN and UCAN state that that have deferred to DRA's opinion on the specifics of SoCalGas' pipeline safety programs, they did recommend a reporting requirement similar to that of Pacific Gas and Electric Company (PG&E). SoCalGas does not oppose reporting requirements but such requirements should be meaningful, suited for the purpose intended, and not duplicative.

As for capital, SoCalGas finds inconsistencies between the two DRA witnesses' recommendations covering Gas Engineering's GRC. The DRA witness for O&M rejects SoCalGas' recommendations for the very same programs the DRA capital witness accepts. The DRA witness for capital fully understood the importance of the TIMP and DIMP programs, which merited the acceptance of SoCalGas' programs, with one small exception that will be addressed in this testimony.

The DRA capital witness did not agree with SoCalGas' entire capital forecast and rejected some of SoCalGas' recommendations using faulty logic. For example, DRA would either selectively choose historical data, or adopt 2010 data whichever produced the lowest result. Conversely, DRA refrained from using data that would produce a higher result. SoCalGas rejects DRA's recommendations where DRA deliberately selected historical data to ignore the complete picture. SoCalGas will show in this rebuttal testimony why its forecast is the reasonable choice for the Commission to adopt.

- Transmission, Capital – DRA greatly reduced the funding by ignoring the five-year average and selectively choosing a value that produced a lower forecast, specifically for the New Addition budget category.

- Transmission Integrity Management & Distribution Integrity Management Programs (PIP), Capital – DRA was almost in full agreement with SoCalGas' TY2012 for its pipeline integrity programs. Unlike DRA's O&M witness, its capital witness understood the importance of SoCalGas' pipeline safety programs and accepted nearly all of SoCalGas' recommendations. SoCalGas will address what might be a misunderstanding by DRA of the use/reuse of pig launchers.
- Compressor Station Capital – DRA greatly reduced SoCalGas' request for environmental compliance spending on the premise that the rules are not a tangible reality. SoCalGas will rebut DRA's contention that the environmental rules are not applicable to SoCalGas. I defer to SoCalGas environmental witness Ms. Haines, Exhibit SCG-215, for a complete and detailed assessment of the air quality rules that are the foundation of SoCalGas' request. SoCalGas' request for capital assures timely compliance with the Mojave Desert Air Quality Management District MDAQMD regulations affecting its compressor engines under the air district's jurisdiction.
- Land Rights, Capital – DRA again categorically denied SoCalGas' request to fund land rights based on the contention that such compliance is unfounded. SoCalGas environmental witness Ms. Haines, Exhibit SCG-215, provides a complete and detailed assessment of the importance of having to mitigate for environmental disturbance when pipeline projects have been declared by the permitting agencies to require some quantity of land mitigation. Further SoCalGas will rebut DRA's contention that this mitigation effort is speculative.
- Laboratory Equipment, Capital –DRA adopts SoCalGas' TY2012 proposed increase of $295,000.

- Sustainable SoCal, Capital – DRA categorically rejects SoCalGas' request to install biogas treating facilities. However, DRA did not take exception to the cost estimates; thus if the Commission approves this program, these costs as presented in my testimony should be adopted in their entirety. Instead DRA rejected the request based on policy[1]. The merits of the program are discussed by SoCalGas witness Ms. Wright.

In the timeframe available to respond to DRA and intervenor testimony, SoCalGas did not address each and every DRA and intervenor proposal. However, it should not be assumed that failure to address any individual issue implies any agreement by SoCalGas with the DRA or intervenor proposal.

II. GAS ENGINEERING O&M (NON-SHARED SERVICES)

SoCalGas is requesting total TY2012 O&M expenses for its Gas Engineering workgroup of $21,383,000. This is derived from using the five-year historical average of $10,417,000, to which new or incremental changes, not reflected in historical spending levels, of $10,966,000, have been added to meet the increasing and primarily regulatory-driven demands on the workforce.

In its presentation, DRA has recommended a reduction of $10.566 million, or nearly 50%, of SoCalGas' request. DRA's contentions are based largely on its interpretations of the content, applicability, and timing of various environmental regulatory requirements that SoCalGas has shown as having significant incremental impact to its organization.

The following sections address each of the arguments presented by DRA, TURN and UCAN, and SCGC, and will confirm that SoCalGas' projections are accurate, reasonable, and should be adopted by the Commission.

[1] DRA-045, p. 25.

A. Base Level Expense - Core/Routine Work

Under the broad category of General Engineering, many engineering activities are performed for safe and reliable operations. After careful analysis of the historical data, it was evident that the 2005-2009, five-year average was the most reasonable foundation for the base forecast. Gas Engineering is a mature organization with a well-defined set of routine roles and responsibilities. The nature of the routine work performed, primarily Operations and Engineering Support for Gas Transmission, Underground Storage, and Gas Distribution, is relatively stable with natural variations from year to year which is expected. The five-year forecast methodology is fully supported by the historical data as presented in my revised direct testimony and workpapers and shown in the table below.

Table RKS-2
Gas Engineering 2005-2009 Recorded / TY2012 Forecast
(Thousands of 2009 Dollars)

Description	2005	2006	2007	2008	2009	2012
Gas Engineering	$10,114	$10,718	$10,631	$10,438	$10,189	$21,383

In its recommendation for base level funding, DRA chooses to include only the more recent historical data and not the entire data set provided, 2005-2009. It states that "the annual expenses for Gas Engineering have been slightly decreasing from 2006 to 2009" but fails to mention that the 2009 data is less than 1% different than the 2005 value which is absent from its analysis. Further, DRA disregards the variability evident in the historical data by recommending essentially the lowest value from the entire dataset. Including 2005 data would contradict DRA's assertion that the numbers were trending downward to support use of 2009 as the base forecast. By selectively choosing to ignore 2005 cost data, it is readily apparent that DRA has chosen a base forecast method designed to produce the lowest level of funding. Further, DRA conveniently ignored the 2010 data that validates SoCalGas' forecast.

In addition to the base expense level discussed above, the following incremental expenses are requested which reflect the expanding responsibility and activity Gas Engineering is experiencing and will continue to experience in the Test Year and beyond.

B. Engineering Analysis Center (EAC)

SoCalGas is requesting incremental expenses of $180,000 primarily to support the impacts of increased environmental regulations Mojave Desert Air Quality Management District, (MDAQMD Rule 1160 and AB 32) associated with the various monitoring, sampling, analyzing, reporting, and recordkeeping activities driven by the new regulations.

The EAC is a technical support organization. One of its key functions is providing support for over 200,000 horsepower of compression used for transmission and storage activities. The compressor engines are geographically dispersed throughout the SoCalGas service territory and, as such, fall under various air quality management regulations and land-use permitting requirements. This funding request supports the incremental activities driven by changes to MDAQMD Rule 1160 and AB32, but also EPA 40 CFR Part 98 Subpart W.

In this effort, the EAC's primary responsibility is engineering and technical support rather than monitoring activity. This includes, among other activities, evaluation of monitoring methods and rules, support during facility fugitive gas surveys, engineering direction for reporting systems, development of standard operating procedures, and review of developing rules. As new air quality rules are applied to engines, there is a heightened need for engine and compressor analysis, and more frequent condition monitoring. These result in additional maintenance, tuning, and repairs above those specifically required to maintain compliance. Additionally and important to note is that this technical support is required ahead of rule implementation, and even before and during the rulemaking process. For example, the EAC is currently involved in a pilot program with the MDAQMD to demonstrate emission control technology to help with development of Rule 1160. A Technical Advisor oversees the troubleshooting, tuning, and testing efforts associated with this project.

DRA proposes to disallow the entire $180,000 request based on its understanding that the anticipated revisions to MDAQMD Rule 1160 and AB 32 will be effective some time after the TY2012. DRA states: "SoCalGas has provided no evidence indicating that any of the identified regulations will require compliance activities during the TY."[2]

DRA does not dispute the costs to implement the compliance measures submitted in this section of testimony and workpapers, but rather bases its opposition on the status and timing of the compliance requirements. SoCalGas' Environmental witness, Ms. Haines, Exhibit SCG-215, provides information in her rebuttal testimony on the revised Rule 1160[3]and AB 32[4] that supports the timing of these rules publications and SoCalGas' need for additional funding to implement the rule as requested by the Company.

SoCalGas has therefore provided substantial evidence to support the request for incremental funding for new activities required of the EAC. Since there still exists some uncertainty regarding the cost impact of new regulations, the Commission should establish the New Environmental Regulatory Balancing Account (NERBA) proposed by SoCalGas.

C. Planning and Analysis

<u>Rebuttal to DRA</u>

SoCalGas is requesting incremental non-labor expenses of $9.5 million to comply with two significant elements of "The California Global Warming Solutions Act of 2006" (AB 32). The first is $4.5 million for the AB32 Cost of Implementation Fees ("Administrative Fees") which will fund California state agency activities to implement AB 32, and second is $5.0

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[2] DRA-44, p. 70, lines 1-2.
[3] SCG-215
[4] Id.

million for the emissions credit/offset Cap and Trade program. The "Administrative Fee" is formula-driven, based on a regulatory supplied factor applied to SoCalGas' annual gas throughput. The Cap and Trade expense will be based on the real-time market value for publically traded credits/allowances.

DRA is recommending zero funding for the AB 32-driven request of $4.5 million for Administration Fees and the $5.0 million Cap and Trade fee forecasted. It asserts that the regulations are not yet final and will not apply to SoCalGas until the next rate case cycle.

DRA does not dispute the costs presented in my testimony and workpapers that are required to comply with the new regulations, but rather bases its opposition on the status and timing of the compliance requirements. SoCalGas' Environmental witness, Ms. Haines, provides comprehensive information in her rebuttal testimony on AB 32 Cap and Trade requirements[5] and Administration fees[6] that supports the timing and impact on SoCalGas' need for additional funding to implement the rule as requested by the Company.

Additionally, SoCalGas had based its original Administrative Fee forecast on the most current estimates of the emission factor which produced the forecast estimate of $4.5 million. For 2010, SoCalGas was invoiced and has remitted payments of over $5.8 million for 2010 and has received the 2011 invoice of over $5.6 million. These fees are already being administered and the TY2012 forecast is proving to be too low based on recent invoices.

SoCalGas has provided substantial evidence demonstrating that its request for AB 32-related fees is valid. Since some uncertainty still exists regarding the cost impact of AB 32, the Commission should establish the NERBA proposed by SoCalGas and include these costs therein.

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[5] Id.
[6] Id.

Rebuttal to SCGC

In Southern California Generation Coalition's (SCGC's) testimony, Ms Yap states at p. 15, lines 12 – 19:

> "Instead of recovering administrative fee expense through base rates, SoCalGas should recover administrative fee expense through the NERBA. The Preliminary Statement language that establishes the NERBA should track the Preliminary Statement language for the Environmental Fee Memorandum Account ("EFMA") and state that is applicable "to all customer classes, except for any classes that may be specifically excluded by the Commission or direct billed by the CARB." Attachment F: SoCalGas Preliminary Statement Part VI, EFMA, December 17, 2010. This would prevent SoCalGas from recovering ARB administrative fee expense from customers that pay the administrative fee directly to ARB."

The costs for the administrative fees will only be collected from customers that do not pay them directly to CARB. This will be accomplished as follows:

- Until these costs are included in the authorized revenue requirement, they will be included in the amount of the NERBA account that is to be amortized in rates each year.
- Once these fees are included in the authorized revenue requirement, they will be identified and removed from the revenue requirement before it is used to calculate transportation rates, and these costs will then be included, along with the NERBA amount for the prior year's over or under collection, and added only to those customers' rates that do not pay CARB directly.

D. Sustainable SoCal

SoCalGas requests incremental O&M funding of $606,000 to fund the ongoing costs associated with the operation and maintenance of four biogas conditioning systems. (DRA states $1.272 million its testimony referencing my December 2010 testimony. This was modified to

$606,000 in July 2011, revised testimony)[7]The purpose of these systems is to help eliminate the amount of greenhouse gases emitted to the atmosphere by capturing raw biogas and upgrading it to pipeline quality biomethane. This will cover the labor and non-labor expenses associated with routine maintenance, replacement of worn parts, and system operational costs.

SoCalGas requests incremental funding of $11,272,000 in capital for the Sustainable SoCal Program, with these associated O&M expenses of $606,000. While DRA proposes disallowing the entire Sustainable SoCal program, there were no oppositions from other intervenors. DRA did not challenge the implementation costs associated with the Sustainable SoCal Program. DRA instead questions the policy of SoCalGas implementing this program.

DRA's recommendation for disallowance of funding for this program is primarily a policy issue. Since Ms. Wright is the policy witness sponsoring the business case for the Sustainable SoCal Program, I defer these issues to her testimony regarding DRA's recommendation and issues related to Sustainable SoCal Program.

Based on the above discussion, the Commission should reject DRA's selective use of the historical data in its forecasting methodology and approve SoCalGas' total TY2012 forecast of $21,383,000. This comprises the base-level, five-year average of $10,417,000 plus the incremental expenses of $10,966,000.

III. PIPELINE INTEGRITY O&M – TRANSMISSION (NON-SHARED SERVICES)

SoCalGas is requesting TY2012 funding for O&M activities related to its Transmission Integrity Management Program (TIMP) of $24,760,000. This is a zero-based forecast, developed from a finite set of projects and associated support activities. This request provides SoCalGas with the necessary funding to complete the remaining federally mandated baseline assessments, as well as all necessary re-assessments, both of which are required by 49 CFR 192, Subpart "O"

[7] SCG-04-R, p. RKS-25.

– *Gas Transmission Pipeline Integrity Management*. Per 49 CFR 192.923(4)(d) – "*Time Period* - 'An operator must complete the baseline assessment of all covered segments by December 17, 2012.'" SoCalGas has implemented and is managing its TIMP program, through its Baseline Assessment Plan (BAP), to meet this compliance requirement date.

DRA proposes a drastic reduction of $13.7 million for TY2012. This recommendation appears to be based on a misinterpretation of the information presented in my testimony, workpapers, and SoCalGas' data request responses. If DRA's request is adopted SoCalGas would fall well short of the resources needed to complete the baseline assessments and reassessments required under 49 CFR Subpart "O." DRA's apparent belief that SoCalGas has already completed the required baseline assessments is mistaken.

In its testimony, DRA states:

"SCG's data shows that it has already completed the initial assessment of its system."[8];

"SoCalGas has already performed 32 percent above the required number of miles."[9];

"Based on the information provided, SCG is now in the reassessment phase of the TIMP because the assessments for the initial phase have been completed. SCG's data has shown as much."[10]

It is true that SoCalGas has already begun to reassess pipelines that were baseline assessed early in the program. This is because the baseline assessment phase must be completed within 10 years, but pipelines must be re-assessed within seven years of their prior assessment. Pipelines that were baseline assessed in 2003, 2004, and 2005 require a re-assessment no later than 2010, 2011, and 2012, respectively. These re-assessments must be completed along with all of the remaining baseline assessments for these given years.

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[8] DRA-44, p. 77, line 15.
[9] Id., line 18.
[10] Id., p. 78, line 3.

SoCalGas has not completed the required baseline assessments, and is not scheduled to finish them until December 17, 2012. The baseline assessment aspect of TIMP is essentially a ten-year program. In compliance with federal law, SoCalGas has analyzed its transmission pipeline system and developed the baseline assessment plan (BAP) to complete all required assessments by December 2012. It is important to note that many of the remaining assessments will be more costly than previously experienced because they are more complex and the ability to use traditional smart pigging technology is very limited. DRA requested a copy of the BAP in a data request, DRA-SCG-022-DAO. SoCalGas' response to this data request includes a copy of the BAP, which is included as Attachment-A to this rebuttal testimony. Pages 23 thru 35 of the BAP clearly show the specific pipe segments that were scheduled for completion of their baseline assessments in 2011 and 2012. For 2012, there are 271 segments scheduled for assessment, totaling 61.57 miles which is an average of 0.23 miles per segment.

In reviewing DRA's testimony, it is likely that the misunderstanding stems from DRA's misinterpretation of SoCalGas' response to questions 1(a) and 1(c) of DRA-SCG-022-DAO. The specific questions and responses are as follows:

Portion of DRA data request DRA-SCG-022-DAO:

1. Please provide the following information regarding the Pipeline Integrity Transmission Program for years 2005-2010 YTD.

    a. The number of miles of mains inspected,

    Response: Please see the response to Item "c." below for the number of miles of transmission pipeline inspected

    c. The number of miles of mains inspected by method of inspection

    Response: The Table below indicates the number of miles of transmission pipeline inspected by method of inspection. Included in these totals are all inspected pipelines both HCA and non-HCA. The completed 2010 mileage data is currently being reconciled in preparation for the annual reporting cycle.

	Year					
Method used	**2005**	**2006**	**2007**	**2008**	**2009**	**Total**
ECDA	5.72	86.25	83.43	82.67	37.96	296.03
Hydro test	18.38	1	0	0	0.39	19.77
ILI	261.81	589.69	246.83	36.86	63.15	1198.33
Total	285.91	676.93	330.26	119.53	101.49	1,514.13

(In the table provided in that response and shown, ECDA is 'External Corrosion Direct Assessment' and ILI is 'in-line inspection'. 'Hydrotest', or 'hydrostatic testing' is a stress testing technique using water under pressure.)

DRA correctly points out that the total miles inspected at that time was 1,514 miles, but seemingly overlooked the response in 1(c) that states: "Included in these totals are all inspected pipelines both HCA and non-HCA." To clarify for the record, of the 1,514 miles inspected, 824 miles were HCA. This represents approximately 72% of the total HCA miles (1,149) as presented in my direct testimony, and roughly 54% of the total miles of pipe assessed (1,514) at the end of 2009.

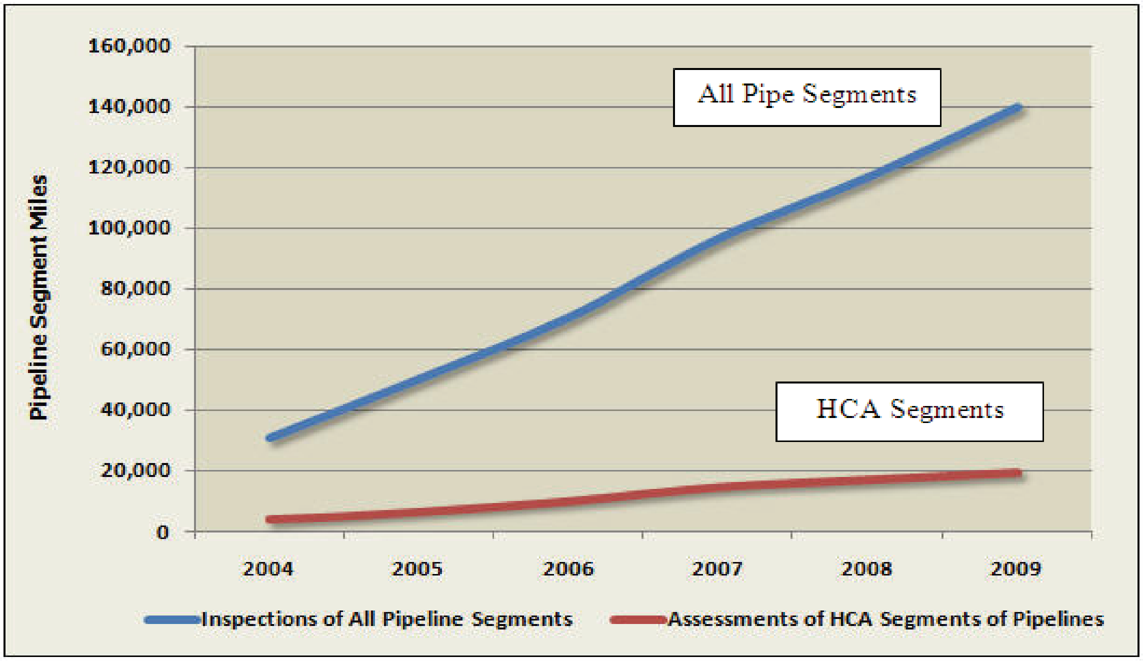
DRA's confusion seems to come from the fact that SoCalGas has assessed both HCA pipe segments as required by TIMP and non-HCA segments that are not part of the mandatory baseline assessments required by year-end 2012. SoCalGas has inspected more miles than required for several reasons. First, it was the most prudent action to take when planning the locations for the most logical start (launch) and stop (receive) points in which to insert pipeline inspection and cleaning tools (also called "pigs") where those could physically be accommodated and installed on the system. Wherever possible, locations are chosen within company facilities and/or away from areas that impact the general public such as public roads and intersections. Often these locations-of-choice are some distance before or past the HCA boundary. One of the benefits of this approach is that once the inspection tool is inside the pipeline, the incremental costs of running the tool for additional miles are minimal. For that reason, SoCalGas will continue to select locations to install the launcher and receiver assemblies that maximize economic and convenience factors such as using existing company facilities as sites for these installations. In most cases, this results in positioning the launchers upstream of the beginning of a HCA segment and the receiver downstream of the end of a HCA segment. This results in achieving PHMSA's ultimate goal of assessing more pipeline miles, which includes non-HCA pipe segments. This approach is prudent, provides additional safety benefits, and is not unique to SoCalGas.

As depicted in Figure RKS-1 below, on its Integrity Management (IM) website, PHMSA has summarized the annual reporting data received from all natural gas operators across the country. Its description of the graph is as follows: *"The top (blue) line represents inspections performed as a result of the GAS IM Rule, including those performed on High Consequence Area (HCA) segments, as well as on segments adjacent to HCA segments. The bottom (red) line shows only those HCA segments that have been fully assessed."*[11] As an industry, the total HCA miles assessed are only about 14% of the total miles assessed.

[11] http://primis.phmsa.dot.gov/gasimp/PerformanceMeasures.htm

Figure RKS-1

PHMSA Data from DOT GAS-IMP website
Industry Summary of miles Inspected/Assessed due to IMP



In its testimony, DRA states: *"DRA believes that SCG's historical work level and historical expenses are the best indicators of how much of the system has been assessed and how much more needs to be done, and at what cost."*[12] Based on the projects remaining to be completed in the BAP, however, historical expenses are clearly not the best indicator of how much more needs to be done and at what cost. The historical data is used to assist in developing the individual project costs, but the finite list of projects must be completed by December 17, 2012. The BAP is the only gauge of how much of the system has been assessed and what remains to be done. The BAP shows specific projects at specific costs that must be completed by December 17, 2012. The historical average would be a good indicator only: If it included both the baseline assessments and the reassessments in each year as is the case now that the two periods overlap; and if the cost to perform the remaining baseline assessments were the same per

[12] DRA-44, p. 77, lines 12–14.

year as the previous assessments. Neither is the case. As noted above and in my direct testimony,[13] historical data does not reflect the fact that the remaining baseline assessments now have started to overlap with the required reassessments. Historical data would capture only the annual cost of baseline assessments without the overlapping reassessments. Thus, historical costs are not a good indicator of future costs for this reason alone.

In addition, as discussed in my direct testimony,[14] a fundamental tenet of integrity management is to prioritize assessment of relatively higher risk pipelines before relatively lower risk pipelines. Thus, towards the end of the program the pipe segments with lower values are assessed. These segments tend to be much shorter in length and smaller in diameter than large-diameter lines carrying greater gas volumes. These shorter segments make up a smaller percentage of the required mileage but are more costly to address on a per-mile basis. This is primarily due to the requirements of the rule and the inability to apply the fixed costs of an assessment over a longer pipe segment. For a given assessment method, the rule requires the same procedures be applied regardless of the segment's length. As noted above, once the ILI tool has been inserted into the pipe, the cost of inspecting additional miles is minimal. But with a shorter pipe segment, the much-larger cost of launching and receiving the tool is no different than for a longer pipe segment.

In addition to the smaller length segments, SoCalGas is also faced with inspecting and assessing steel pipe within casings, or "cased main."[15] These segments are typically short in length (railroad, river, and roadway crossings) but require incrementally more excavation and specialty tool usage. When these additional expenses are applied to such short lengths, the unit

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[13] SCG-05-R, p. RKS-26, lines 9-13; p. RKS-30, lines 16-24.
[14] Id., p. RKS-25, 26.
[15] Id., pp. RKS-28 through 30.

costs are driven even higher. Although DRA was provided all of this information, it chose to ignore it to produce a lower forecast.

Each pipe segment in the BAP is different and must be analyzed and assessed based on its specific integrity issues, not an average of what has happened with other segments that have been completed. The expense for each of these individual assessments has been presented in testimony workpapers. SoCalGas has developed its BAP and is successfully working through each segment with the goal of completion by December, 2012.

In order to allow SoCalGas to continue this program and meet the federally mandated deadline for baseline assessments, it is paramount that the forecasted expenses as detailed in the testimony and workpapers be approved. The Commission therefore should approve the entire TIMP O&M non-shared services request of $24.8 million.

In response to DRA's comment on the continuation of a one-way balancing account for TIMP[16], DRA probably intended to reference the DIMP program for continued one-way balancing. There has been no balancing of TIMP costs for SoCalGas. There is currently such balancing for SoCalGas' DIMP.

A. Balancing Account - TIMP

Both DRA and TURN and UCAN have proposed that TIMP be subject to a balancing account. Further SB 879, which was recently signed by the Governor, directs the Commission to establish balancing accounts for TIMP costs. Specifically, SB879 requires that:

> " In any ratemaking proceeding in which the commission authorizes a gas corporation to recover expenses for the gas corporation's transmission pipeline integrity management program established pursuant to Subpart O (commencing with Section 192.901) of Part 192 of Title 49 of the United States Code or related capital expenditures for the maintenance and repair of transmission pipelines, the commission shall require the gas

[16] DRA-44, p. 78, lines 20-21.

> corporation to establish and maintain a balancing account for the recovery of those expenses. Any unspent moneys in the balancing account in the form of an accumulated account balance at the end of each rate case cycle, plus interest, shall be returned to ratepayers through a true-up filing. Nothing in this section is intended to interfere with the commission's discretion to establish a two-way balancing account."

In light of these developments, SoCalGas proposes that TIMP be subject to a two-way balancing account over this rate case cycle. A two-way balancing account is in the best interest of all stakeholders. Any under-spending would be returned to ratepayers, but if SoCalGas finds that the prudent application of additional expenses is warranted for pipeline safety, it is reasonable to expect SoCalGas to incur those expenses and recover them in rates. Under regular balancing account treatment, the periodic expenses are reported in the Annual Regulatory Account Balance Update to the Commission, during which intervenors have the opportunity to review those expenses for reasonableness.

Pipeline safety is of the utmost importance to SoCalGas. Its policies, practices and track record are a testament to this. One-way balancing account treatment incents spending only to the level established for that activity, which is appropriate in many instances. Because of the large degree of uncertainty of these costs and the potential for additional scope and requirements arising as the TIMP programs evolve and mature, SoCalGas believes that the added characteristics of a two-way balancing account are warranted. The two-way treatment will permit SoCalGas to address as-yet-unforeseen circumstances, yet will still provide ratepayer protection in the form of reasonableness review before SoCalGas is permitted to recover its costs in rates.

The Commission's Independent Review Panel, created to review the San Bruno incident, noted in its report that there is a disconnect between DRA and the Commission's Safety Branch. This disconnect can lead to adverse outcomes when it comes to pipeline safety. The following excerpt is one of the findings made by the Panel:

> *One-way balancing accounts create a perverse incentive for the utility to spend exactly as the stakeholders have negotiated – spending no less or no more than is authorized for a given activity.*[17]

SoCalGas requests the Commission to recognize the uncertainty and volatility of the current regulatory environment with respect to pipeline safety at both the state and federal levels. SoCalGas must be allowed to continue to operate within this environment with the focus and discretion it has always used in providing safe and reliable service to its customers and employees. Two-way balancing is the mechanism to achieve the common goals for all stakeholders while providing flexibility to manage safety concerns and fiscal oversight.

It is readily apparent that the pipeline safety landscape continues to change at a very rapid rate creating a level of uncertainty at both the state and federal levels. At the federal level there are several bills being sponsored that would increase the requirements for natural gas pipelines. An example is a bill sponsored by Senator Lautenberg addressing among other issues the requirements for: Damage Prevention, excess flow valves, public awareness, pipe data collection, expansion of HCAs, etc. Concurrently, PHMSA has issued an Advanced Notice of Proposed Rulemaking (ANPRM) to further enhance pipeline safety, addressing such things as expansion of HCAs, new requirements for data collection, valve spacing, corrosion control, etc.

At the State level, there were five bills recently signed into law aimed at improving natural gas safety in the state. These bills address various pipeline safety aspects, such as monitoring safety spending by the state' utilities, requiring new automatic- or remotely-controlled pipeline shutoff valves, and providing for more detailed emergency response plans.

Included below are brief summaries of the recently enacted legislation that is causing the future uncertainty of pipeline integrity requirements:

[17] Report of the Independent Review Panel San Bruno Explosion, prepared for CPUC, Revised Copy, June 24, 2011, p. 107.

SB 44 - Public utilities: gas pipeline emergency response standards. (Corbett)

- Participate in state's pipeline safety program to certify natural gas pipelines.
- Develop and implement emergency response plans compatible with federal regulations.

AB 56 - Gas corporations: rate recovery and expenditure: intrastate pipeline safety. (Hill)

- Regular meetings with first responders to discuss and review contingency plans for emergencies in vicinity of pipelines.
- Regular reporting to CPUC of a gas transmission and storage safety report.

SB 705 - Natural gas: service and safety. (Leno)

- Requires gas IOUs to develop and implement plans for safe and reliable operation of intrastate pipelines by December 31, 2012. The plan must be reviewed and updated periodically.

SB 216 - Public utilities: intrastate natural gas pipeline safety. (Yee)

- Automated shut-off valves and associated valve plan.

SB 879 - Natural gas pipelines: safety. (Padilla)

- Establish balancing account for integrity management expenses of transmission pipelines.

In light of new laws and regulations it is important to have a two-way balancing account to accommodate the new requirements that continue to be imposed on the company in management of the TIMP. The Commission therefore should adopt two-way balancing for TIMP activities and not require SoCalGas to amortize the balance in rates each January 1; instead, SoCalGas should carry the balance forward into the following year.

B. Integrity Reporting – TIMP

SoCalGas opposes TURN and UCAN's proposal to impose reporting measures similar to PG&E. SoCalGas does not oppose reporting requirements but such requirements should be meaningful, suited for the purpose intended, and not duplicative.

TURN and UCAN's recommendation is misdirected because the reporting requirements stipulated in PG&E's Gas Accord are a direct result of incidents such as Rancho Cordova, San Bruno and other safety-related concerns.[18] Under the Gas Accord V Settlement, PG&E is required to provide semi-annual reports not only on its pipeline integrity efforts but on its gas storage activities as well[19]. The broad brush with which TURN and UCAN have proposed to paint SoCalGas is inappropriate because the operator-specific reporting extends well beyond the reach of pipeline integrity due to the safety issues specific to PG&E's operation. It is also inappropriate to raise this matter in this GRC when TURN and UCAN could have raised it in other proceedings addressing pipeline safety. Further, SoCalGas notes that none of the DRA operational witnesses in this proceeding mentioned, much less recommended, any need for additional reporting for distribution, transmission or underground storage.

For SoCalGas the information that is being requested appears duplicative. Integrity management information is supplied to PHMSA with a copy to this Commission's Consumer Protection and Safety Division (CPSD), providing it again does nothing to enhance pipeline safety. For example, SoCalGas files with this Commission FORM PHMSA F71000.2-1 which provides details on HCA miles assessed and reassessed in a given year and by what assessment method, e.g. ILI, pressure test, etc. SoCalGas has provided a copy of its most recent F7100.2-1 form as Attachment A. Additionally, SoCalGas has provided its Baseline Assessment Plan

[18]A.09-09-013, "Revised Scoping Memo and Ruling Adding an Additional Phase, October 15, 2010, #435005.
[19] D. 11-04-031, Appendix C, p.58.

(BAP) to DRA. The BAP is a compliance roadmap calling out specific actions for each pipeline covered under TIMP. SoCalGas has used the BAP to develop its project-specific zero-based forecast.

In terms of spending metric information, the two-way balancing account would provide the type of information being requested. As discussed earlier in this testimony under Balance Accounts, SoCalGas would provide annual updates and would enable interested parties an opportunity to review the reasonableness of those expenses. Requiring additional reporting to provide the same information is needlessly redundant. SoCalGas understands the Commission's need for additional scrutiny of PG&E, and it was clearly stated in the revised scoping memo of the Gas Accord. SoCalGas is not similar situated and thus does not warrant the additional acute reporting.

In closing, TURN and UCAN deferred to DRA on pipelines safety matters and should also have done so for reporting. The Commission should reject TURN and UCAN's recommendation based on the following: 1—DRA did not recommend any additional reporting requirements; 2—PG&E's reporting requirements were fashioned to meet a specific safety mandate, and; 3—much of the information PG&E must report is already being sent by SoCalGas to CSPD.

Finally, if the intervenors are truly interested in enhancing pipeline safety, they should not recommend adding another report for CPSD to review, but instead should support the Commission's efforts to acquire the resources needed to review and analyze the existing reports to further assure public safety, which was identified by the Independent Panel Review.

IV. PIPELINE INTEGRITY O&M – DISTRIBUTION (NON-SHARED SERVICES)

SoCalGas requests TY2012 O&M funding of $31,097,000 for its Distribution Integrity Management Program (DIMP). As mandated by 49 CFR 192.1005, SoCalGas has developed and implemented its DIMP. Integral to this plan are the programs and associated expense funding requested in this GRC.

DRA has proposed a 77% reduction in DIMP program funding from the requested $31,102,000 to $7,151,000. While DRA has proposed drastic reductions to SoCalGas' funding request for its DIMP program, it should be recognized that DRA does not dispute the fact that the various programs that SoCalGas has identified will improve safety of customers, employees and the public at large. Additionally, DRA does not dispute that state and federal regulators recognize the need to improve the safety of the natural gas distribution system and that it needs to improve in a significant manner.

In accordance with regulations, SoCalGas formally implemented its DIMP on August 2, 2011. At the time direct testimony was prepared, the majority of DIMP costs were based on initial assessments of these programs. As DRA points out, some of the initial forecasts were based on less than complete studies and datasets. However, these initial studies established program definition and cost estimates as well as identifying areas where additional rigorous program development would be required. The DIMP elements are now supported by more detailed and rigorous engineering analysis that fully supports the GRC forecast. The forecast for this GRC request was performed before the DIMP plan was solidified.

The specific DIMP elements addressed in my direct testimony are: 1) The inspection, repair and/or replacement of anodeless (AL) risers; 2) Identification and mitigation of above-ground facilities subjected to high-speed vehicular damage; 3) the Sewer Lateral Inspection Program; and 4) Other damage prevention activities. Each of these programs will indisputably improve the safety of the SoCalGas distribution pipeline system for customers, employees, and the public in general.

The discussion below will show the distinct safety threats addressed by DIMP and clarify any confusion DRA might have regarding whether DIMP is incremental to the core regulatory programs. DRA took no exception to any of the programs in terms of their effectiveness, but rather confused the programs as simply an existing program funded elsewhere.

DRA's testimony was contradictory among its own witnesses. On one hand, DRA denied a large portion of SoCalGas' request for DIMP O&M,[20] yet approved DIMP capital funding for the exact same safety compliance programs.[21.]

A. Anodeless Riser (AL) Program

SoCalGas requests incremental funding of $15,033,000 to address the implementation of the DIMP-driven AL Riser inspection program. SoCalGas has been addressing this threat by inspections and repairs/replacements during routine field work. However, given the threat posed to safety when AL risers begin to leak and the length of time it will take to mitigate this threat as part of core activities, SoCalGas has deemed it prudent to accelerate this activity in systematic fashion and in accordance with DIMP. SoCalGas concurs with DRA that the threat of leakage on AL Risers is not a new threat, but that does not diminish then need to address this threat in a more aggressive fashion in accordance with DIMP.

DRA bases the majority of its opposition on a perceived lack of sufficient data and analysis to justify SoCalGas' request. In its testimony, DRA states: "*If there is a safety threat that exists, then SCG should prepare and file a thorough engineering study to justify its request. SCG's proposal for additional funding for AL risers in Engineering lacks thorough data, analysis, and a detailed study as part of the GRC filing to the Commission to justify the*

[20]DRA-44, p. 80, Table 44-21A.
[21]DRA-45, p. 16-17.

substantial increase in costs."[22] However, DRA does not mention the fact that, in response to DRA-SCG-040-DAO, SoCalGas provided, in response to Question 3(a), a copy of its comprehensive engineering analysis report explaining in great detail the issues that are driving this DIMP request. Also attached to this data response are the pilot program data used in the analysis. This data response is included in Attachment-B at the end of this rebuttal testimony. This report provides comprehensive analysis of the AL Riser threat including a brief historical background of AL Risers and details of the scope and results of a research project conducted to "determine the state of the system and to investigate if other potential problems exist with anodeless risers."[23]

Based on the results of this research project, it was concluded through statistical analysis that SoCalGas can expect an AL Riser failure rate of 15%, requiring the replacement of over 300,000 AL Risers. Additionally, as this analysis noted,

> "SoCalGas has been involved in research to develop an effective means of mitigating the above-ground and ground-level corrosion on anodeless risers. This effort has lead to the implementation of the Trenton Wax Tape solution, which is effective at arresting further corrosion of corroded surfaces without extensive surface preparation and provides an effective protective barrier of the above-ground section of the riser in the severe environmental conditions that are typical of riser installation. This effective mitigation measure will accomplish two goals. First, it will minimize the corrosion threat upon application, and second it will prolong the life of the riser without the added expense of replacement. Risers that are structurally unsound and those found leaking will be replaced."[24]

The research report also provides a section detailing the cost/benefits of the DIMP-driven AL Riser program. The performance of the old paint option is estimated to last three to five years, while the duration of the Wax Tape is estimated to be in excess of 30 years. The cost of applying the spray paint is estimated to be $0.70 per riser, compared with a cost of $1.00 per

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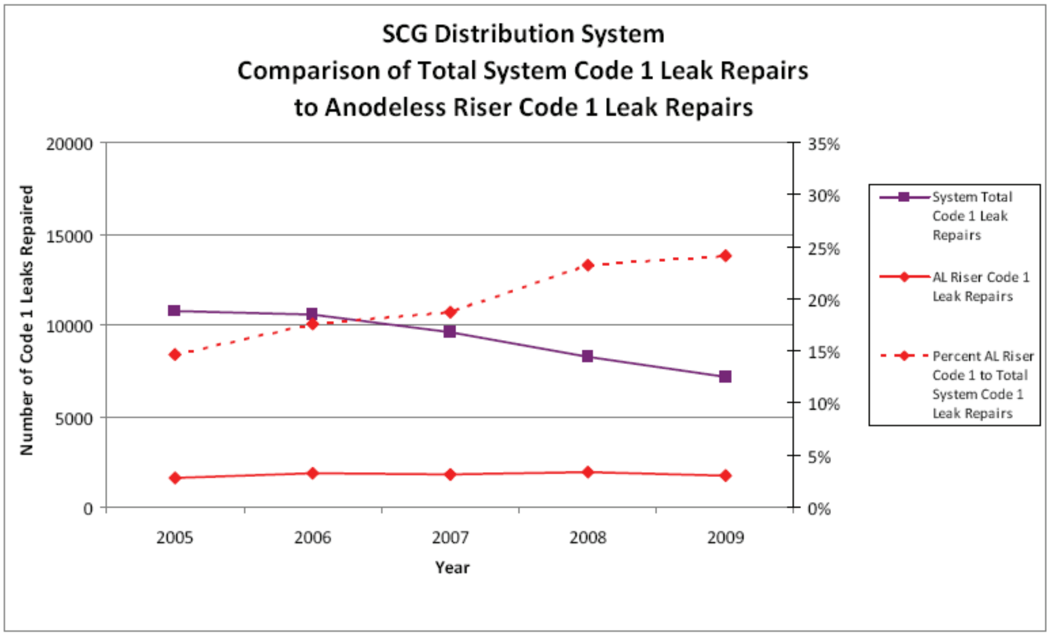
[22] DRA-44, p. 84, lines 4-8
[23] Attachment-B, DIMP-Driven Anodeless Riser Inspection Project Pilot Research Survey Final Report, p. 5
[24] Id., p. 6

riser for the Wax Tape. For minimal incremental cost per riser, SoCalGas can expect tremendous increases in AL Riser life expectancy.

The research showed that AL riser leak repairs constitute 30% of all system leak repairs and 25% of all hazardous “Code 1” leak repairs, as depicted in the following graph showing the trend of AL riser leak repairs as a percentage of hazardous; Code 1 leak repairs:

Figure RKS-2



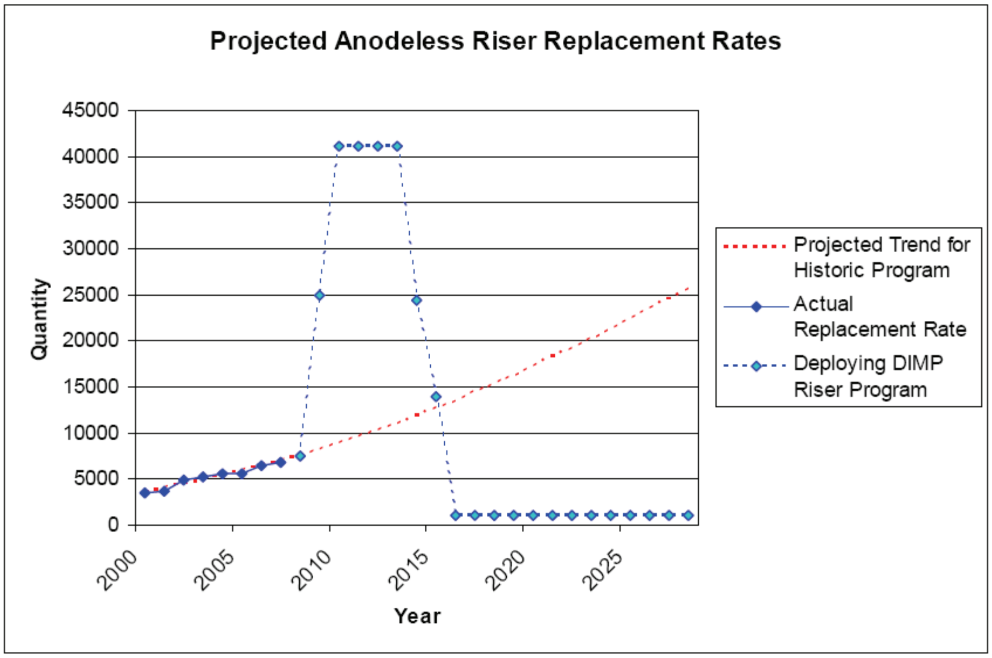
Because AL riser leak repairs represent 30% of all system leaks and nearly 25% of all hazardous system leak repairs, it was identified as a key system threat requiring accelerated action under DIMP.

The analysis provided to DRA also compared the costs and benefits of the core AL riser program with the accelerated DIMP focus:

> "To estimate the cost benefit between the two programs the future replacement rate of anodeless risers was projected using the combination of historic replacement rates and a population model based on the annual installation rates of anodeless risers. Figure [RKS-3] below graphically depicts these two trends along with the additional accelerated DIMP –Driven program proposed. The figure shows the rate of Anodeless riser leaks have been increasing historically when viewed over a longer time interval and from the new data provided by the engineering study is predicted to increase significantly over the coming years. The systematic and system-wide preventive maintenance approach proposed to inspect, replacement or repair the entire riser population over the course of the next seven years in turn drops the riser failure rate to near zero. Doing so eliminates an estimated $6,000,000 (2009$) in annual replacement costs that would have been incurred from using the old paint method. More importantly, and what the graph cannot depict, are the hazardous leaks that will be prevented

from occurring, and the potential incidents that may be avoided both during the program years and subsequent to the program's completion."25

Figure RKS-3



This data means that, while there will be an increased cost of the seven years of the DIMP-driven AL riser program, these costs will be offset by savings in later years and thus the DIMP-driven AL riser program breaks even in 9.4 years and then reduces costs thereafter, without even considering the potential avoidance of damage to persons or property by repairing hazardous leaks earlier than otherwise.

Addressing DRA's questioning of the adequacy of supporting historical data, the response to Question 3(c) of DRA-040-DAO explains the associated historical data for numbers and costs of inspections, repairs and replacements. The table from the data request has been duplicated below.

[25] Attachment-B, DIMP-Driven Anodeless Riser Inspection Project Pilot Research Survey Final Report, p. 9-10

Table RKS-4

Copy of Data Table supplied in response to
Data request DRA-SCG-040-DAO, Question 3(C)

Year	Units Inspect/ Repaired	Inspect/ Repair Expense (2009$)	Unit Cost for Inspect/ Repair		Units Replaced	Replacement Expense (2009$)	Unit cost for Replacement
2005	23,487*	$205,155	$8.73*		5,229	$1,589,053	$303.89
2006	29,648*	$258,972	$8.73*		5,643	$2,023,846	$358.65
2007	38,542*	$336,658	$8.73*		5,622	$2,069,637	$368.13
2008	48,793*	$426,202	$8.73*		6,368	$2,275,811	$357.38
2009	43,524	$380,176	$8.73		6,796	$2,478,508	$364.70

(*) These values estimated based on the discussion included in response to Question No. 3c.

From the above table, the cost values and numbers of risers replaced are clearly actual, recorded data. DRA takes issue that the values for the numbers of AL risers inspected/repaired are not actual/recorded values. DRA states "*SCG provided an estimate of what the expenses and the number of AL risers mitigated could have been for years 2005-2008. No actual recorded data was provided. SCG states, "[w]hen reviewing the most recent data, it became apparent that there were inconsistencies in the tally of the number of units inspected/repaired...It was determined that the legacy systems were not capturing all of the data." The only historical information SCG provided was the 2009 recorded units of work and associated expenses*."[26] However, as further explained by SoCalGas in its data response, "*Historically, the number of AL risers mitigated (repaired or replaced), and the associated expenses incurred are recorded in different systems and by different processes. The expenses are recorded by activity-type on an employee's time card and are consolidated and tracked by account number based on the amount of time allotted to the activity, in this case AL Riser repair or replacement.*"[27] Since the "inspection" portion of this activity was performed, as needed, when a service person was already visiting the customer for

[26] DRA-44, p. 82, lines 1-7.
[27] DRA-SCG-040-DAO, Response to Question 3(c).

other reasons, only the time for the inspection was recorded for accounting/ time keeping purposes. There was no historical tally kept for the numbers of these inspections, but the time spent performing the inspection was recorded. If the inspection determined that a replacement was required then a separate order was generated, which allows for the tracking of total number and costs of replacement. This process discrepancy was recognized in 2009 and the record-keeping was modified to capture the inspection tallies also. From the tally information gained in 2009, SoCalGas provided estimated values for the 2005-2008 inspection numbers.

SoCalGas generally objects to the use of 2010 data as the basis for TY2012 forecasts. The forecast for the AL riser program was zero-based since it is an incremental activity above historic cost levels. DRA, however, forecasts the level of funding for this program based on recorded 2010 data, but this program was still ramping up in 2010. If the Commission decides to use 2010 recorded data in this GRC, it is necessary to understand that data. The numbers of incremental AL Risers that have been addressed and mitigated through the DIMP efforts are shown in Table RKS-5 below. The 2011 values are current through September 21, 2011. As the data shows, SoCalGas has been steadily increasing its program activity. The 2010 data that DRA uses for its forecast was based on a program in its early stages of development. Also evident in the data are the number of AL Risers that were replaced due to their condition for potential leakage. Moreover, it shows the number of risers that have been treated with the new Trenton Wax Tape that will prolong their service lives for decades longer than the previous repair method.

Table RKS-5
Anodeless Riser Inspection, repair, replacement

	2010	2011	% increase
# Risers Inspected	5,944	31,574	531%
# Trenton Coating Applied	5,277	27,445	520%
# Risers Replacement Orders	636	5,990	942%

As this discussion demonstrates, SoCalGas provided a great amount of supporting data and fully answered all of DRA's inquiries. This program has now been implemented beyond the early start-up phase. Additionally, the information gained from the AL Riser research project has further confirmed that accelerated and focused activities associated with the threat posed by AL Risers is a prudent and cost-effective effort that promotes the safety of customers. The Commission therefore should approve the full requested amount of $15,033,000 required to continue this DIMP-related activity.

B. Vehicular Damage to Above Ground Facilities[28] (Gas Infrastructure Protection Program, or GIPP)

SoCalGas requests TY2012 O&M funding of $2,252,000 for the DIMP-driven activity to address high-speed vehicular damage to above-ground facilities. The forecasting methodology chosen was zero-based, because of the well-defined objective of the program and because it is a new approach with a specific start and stop date to mitigate the threat. SoCalGas has developed its forecast using the specific numbers of facilities and types of protection required. Although DRA suggests that this DIMP-driven program is similar to what is currently performed today as a core activity, it is not. As explained below, this is a fundamentally different approach than the current routine activities performed by field operations.

DRA does not challenge the safety benefits from protecting these facilities from high-speed vehicle impacts, but takes the position is that any additional vehicular damage mitigation activity through this new program "is unjustified because it was based on premature assessments of the work needed."[29] Furthermore, DRA states that the identified level of work in SoCalGas' TY2012 forecast is "not substantiated because SoCalGas' request was based on a forecast

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[28] The program name has been changed to the Gas Infrastructure Protection Program (GIPP) to better communicate the program's focus and minimize any uncertainty surrounding the program's objectives.
[29] DRA-44, p. 85, line 14.

number of facilities that was not confirmed for accuracy."[30] In its testimony, DRA correctly quotes an excerpt from SoCalGas' Above Ground Gas Facility Assessment dated March 30,2010, which states that: "…the team has not quantified the error rate of these data. Identifying the accuracy of these data beyond a subjective opinion would require an expanded scope of work."

Due to this uncertainty with the initial assessment, SoCalGas embarked upon a more comprehensive and analytical study to better develop the project scope, validate earlier concerns, and identify those facilities potentially at risk from higher speed vehicular collisions more clearly. DRA has labeled SoCalGas' earlier study as a "premature assessment," but it has been superseded by a much more rigorous and in-depth analytical study that fully examined facilities at risk from vehicular collisions. This study has progressed and now provides the basis for the Gas Infrastructure Protection Program (GIPP). While this program was in an initial stage of development when this GRC application was filed, it is no longer "preliminary" in nature and fully supports SoCalGas' requested funding.

SoCalGas now has a complete foundational study and predictive model for at-risk facilities based upon eight years of actual Claims data. The results of this effort, as well as the GIPP implementation plan, are set forth in Attachment C. This engineering study has allowed SoCalGas to more accurately identify the estimated quantity of at-risk facilities and prioritize them. The original Assessment was based on the identification of MSAs and other at-risk facilities located within 50 feet of an intersection. The GIPP study provides a more rigorous and analytical examination based upon many other risk factors and forms a firm basis for the forecast presented in my revised direct testimony.

As stated in the Executive Summary of the GIPP Implementation Plan:

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[30] Id., line 16.

"An in-depth investigation of historical claims data where aboveground facilities were impacted by vehicular traffic was utilized to determine the characteristics for an algorithm that ranks the probability of occurrence.

The results of the investigation indicate that Commercial, Industrial and High Pressure Residential gas facilities are the most vulnerable. There are over 352,000 Commercial, Industrial and HP Residential customers in the system of which 122,000 are estimated to require some type of mitigation. It is estimated that approximately 95,600 of these facilities will require mitigation through the existing meter guard program, while 26,500 of them will be mitigated under the GIPP."[31]

GIPP mitigation efforts include below-ground relocations of above-ground facilities, installation of protective barriers, and potential installation of High Pressure Excess Flow Valves (HPEFVs) and protective barriers.

Table RKS-6 summarizes the differences between the initial Assessment and the subsequent detailed risk analysis study.

Table RKS-6
Comparison of Original "Assessment" and the GIPP study

Component Description	**Assessment Study** (facilities within 50-ft of an intersection)	Detailed Risk Analysis Study (GIPP)
MSAs requiring inspection	145,000	352,000
High Risk MSAs	10,492	26,500
Mitigation Solution	8,430 EFVs	6,700 (Relocation of HP FSRs or HP EFV)
		19,700 (EFV's, Relocations, Protective Barrier)
Mitigation cost per facility	$1,000 EFVs:	$4,500 (Relocating HP FSRs)
	$1,500 (Protective Barriers)	$1,800 (HP EFV on HP FSRs)
		$1,500 (Relocations, Protective Barriers, EFVs)

Table RKS-7 summarizes the cost to mitigate the 26,500 facilities. Based on the detailed risk analysis study, these expenses are forecasted to be approximately $4.7 million in O&M and $3.3 million in capital, per year, if mitigated within a five-year period.

Table RKS-7
GIPP mitigation Forecast

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[31] Attachment-C

GIPP Forecast Worksheet (Direct costs)										
Project	2011		2012		2013		2014		2015	
	O&M	Capital	O&M	Capital	O&M	Capital	O&M	Capital	O&M	Capital
Project Management	$ 506,000		$ 315,000		$ 315,000		$ 315,000		$ 315,000	
C&I Inspections	$ 194,800		$ 300,000		$ 300,000		$ 300,000		$ 300,000	
Standard Protection	$ 16,000	$1,393,200	$1,662,904	$3,296,914	$1,662,904	$3,296,914	$1,662,904	$3,296,914	$1,662,904	$3,296,914
HP Relocations	$1,320,000	$ 110,000	$ 925,978		$ 925,978		$ 694,484		$ 462,989	$ 65,190
HP EFV			$1,500,000		$1,560,000		$1,770,000		$2,100,000	
Total Forecast	**$2,036,800**	**$1,503,200**	**$4,703,882**	**$3,296,914**	**$4,763,882**	**$3,296,914**	**$4,742,388**	**$3,296,914**	**$4,840,893**	**$3,362,104**
# of Sites Mitigated (Total 26,536)	**1433**		**6119**		**6169**		**6294**		**6519**	

DRA correctly notes that SoCalGas has been protecting MSAs from vehicular impacts in accordance with Commission and federal regulations. The existing SoCalGas design standards were developed to protect gas facilities from the most common impact occurrences / impact forces caused by slow-moving passenger vehicles and light trucks primarily in alleyways, driveways, and parking lot-type locations. Furthermore, although these protective devices required by current standards are capable of withstanding forces induced by light vehicles at slow speeds, they traditionally have served more as warning devices by alerting the driver to stop immediately upon contact. These design standards developed by SoCalGas are comparable to the protective devices used for similar facilities throughout the gas utility industry. SoCalGas' practices and procedures conform to both 49 CFR 192.353(a) Customer meters and regulators and 192.317(b) Protection from hazards.

The existing designs are intended to address the more frequent and common threats and not the less frequent incidents involving higher vehicular speeds or heavy commercial vehicles as I noted in direct testimony.[32] Specifically, existing gas standards require protective barriers at facilities located within three feet of driveways, roadways, alleys, parking stalls, wheel bumpers, trash collection areas, and locations where industrial equipment may operate. The new Claims-based study identified that facilities within a 10-foot proximity of vehicles in operation should

[32] SCG-05-R, p. RKS-43, 44.

also be protected from these threats as they account for 94% of SoCalGas incidents that were surveyed. Thus, the expanded distance for protection from traffic increases the number of high-risk facilities that require mitigation.

Finally, in its testimony, DRA refers to the number of recorded incidents SoCalGas has reported. It recognizes that "*From 2005 to 2009, the average number of recorded incidents that involved vehicles was 318 per year. The 2009 number of recorded incidents was 293, which is the lowest during this period.*"[33] DRA goes on to surmise that "*SCG is currently receiving funding for vehicular damage mitigation under Gas Distribution. The level of funding received should be sufficient for this work activity because the number of incidents appears to be level in recent years. There does not appear to be a spike in the number of incidents or any other influencing factors that would warrant immediate increased action by SCG. SCG cannot merely speculate about the possibility of risks it has not thoroughly analyzed and request ratepayer funding to lessen such unquantified risks.*"[34] DRA seems comfortable with SoCalGas experiencing approximately 300 vehicle-related incidents per year since there has been no "spike" in occurrences and therefore proposes that SoCalGas not make any additional efforts to protect its facilities and the public from a known safety threat. DRA's GIPP funding recommendation fails to recognize the change in pipeline safety under DIMP. PHMSA has requested that operators address threats that could have low probability and high consequences.[35] Second, DRA has ignored the additional and detailed analysis in their proposal which was provided to DRA.

SoCalGas has performed a thorough analysis of the vehicular impact threat. In response, it has produced a well-developed plan to address the threat. The Commission therefore should

[33] DRA-44, p. 85, lines 3-5.
[34] Id., p. 86, lines 17-22.
[35] SCG-05-R, p. RKS-45.

approve the TY2012 funding request of $2.3 million for the GIPP as originally proposed clearly justified above.

C. Sewer Lateral Inspection Program (SLIP)

SoCalGas is requesting $7,503,700 in TY2012 for its Sewer Lateral Inspection Program (SLIP). SoCalGas' SLIP is a part of the larger DIMP initiative. SLIP will address situations where the integrity of the system is compromised when a trenchless pipeline installation accidentally penetrates through all or a portion of a sewer lateral. This condition will eventually cause a blockage from root intrusions or other materials congregating in the sewer line. Plumbers or property owners may pierce through and cause damage to the gas pipeline when trying to clean out the blockage. When this occurs, breached gas can leak into the sewer line or elsewhere, creating the potential for significantly high consequences to both persons and property.

A review of claims data from 2000 - 2010 revealed 175 claims in the SoCalGas service territory specifically related to damaged sewer laterals associated with trenchless technology installation of gas pipes. Fortunately, the claims resulted in relatively minor property damage and did not cause explosions, fires, or injuries. However, the potential for catastrophic incidents exists in these situations as underscored by well-documented tragic incidents in other areas of the United States:

- February 16, 2002 - A natural gas explosion occurred at a mobile home park from a gas line bisecting the clay sewer pipe. A plumbing contractor was removing tree roots from a sanitary sewer line in the 127-unit mobile home park when the intruding gas line was struck.
- May 8, 2004 - Incident in Phoenix, AZ - A natural gas explosion occurred at a mobile home park when a plumbing contractor was clearing a clogged sewer lateral.
- March 13, 2006 - Middletown, Ohio -Gas in sewer cross bore connection ruptured during drain cleaning.

- February 1, 2010 - St. Paul, MN — A contractor cut a natural gas line while attempting to unclog a sewer pipe in the basement of a residence. The plumber was seriously injured and the fire destroyed the home.

DRA does not oppose the SLIP conceptually. However, given DRA's support of this important program, SoCalGas is puzzled by DRA's proposed TY2012 forecast developed simply using 2010 recorded expenses. In proposing this forecast, DRA failed to understand the scope of SLIP-related work performed in 2010. If the Commission decides to use 2010 data to forecast TY2012 expenses, it should be informed that, in 2010, funding was used as part of a pilot program to determine the magnitude of the sewer conflict issue. This program assisted SoCalGas in further refining its cost estimates through an assessment of the SoCalGas system using its own records and performing actual field inspections. The pilot program actions and data refute DRA's assertion that SoCalGas' estimated number of sewer conflicts is an inflated estimate based on findings of Southwest Gas.[36]

Due to the SoCalGas assessment performed in 2010, cross bore sewer lateral conflicts are now expected to be <u>**more than eight times likelier to occur**</u> than presented in the original testimony. Based upon actual field observations and recorded SoCalGas system infrastructure data obtained in 2010, more than 3,400 conflicts are projected to exist as opposed to the earlier estimate of 410. The cost of performing video inspections has also proven to be much higher than originally estimated. SoCalGas' cost estimates are no longer based upon extrapolation of information from other utilities; rather the data and costs are current, relevant, and specific to the SoCalGas system. This SoCalGas-specific data demonstrates that the TY2012 forecast was actually understated.

If DRA's recommendation of $622,000 for TY2012 is adopted, it would take nearly **60 years to mitigate this serious safety issue.** The proposition of establishing a six-decade-long

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[36] DRA-44, p. 88.

program to find and repair existing sewer lateral conflicts would be an ill-conceived response from a safety perspective. Indeed, another California gas utility, The City of Palo Alto Utilities Department, which is concerned about the cross-bore safety issue, plans to complete its inspection program in less than two years.[37]

A five-year program as proposed by SoCalGas to aggressively search, identify, and clear the system of sewer lateral conflicts is not an unduly accelerated program given the situation that has been demonstrated to exist at SoCalGas. The proposed plan is an achievable goal within a very reasonable amount of time to mitigate this risk.

Contrary to the assertion of DRA, SoCalGas has not had a formal SLIP in the past. Prior to the 2010 assessment as previously described, problems associated with sewer laterals were simply repaired as part of routine Field Operations activities. The SLIP as proposed will proactively inform and warn the public of the potential hazard, systematically search for conflicts using state-of-the-art technologies, and repair conflicts in advance of any incident, instead of relying upon after-the-fact repairs when conflicts are discovered by others. Further, this program will effectively arrest the threat and enable SoCalGas to identify and address other threats as envisioned under DIMP.

DRA takes issue with the forecasting methodology employed by SoCalGas to estimate the number of potential sewer conflicts. DRA's criticism of the forecasting methodology that was based upon information from other utilities is now moot since SoCalGas has completed its own internal assessment. A review of thousands of field and video inspections in 2010 determined that more than 3,400 conflicts are likely to exist within the system. Thus, the TY2012 forecasts developed by SoCalGas are now fully supported with actual data as recommended by DRA. Table RKS-8 identifies these key SLIP components that were

[37] Attachment-C: City of Palo Alto Press Release dated April 26, 2010.

authenticated in 2010. A further validation of the sewer conflict numbers identified in the 2010 assessment was also observed in the SLIP work performed during the first eight months of 2011, where 55 conflicts were found after 7,171 field inspections.

Table RKS-8
Comparison of Original Testimony data with Revised Information Obtained from the SoCalGas SLIP Assessment in 2010

Program Component		Original Estimate	Revised Estimate
Records Review	Units	361,000	361,000
	Cost	$18,050,00	$19,070,000
Video/Field Inspections	Units	144,000	162,000
	Cost	$16,900,000	$64,660,000
Number of Conflicts	Units	410	3,400
	Cost	$820,000	$4,290,000
Communications Program		$160,000	$160,000
Total Program Cost (Five Year)		**$35,930,000**	**$88,180,000**

All cost estimates presented in this rebuttal testimony for video/field inspections, records review expenses, and conflict repair costs, are based upon the units of work completed and costs that were actually incurred in 2010 during the SLIP assessment. More detail on the data sources is available in Attachment-D to this testimony. The Communications Program expenses are based on postage costs and mailings of annual letters to the 361,000 potentially at-risk customers, and to plumbers.

In summary, the nearly 60-year remediation proposed by DRA is wholly inadequate given the potential threat to persons and property. The original funding request of $7.503 million per year is more than justified and must be sustained.

D. Damage Prevention (DP) and DIMP Activities

SoCalGas is requesting the Commission approve its TY2012 forecast of $1,455,000 for incremental O&M funding to enhance its DIMP-driven Damage Prevention (DP) activities. Under this program, six incremental FTEs will be added to focus on damage prevention programs within the company. The efforts will lead to more effective surveillance of the system and help to define enhancements to the damage prevention programs. Additional funding is requested for additional/accelerated leakage survey activities, enhanced pipe locating equipment, and pipeline marking materials. As with the other DIMP-driven programs, this forecast is zero-based for TY2012, developed to support the new DIMP federal mandates.

DRA is generally supportive of these incremental DP activities but concludes that SoCalGas has not adequately justified the need for six additional FTEs and proposes instead that the cost of four FTEs be authorized. SoCalGas notes that DRA's damage prevention data request should be referenced as "DRA-SCG-048-DAO" instead of "DRA data request DRA-41" as it is shown in DRA's testimony.

SoCalGas appreciates DRA's acknowledgment of the importance of focusing additional resources on one of the leading threats to distribution piping systems: pipeline damage including that from third-parties. As mentioned in its response to DRA's data request, SoCalGas explained that "Damage Prevention" is currently not a centrally defined and managed program. The activities integral to damage prevention are defined in a number of various policies, procedures, and standards and are implemented by a number of organizations within field operations and engineering staff.[38] As further stated in the response to DRA's data requests,

> "The initial scope for this DIMP-driven damage prevention program is to address and evaluate current damage prevention activities for two distinct purposes. The

[38] DRA-SCG-048, Q1(c).

> first for short term or immediate impacts. This is to evaluate and implement enhancements to existing DP practices and standards for near-term benefits.
> The second, and parallel, effort is to make a more comprehensive evaluation of the universe of damage prevention activities to determine if there is a more effective and impactful method for management. This could include the use of industry benchmarking or consultants who specialize in the field of damage prevention.
> Both short and long term efforts will require additional, focused resources to properly address the amount of research, analysis, and implementation efforts this program is expected to require."[39]

In order to effectively address the goals set forth in this DP enhancement program, dedicated resources must be available. SoCalGas determined that the minimum number of FTEs necessary for this purpose is six given its size and its large and diverse service territory.

The Commission therefore should adopt SoCalGas' full request of $1,455,000 in TY2012 to provide the necessary resources to ensure the continued safety of its distribution piping system through analysis and implementation of enhancements of its damage prevention programs.

E. Balancing Account- DIMP

In their testimony, TURN and UCAN propose one-way balancing account treatment for DIMP activities. In response, SoCalGas proposes two-way balancing treatment over this rate case cycle and opposes TURN and UCAN's request for one-way balancing.

SoCalGas has been performing DIMP activities under a one-way balancing account during the current GRC cycle. As discussed above in connection with two-way balancing account treatment for TIMP, one-way balancing account treatment creates incentives that are inconsistent with a maximum focus on pipeline safety, as the Commission's Independent Panel Review found. Each DIMP activity proposed in my testimony will indisputably improve the safety of SoCalGas' natural gas distribution system and no party has argued otherwise. As with

[39] Id., Q1(h).

TIMP, the Commission should ensure that SoCalGas has every incentive to invest in distribution pipeline safety where it makes sense to do so.

There are checks and balances associated with this type of funding, and would not provide SoCalGas carte blanche to freely spend. As explained in the TIMP Balancing Account discussion, a two-way balancing account is in the best interest of all stakeholders. Any under-spending would be returned to ratepayers, but if SoCalGas finds that the prudent application of additional expenses is warranted for pipeline safety, it is reasonable to expect SoCalGas to incur those expenses and recover them in rates. Under regular balancing account treatment, the periodic expenses are reported in the Annual Regulatory Account Balance Update to the Commission, during which intervenors have the opportunity to review those expenses for reasonableness.

Regulatory uncertainty is another valid reason for DIMP two-way balancing. As explained in the TIMP Balancing Account section of this testimony, the same drivers/factors apply to the DIMP. On the legislative horizon, it appears that additional requirements will be mandated creating the same sort of uncertainty. For example, the recent state inquiries into Aldyl-A pipe will likely precipitate additional safety measures related to the distribution pipeline system.

The Commission therefore should adopt two-way balancing for DIMP activities. As with the existing DIMP balancing account, SoCalGas should not amortize the balance in rates each January 1, but instead should carry the balance forward into the following year.

F. Integrity Reporting – DIMP

SoCalGas opposes TURN and UCAN's proposal to impose reporting measures similar to PG&E. SoCalGas does not oppose reporting requirements but such requirements should be meaningful, suited for the purpose intended, and not duplicative. SoCalGas proposes the same approach on reporting for its DIMP two-balancing activities and for the same reasons discussed above for TIMP. Further, as with Transmission reporting, SoCalGas provides PHMSA as well as a copy to this Commission's Consumer Protection and Safety Branch (CPSD) a PHMSA FORM 700.1-1 to detail its distribution safety activities, which a copy has been provided as Attachment E. As stated under reporting for TIMP above, the Commission should reject TURN and UCAN's recommendation based on the following: 1—DRA did not recommend any additional reporting requirements; 2—PG&E's reporting requirements were fashioned to meet a specific safety mandate, and; 3—much of the information similar to what PG&E must report is already being sent to CSPD by SoCalGas.

Finally, if the intervener is truly interested in enhancing pipeline safety, it should not recommend adding another report to CPSD's burden to review. Rather, TURN and UCAN should redirect its attention to efforts and support the Commission's *efforts to acquire the resources needed to review and analyze the existing reports to further assure public safety, which was identified by the Independent Panel Review*

V. PUBLIC AWARENESS (NON-SHARED SERVICES)

SoCalGas requests the Commission approve its TY2012 forecast of $1,159,000 for incremental funding to enhance its federally mandated Public Awareness (PA) program. The PA program forecast is derived from base-year 2009 expenses plus incremental expenses required for TY2012, using a planned schedule of communication activities and analysis of the effectiveness of these activities.

DRA took exception to SoCalGas' request for this incremental funding and has instead proposed the base-year 2009 expense of $307,000. To justify its proposal, DRA states: "Between 2006 and 2009, SCG spent an average of $314,000 per year on the public awareness program and the annual expense does not fluctuate."[40] DRA contends that "SCG's request is not for any new activities or to address any new requirements that would require action by SCG in TY2012. The API's assessment requirement is part of the language of 49 C.F.R., Section 192.616."[41] While there have been no new requirements imposed in Section 192.616, SoCalGas is requesting funds to implement new or enhanced activities, refine its program, and create a tailored approach to segments of the affected stakeholders to communicate safety messages geared for them. As noted in my direct testimony but ignored by DRA, three federal goals drive PA costs. These goals are as follows: 1) review and evaluate results; 2) identify gaps; and 3) continually improve the program through completed surveys.[42] For example, one audience segment on which SoCalGas will focus its efforts is the agricultural segment. This group currently is part of the "excavator" segment, but it is more appropriate to break it out as a separate audience and create an outreach tailored for it. To launch and put together this effort will require $70,000 plus additional follow-up and measurement specific to this segment. Another example of this effort is to enhance the outreach to schools. This will require further analysis and message tailoring to ensure that this segment is reached in a more effective manner.

As noted in my direct testimony, SoCalGas measures its audience every four years as prescribed under AP 1162. SoCalGas' PA plan has been in effect since June 20, 2006. Integral to the success of the plan is periodic evaluation and assessment to determine the effectiveness of the communications to their target audiences. These evaluations are expected to generate extensive amounts of data which will require like amounts of analysis, and generate recommendations for continuous improvement to the program. As stated in my direct testimony, *"If the initial assessment survey finds gaps in conveying the messages, the operator must address*

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[40] DRA-44, p. 94.
[41] Id., p. 93.
[42] SCG-05-R, p. RKS-50

them or improve the communication process. Part of the challenge for SoCalGas will be effectively reaching its diverse customer base. There are multiple languages, myriad media outlets, and lifestyle choices affecting SoCalGas' ability to reach the stakeholders required by PHMSA."[43] Additionally, the time span of four years appears too long to gather a meaningful result, and SoCalGas will measure effectiveness more frequently. SoCalGas' Customer Communications department which provides guidance and advice to measure effectiveness has recommended changes to the PA survey frequency. Their guidance is to conduct more frequent effectiveness surveys of our affected stakeholders annually from the current process, because there is too much "noise" in the marketplace to identify needed enhancements. The current process as defined by API 1162 is to measure affected stakeholders once every four years. In its request for funding, SoCalGas is prudently anticipating the need for changes to its program during this comprehensive effectiveness evaluation. These incremental funds will be used to drive a fundamental goal of the federal PA regulations, to continuously improve gas pipeline public awareness and safety-related customer communications in an ever-evolving landscape of pipeline safety regulations. This new environment is evident in the series of pipeline safety-related legislation that has either been adopted or proposed as noted in Section IIIA of this testimony.

With the enactment of these new state laws it is clear that more needs to be done with respect to public awareness. SoCalGas has recognized early on that continuous improvement is a necessity and has requested funding to fulfill that aim by collecting additional information, targeting groups identified through the evaluation process with a more tailored message to achieve the proper outcome.

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[43] Id. p. RKS-51.

DRA seems to ignore the continuous element of PHMSA's public awareness requirement by dismissing SoCalGas' recommendation as an activity driven by customer growth. Safety regulations and improvements are not dependent on customer growth. Simply looking at the recent abundance of new pipeline safety laws is a clear indication of the increased focus on pipeline safety and public awareness. Further, SoCalGas anticipates additional requirements beyond what it has forecasted in its GRC, but needs funding just to meet the current requirements.

The need to fulfill additional regulatory requirements is driving SoCalGas' request for incremental PA funding. The activities described above are incremental to the 2009 recorded expense level. These new activities are not included in the 2009 expense numbers and require increased funding to implement. The Commission should acknowledge the nature and importance of these activities and therefore approve SoCalGas' TY2012 funding forecast for its PA program of $1,159,000.

VI. SHARED SERVICES O&M

DRA did not seek changes to the shared services costs for SoCalGas of $16,053,000 for Gas Engineering. Therefore the Commission should adopt SoCalGas' entire Shared Services request

VII. CAPITAL EXPENSE - GAS ENGINEERING

DRA proposes that the Commission make significant reductions to several of the critical Transmission Budget Categories (BCs) that provide for new additions, pipeline replacements, compressor stations, land rights, laboratory equipment, and renewable energy programs.

In its recommendations, DRA often adopts an "all-or-nothing" approach citing" There are so many uncertainties regarding the feasibility and timing of these projects"[44], "Because of this uncertainty, DRA recommends removal of the requested funding for this project"[45], and "DRA also determined that the strategy . . . is very speculative",[46]. In the construction of gas facilities there will always be some inherent uncertainty and use of estimates, but that is not sound basis to disallow the entire forecasted spend of a portfolio of projects. The gauntlet of regulatory requirements, jurisdictional permitting, resource planning and scheduling makes for a dynamic project environment. While there may be some uncertainties in timing and expense, what is certain is that a reasonable level of expense will be necessary. The wholesale striking of entire capital budget forecasts is unreasonable.

In the discussion to follow, SoCalGas will show that DRA's recommendations for specific budget projects are unfounded, and that SoCalGas' forecasts for those capital activities should be approved.

A. New Additions (BC's: 301, 311, 321, and 331)

Transmission Pipelines – New Additions (Budget codes 301 & 311) includes costs associated with the design and installation of new transmission pipelines to serve new customer loads and/or to improve the ability to move natural gas to points of critical need at adequate pressure.

SoCalGas' forecast for 2010 was zero-based as the sum of six known projects at $9,519,000 own though the five-year average in this BC is $19,292,000. That the 2010 forecast was conservative is further evidenced by the 2010 recorded costs which were $12,727,000. DRA does not challenge SoCalGas' 2010 forecast although it has recommended adopting the

[44] DRA-45, p. 18, line 5.
[45] Id., p. 20, line 5.
[46] Id., p. 21, line 3.

2010 recorded cost in other BCs when the recorded is lower than forecasted. While SoCalGas objects to the use of 2010 data for forecasting purposes, it must note that DRA proposes to adopt the actual 2010 cost when it is lower than forecast and the forecast if it is lower than the actual 2010 cost.

The SoCalGas forecast for 2011 was also zero-based and conservative at the sum of three projects expected for 2011 when the plan was prepared in spring of 2010. The sum of the three projects was $11,191,000, much lower than the five-year average. For 2012, SoCalGas used the five-year average of $19,292,000. It is noteworthy that one of the five recorded years, 2005, had recorded costs of $31,682,000.

Despite conservative planning by SoCalGas, DRA remarkably recommends zero funding for new construction in 2011 and would reduce SoCalGas' funding by $13,364,000 in 2012, down to $5,928,000. DRA bases its recommended disallowance on SoCalGas' answer to a single question it asked in DRA-SCG-50-KCL. In that data request, DRA asked only for the status of the three 2011 projects that constituted the active list in spring of 2010. In SoCalGas' response, it reported that all three projects were delayed. DRA therefore concludes that SoCalGas must need zero funds in 2011. In retrospect, SoCalGas should have noted in its response that it is routine for projects to become delayed and that when that happens, other needed projects inevitably arise. But SoCalGas answered the narrow question with a narrow response. In fact, project lists and priorities are reviewed and adjusted monthly.

Actual projects now expected in 2011 are:

- Mandalay Peaker Plant
- Pt. Loma Waste Water Plant
- Anaheim Peaker Plant
- North/South System Interconnect

Projects currently expected for 2012 are:

- City of Palmdale UEG
- Mandalay Peaker Plant
- North/South System Interconnect
- Apex Pio Pico Peaker Plant
- Quail Brush Peaker Plant
- CPV Sentinel – North Palm Springs

As can be seen, there are many transmission line extension projects now for being worked in 2011 and slated for 2012. SoCalGas has no record of ever spending zero dollars in the 3X1 series of BCs. In fact, in recorded years 2005 through 2009, SoCalGas' recorded annual spending varied from a maximum of $31,682,000 in 2005 to a minimum of $5,565,000 in 2006. Base year 2009 spending was $25,768,000. As noted above, the five-year average is $19,292,000, which is SoCalGas' forecast for TY2012. Further evidence of the appropriateness of SoCalGas' forecasts is provided by looking at recorded year 2010, in which SoCalGas' recorded spending was more than $3,000,000 greater than the GRC forecast. For 2012, the five-year average as eminently reasonable.

SoCalGas notes that DRA has no quarrel with SoCalGas' use of five-year averaging elsewhere in DRA-45 but takes issue with new transmission line additions based on the unfounded belief that the three projects encountering delays equates to zero demand for funds in 2011 and vastly reduced funding in 2012. As demonstrated above, the demand for these projects fully justifies SoCalGas' forecasts for 2011 and 2012. Therefore, the Commission should adopt the forecast as submitted by SoCalGas as realistic and reasonable and reject the reductions proposed by DRA. If the Commission adopts 2010 recorded costs elsewhere that are less than forecasted, it should adopt the 2010 recorded spending of $12,727,000 rather than the 2010 GRC forecast of $9,519,000 for this area.

B. Replacement and Pipeline Integrity Program (BC's: 302, 312, 322, and 332)

Historically, Budget Codes 302, 312, 322 and 312 have included the cost of replacing transmission pipelines or pipeline sections found to have reached the end of their effective service lives through a combination of age, condition, or external threat such as landslides and/or natural disaster. Since 2002, costs in these budget codes have been heavily influenced by the new Federal Pipeline Integrity rules discussed in the preamble to my direct testimony in Exhibit SCG-05-R. Under these rules, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, collect information about the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents occur.

DRA's proposed reductions are fairly nominal (4.39% in 2011 and 1.45% in 2012) but SoCalGas' estimated amounts for 2011 and 2012 should be adopted by the Commission instead. This is due to the fact that DRA bases its recommended reductions on adjusting how many pig launcher/receiver assemblies should be temporary vs. permanent. SoCalGas has based its forecast on site-specific reviews of project conditions and gas operations requirements which dictate what sites lend themselves to temporary or permanent launchers/receivers. For instance, SoCalGas must determine which lines have to be shut down in order to "pig" them vs. which can be pigged while in service, or "hot." In summary, operational considerations plus local knowledge of available sites factor into decisions of permanent vs. temporary launchers and receivers. SoCalGas is well-positioned to make these determinations and therefore the Commission should adopt SoCalGas' original estimates for BC 3X2 as reasonable, valid, and based on detailed knowledge of job conditions and operational necessities.

C. Compressor Stations (BC's: 305, 315, 325, and 335)

This Budget Code includes the costs associated with installing and replacing compressor station equipment used in connection with SoCalGas' transmission system operations. The nature of compressor station operations requires the maintenance of facility reliability and safety. To keep operating costs down, reliance is placed on automation, remote control, and automatic data gathering systems to monitor performance data such as flows, pressures, and temperatures

In its proposal, DRA addresses two new air emissions rules, Federal RICE/NESHAP and Mohave Desert Air Quality Management District (MDAQMD) Rule 1160. With respect to RICE/NESHAP, DRA proposes adoption of SoCalGas' latest estimate of Capital requirements which it provided to DRA in response to DRA-SCG-050-KCL. SoCalGas agrees with that recommendation, which reduces this funding from $3,588,000 to $1,707,000.

With respect to MDAQMD's proposed Rule 1160, SoCalGas notes that DRA takes no issue with SoCalGas' cost of compliance determination but rather takes issue with the timeline SoCalGas uses to distribute its cost to comply with this revised rule. Specifically, DRA states, "SoCalGas' projection for MDAQMD Rule 1160 was based on the anticipated revisions to the rule. At this time, there is no indication that any changes will be made and/or finalized by 2012."

DRA proposes a complete disallowance of SoCalGas' estimates of capital costs related to compliance with Rule 1160. The testimony of Ms. Haines addresses the timing of the implementation of the revised rule. As SoCalGas stated in DRA-SCG-050-KCL in March 2011, "We make no change to the original estimate of the cost of complying with the anticipated revisions to MDAQMD Rule 1160." Based on the testimony of Ms. Haines, regarding timing of the regulations and my unchallenged direct testimony on the cost of compliance, the Commission should adopt the forecasts of SoCalGas as realistic and appropriate.

D. Pipeline Land Rights

This Budget category includes costs associated with the acquisition of land and land rights necessary to conduct natural gas transmission activities.

SoCalGas' forecasts in this BC are zero-based as the costs of two separate but necessary land purchases. The first is the purchase of "buffer lands" at three remote compressor stations at $6,000,000 over two years. The second is the purchase of "mitigation lands" related to compliance with Section 10 of the Federal Endangered Species Act (ESA) and Section 2081 of the California State Fish and Game Code at an estimated cost of $6,300,000 in 2012. DRA recommends that both purchases be denied in total.

With respect to the "buffer land" issue, DRA's proposal ignores the reality of the Federal Clean Air Act and California's AB 2588 enacted in 1987. DRA refers to these laws as "new emission regulations" and calls the need for purchases of adjacent lands as "purely speculation." The Clean Air Act and AB 2588 are not speculation, are in effect, and the North Needles, Newberry Springs, and Blythe sites are subject to them. DRA also states, "SoCalGas has not presented any detailed analysis to back up its proposed land purchases," even though SoCalGas' response to data request DRA-SCG-125-KCL presented a detailed and compelling case for these purchases vs. the very real possibilities of otherwise spending much greater sums for EPA-ordered emissions mitigation. SoCalGas went on to explain in its response that as soon as people (called "sensitive receptors") take residence adjacent to these sites, the Air Quality Boards can issue mitigation orders that, in a worst case, could require the sites to be converted from reciprocating-engine-driven compressors to electric-motor-driven compressors. The argument presented was, to paraphrase, spend $6 million now for adjacent land while prices are low, or face the real possibility of spending up to $33 million at each site upon arrival of one or more "sensitive receptors." SoCalGas does not think that leaving itself and its ratepayers open to that very real threat is a prudent business measure. Simply stated, the time to take action is now. Lastly, adding buffer property around these stations would have the effect of alleviating the concerns new residents would naturally have related to the very high operating pressures of these nearby plants. The $2,000,000 in 2011 and $4,000,000 in 2012 requested by SoCalGas for purchase of buffer lands around these critical sites is a prudent and timely business and economic decision that is essential for continued operation of these critical facilities.

DRA also proposes complete denial of funding related to “mitigation lands” that are central to compliance with Section 10 of the Federal Endangered Species Act (ESA) and Section 2081 of the California State Fish and Game Code at an estimated cost of $6,300,000 in 2012. Although my testimony sponsors the capital costs associated with the mitigation lands, Ms. Haines is the policy witness sponsoring the business case for SoCalGas’ compliance plan. Since DRA's recommendation for disallowance of funding for Mitigation Lands is primarily a policy issue, Ms. Haines’ rebuttal testimony, Exhibit SCG-X, section III. C. addresses DRA's recommendation and issues related to SoCalGas’ compliance plan to which purchase of mitigation lands is central. As discussed in Ms. Haines' rebuttal testimony, SoCalGas’ compliance plan supports the intent of the Environmental laws referenced above, the preferences of both the EPA and the California F&G Commission and follows established precedence. Therefore, the proposed funding for Mitigation Lands Purchase should be adopted by the Commission.

E. Laboratory Equipment (Budget Code 730)

SoCalGas requested incremental funding in 2011 for four optical imaging devices and nine high-volume samplers for a total of $670,000 over its 2010 forecast of $265,000. All are related to new Subpart W of the Mandatory Reporting Rule. The new tools are specific to the Transmission and Storage functions. DRA recommends reducing the number of tools to one optical imaging device and three high-volume samplers which would reduce SoCalGas' estimate for 2011 by $480,000. DRA quotes its own testimony in DRA-44 that "the new rule that became effective on November 8, 2010 is far less stringent on the types of sites and number of sites that require monitoring." DRA may have overlooked that, in DRA-44, it acknowledges that new Subpart W remains applicable to "Custody Transfer Gate Stations," which are Transmission facilities. This misunderstanding is further rebutted in the testimony of Ms. Haines in, Exhibit SCG-215. Inasmuch as the Transmission and Storage functions are largely unaffected by the recent changes to the originally-proposed Subpart W rules, the requested incremental new tools should remain in the 2011 estimate and the Commission should adopt SoCalGas' original estimate.

F. Sustainable SoCal Program (Budget Code 0399)

SoCalGas is requesting funding of $11,272,000, in capital, for the "Sustainable SoCal" Program. The Sustainable SoCal Program will promote the market development of pipeline quality biogas from waste-water treatment facilities in the SoCalGas service territory. The majority of this biogas is currently an untapped source of sustainable energy. This project would install treatment facilities at four locations.

DRA recommends disallowing the Sustainable SoCal program. Although my direct testimony sponsors the implementation costs associated with the Sustainable SoCal Program, Ms. Gillian Wright is the policy witness sponsoring the business case for the Sustainable SoCal Program (see Exhibit SCG-09 section IV.B.1). Since DRA's proposal for disallowance funding for Sustainable SoCal Program is primarily a policy issue, Ms. Wright's rebuttal testimony, Exhibit SCG-209, section III.H addresses DRA's recommendation and issues related to Sustainable SoCal Program. If the Commission approves this program, it should also approve the uncontested implementation costs set forth in my direct testimony.

VIII. SUMMARY AND CONCLUSION

As presented in this rebuttal, SoCalGas has reiterated its forecast methodologies and shown that its forecasts for O&M and capital expenses are reasonably and prudently derived. In particular, the requirements for Pipeline Integrity (TIMP and DIMP) and new environmental regulations, as well as the capital for compressor and pipeline and other infrastructure are necessary, a benefit to ratepayers, and in the public interest and the interests of safety and reliability. Finally, those activities required for DOT TIMP and DIMP-driven compliance will be recorded in the TIMP-Balancing Account and DIMP-Balancing Account, respectively.
I therefore respectively request that the Commission adopt the forecasts shown in my testimony, Exhibit SCG-05-R.

This concludes my prepared rebuttal testimony.

ATTACHMENT-A - Transmission Integrity

SoCalGas Response to Data Request DRA-SCG-022-DAO

ATTACHMENT-A - Transmission Integrity

SoCalGas Response to Data Request DRA-SCG-022-DAO

DRA DATA REQUEST
DRA-SCG-022-DAO
SOCALGAS 2012 GRC
SOCALGAS RESPONSE
DATE RECEIVED: DECEMBER 8, 2010
DATE RESPONDED: JANUARY 13, 2011

Exhibit Reference: SCG-5, Gas Engineering, Non-Shared Services

Subject: Pipeline Integrity Transmission

Please provide the following:

1. Please provide the following information regarding the Pipeline Integrity Transmission Program for years 2005-2010 YTD.
    a. The number of miles of mains inspected,
    b. The annual cost of inspection,
    c. The number of miles of mains inspected by method of inspection,
    d. The average cost per mile of mains inspected by method of inspection,
    e. The number of miles of mains repaired,
    f. The annual cost of repair,
    g. The repair cost per mile, or per foot if applicable,
    h. The annual program cost.

SoCalGas Response:

Note 1: The questions posed above refer to "miles of mains". The Pipeline Integrity Transmission program applies to DOT defined transmission pipelines. The responses below address DOT transmission pipeline mileage.
Note 2: The 2010 expense data are not yet finalized and will be provided in the future.

a. Please see the response to Item "c." below for the number of miles of transmission pipeline inspected.

b. The activities performed within the Transmission Pipeline Integrity workgroup constitute those necessary for successful completion of pipeline inspections. There are a number of steps involved before an inspection can be considered complete and the mileage counted. These steps are further explained in Mr. Stanford's testimony and associated Workpapers. The annual O&M costs are summarized on page 28 and 31 of exhibit SCG-05-WP and are repeated in the table below. The capital costs from which the 2012 forecasts have been derived are also shown in the table below.

Response to Question 1 (Continued)

It should be noted that most integrity projects span multiple years due to their size and scope and have both capital and O&M components depending on applicable accounting rules. The project inspection costs will likewise be applied over multiple years, during the year the activity was performed. However, reporting of the inspected pipeline mileage for a given project occurs in the year that the project was completed. These scheduling differences should be considered if attempting to perform a correlation between annual recorded inspection costs and annual completed mileage totals.

The table below indicates the year in which inspection activity costs were performed and expenses incurred.

	2005	2006	2007	2008	2009
O&M	$4,283,707	$9,239,520	$11,129,153	$9,957,405	$11,442,069
Capital	$34,543,034	$35,406,191	$40,852,753	$25,406,164	$37,191,446

c. The Table below indicates the number of miles of transmission pipeline inspected by method of inspection. Included in these totals are all inspected pipelines both HCA and non-HCA. The completed 2010 mileage data is currently being reconciled in preparation for the annual reporting cycle.

	Year					
Method used (miles)	2005	2006	2007	2008	2009	Total
ECDA	5.72	86.25	83.43	82.67	37.96	296.03
Hydrotest	18.38	1.00	0.00	0.00	0.39	19.77
ILI	261.81	589.69	246.83	36.86	63.15	1198.33
Total	285.91	676.93	330.26	119.53	101.49	1514.13

d. The following table shows the average cost per mile of pipelines inspected by method of inspection based on historical expenditures and mileage completed:

Method	Average $ per mile
ECDA:	$92,591
ILI:	$161,013
Hydro:	$823,087

e. There have been approximately 3.45 miles of pipe repaired as a result of the program. Included in this value are the repairs made by either physical replacement of sections of pipe or the installation of repair bands.

Response to Question 1 (Continued)

f. The table below shows the repair costs in the year performed:

	Year					
	2005	**2006**	**2007**	**2008**	**2009**	**Total**
Repair $	$7,519,070	$312,290	$5,168,816	$9,811,835	$1,624,904	$ 22,436,914

g. Based on the data from the above responses to Q1e and Q1f:
The average repair cost per mile = $ 7,091,729 or $1,343 per foot (cost per mile/5280)

h. The requirements for a pipeline integrity program as mandated in 49 CFR 192 Subpart O, and further developed in ASME B31.8S (included by reference in Subpart O) are comprehensive and far-reaching in nature. While the physical inspection of pipe segments are an integral part of the program there are also foundational and managerial aspects to the rule that are equally as important. The program requirements are not fully met even though the inspection is completed.
The response to Question 1b addresses the expenses related to the inspection activities of the piping system. The total annual program costs included in this response includes those values as well as the expenses required to meet the remainder of the IMP mandates. There are significant efforts and expenses focused on the non-inspection aspects of the program. These additional mandated activities include:

- Development and maintenance of the written plan including policy and procedural documents
- Gathering, reviewing, integrating, and analyzing data
- Threat and risk model maintenance and application
- Performance reporting
- Management of change activities
- Program quality control activities
- Provide integrity training
- Provide regulatory audit support and response.

The annual program costs as reflected in exhibit SCG-05 are summarized below.
(in thousands of $2009)

O&M	2005	2006	2007	2008	2009
NSS	$3,022	$8,362	$10,398	$9,157	$10,961
USS (Booked)	$2,869	$3,462	$3,284	$2,665	$3,216
Capital	$34,543	$35,406	$40,853	$25,406	$37,191

2. On page RKS-28, SCG states that it is actively pursuing a hybrid technology of ILI to assess cased main.
   a. When did SCG first begin to use this hybrid technology?
   b. Identify the timeframe, the annual expenses, and the number of miles of pipeline that SCG assessed using this technology.
   c. Provide a copy of all calculations and documents SCG relied on to conclude that this technology costs as much as three to five times per inspections and is greater on a per-foot-of-pipeline-inspected basis. (Page RKS-28).

SoCalGas Response:

a. The discussion of "hybrid technology of ILI" refers to the movement of the ILI tool by methods other than the inline pressure differential method most commonly used. Other methods used and/or being developed are "tethered pigging" which is when the tool is being pushed or pulled through the line, and robotic tools that are self-contained, motorized, and remotely operated from above. SoCalGas actively began using the tethered pigging method in 2010.

b. 2010 is the first year SoCalGas has used the tethered pigging inline inspection technology. To date, there have been two jobs completed totaling 1,197 feet or 0.23 miles. The total expenses were $957,847, of which approximately $383,139 is related to O&M activities.

c. The testimony statement quoted for this question is meant to focus the reader to the fact that tethered ILI projects are by nature much shorter in pipe length than a traditional ILI project. A typical tethered-ILI job will be no longer than a few hundred feet as opposed to miles for standard ILI projects. The initial estimates for tethered-ILI projects were garnered from existing contractors based on their experience and in comparison to the more traditional ILI jobs.
   The primary reason for the increase in per-foot project costs between the two methods of moving the ILI tool is the required fixed set-up costs. On longer mileage jobs the fixed costs can be spread out resulting in lower unit costs. Conversely, the shorter tethered jobs will exhibit higher unit costs.
   There have been two completed tethered-ILI projects in 2010. Preliminarily, the total capital and O&M expenses for the jobs were approximately $958,000. A total of 1,197 feet of pipe were inspected. That equates to roughly $800 per foot. In comparison, the traditional ILI projects are costing an average of $220 per foot. (from response to Q1d: $161,013/5280). That demonstrates tether-ILI expenses roughly 3.5 times that of traditional ILI.

3. Define “baseline” and “baseline assessments” as discussed in testimony on pages RKS-24 to RKS-31, and provide a copy of the Baseline Assessment Plan.

SoCalGas Response:

The definition of *assessment* in 49 CFR, §192.903 reads: Assessment is the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment. The terms “baseline” and “baseline assessment”, in the context of Mr. Stanford’s testimony, are synonymous terms. They describe the initial IMP assessment of a pipe segment to evaluate its current physical and operational status as well as provide a set of data to which subsequent assessments can be compared.

A copy of the utilities’ Baseline Assessment Plan is attached below:

Baseline Assessment Plan Schedule

Company	Pipeline	Segment Name	Segment Length	Inspection Method Used or Planned	Compled Date	Planned Baseline Mileage Complete Date	Planned Reassess Date
So Cal	2001WEST	1121641	0.65	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	1121642	0.36	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	1121643	0.54	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	1121644	0.29	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	1121645	0.42	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	1121646	0.60	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	1121647	0.76	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	1121648	3.08	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	1121649	0.81	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	1121650	0.36	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	1121651	1.11	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	1121652	0.71	ILI	06/06/03	Complete	07/31/10
So Cal	2001WEST	3098734	0.46	ILI	06/06/03	Complete	06/06/10
So Cal	2001WEST	1121654	7.11	ILI	06/06/03	Complete	06/06/10
So Cal	2001WEST	3098735	0.37	ILI	06/06/03	Complete	06/06/10
So Cal	2001WEST	1121657	6.32	ILI	06/06/03	Complete	06/06/10
So Cal	2001WEST	1121658	0.82	ILI	06/06/03	Complete	06/06/10
So Cal	2001WEST	1121658	0.37	ILI	06/06/03	Complete	06/06/10
So Cal	2001WEST	3098737	0.75	ILI	06/06/03	Complete	06/06/10
So Cal	2001WEST	1121659	4.76	ILI	06/06/03	Complete	06/06/10
So Cal	160	1121639	0.77	ILI	07/08/03	Complete	07/08/10
So Cal	1005	1121263	2.50	ILI	07/08/03	Complete	07/31/10
So Cal	1005	1121264	2.72	ILI	07/08/03	Complete	07/31/10
So Cal	1005	1121882	0.35	ILI	07/08/03	Complete	07/31/10
So Cal	1005	1121885	0.62	ILI	07/08/03	Complete	07/31/10
So Cal	1005	3267050	0.17	ILI	07/08/03	Complete	07/31/10
So Cal	1005	1121886	0.48	ILI	07/08/03	Complete	07/31/10
So Cal	1005	1121265	0.52	ILI	07/08/03	Complete	07/31/10
So Cal	1005	1121266	0.80	ILI	07/08/03	Complete	07/31/10
So Cal	1005	1121268	0.45	ILI	07/08/03	Complete	07/31/10
So Cal	1005	1121267	1.94	ILI	07/08/03	Complete	07/31/10
So Cal	1005	1121269	0.40	ILI	07/08/03	Complete	07/31/10
So Cal	80	1121228	0.55	ILI	08/14/03	Complete	08/14/10
So Cal	80	1121228	0.65	ILI	08/14/03	Complete	07/18/13
So Cal	1175	1121298	1.98	ILI	04/07/04	Complete	04/07/11
So Cal	1005	1121270	0.37	ILI	04/16/04	Complete	07/31/10
So Cal	2000	3098590	0.65	ILI	09/04/04	Complete	09/04/11
So Cal	2000	3098591	0.31	ILI	09/04/04	Complete	09/04/11
So Cal	2000	3098592	0.58	ILI	09/04/04	Complete	09/04/11
So Cal	2000	3098593	0.35	ILI	09/04/04	Complete	09/04/11
So Cal	2000	3098594	0.45	ILI	09/04/04	Complete	09/04/11
So Cal	2000	3098595	0.76	ILI	09/04/04	Complete	09/04/11
So Cal	2000	3098596	1.10	ILI	09/04/04	Complete	09/04/11
So Cal	2000	3098597	1.72	ILI	09/04/04	Complete	09/04/11
So Cal	2000	3098598	1.39	ILI	09/04/04	Complete	09/04/11
So Cal	2000	3098599	1.50	ILI	09/04/04	Complete	09/04/11
So Cal	2000	3098600	0.97	ILI	09/04/04	Complete	09/04/11
So Cal	6906 LT 1	1123501	0.01	ECDA	09/14/04	Complete	09/14/04
So Cal	2003	1165326	11.77	ILI	10/09/04	Complete	10/09/11
So Cal	2002	1155166	3.70	ILI	10/21/04	Complete	10/21/11
So Cal	2003	1165326	15.27	ILI	10/21/04	Complete	10/21/11
So Cal	2002	1155166	0.70	ILI	11/05/04	Complete	11/05/11
So Cal	2002	3266431	2.46	ILI	11/05/04	Complete	11/05/11

Baseline Assessment Plan Schedule

So Cal	1170	1121295	0.22	ILI	11/16/04	Complete	11/16/11
So Cal	1170	1121296	5.68	ILI	11/16/04	Complete	11/16/11
So Cal	3007	1121621	4.42	ILI	11/16/04	Complete	11/16/11
So Cal	6906 LT 1	1123501	0.03	ECDA	12/11/04	Complete	09/14/04
So Cal	2001WEST	1121660	0.64	ILI	12/13/04	Complete	12/13/11
So Cal	2001WEST	3098739	5.66	ILI	12/13/04	Complete	12/13/11
So Cal	2001WEST	3266928	11.29	ILI	12/13/04	Complete	12/13/11
So Cal	2001WEST	3266919	0.42	ILI	12/16/04	Complete	12/16/11
So Cal	6906	1121713	12.21	Hydrotest	02/01/05	Complete	02/01/12
So Cal	6906	1121714	4.18	Hydrotest	02/01/05	Complete	01/27/12
So Cal	6906	1121715	1.48	Hydrotest	02/01/05	Complete	01/27/12
So Cal	6906 LT 1	1123501	0.01	ECDA	02/01/05	Complete	09/14/04
So Cal	2000	3098611	0.38	ILI	02/08/05	Complete	09/04/11
So Cal	2000	3098612	1.62	ILI	02/08/05	Complete	09/04/11
So Cal	2000	3098613	13.87	ILI	02/08/05	Complete	09/04/11
So Cal	408	1122441	0.18	ECDA	04/01/05	Complete	04/01/10
So Cal	1025	3266411	0.16	ECDA	06/28/05	Complete	09/30/10
So Cal	1025	3266411	0.05	ECDA	06/28/05	Complete	09/30/10
So Cal	1025	3266411	0.08	ECDA	06/28/05	Complete	09/30/10
So Cal	PGR6	3098771	0.25	Hydrotest	07/27/05	Complete	07/27/12
So Cal	PGR6-D	3098816	0.01	Hydrotest	07/27/05	Complete	07/27/10
So Cal	PGR6-E	3098817	0.03	Hydrotest	07/27/05	Complete	07/27/10
So Cal	PGR6-F	3098813	0.02	Hydrotest	07/27/05	Complete	07/27/10
So Cal	PGR6-F1	3098814	0.01	Hydrotest	07/27/05	Complete	07/27/10
So Cal	PGR6-F2	3098815	0.03	Hydrotest	07/27/05	Complete	07/27/10
So Cal	PGR6-G	3098819	0.02	Hydrotest	07/27/05	Complete	07/27/10
So Cal	235 West	2544229	0.63	ILI	08/11/05	Complete	08/11/09
So Cal	235 West	2544230	0.27	ILI	08/11/05	Complete	08/11/09
So Cal	235 West	2544230	0.27	ILI	08/11/05	Complete	08/11/09
So Cal	235 West	2544230	0.03	ILI	08/11/05	Complete	08/11/09
So Cal	235 West	2544230	0.28	ILI	08/11/05	Complete	08/11/09
So Cal	1167	1121293	1.81	ILI	09/08/05	Complete	09/08/12
So Cal	1167	1121294	0.01	ILI	09/08/05	Complete	09/08/12
So Cal	335	1121229	0.43	ILI	10/07/05	Complete	10/07/12
So Cal	335	1121230	0.54	ILI	10/07/05	Complete	10/07/12
So Cal	335	1121231	2.83	ILI	10/07/05	Complete	10/07/12
So Cal	335	1121232	7.75	ILI	10/07/05	Complete	10/07/12
So Cal	335	1121234	2.99	ILI	10/07/05	Complete	10/07/12
So Cal	335	1121235	1.06	ILI	10/07/05	Complete	10/07/12
So Cal	335	1121236	1.13	ILI	10/07/05	Complete	10/07/12
So Cal	335	1121237	3.75	ILI	10/07/05	Complete	10/07/12
So Cal	1027	1121277	0.27	ILI	10/18/05	Complete	10/18/12
So Cal	1027	1121278	0.58	ILI	10/18/05	Complete	10/18/12
So Cal	1027	1121279	0.13	ILI	10/18/05	Complete	10/18/12
So Cal	1027	1121280	2.17	ILI	10/18/05	Complete	10/18/12
So Cal	1027	1121281	1.96	ILI	10/18/05	Complete	10/18/12
So Cal	1027	1121282	0.89	ILI	10/18/05	Complete	10/18/12
So Cal	1027	3098572	0.37	ILI	10/18/05	Complete	10/18/12
So Cal	1027	1121283	0.50	ILI	10/18/05	Complete	10/18/12
So Cal	1027	1121285	0.61	ILI	10/18/05	Complete	10/18/12
So Cal	1027	3098573	0.51	ILI	10/18/05	Complete	10/18/12
So Cal	1027	1121287	0.63	ILI	10/18/05	Complete	10/18/12
So Cal	1027	3098575	2.54	ILI	10/18/05	Complete	10/18/12
So Cal	1027	1121289	1.96	ILI	10/18/05	Complete	10/18/12
So Cal	1027	1121290	2.07	ILI	10/18/05	Complete	10/18/12
So Cal	1027	3098576	0.44	ILI	10/18/05	Complete	10/18/12
So Cal	1027	1121291	1.12	ILI	10/18/05	Complete	10/18/12
So Cal	1185	1121803	0.76	ECDA	10/23/05	Complete	10/23/10

Baseline Assessment Plan Schedule

So Cal	4002	1590226	0.59	ECDA	10/23/05	Complete	10/23/10
So Cal	4002	1590224	0.81	ECDA	10/23/05	Complete	10/23/10
So Cal	235 West	3098744	0.32	ILI	10/24/05	Complete	10/24/12
So Cal	235 West	2544234	0.54	ILI	10/24/05	Complete	10/25/12
So Cal	235 West	2544235	1.97	ILI	10/24/05	Complete	10/26/12
So Cal	235 West	2544236	5.95	ILI	10/24/05	Complete	10/27/12
So Cal	235 West	3266781	1.20	ILI	10/24/05	Complete	10/28/12
So Cal	235 West	3098745	0.26	ILI	10/24/05	Complete	10/29/12
So Cal	235 West	3266634	0.44	ILI	10/24/05	Complete	10/30/12
So Cal	235 West	2544238	0.70	ILI	10/24/05	Complete	10/31/12
So Cal	235 West	2544239	1.38	ILI	10/24/05	Complete	11/01/12
So Cal	235 West	2544240	0.53	ILI	10/24/05	Complete	11/02/12
So Cal	235 West	2544241	3.10	ILI	10/24/05	Complete	11/03/12
So Cal	767	1121712	5.44	ILI	10/25/05	Complete	10/25/12
SDGE	2009	1122095	0.28	ECDA	11/17/05	Complete	11/04/10
SDGE	2009	1122096	0.59	ECDA	11/17/05	Complete	11/04/10
So Cal	1021	1121910	0.68	ECDA	11/18/05	Complete	11/18/10
So Cal	3003	3266441	1.46	ILI	12/03/05	Complete	12/03/12
So Cal	3003	3266442	0.80	ILI	12/03/05	Complete	12/03/12
So Cal	3003	3266443	1.45	ILI	12/03/05	Complete	12/03/12
So Cal	3003	3266444	11.08	ILI	12/03/05	Complete	12/03/12
So Cal	3003	3266444	0.02	ILI	12/03/05	Complete	12/03/12
So Cal	4000	1155168	6.75	ILI	12/08/05	Complete	12/08/12
SDGE	2010	1122680	1.43	ECDA	01/26/06	Complete	01/26/13
SDGE	49-29	3266904	0.00	ECDA	01/26/06	Complete	01/26/13
SDGE	49-29	3266905	0.00	ECDA	01/26/06	Complete	01/26/13
So Cal	1013	1121276	4.42	ILI	01/31/06	Complete	02/03/13
So Cal	1013	3266423	4.42	ILI	01/31/06	Complete	02/03/13
So Cal	1013	3266423	0.36	ILI	01/31/06	Complete	02/03/13
So Cal	1013	1121276	0.36	ILI	01/31/06	Complete	02/03/13
So Cal	1015	1121633	0.61	ECDA	02/03/06	Complete	02/03/13
So Cal	1015	1121633	0.67	ECDA	02/03/06	Complete	02/03/13
So Cal	1015ST1		0.00	ECDA	02/03/06	Complete	02/03/13
So Cal	2000	3098601	0.70	ILI	02/13/06	Complete	02/13/13
So Cal	2000	3098602	0.40	ILI	02/13/06	Complete	02/13/13
So Cal	2000	3098603	0.79	ILI	02/13/06	Complete	02/13/13
So Cal	2000	3098604	2.35	ILI	02/13/06	Complete	02/13/13
So Cal	2000	3098605	1.49	ILI	02/13/06	Complete	02/13/13
So Cal	2000	3098606	1.41	ILI	02/13/06	Complete	02/13/13
So Cal	2000	3098607	0.87	ILI	02/13/06	Complete	02/13/13
So Cal	2000	3098609	5.72	ILI	02/13/06	Complete	02/13/13
So Cal	2000	3098610	4.34	ILI	02/13/06	Complete	02/13/13
So Cal	1180	1121255	1.73	ILI	02/17/06	Complete	02/17/13
So Cal	1180	1121256	0.64	ILI	02/17/06	Complete	02/17/13
So Cal	1180	1121257	0.20	ILI	02/17/06	Complete	02/17/13
So Cal	4000	1121628	1.41	ILI	03/16/06	Complete	03/16/13
So Cal	4000	1121629	1.64	ILI	03/16/06	Complete	03/16/13
So Cal	4000	1121630	21.67	ILI	03/16/06	Complete	03/16/13
So Cal	4000	1155168	3.21	ILI	03/16/06	Complete	03/16/13
So Cal	4002	1121702	0.00	ILI	04/03/06	Complete	04/03/13
So Cal	4002	1121703	1.63	ILI	04/03/06	Complete	04/03/13
So Cal	4002	3098750	2.22	ILI	04/03/06	Complete	04/03/13
So Cal	4002	3098751	7.62	ILI	04/03/06	Complete	04/03/13
So Cal	4002		0.32	ILI	04/03/06	Complete	04/03/13
So Cal	4002	1121707	1.93	ILI	04/03/06	Complete	04/03/13
So Cal	4002		0.49	ILI	04/03/06	Complete	04/03/13
So Cal	4002	1121708	2.42	ILI	04/03/06	Complete	04/03/13
So Cal	33-120	1121419	0.35	ECDA	04/12/06	Complete	04/12/13

Baseline Assessment Plan Schedule

So Cal	33-120	3098629	0.48	ECDA	04/12/06	Complete	04/12/13
So Cal	33-120	1121420	0.12	ECDA	04/12/06	Complete	04/12/13
So Cal	33-120	1121421	3.15	ECDA	04/12/06	Complete	04/12/13
So Cal	33-120	1121422	0.19	ECDA	04/12/06	Complete	04/12/13
So Cal	225	3266629	3.13	ILI	04/17/06	Complete	04/17/13
So Cal	225	3266630	1.03	ILI	04/17/06	Complete	04/17/13
So Cal	225	3266631	5.83	ILI	04/17/06	Complete	04/17/13
So Cal	225	3266632	0.44	ILI	04/17/06	Complete	04/17/13
So Cal	225	3266627	0.45	ILI	05/04/06	Complete	05/04/13
So Cal	225	3266628	0.56	ILI	05/04/06	Complete	05/04/13
So Cal	324	1121687	0.41	ILI	05/25/06	Complete	05/25/13
So Cal	324	1121688	0.53	ILI	05/25/06	Complete	05/25/13
So Cal	324	1121689	0.97	ILI	05/25/06	Complete	05/25/13
So Cal	324	1121690	0.46	ILI	05/25/06	Complete	05/25/13
So Cal	324	1121691	0.41	ILI	05/25/06	Complete	05/25/13
So Cal	324	1121692	0.92	ILI	05/25/06	Complete	05/25/13
So Cal	324	1121693	0.30	ILI	05/25/06	Complete	05/25/13
So Cal	4000	1121622	3.46	ILI	05/30/06	Complete	05/30/13
So Cal	4000	1121623	0.51	ILI	05/30/06	Complete	05/30/13
So Cal	4000	1121624	0.75	ILI	05/30/06	Complete	05/30/13
So Cal	4000	1121625	0.66	ILI	05/30/06	Complete	05/30/13
So Cal	4000	3098686	0.70	ILI	05/30/06	Complete	05/30/13
So Cal	4000	1121626	0.72	ILI	05/30/06	Complete	05/30/13
So Cal	3000 WEST	1121722	1.84	ILI	06/02/06	Complete	06/02/13
So Cal	3000 WEST	1121723	0.88	ILI	06/02/06	Complete	06/02/13
So Cal	3000 WEST	1121724	37.81	ILI	06/02/06	Complete	06/02/13
So Cal	80	1121228	0.02	ILI	07/18/06	Complete	07/18/13
So Cal	G80.01	3098769	0.07	Hydrotest	07/18/06	Complete	07/18/13
So Cal	G80.02	1590190	0.01	Hydrotest	07/18/06	Complete	07/18/13
So Cal	G80.03	1590191	0.01	Hydrotest	07/18/06	Complete	07/18/13
So Cal	1028	1121240	0.39	ILI	07/19/06	Complete	07/19/13
So Cal	1028	1121241	0.70	ILI	07/19/06	Complete	07/19/13
So Cal	1028	3098536	0.09	ILI	07/19/06	Complete	07/19/13
So Cal	1028	1121243	2.20	ILI	07/19/06	Complete	07/19/13
So Cal	1028	1121244	2.06	ILI	07/19/06	Complete	07/19/13
So Cal	1028	1121246	0.89	ILI	07/19/06	Complete	07/19/13
So Cal	1028	1610322	1.03	ILI	07/19/06	Complete	07/19/13
So Cal	1028	1121248	0.76	ILI	07/19/06	Complete	07/19/13
So Cal	1028	3098537	0.64	ILI	07/19/06	Complete	07/19/13
So Cal	1028	3098538	0.31	ILI	07/19/06	Complete	07/19/13
So Cal	1028	3098539	1.05	ILI	07/19/06	Complete	07/19/13
So Cal	1028	3098540	2.43	ILI	07/19/06	Complete	07/19/13
So Cal	1028	1121251	2.93	ILI	07/19/06	Complete	07/19/13
So Cal	1028	3098541	0.16	ILI	07/19/06	Complete	07/19/13
So Cal	1028	1121253	1.25	ILI	07/19/06	Complete	07/19/13
So Cal	1028	1121254	1.18	ILI	07/19/06	Complete	07/19/13
SDGE	3010	3266708	0.27	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1123173	0.00	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1123173	4.02	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1123175	0.57	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1123175	0.38	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1123176	0.80	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1123176	1.01	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1122683	0.62	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1122683	0.01	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1122683	2.80	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	3266709	1.06	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1122685	2.54	ECDA	08/14/06	Complete	03/16/14

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SDGE	3010	3098801	0.32	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	3098802	3.90	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	3098802	4.01	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1122687	3.70	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1122687	2.21	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	3266710	0.45	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	3266711	0.37	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	3266712	0.40	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	1122694	1.08	ECDA	08/14/06	Complete	03/16/14
SDGE	3010	3266713	1.15	ECDA	08/14/06	Complete	03/16/14
So Cal	5000(1)	1596617	0.49	ILI	08/15/06	Complete	08/15/13
So Cal	5000(1)	1596618	0.74	ILI	08/15/06	Complete	08/15/13
So Cal	5000(1)	1596618	0.23	ILI	08/15/06	Complete	08/15/13
So Cal	1229	1590138	0.00	Hydrotest	08/19/06	Complete	10/19/13
So Cal	1013	1121276	0.04	ILI	08/23/06	Complete	02/03/13
So Cal	1013	3266423	0.04	ILI	08/23/06	Complete	02/03/13
So Cal	1015	1121633	1.81	ECDA	08/24/06	Complete	08/24/13
So Cal	1015	1121633	1.36	ECDA	08/24/06	Complete	02/03/13
So Cal	1015	1122696	0.04	ECDA	08/24/06	Complete	08/24/13
So Cal	1015	1122696	1.04	ECDA	08/24/06	Complete	08/24/13
So Cal	1015	1122696	1.02	ECDA	08/24/06	Complete	08/24/13
So Cal	1015	1122696	0.08	ECDA	08/24/06	Complete	08/24/13
So Cal	1015	1122696	3.22	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122636	0.33	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122636	1.02	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122636	0.33	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	3098709	1.37	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	3098710	0.60	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122637	0.37	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122637	0.18	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122637	0.61	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	3098711	0.82	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	3098712	1.12	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122638	0.84	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122638	0.73	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	3098713	0.42	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122645	0.15	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122645	0.97	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122646	1.72	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	1122646	0.46	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	3098714	0.61	ECDA	08/24/06	Complete	08/24/13
So Cal	6900	3098715	1.12	ECDA	08/24/06	Complete	08/24/13
So Cal	85 South	1123570	0.31	ECDA	09/06/06	Complete	09/06/13
So Cal	85 South	3266873	0.64	ECDA	09/06/06	Complete	09/06/13
So Cal	85 South	3266874	0.52	ECDA	09/06/06	Complete	09/06/13
So Cal	85 South	3266875	0.36	ECDA	09/06/06	Complete	09/06/13
So Cal	85 South	1123571	2.39	ECDA	09/06/06	Complete	09/06/13
So Cal	85 South	1123573	0.58	ECDA	09/06/06	Complete	09/06/13
So Cal	85 South	1123574	0.63	ECDA	09/06/06	Complete	09/06/13
So Cal	85 South	1123575	0.25	ECDA	09/06/06	Complete	09/06/13
So Cal	407	3266659	2.14	ILI	09/08/06	Complete	09/08/13
So Cal	407	3266660	1.24	ILI	09/08/06	Complete	09/08/13
So Cal	1229	1590138	0.01	Hydrotest	09/08/06	Complete	10/19/13
So Cal	2001 East	1121716	0.29	ILI	09/16/06	Complete	09/16/13
So Cal	2001 East	1121717	0.58	ILI	09/16/06	Complete	09/16/13
So Cal	2001 East	1121718	2.39	ILI	09/16/06	Complete	09/16/13
So Cal	2001 East	3098805	0.40	ILI	09/16/06	Complete	09/16/13
So Cal	2001 East	1121719	0.51	ILI	09/16/06	Complete	09/16/13

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So Cal	2001 East	1121720	0.18	ILI	09/16/06	Complete	09/16/13
So Cal	2000	3098589	0.34	ILI	09/19/06	Complete	02/27/15
So Cal	2000	1121308	0.51	ILI	09/19/06	Complete	02/27/15
So Cal	2000	1121309	1.87	ILI	09/19/06	Complete	02/27/15
So Cal	2000	1121310	0.52	ILI	09/19/06	Complete	02/27/15
So Cal	2000	1121311	0.00	ILI	09/19/06	Complete	02/27/15
So Cal	6900	1122635	0.93	ECDA	09/19/06	Complete	08/23/13
So Cal	6900	1122636	1.44	ECDA	09/19/06	Complete	08/24/13
So Cal	6900	1122637	1.48	ECDA	09/19/06	Complete	09/19/13
So Cal	6900	1122637	0.49	ECDA	09/19/06	Complete	09/19/13
So Cal	6900	1122638	1.58	ECDA	09/19/06	Complete	08/24/13
So Cal	6900	1122645	1.16	ECDA	09/19/06	Complete	08/24/13
So Cal	6900	1122646	2.18	ECDA	09/19/06	Complete	08/24/13
So Cal	6900	3098716	0.07	ECDA	09/19/06	Complete	09/19/13
So Cal	41-6501	1122584	0.44	ECDA	09/24/06	Complete	09/24/13
So Cal	41-6501	1122584	0.01	ECDA	09/24/06	Complete	09/24/13
So Cal	41-6505	1122586	0.15	ECDA	09/24/06	Complete	09/24/13
So Cal	41-90	1122588	0.18	ECDA	09/24/06	Complete	09/21/13
So Cal	35-1179	1121444	0.45	ECDA	10/11/06	Complete	10/11/13
So Cal	41-19	2579899	0.16	ECDA	10/13/06	Complete	10/13/13
So Cal	41-19	2579899	0.28	ECDA	10/13/06	Complete	10/13/13
So Cal	41-19	2579901	0.05	ECDA	10/13/06	Complete	10/13/13
So Cal	1014	1121239	0.05	ILI	10/16/06	Complete	10/16/13
So Cal	2000	1121312	0.00	ILI	10/16/06	Complete	02/27/15
So Cal	2006	3266432	5.54	ILI	10/16/06	Complete	10/16/13
So Cal	4000	1155168	0.00	ILI	10/16/06	Complete	03/16/13
So Cal	1229	1590138	0.49	Hydrotest	10/19/06	Complete	10/19/13
So Cal	324	1122755	0.19	ECDA	10/24/06	Complete	10/24/13
So Cal	324	1122756	0.77	ECDA	10/24/06	Complete	10/24/13
So Cal	324	1122757	1.86	ECDA	10/24/06	Complete	10/24/13
So Cal	324	1122758	2.88	ECDA	10/24/06	Complete	10/24/13
So Cal	1192	1121301	0.84	ILI	10/27/06	Complete	10/27/13
So Cal	1192	1121302	9.71	ILI	10/27/06	Complete	10/27/13
So Cal	2001 East	1121720	0.26	ILI	10/30/06	Complete	10/30/13
So Cal	1181	1121299	0.22	ILI	11/03/06	Complete	11/03/13
So Cal	1181	1121300	4.49	ILI	11/03/06	Complete	11/03/13
So Cal	293	1121334	0.40	ECDA	11/12/06	Complete	11/12/13
So Cal	7000	1121806	0.22	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121807	0.24	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121808	0.28	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121809	0.27	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121810	0.96	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121811	0.26	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121812	0.33	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121813	0.30	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121814	0.39	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121815	0.29	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121816	0.26	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121817	0.43	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121818	0.19	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121819	0.32	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121820	0.44	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121821	0.23	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121822	0.44	ECDA	11/13/06	Complete	11/13/13
So Cal	7000	1121823	0.61	ECDA	11/13/06	Complete	11/13/13
So Cal	1018	1121634	6.19	ILI	12/04/06	Complete	12/04/13
So Cal	1018	1121635	1.26	ILI	12/04/06	Complete	12/04/13
So Cal	1018	1121636	1.65	ILI	12/04/06	Complete	12/04/13

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So Cal	1018	1121637	6.22	ILI	12/04/06	Complete	12/04/13
So Cal	1018	1121638	8.63	ILI	12/04/06	Complete	12/04/13
So Cal	41-6000-2	1122166	0.15	ECDA	12/20/06	Complete	12/20/13
So Cal	41-6000-2	1122166	0.10	ECDA	12/20/06	Complete	12/20/13
So Cal	41-6000-2	1122167	0.12	ECDA	12/20/06	Complete	12/20/13
So Cal	41-6000-2	1122168	0.15	ECDA	12/20/06	Complete	12/20/13
So Cal	41-6000-2	1122169	0.06	ECDA	12/20/06	Complete	12/20/13
So Cal	41-6000-2	1122170	0.10	ECDA	12/20/06	Complete	12/20/13
So Cal	41-6000-2	1122171	0.10	ECDA	12/20/06	Complete	12/20/13
So Cal	41-6000-2	1122172	0.08	ECDA	12/20/06	Complete	12/20/13
So Cal	41-6000-2	1122173	0.05	ECDA	12/20/06	Complete	12/20/13
So Cal	41-6000-2	1122164	0.15	ECDA	12/20/06	Complete	12/20/13
So Cal	41-6000-2	1122165	0.19	ECDA	12/20/06	Complete	12/20/13
So Cal	115	3098578	9.11	ILI	01/12/07	Complete	01/12/14
So Cal	115	3098580	8.43	ILI	01/12/07	Complete	01/12/14
So Cal	45-163	1122623	0.66	ECDA	01/17/07	Complete	01/17/14
So Cal	45-163	1122623	0.18	ECDA	01/17/07	Complete	01/17/14
So Cal	45-163	1122623	0.00	ECDA	01/17/07	Complete	01/17/14
So Cal	45-163	1122623	1.11	ECDA	01/17/07	Complete	01/17/14
So Cal	45-163	1122624	0.70	ECDA	01/17/07	Complete	01/17/14
So Cal	45-163	1122624	0.30	ECDA	01/17/07	Complete	01/17/14
So Cal	45-163	1122625	0.05	ECDA	01/17/07	Complete	01/17/14
So Cal	45-163	1122625	0.86	ECDA	01/17/07	Complete	01/17/14
So Cal	8109	3098549	0.79	ILI	02/14/07	Complete	02/14/14
So Cal	8109	3098550	0.33	ILI	02/14/07	Complete	02/14/14
So Cal	8109	3098551	0.61	ILI	02/14/07	Complete	02/14/14
So Cal	8109	3098552	3.11	ILI	02/14/07	Complete	02/14/14
So Cal	8109	3098554	0.15	ILI	02/14/07	Complete	02/14/14
SDGE	1600	2579962	0.31	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579963	0.53	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579966	0.64	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	3098834	1.32	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579967	1.18	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579967	0.29	ECDA	03/03/07	Complete	03/02/14
SDGE	1600	2579970	0.25	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	3266741	0.17	ECDA	03/03/07	Complete	03/04/14
SDGE	1600	3266742	1.46	ECDA	03/03/07	Complete	03/05/14
SDGE	1600	2579975	0.23	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	3098835	0.14	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	3098836	0.14	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	3098836	0.13	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579980	2.06	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	3266743	0.49	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579985	1.50	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579986	0.23	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579986	0.19	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579986	0.38	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	3266744	0.58	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579988	0.43	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	3266745	0.33	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579990	3.80	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579991	0.01	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579991	2.04	ECDA	03/03/07	Complete	03/03/14
SDGE	1600	2579992	1.31	ECDA	03/03/07	Complete	03/03/14
SDGE	3010	3266714	0.28	ECDA	03/16/07	Complete	03/16/14
So Cal	1010	3266417	0.19	ILI	03/29/07	Complete	03/29/14
So Cal	1010	3266418	0.31	ILI	03/29/07	Complete	03/29/14
So Cal	1010	3266419	0.27	ILI	03/29/07	Complete	03/29/14

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So Cal	1010	3266420	0.35	ILI	03/29/07	Complete	03/29/14
So Cal	1010	3266421	0.22	ILI	03/29/07	Complete	03/29/14
So Cal	1205	1121303	7.72	ILI	04/12/07	Complete	04/12/14
So Cal	3003	3266445	3.02	ILI	04/12/07	Complete	04/12/14
So Cal	35-20	3098631	0.37	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3098632	1.29	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3098633	0.47	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3098634	0.47	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3098635	0.76	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3266999	2.54	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3267000	0.21	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3267001	0.20	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3267002	0.74	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3267003	0.31	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3267004	5.84	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3267005	0.41	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3267006	0.62	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3267007	0.57	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3267008	0.12	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3267009	0.79	ILI	05/21/07	Complete	05/21/14
So Cal	35-20	3266998	0.84	ILI	05/21/07	Complete	05/21/14
So Cal	31-09	1121377	1.01	ECDA	05/24/07	Complete	05/24/14
So Cal	31-09	1121377	0.91	ECDA	05/24/07	Complete	05/24/14
So Cal	31-09	1121377	0.23	ECDA	05/24/07	Complete	05/24/14
So Cal	31-09	1121378	0.11	ECDA	05/24/07	Complete	05/24/14
So Cal	31-09	3266951	0.08	ECDA	05/24/07	Complete	05/24/14
So Cal	31-09	3098627	0.58	ECDA	05/24/07	Complete	05/24/14
So Cal	31-09	3098627	0.04	ECDA	05/24/07	Complete	05/24/14
So Cal	31-09	3208621	0.61	ECDA	05/24/07	Complete	05/24/14
So Cal	31-09	3208621	0.68	ECDA	05/24/07	Complete	05/24/14
So Cal	31-09	3208621	0.02	ECDA	05/24/07	Complete	05/24/14
So Cal	3008	1121358	0.55	ECDA	06/14/07	Complete	06/14/14
So Cal	1024	3098568	1.63	ILI	06/22/07	Complete	06/22/14
So Cal	1176	3098584	3.79	ILI	06/22/07	Complete	06/22/14
So Cal	1011	1121899	0.21	ECDA	08/29/07	Complete	08/29/14
So Cal	1011	1121899	0.62	ECDA	08/29/07	Complete	08/29/14
So Cal	1011	3266422	0.81	ECDA	08/29/07	Complete	08/29/14
So Cal	404	3098753	0.88	ILI	09/14/07	Complete	09/14/14
So Cal	404	3098754	3.56	ILI	09/14/07	Complete	09/14/14
So Cal	404	3098755	4.34	ILI	09/14/07	Complete	09/14/14
So Cal	404	3098756	0.16	ILI	09/14/07	Complete	09/14/14
So Cal	36-9-06	1121532	0.47	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1121532	0.01	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1121532	0.29	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1121532	0.09	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1121532	1.55	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1589782	0.16	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1121544	0.03	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	3266495	0.09	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1121545	0.40	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1121546	1.08	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1121542	0.02	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	3098642	0.37	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1121529	0.31	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1121531	0.27	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	1121531	1.02	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	3266496	0.48	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	3266497	0.30	ECDA	10/04/07	Complete	10/04/14

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So Cal	36-9-06	3266498	0.79	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	3266499	0.80	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	3266500	1.44	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	3266501	0.23	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	3266502	0.54	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06	3266503	1.41	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06-A	3266504	0.14	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06-A	3266504	0.01	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06-A	3266505	0.17	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06-A	3266505	0.06	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06-A	3266506	0.38	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06-A	3266506	1.25	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06-A	3266506	0.07	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06-A	3266506	0.36	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06-E	1121553	1.00	ECDA	10/04/07	Complete	10/04/14
So Cal	36-9-06-E	1121554	0.00	ECDA	10/04/07	Complete	10/04/14
So Cal	800	3098760	0.28	ILI	10/05/07	Complete	10/05/14
So Cal	800	3098761	0.34	ILI	10/05/07	Complete	10/05/14
So Cal	800	3098762	0.63	ILI	10/05/07	Complete	10/05/14
So Cal	3005	1121356	0.02	ECDA	10/12/07	Complete	10/12/14
So Cal	1016	3098566	5.31	ILI	10/15/07	Complete	10/15/14
So Cal	1016	3098567	8.09	ILI	10/15/07	Complete	10/15/14
So Cal	1004	3174685	0.36	ILI	10/18/07	Complete	10/18/14
So Cal	1004	3174686	2.03	ILI	10/18/07	Complete	10/18/14
So Cal	1004	3174687	2.68	ILI	10/18/07	Complete	10/18/14
So Cal	1004	1121260	0.13	ILI	10/18/07	Complete	10/18/14
So Cal	404	1122840	1.06	ILI	10/29/07	Complete	10/29/14
So Cal	404	3098758	5.43	ILI	10/29/07	Complete	10/29/14
So Cal	404	3098759	12.72	ILI	10/29/07	Complete	10/29/14
SDGE	3012	1121805	0.61	ECDA	10/31/07	Complete	10/31/14
SDGE	3600	3266882	0.03	ECDA	10/31/07	Complete	10/31/14
SDGE	3600	3266882	0.02	ECDA	10/31/07	Complete	10/31/14
SDGE	3600	3266882	2.07	ECDA	10/31/07	Complete	10/31/14
SDGE	3600	1122849	0.97	ECDA	10/31/07	Complete	10/31/14
So Cal	765	3098721	6.00	ILI	11/02/07	Complete	11/16/14
So Cal	765	3098721	11.45	ILI	11/16/07	Complete	02/20/15
So Cal	765	3098722	0.21	ILI	11/16/07	Complete	11/16/14
So Cal	765	3098723	0.29	ILI	11/16/07	Complete	11/16/14
So Cal	765	3098724	0.58	ILI	11/16/07	Complete	11/16/14
So Cal	765	3098725	2.74	ILI	11/16/07	Complete	11/16/14
So Cal	1004	3098556	0.51	ILI	11/27/07	Complete	11/27/14
So Cal	1004	2212438	0.45	ILI	11/27/07	Complete	11/27/14
So Cal	1004	3098557	8.16	ILI	11/27/07	Complete	11/27/14
So Cal	1004	1121259	0.18	ILI	11/27/07	Complete	11/27/14
So Cal	1004	3098558	2.81	ILI	11/27/07	Complete	11/27/14
So Cal	1004	3174664	0.59	ILI	11/27/07	Complete	11/27/14
So Cal	1004	3174674	3.92	ILI	11/27/07	Complete	11/27/14
So Cal	1004	3174678	1.34	ILI	11/27/07	Complete	11/27/14
SDGE	3600	3266883	2.58	ECDA	11/27/07	Complete	11/27/14
SDGE	3600	3266883	4.70	ECDA	11/27/07	Complete	11/27/14
SDGE	3600	3266882	2.83	ECDA	11/27/07	Complete	11/27/14
So Cal	127	1122016	0.09	ILI	11/29/07	Complete	01/12/14
So Cal	127	1122017	0.20	ILI	11/29/07	Complete	01/12/14
So Cal	406	1122140	0.79	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122141	0.47	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122142	1.11	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122143	0.73	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122144	1.47	ILI	12/10/07	Complete	12/10/14

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So Cal	406	1122145	0.44	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122146	0.61	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122147	0.79	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122148	0.35	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122149	0.44	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122150	4.14	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122151	1.17	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122152	0.87	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122153	2.77	ILI	12/10/07	Complete	12/10/14
So Cal	406	1122154	7.97	ILI	12/10/07	Complete	12/10/14
So Cal	35-20-A	1121462	0.25	ECDA	12/10/07	Complete	12/10/14
So Cal	35-20-A	1121462	0.05	ECDA	12/10/07	Complete	12/10/14
So Cal	35-20-A	1121463	0.55	ECDA	12/10/07	Complete	12/10/14
So Cal	35-20-A	1121464	0.27	ECDA	12/10/07	Complete	12/10/14
So Cal	35-20-A	1121464	0.83	ECDA	12/10/07	Complete	12/10/14
SDGE	1602	1122030	0.71	ECDA	12/12/07	Complete	12/12/14
SDGE	1602	1122030	0.04	ECDA	12/12/07	Complete	12/12/14
SDGE	1603	1122031	0.42	ECDA	12/12/07	Complete	12/12/14
SDGE	3600	1122848	1.18	ECDA	12/12/07	Complete	12/12/14
SDGE	3600	3266883	1.10	ECDA	12/12/07	Complete	12/12/14
SDGE	3600	3266883	0.02	ECDA	12/12/07	Complete	12/12/14
SDGE	3600	3266883	4.55	ECDA	12/12/07	Complete	12/12/14
SDGE	3600	3266883	1.81	ECDA	12/12/07	Complete	12/12/14
So Cal	36-1001	1122768	0.09	ECDA	12/15/07	Complete	12/15/14
So Cal	37-07	3266794	0.99	ECDA	01/10/08	Complete	01/10/15
So Cal	37-07	3266794	0.54	ECDA	01/10/08	Complete	01/10/15
So Cal	37-07	3266795	0.57	ECDA	01/10/08	Complete	01/10/15
So Cal	37-07	3266795	0.04	ECDA	01/10/08	Complete	01/10/15
So Cal	765	3098721	6.36	ILI	02/20/08	Complete	02/20/15
So Cal	30-18	1123003	0.44	ECDA	05/15/08	Complete	05/15/15
So Cal	30-18	1123003	0.30	ECDA	05/15/08	Complete	05/15/15
So Cal	30-18	1123006	0.12	ECDA	05/15/08	Complete	05/15/15
So Cal	30-18	1123008	0.23	ECDA	05/15/08	Complete	05/15/15
So Cal	30-18	1123008	0.18	ECDA	05/15/08	Complete	05/15/15
So Cal	30-18	1123008	0.04	ECDA	05/15/08	Complete	05/15/15
So Cal	30-18	1123005	0.13	ECDA	05/15/08	Complete	05/15/15
So Cal	30-18	1123002	0.30	ECDA	05/15/08	Complete	05/15/15
So Cal	30-18	1123004	0.04	ECDA	05/15/08	Complete	05/15/15
So Cal	1019	1121906	14.55	ILI	05/22/08	Complete	05/22/15
So Cal	33-37	1610038	0.31	ECDA	05/22/08	Complete	05/22/15
So Cal	33-37	1610039	0.29	ECDA	05/22/08	Complete	05/22/15
So Cal	33-37	1610040	0.44	ECDA	05/22/08	Complete	05/22/15
So Cal	33-37	3098827	0.14	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610012	0.04	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610012	0.55	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610012	0.01	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610012	0.13	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610012	0.63	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610012	0.12	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610012	0.02	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610012	0.30	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3098828	1.22	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3098829	0.26	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131383	0.33	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131383	0.15	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131390	0.62	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131391	0.28	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131392	0.32	ECDA	05/22/08	Complete	05/22/15

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So Cal	36-37	3131393	0.27	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131393	0.16	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131393	0.12	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131393	0.04	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131394	0.08	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3098830	0.16	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131395	0.11	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131400	0.08	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131399	0.04	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131401	0.20	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610028	0.77	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610028	0.04	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610035	0.01	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610035	0.10	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	1610035	0.44	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131403	0.15	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131404	0.13	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131405	0.40	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131406	0.14	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131407	0.26	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131408	0.19	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131409	0.07	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131409	0.28	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131410	0.05	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131410	0.24	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131411	0.07	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131411	0.20	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131411	0.19	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131412	0.10	ECDA	05/22/08	Complete	05/22/15
So Cal	36-37	3131413	0.50	ECDA	05/22/08	Complete	05/22/15
So Cal	3001	1121337	5.23	ILI	06/06/08	Complete	06/06/15
SDGE	49-16	1122035	0.14	ECDA	07/10/08	Complete	07/10/15
SDGE	49-16	1122036	2.17	ECDA	07/10/08	Complete	07/10/15
SDGE	49-16	1122037	0.75	ECDA	07/10/08	Complete	07/10/15
SDGE	49-16	1122038	0.35	ECDA	07/10/08	Complete	07/10/15
SDGE	49-16	1122038	0.87	ECDA	07/10/08	Complete	07/10/15
SDGE	49-18	1122045	0.12	ECDA	07/10/08	Complete	07/10/15
SDGE	49-18	1122046	1.67	ECDA	07/10/08	Complete	07/10/15
SDGE	49-18	1122047	0.20	ECDA	07/10/08	Complete	07/10/15
SDGE	49-18	1122047	0.38	ECDA	07/10/08	Complete	07/10/15
SDGE	49-18	1122047	2.05	ECDA	07/10/08	Complete	07/10/15
SDGE	49-18	1122049	0.46	ECDA	07/10/08	Complete	07/10/15
SDGE	49-18	1122049	1.83	ECDA	07/10/08	Complete	07/10/15
SDGE	49-18	1122050	0.34	ECDA	07/10/08	Complete	07/10/15
SDGE	49-21	1122102	0.86	ECDA	07/10/08	Complete	07/10/15
So Cal	36-6593	1121506	0.18	ECDA	07/14/08	Complete	07/14/15
So Cal	36-6593	1121506	0.18	ECDA	07/14/08	Complete	07/14/15
So Cal	36-6593	1121507	0.50	ECDA	07/14/08	Complete	07/14/15
So Cal	36-6593	1121508	0.03	ECDA	07/14/08	Complete	07/14/15
So Cal	36-1007	3098749	0.26	ECDA	07/30/08	Complete	07/30/15
So Cal	36-1007	1122783	0.47	ECDA	07/30/08	Complete	07/30/15
So Cal	36-1007	1122784	0.22	ECDA	07/30/08	Complete	07/30/15
So Cal	36-1007	1122785	0.64	ECDA	07/30/08	Complete	07/30/15
So Cal	36-1007	1122785	0.25	ECDA	07/30/08	Complete	07/30/15
So Cal	36-1007	1122786	0.29	ECDA	07/30/08	Complete	07/30/15
So Cal	36-1007	1122787	0.20	ECDA	07/30/08	Complete	07/30/15
So Cal	36-1007	1122787	0.23	ECDA	07/30/08	Complete	07/30/15
SDGE	1601	1122210	0.99	ECDA	09/05/08	Complete	09/05/16

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SDGE	1601	1122210	1.26	ECDA	09/05/08	Complete	09/05/16
SDGE	1601	1122210	0.83	ECDA	09/05/08	Complete	09/05/16
SDGE	1601	1122211	0.39	ECDA	09/05/08	Complete	09/05/16
SDGE	1601	1122212	2.92	ECDA	09/05/08	Complete	09/05/16
SDGE	1601	1122212	3.67	ECDA	09/05/08	Complete	09/05/16
SDGE	1601	1122213	2.41	ECDA	09/05/08	Complete	09/05/16
SDGE	1601	1122844	0.30	ECDA	09/05/08	Complete	09/05/16
SDGE	1604	3266430	0.16	ECDA	09/05/08	Complete	09/05/16
SDGE	1604	3266430	0.11	ECDA	09/05/08	Complete	09/05/16
SDGE	1604	3266430	0.44	ECDA	09/05/08	Complete	09/05/16
SDGE	1604	3266430	0.34	ECDA	09/05/08	Complete	09/05/16
SDGE	1601	1122844	0.01	ECDA	09/15/08	Complete	09/05/16
So Cal	37-18	1123051	0.00	ECDA	09/24/08	Complete	09/24/15
So Cal	37-18	1123051	0.96	ECDA	09/24/08	Complete	09/24/15
So Cal	37-18	1123052	0.11	ECDA	09/24/08	Complete	09/24/15
So Cal	37-18	1123050	0.71	ECDA	09/24/08	Complete	09/24/15
So Cal	37-18	1123050	0.64	ECDA	09/24/08	Complete	09/24/15
So Cal	37-18	1123050	0.04	ECDA	09/24/08	Complete	09/24/15
So Cal	37-18	1123049	1.22	ECDA	09/24/08	Complete	09/24/15
So Cal	37-18-F	3266748	0.06	ECDA	09/24/08	Complete	09/24/15
So Cal	37-18-F	3266749	1.93	ECDA	09/24/08	Complete	09/24/15
So Cal	37-18-J	3098660	0.20	ECDA	09/24/08	Complete	09/24/15
So Cal	37-18-K	3266750	1.41	ECDA	09/24/08	Complete	09/24/15
So Cal	37-18-K	3266751	0.45	ECDA	09/24/08	Complete	09/24/15
So Cal	41-05	1122470	0.90	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122470	0.12	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122471	0.26	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122472	0.16	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122474	0.31	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122475	0.27	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122476	0.46	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122476	0.45	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266554	0.26	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266554	0.10	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122477	0.31	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122478	0.43	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266555	0.17	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266556	0.12	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266557	0.08	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266558	0.12	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266559	0.15	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266560	0.56	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266561	0.21	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266767	0.08	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266767	0.23	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122464	0.24	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122465	0.06	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122465	0.53	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122466	0.33	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122467	0.19	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122468	0.22	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122469	0.65	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122442	0.15	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122442	0.14	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122443	0.28	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122444	0.15	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	2280510	0.14	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	2291409	0.17	ECDA	10/16/08	Complete	10/16/15

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So Cal	41-05	2428277	0.14	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122455	0.48	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122456	0.64	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122456	0.27	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122457	0.27	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122458	0.14	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122458	0.02	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122458	0.02	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122458	0.06	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	1122459	0.28	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	2425508	0.26	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	2425509	0.06	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	2425509	0.15	ECDA	10/16/08	Complete	10/16/15
So Cal	41-05	3266863	0.46	ECDA	10/16/08	Complete	10/16/15
So Cal	32-25	1123016	0.78	ECDA	10/21/08	Complete	10/21/15
So Cal	32-25	1123016	0.13	ECDA	10/21/08	Complete	10/21/15
So Cal	32-25	1123017	0.18	ECDA	10/21/08	Complete	10/21/15
So Cal	44-725	2308710	0.16	ECDA	10/29/08	Complete	10/29/15
So Cal	44-725	2308711	0.32	ECDA	10/29/08	Complete	10/29/15
So Cal	36-1001	3098748	0.04	ECDA	10/31/08	Complete	10/31/15
So Cal	1202	1121999	7.59	ILI	11/06/08	Complete	12/18/16
SDGE	3011	1121359	0.48	ECDA	11/06/08	Complete	11/06/15
SDGE	3011	1121360	0.00	ECDA	11/06/08	Complete	11/06/15
SDGE	3011	1121360	0.92	ECDA	11/06/08	Complete	11/06/15
SDGE	3011	1121360	0.13	ECDA	11/06/08	Complete	11/06/15
So Cal	32-24	3266677	0.10	ECDA	11/06/08	Complete	11/06/15
So Cal	32-24	2308685	0.53	ECDA	11/06/08	Complete	11/06/15
So Cal	1200	1121996	1.32	ILI	12/18/08	Complete	12/18/16
So Cal	1200	1121997	0.45	ILI	12/18/08	Complete	12/18/16
So Cal	1200	1121998	1.41	ILI	12/18/08	Complete	12/18/16
So Cal	32-60	2308886	0.19	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	2308887	0.57	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	2308887	0.59	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	2308887	0.00	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	3099086	0.62	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	3099087	0.14	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	3099089	0.18	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	2308891	0.36	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	2308891	0.01	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	2308891	0.01	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	3099090	0.66	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	3099091	1.90	ECDA	01/23/09	Complete	01/23/16
So Cal	32-60	3099092	0.14	ECDA	01/23/09	Complete	01/23/16
So Cal	1020	1121907	2.64	ILI	03/05/09	Complete	03/05/16
So Cal	1020	1121908	0.57	ILI	03/05/09	Complete	03/05/16
So Cal	1020	1121909	2.32	ILI	03/05/09	Complete	03/05/16
So Cal	247	1121317	0.21	ILI	03/11/09	Complete	03/11/16
So Cal	247	1122122	3.06	ILI	03/11/09	Complete	03/11/16
So Cal	247	1122123	0.40	ILI	03/11/09	Complete	03/11/16
So Cal	247	1121314	0.34	ILI	03/11/09	Complete	03/11/16
So Cal	247	1121315	0.23	ILI	03/11/09	Complete	03/11/16
So Cal	247	1121316	0.11	ILI	03/11/09	Complete	03/11/16
SDGE	49-13	3098586	0.09	ECDA	03/23/09	Complete	03/23/16
SDGE	49-13	1122019	0.37	ECDA	03/23/09	Complete	03/23/16
SDGE	49-13	3267026	0.28	ECDA	03/23/09	Complete	03/23/16
SDGE	49-13	3098587	0.27	ECDA	03/23/09	Complete	03/23/16
SDGE	49-15	3266881	1.11	ECDA	03/23/09	Complete	03/23/16
SDGE	49-15	1122029	0.69	ECDA	03/23/09	Complete	03/23/16

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SDGE	49-15	1122027	0.93	ECDA	03/23/09	Complete	03/23/16
SDGE	49-15	1122028	0.01	ECDA	03/23/09	Complete	03/23/16
So Cal	85 South	3098832	0.09	ECDA	04/13/09	Complete	04/13/16
So Cal	35-10	1121443	1.14	ECDA	04/24/09	Complete	04/24/17
So Cal	35-10	1121436	0.31	ECDA	04/24/09	Complete	04/24/17
So Cal	35-10	1121439	0.26	ECDA	04/24/09	Complete	04/24/17
So Cal	35-10	1121440	1.21	ECDA	04/24/09	Complete	04/24/17
So Cal	35-10	1121441	0.15	ECDA	04/24/09	Complete	04/24/17
So Cal	35-10	1121442	0.08	ECDA	04/24/09	Complete	04/24/17
So Cal	7039	1121824	0.62	ILI	06/03/09	Complete	06/03/16
So Cal	7039	1121825	0.28	ILI	06/03/09	Complete	06/03/16
So Cal	7039	3098546	0.25	ILI	06/03/09	Complete	06/03/16
So Cal	7039	1121827	0.71	ILI	06/03/09	Complete	06/03/16
So Cal	7039	1121829	0.42	ILI	06/03/09	Complete	06/03/16
So Cal	7039	1121830	2.85	ILI	06/03/09	Complete	06/03/16
So Cal	7039	1121831	1.17	ILI	06/03/09	Complete	06/03/16
So Cal	7039	3098548	0.39	ILI	06/03/09	Complete	06/03/16
So Cal	7039	1121833	1.20	ILI	06/03/09	Complete	06/03/16
So Cal	235 West	2544231	1.48	ILI	06/18/09	Complete	06/30/09
So Cal	235 West	2544232	0.28	ILI	06/18/09	Complete	06/30/09
So Cal	235 West	2544233	1.62	ILI	06/18/09	Complete	06/30/09
So Cal	235 West	2544233	0.00	ILI	06/18/09	Complete	06/30/09
So Cal	235 West	2544233	0.42	ILI	06/18/09	Complete	06/30/09
So Cal	235 West	2544233	0.42	ILI	06/18/09	Complete	06/30/09
So Cal	1017	3208101	4.46	ECDA	06/19/09	Complete	06/19/16
So Cal	1017	1121905	2.75	ECDA	06/19/09	Complete	06/19/16
So Cal	8032	1122666	0.43	ECDA	07/20/09	Complete	07/20/16
So Cal	7025	1122191	0.23	ECDA	07/29/09	Complete	07/29/16
So Cal	38-501	1122364	0.18	ECDA	8/26/2009	Complete	8/26/2016
So Cal	38-501	1122365	0.17	ECDA	8/26/2009	Complete	8/26/2016
So Cal	38-501	1122366	0.47	ECDA	8/26/2009	Complete	8/26/2016
So Cal	38-501	3266871	0.22	ECDA	8/26/2009	Complete	8/26/2016
So Cal	38-501	3266872	0.15	ECDA	8/26/2009	Complete	8/26/2016
So Cal	2000	3098613	2.41	ILI	09/29/09	Complete	09/04/11
So Cal	36-9-21	1122318	1.53	ECDA	10/08/09	Complete	10/08/16
So Cal	36-9-21	1122319	0.84	ECDA	10/8/2009	Complete	10/8/2016
So Cal	36-9-21	1122320	0.57	ECDA	10/8/2009	Complete	10/8/2016
So Cal	36-9-21	1122323	0.17	ECDA	10/8/2009	Complete	10/8/2016
So Cal	36-9-21	1122314	0.22	ECDA	10/8/2009	Complete	10/8/2016
So Cal	36-9-21	1122328	0.67	ECDA	10/8/2009	Complete	10/8/2016
So Cal	36-9-21	1122315	0.56	ECDA	10/8/2009	Complete	10/8/2016
So Cal	36-9-21	1122316	0.27	ECDA	10/8/2009	Complete	10/8/2016
So Cal	1173	3266995	2.86	ILI	10/15/09	Complete	11/03/16
So Cal	1172	3266412	2.66	ILI	11/03/09	Complete	11/03/16
So Cal	1172	3266413	0.71	ILI	11/03/09	Complete	11/03/16
So Cal	44-1008	3266404	0.18	ECDA	12/7/2009	Complete	12/7/2016
So Cal	44-1008	3266405	0.68	ECDA	12/7/2009	Complete	12/7/2016
So Cal	44-1008	3266406	0.14	ECDA	12/7/2009	Complete	12/7/2016
So Cal	44-1008	3266407	0.16	ECDA	12/7/2009	Complete	12/7/2016
So Cal	44-1008	3266408	0.14	ECDA	12/7/2009	Complete	12/7/2016
So Cal	43-1106	1138987	0.25	ECDA	12/18/2009	Complete	12/18/2016
So Cal	45-1106	3266762	0.70	ECDA	12/18/2009	Complete	12/18/2016
So Cal	5000(2)	1596621	0.05	ECDA	02/16/10	Complete	02/16/17
So Cal	5000(2)	1596622	1.28	ECDA	02/16/10	Complete	02/16/17
So Cal	3002	1122845	0.38	ILI	02/24/10	Complete	02/24/17
So Cal	35-20-A1	3266801	0.23	ECDA	2/25/2010	Complete	2/25/2017
So Cal	5000(4)	1123200	0.14	ILI	03/01/10	Complete	03/01/17
So Cal	5000(4)	1123201	2.03	ECDA	03/01/10	Complete	03/01/17

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So Cal	5000(4)	1123202	0.92	ILI	03/01/10	Complete	03/01/17
So Cal	5000(4)	3266715	1.50	ECDA	03/01/10	Complete	03/01/17
So Cal	5000(4)	3266715	0.71	ECDA	03/01/10	Complete	03/01/17
So Cal	8045	1122670	0.35	ECDA	3/2/2010	Complete	3/2/2017
So Cal	5000(3)	1123193	0.30	ECDA	03/08/10	Complete	03/08/17
So Cal	5000(3)	1123194	1.40	ECDA	03/08/10	Complete	03/08/17
So Cal	5000(3)	1123195	1.29	ECDA	03/08/10	Complete	03/08/17
So Cal	5000(3)	3098807	1.15	ILI	03/08/10	Complete	03/08/17
So Cal	5000(3)	1123196	1.42	ECDA	03/08/10	Complete	03/08/17
So Cal	5000(3)	1123197	0.33	ILI	03/08/10	Complete	03/08/17
So Cal	5000(3)	1123198	0.68	ECDA	03/08/10	Complete	03/08/17
So Cal	5000(3)	1123199	0.57	ECDA	03/08/10	Complete	03/08/17
SDGE	49-24	3098622	0.32	ECDA	03/11/10	Complete	03/11/17
SDGE	49-24	3098624	0.18	ECDA	03/11/10	Complete	03/11/17
SDGE	49-24	1122119	0.58	ECDA	03/11/10	Complete	03/11/17
SDGE	49-24	3266817	0.14	ECDA	03/11/10	Complete	03/11/17
SDGE	49-24	3266907	0.08	ECDA	03/11/10	Complete	03/11/17
SDGE	49-24	3266908	0.67	ECDA	03/11/10	Complete	03/11/17
SDGE	49-30	1121335	0.98	ECDA	03/11/10	Complete	03/11/17
So Cal	2051	1122097	0.65	ILI	03/19/10	Complete	03/19/17
So Cal	2051	1122098	0.83	ILI	03/20/10	Complete	03/20/17
So Cal	2051	1122099	0.50	ILI	03/21/10	Complete	03/21/17
So Cal	765	3098725	1.45	ECDA	4/27/2010	COMP	4/27/2017
So Cal	35-22	1121466	0.17	ECDA	6/9/2010	Complete	6/9/2017
So Cal	38-504	3522	0.83	ECDA	6/9/2010	Complete	6/9/2017
So Cal	38-504	3525	0.14	ECDA	6/9/2010	Complete	6/9/2017
SDGE	401	1122440	0.02	ECDA	06/19/10	Complete	06/19/17
So Cal	38-556	3098675	0.13	ECDA	6/30/2010	Complete	6/30/2017
So Cal	38-556	3098676	0.55	ECDA	6/30/2010	Complete	6/30/2017
So Cal	38-556	1122416	0.28	ECDA	6/30/2010	Complete	6/30/2017
So Cal	38-556	1122417	0.40	ECDA	6/30/2010	Complete	6/30/2017
So Cal	6905	1122207	0.51	ILI	7/15/2010	Complete	7/15/2017
So Cal	6905	1122208	0.51	ILI	7/15/2010	Complete	7/15/2017
So Cal	6905	1122209	0.64	ILI	7/15/2010	Complete	7/15/2017
So Cal	1185	1121800	0.65	ECDA	08/23/10	Complete	08/23/17
So Cal	1185	1121801	0.31	ECDA	08/23/10	Complete	08/24/17
So Cal	1185	1121802	0.39	ECDA	08/23/10	Complete	08/25/17
So Cal	37-15	3098657	0.02	ECDA		09/30/10	
So Cal	38-508	3098793	0.85	ECDA		10/15/10	
So Cal	38-508	3098800	0.06	ECDA		10/15/10	
So Cal	38-508	3130728	0.18	ECDA		10/15/10	
So Cal	38-508	1122369	0.25	ECDA		10/15/10	
So Cal	38-508	1122380	0.08	ECDA		10/15/10	
So Cal	38-508	1123158	0.13	ECDA		10/15/10	
So Cal	38-508	1122372	0.21	ECDA		10/15/10	
So Cal	38-508	1122373	0.28	ECDA		10/15/10	
So Cal	38-508	1122376	0.02	ECDA		10/15/10	
So Cal	38-508	1122378	0.44	ECDA		10/15/10	
So Cal	38-508	1122367	0.18	ECDA		10/15/10	
So Cal	38-508	3098799	0.16	ECDA		10/15/10	
So Cal	38-508	3130053	0.27	ECDA		10/15/10	
So Cal	38-508	3098797	0.09	ECDA		10/15/10	
So Cal	35-6526	1121478	0.19	ECDA		10/23/10	
So Cal	35-6526	1121479	0.44	ECDA		10/23/10	
So Cal	35-6526	1121480	0.37	ECDA		10/23/10	
So Cal	35-6526	1121481	0.27	ECDA		10/23/10	
So Cal	35-6526	1121482	0.30	ECDA		10/23/10	
So Cal	35-6526	3267021	0.36	ECDA		10/23/10	

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So Cal	30-08	1122999	0.09	ECDA		10/30/10	
So Cal	30-6209	1121364	0.03	ECDA		10/30/10	
So Cal	30-78	1123012	0.02	ECDA		10/30/10	
So Cal	38-230	1122355	0.19	ILI		10/30/10	
So Cal	38-230	1122356	0.09	ILI		10/30/10	
So Cal	38-552	1122403	0.10	ILI		10/30/10	
So Cal	38-552	1122404	0.11	ILI		10/30/10	
So Cal	38-552	1122405	0.09	ILI		10/30/10	
So Cal	38-552	1122406	0.07	ILI		10/30/10	
So Cal	38-552	1122407	0.14	ILI		10/30/10	
So Cal	38-552	1122408	0.49	ILI		10/30/10	
So Cal	38-552	1122409	0.00	ILI		10/30/10	
So Cal	38-552	3098671	0.12	ILI		10/30/10	
So Cal	38-552	1122399	0.07	ILI		10/30/10	
So Cal	38-552	1122402	0.06	ILI		10/30/10	
So Cal	38-552	1122400	0.24	ILI		10/30/10	
So Cal	38-552	1122401	0.29	ILI		10/30/10	
So Cal	103	1122703	0.17	ILI		10/31/10	
So Cal	325	1121760	0.07	ILI		10/31/10	
So Cal	325	1121761	0.39	ILI		10/31/10	
So Cal	325	1121762	1.06	ILI		10/31/10	
So Cal	325	1121763	0.44	ILI		10/31/10	
So Cal	30-32	3266446	0.09	ECDA		10/31/10	
So Cal	30-32	3267044	0.02	ECDA		10/31/10	
So Cal	30-32	3267045	0.01	ECDA		10/31/10	
So Cal	30-32	3267046	0.01	ECDA		10/31/10	
So Cal	30-32	3267047	0.11	ECDA		10/31/10	
So Cal	30-32	1121361	0.55	ECDA		10/31/10	
So Cal	30-32	3267041	0.19	ECDA		10/31/10	
So Cal	30-32	3267042	0.05	ECDA		10/31/10	
So Cal	30-32	3267043	0.05	ECDA		10/31/10	
So Cal	32-8042	1123025	0.04	ECDA		10/31/10	
So Cal	35-01	1123037	0.03	ECDA		10/31/10	
So Cal	35-01	1123038	0.03	ECDA		10/31/10	
So Cal	35-01	1123036	0.05	ECDA		10/31/10	
So Cal	35-01	1123035	0.01	ECDA		10/31/10	
So Cal	35-01	1123033	0.18	ECDA		10/31/10	
So Cal	35-01	1123034	0.28	ECDA		10/31/10	
So Cal	35-01	1123031	0.31	ECDA		10/31/10	
So Cal	35-01	1123032	0.13	ECDA		10/31/10	
So Cal	35-01	1123030	0.60	ECDA		10/31/10	
So Cal	35-01	1123029	0.15	ECDA		10/31/10	
So Cal	35-01	3266681	0.02	ECDA		10/31/10	
So Cal	35-39	1121472	0.02	ECDA		10/31/10	
So Cal	36-7-02	1121509	0.89	ECDA		10/31/10	
So Cal	31-21-X	1121384	1.69	ECDA		11/15/10	
So Cal	32-3211	1123019	0.02	ECDA		11/15/10	
So Cal	41-55	1122577	0.31	ECDA		11/15/10	
So Cal	41-55	1122572	0.91	ECDA		11/15/10	
So Cal	41-55-A	1122579	0.13	ECDA		11/15/10	
So Cal	41-55-A	1122580	0.14	ECDA		11/15/10	
So Cal	35-02-H	1123044	0.62	ECDA		11/15/10	
So Cal	35-02-H	1123045	0.97	ECDA		11/15/10	
So Cal	35-02-H	1123041	1.07	ECDA		11/15/10	
So Cal	31-50	1123498	0.01	ECDA		11/15/10	
So Cal	33-6261	1121432	0.02	ECDA		11/15/10	
So Cal	38-205	3266912	0.15	ECDA		11/15/10	
So Cal	38-205	3266913	0.28	ECDA		11/15/10	

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So Cal	38-205	3266914	0.09	ECDA		11/15/10	
So Cal	38-205	3266915	0.12	ECDA		11/15/10	
So Cal	38-205	3266916	0.10	ECDA		11/15/10	
So Cal	38-205	3266917	0.07	ECDA		11/15/10	
So Cal	38-504	3267022	0.11	ECDA		11/15/10	
So Cal	38-504	3524	0.25	ECDA		11/15/10	
So Cal	38-504	1122793	1.32	ILI		11/15/10	
So Cal	41-12	1122507	0.24	ECDA		11/15/10	
So Cal	41-12	1122502	0.09	ECDA		11/15/10	
So Cal	41-12	3267025	0.16	ECDA		11/15/10	
So Cal	41-12	1122503	0.15	ECDA		11/15/10	
So Cal	41-12	1122504	0.16	ECDA		11/15/10	
So Cal	41-12	1122505	0.13	ECDA		11/15/10	
So Cal	41-12	1122506	0.16	ECDA		11/15/10	
So Cal	1026	1121942	1.63	ILI		11/30/10	
So Cal	1026	1121941	0.47	ILI		11/30/10	
So Cal	1026	1121938	3.33	ILI		11/30/10	
So Cal	1026	1121939	0.70	ILI		11/30/10	
So Cal	1026	1121937	0.17	ILI		11/30/10	
So Cal	1026	1121936	0.23	ILI		11/30/10	
So Cal	1026	1121928	0.16	ILI		11/30/10	
So Cal	1026	1121929	0.14	ILI		11/30/10	
So Cal	1026	1121930	0.23	ILI		11/30/10	
So Cal	1026	1121931	0.28	ILI		11/30/10	
So Cal	1026	1121932	0.27	ILI		11/30/10	
So Cal	1026	1121922	1.40	ILI		11/30/10	
So Cal	1026	1121923	1.91	ILI		11/30/10	
So Cal	1026	3098569	0.19	ILI		11/30/10	
So Cal	1026	1121924	1.44	ILI		11/30/10	
So Cal	1026	3098570	0.47	ILI		11/30/10	
So Cal	1026	1121926	0.18	ILI		11/30/10	
So Cal	1026	1121927	1.26	ILI		11/30/10	
So Cal	1026	1121920	0.18	ILI		11/30/10	
So Cal	1026	1121916	0.17	ILI		11/30/10	
So Cal	1026	1121915	0.19	ILI		11/30/10	
So Cal	1026	1121955	0.19	ILI		11/30/10	
So Cal	1026	1121912	0.17	ILI		11/30/10	
So Cal	1026	1121913	1.81	ILI		11/30/10	
So Cal	1026	1121914	1.37	ILI		11/30/10	
So Cal	1026	1121951	0.76	ILI		11/30/10	
So Cal	1026	1121952	1.52	ILI		11/30/10	
So Cal	1026	1121953	0.21	ILI		11/30/10	
So Cal	1026	3098571	0.11	ILI		11/30/10	
So Cal	1026	1121945	0.20	ILI		11/30/10	
So Cal	1026	1121947	0.67	ILI		11/30/10	
So Cal	1026	1121948	0.78	ILI		11/30/10	
So Cal	1026	1121949	0.94	ILI		11/30/10	
So Cal	1026	1121943	0.31	ILI		11/30/10	
So Cal	6904	1123076	0.36	ECDA		11/30/10	
So Cal	6904	1123077	0.24	ECDA		11/30/10	
So Cal	32-6520	1123020	0.01	ECDA		11/30/10	
So Cal	36-1032 North	1121499	0.08	ECDA		11/30/10	
So Cal	36-1032 North	3266479	0.15	ECDA		11/30/10	
So Cal	36-1032 North	3266480	1.33	ECDA		11/30/10	
So Cal	41-30	1122162	0.13	ILI		11/30/10	
So Cal	41-30	1122163	0.36	ILI		11/30/10	
So Cal	41-30	1122160	0.23	ILI		11/30/10	
So Cal	41-30	3266667	0.57	ILI		11/30/10	

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So Cal	41-30	3266820	0.29	ILI		11/30/10	
So Cal	41-30	3266670	0.29	ILI		11/30/10	
So Cal	41-30	3266671	0.24	ILI		11/30/10	
So Cal	41-30	3266672	0.18	ILI		11/30/10	
So Cal	41-30	3266673	0.26	ILI		11/30/10	
So Cal	42-57	3266826	0.01	ECDA		11/30/10	
So Cal	85 North	3098729	0.31	ECDA		11/30/10	
So Cal	85 North	3098730	0.38	ECDA		11/30/10	
So Cal	85 North	1122676	0.32	ECDA		11/30/10	
So Cal	85 South	3098833	1.84	ECDA		11/30/10	
So Cal	38-366	1122358	0.13	ILI		12/01/10	
So Cal	38-366	1122359	0.44	ILI		12/01/10	
So Cal	38-366	1122360	0.26	ILI		12/01/10	
So Cal	35-40	1121473	0.23	ECDA		12/10/10	
So Cal	41-43	1122537	0.09	ECDA		12/15/10	
So Cal	41-43	3266804	0.01	ECDA		12/15/10	
So Cal	41-43	3246088	0.06	ECDA		12/15/10	
So Cal	41-43	3266805	1.01	ECDA		12/15/10	
So Cal	43-13	1122615	0.47	ECDA		12/15/10	
So Cal	44-133-A	1121382	0.25	ECDA		12/15/10	
So Cal	44-133-A	1121380	0.23	ECDA		12/15/10	
So Cal	1023	1122205	0.86	ECDA		12/20/10	
So Cal	43-121	1122613	0.33	ECDA		12/30/10	
So Cal	43-121	3266814	0.10	ECDA		12/30/10	
So Cal	43-121	3098705	0.16	ECDA		12/30/10	
So Cal	43-121	1122610	0.28	ECDA		12/30/10	
So Cal	43-121	3266876	0.25	ECDA		12/30/10	
So Cal	43-121	3266877	1.43	ECDA		12/30/10	
So Cal	43-121	1122614	0.03	ECDA		12/30/10	
So Cal	43-121	3266623	0.31	ECDA		12/30/10	
So Cal	43-121	3266624	0.00	ECDA		12/30/10	
So Cal	245	1122120	0.12	ECDA		12/31/10	
So Cal	245	1122121	0.16	ECDA		12/31/10	
So Cal	307	1121370	1.53	ILI		12/31/10	
So Cal	317	1122618	0.26	ILI		12/31/10	
So Cal	1003	1121852	0.22	Hydrotest		12/31/10	
So Cal	1003	1121853	0.42	Hydrotest		12/31/10	
So Cal	1003	3267049	0.05	Hydrotest		12/31/10	
So Cal	1003	1121854	3.99	Hydrotest		12/31/10	
So Cal	1003	3266415	0.21	Hydrotest		12/31/10	
So Cal	1003	1121855	0.33	Hydrotest		12/31/10	
So Cal	1003	1121856	0.29	Hydrotest		12/31/10	
So Cal	1003	1121857	0.28	Hydrotest		12/31/10	
So Cal	1003	1121858	0.35	Hydrotest		12/31/10	
So Cal	1003	1121859	0.30	Hydrotest		12/31/10	
So Cal	1003	1121860	0.21	Hydrotest		12/31/10	
So Cal	1003	3267051	0.30	Hydrotest		12/31/10	
So Cal	1003	1121861	0.26	ILI		12/31/10	
So Cal	1003	1121862	0.23	Hydrotest		12/31/10	
So Cal	1003	1121863	0.21	Hydrotest		12/31/10	
So Cal	1003	1121864	0.24	Hydrotest		12/31/10	
So Cal	1003	1121865	1.12	Hydrotest		12/31/10	
So Cal	1003	1121866	0.17	Hydrotest		12/31/10	
So Cal	1003	1121867	0.22	Hydrotest		12/31/10	
So Cal	1003	1121868	0.22	Hydrotest		12/31/10	
So Cal	1003	1121846	0.34	Hydrotest		12/31/10	
So Cal	1003	1121847	1.98	Hydrotest		12/31/10	
So Cal	1003	1121848	1.08	Hydrotest		12/31/10	

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So Cal	1003	3266416	0.87	Hydrotest		12/31/10	
So Cal	1003	1121849	2.88	Hydrotest		12/31/10	
So Cal	1003	1121850	2.05	Hydrotest		12/31/10	
So Cal	1129	1121976	1.63	ECDA		12/31/10	
So Cal	5041	1122629	0.29	ILI		12/31/10	
So Cal	7038	1122192	2.05	ILI		12/31/10	
So Cal	8107	1122203	0.29	ILI		12/31/10	
So Cal	8109	3266414	0.31	ILI		12/31/10	
So Cal	8109	3098553	0.49	ILI		12/31/10	
So Cal	30-58	1123009	0.04	ECDA		12/31/10	
So Cal	30-6200	1121363	0.02	ECDA		12/31/10	
So Cal	30-6291	1121365	0.01	ECDA		12/31/10	
So Cal	30-72	1121371	0.43	ECDA		12/31/10	
So Cal	30-72	1121372	0.26	ECDA		12/31/10	
So Cal	32-21	1121390	0.73	ECDA		12/31/10	
So Cal	32-21	1121388	2.59	ECDA		12/31/10	
So Cal	32-6522	1123022	0.30	ECDA		12/31/10	
So Cal	35-6405	1121474	0.13	ECDA		12/31/10	
So Cal	35-6425	1123046	0.01	ECDA		12/31/10	
So Cal	35-6524	1121477	0.01	ECDA		12/31/10	
So Cal	36-1002	1121487	0.48	ILI		12/31/10	
So Cal	36-1002	1121488	0.83	ILI		12/31/10	
So Cal	36-1002	1121489	0.24	ILI		12/31/10	
So Cal	36-1002	1121484	0.20	ILI		12/31/10	
So Cal	36-1002	1121485	0.18	ILI		12/31/10	
So Cal	36-1006	1122782	0.14	ECDA		12/31/10	
So Cal	36-8-06	1121525	0.04	ECDA		12/31/10	
So Cal	36-8-06	3266489	0.10	ECDA		12/31/10	
So Cal	36-8-06	1121526	0.09	ECDA		12/31/10	
So Cal	36-8-06	3266490	0.09	ECDA		12/31/10	
So Cal	36-8-06	1121523	0.20	ECDA		12/31/10	
So Cal	36-8-06	3244674	0.15	ECDA		12/31/10	
So Cal	36-8-06	3244675	0.09	ECDA		12/31/10	
So Cal	36-8-06	3244676	0.04	ECDA		12/31/10	
So Cal	36-8-06	3266491	0.10	ECDA		12/31/10	
So Cal	36-8-06	3244677	0.19	ECDA		12/31/10	
So Cal	36-8-06	3266492	0.15	ECDA		12/31/10	
So Cal	36-8-06	3266493	0.22	ECDA		12/31/10	
So Cal	36-8-06	3266494	0.02	ECDA		12/31/10	
So Cal	36-9-09 North	3266386	0.29	ECDA		12/31/2010	
So Cal	36-9-09 North	3266385	0.11	ECDA		12/31/2010	
So Cal	36-9-09 North	3266384	0.21	ECDA		12/31/2010	
So Cal	36-9-09 North	3266382	0.33	ECDA		12/31/2010	
So Cal	36-9-09 North	3266381	0.84	ECDA		12/31/2010	
So Cal	36-9-09 North	3266379	0.16	ECDA		12/31/2010	
So Cal	36-9-09 North	3266378	0.17	ECDA		12/31/2010	
So Cal	36-9-09 North	3266377	0.21	ECDA		12/31/2010	
So Cal	36-9-09 North	3266380	0.00	ECDA		12/31/2010	
So Cal	36-9-09 North	3266376	0.45	ECDA		12/31/2010	
So Cal	36-9-09 North	1121576	0.18	ECDA		12/31/2010	
So Cal	36-9-09 North	3266802	0.15	ECDA		12/31/2010	
So Cal	36-9-09 North	3098654	0.13	ECDA		12/31/2010	
So Cal	36-9-09 North	1121558	0.12	ECDA		12/31/2010	
So Cal	36-9-09 North	1121557	0.01	ECDA		12/31/2010	
So Cal	36-9-09 North	1121579	0.65	ECDA		12/31/2010	
So Cal	36-9-09 North	1121559	0.49	ECDA		12/31/2010	
So Cal	36-9-09 North	3098655	0.18	ECDA		12/31/2010	
So Cal	36-9-09 North	1121580	0.10	ECDA		12/31/2010	

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So Cal	36-9-09 North	1122305	0.12	ECDA		12/31/2010	
So Cal	36-9-09 North	1121583	0.63	ECDA		12/31/2010	
So Cal	36-9-09 North	1121561	0.31	ECDA		12/31/2010	
So Cal	36-9-09 South	1121566	1.73	ECDA		12/31/2010	
So Cal	36-9-09 South	3266785	0.48	ECDA		12/31/2010	
So Cal	36-9-09 South	3266786	0.23	ECDA		12/31/2010	
So Cal	36-9-09 South	3266787	0.04	ECDA		12/31/2010	
So Cal	36-9-09 South	3266788	0.18	ECDA		12/31/2010	
So Cal	36-9-09 South	3266789	0.09	ECDA		12/31/2010	
So Cal	36-9-09 South	3266790	0.29	ECDA		12/31/2010	
So Cal	37-49	3098777	0.19	ECDA		12/31/10	
So Cal	37-49	1123056	0.38	ECDA		12/31/10	
So Cal	37-6183	1123058	0.01	ECDA		12/31/10	
So Cal	38-200	1122346	0.42	ILI		12/31/10	
So Cal	38-200	1122347	0.16	ILI		12/31/10	
So Cal	38-200	1122349	0.10	ILI		12/31/10	
So Cal	38-202	1122354	0.21	ILI		12/31/10	
So Cal	38-202	1122350	0.53	ILI		12/31/10	
So Cal	38-202	1122351	0.24	ILI		12/31/10	
So Cal	38-202	1122353	0.69	ILI		12/31/10	
So Cal	38-351	3266657	0.06	ECDA		12/31/10	
So Cal	38-351	1122788	0.23	ECDA		12/31/10	
So Cal	38-351	1122789	0.24	ECDA		12/31/10	
So Cal	38-351	1122790	0.11	ECDA		12/31/10	
So Cal	38-351	1122791	0.09	ECDA		12/31/10	
So Cal	38-351	1122792	0.16	ECDA		12/31/10	
So Cal	38-516	3127455	0.13	ILI		12/31/10	
So Cal	38-516	3127456	0.17	ILI		12/31/10	
So Cal	38-516	3127454	0.12	ILI		12/31/10	
So Cal	38-516	3127457	0.58	ILI		12/31/10	
So Cal	38-516	3127458	0.12	ILI		12/31/10	
So Cal	38-516	3127459	0.41	ILI		12/31/10	
So Cal	38-516	3127460	0.21	ILI		12/31/10	
So Cal	38-516	3127461	0.13	ILI		12/31/10	
So Cal	38-516	3127463	0.16	ILI		12/31/10	
So Cal	38-516	3127462	0.26	ILI		12/31/10	
So Cal	38-516	1122815	0.03	ILI		12/31/10	
So Cal	38-528	3266388	0.15	ILI		12/31/10	
So Cal	38-528	3266394	0.46	ILI		12/31/10	
So Cal	38-528	3266395	0.07	ILI		12/31/10	
So Cal	38-528	3266396	0.20	ILI		12/31/10	
So Cal	38-528	3266397	0.65	ILI		12/31/10	
So Cal	38-528	3266398	0.03	ILI		12/31/10	
So Cal	38-528	3266399	0.12	ILI		12/31/10	
So Cal	38-528	3266400	0.18	ILI		12/31/10	
So Cal	38-528	3266401	0.04	ILI		12/31/10	
So Cal	38-528	3266402	0.08	ILI		12/31/10	
So Cal	38-959	1122423	0.22	ECDA		12/31/10	
So Cal	38-959	1122424	0.11	ECDA		12/31/10	
So Cal	38-959	1122425	0.05	ECDA		12/31/10	
So Cal	38-959	1122426	0.25	ECDA		12/31/10	
So Cal	41-11	3266885	0.00	ECDA		12/31/10	
So Cal	41-11	3266886	1.40	ECDA		12/31/10	
So Cal	41-11	3266887	0.17	ECDA		12/31/10	
So Cal	41-11	3266888	0.12	ECDA		12/31/10	
So Cal	41-11	3266889	0.61	ECDA		12/31/10	
So Cal	41-11	3266890	0.11	ECDA		12/31/10	
So Cal	41-11	3266891	0.16	ECDA		12/31/10	

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So Cal	41-11	3266892	0.02	ECDA		12/31/10	
So Cal	41-11	3267060	0.12	ECDA		12/31/10	
So Cal	41-11	3266893	0.43	ECDA		12/31/10	
So Cal	41-11	3266894	0.24	ECDA		12/31/10	
So Cal	41-11	3267057	0.03	ECDA		12/31/10	
So Cal	41-11	3267058	0.14	ECDA		12/31/10	
So Cal	41-11	3267059	0.08	ECDA		12/31/10	
So Cal	41-11	3267059	0.08	ECDA		12/31/10	
So Cal	41-11	3266897	0.01	ECDA		12/31/10	
So Cal	41-11	3266898	0.10	ECDA		12/31/10	
So Cal	41-11	3266899	0.15	ECDA		12/31/10	
So Cal	41-11	3266900	0.25	ECDA		12/31/10	
So Cal	41-11	3266901	0.03	ECDA		12/31/10	
So Cal	41-11	3266902	0.40	ECDA		12/31/10	
So Cal	41-11	3266903	0.21	ECDA		12/31/10	
So Cal	41-111	1123060	0.20	ECDA		12/31/10	
So Cal	41-113	1122501	0.91	ECDA		12/31/10	
So Cal	41-128	3266997	0.10	ECDA		12/31/10	
So Cal	41-153	1122846	0.01	ECDA		12/31/10	
So Cal	41-17	3266968	0.04	ECDA		12/31/10	
So Cal	41-17	3266969	0.14	ECDA		12/31/10	
So Cal	41-17	3266970	0.09	ECDA		12/31/10	
So Cal	41-17	3266971	0.14	ECDA		12/31/10	
So Cal	41-17	3098692	0.34	ECDA		12/31/10	
So Cal	41-17	3098693	0.09	ECDA		12/31/10	
So Cal	41-17	1122517	0.78	ECDA		12/31/10	
So Cal	41-17	3266972	0.27	ECDA		12/31/10	
So Cal	41-17	3266973	0.22	ECDA		12/31/10	
So Cal	41-17	1122512	0.65	ECDA		12/31/10	
So Cal	41-17	1122513	0.06	ECDA		12/31/10	
So Cal	41-17-A	3266932	0.28	ECDA		12/31/10	
So Cal	41-17-A	3266952	0.13	ECDA		12/31/10	
So Cal	41-17-A	3266963	0.19	ECDA		12/31/10	
So Cal	41-17-A	1122520	0.11	ECDA		12/31/10	
So Cal	41-21	3266583	0.03	ECDA		12/31/10	
So Cal	41-21	3266584	0.13	ECDA		12/31/10	
So Cal	41-21	3266585	0.06	ECDA		12/31/10	
So Cal	41-21	3266586	0.18	ECDA		12/31/10	
So Cal	41-21	3266587	0.20	ECDA		12/31/10	
So Cal	41-21	3266588	0.09	ECDA		12/31/10	
So Cal	41-21	3266589	0.09	ECDA		12/31/10	
So Cal	41-23-N	1122525	0.41	ECDA		12/31/10	
So Cal	41-23-N	1122526	0.26	ECDA		12/31/10	
So Cal	41-23-N	1122527	0.25	ECDA		12/31/10	
So Cal	41-23-N	3267020	0.39	ECDA		12/31/10	
So Cal	41-25-A	1122529	0.18	ILI		12/31/10	
So Cal	41-25-A	1122530	0.55	ILI		12/31/10	
So Cal	41-25-A	1122532	2.41	ILI		12/31/10	
So Cal	41-25-A	1122533	0.23	ILI		12/31/10	
So Cal	41-25-A	3266590	0.14	ECDA		12/31/10	
So Cal	41-36	1122535	0.10	ECDA		12/31/10	
So Cal	41-44	1122539	0.31	ILI		12/31/10	
So Cal	41-44	1122540	0.34	ILI		12/31/10	
So Cal	41-44	1122541	0.15	ILI		12/31/10	
So Cal	41-44	1122542	1.39	ILI		12/31/10	
So Cal	41-54	1122550	0.09	ECDA		12/31/10	
So Cal	41-54	1122567	0.12	ECDA		12/31/10	
So Cal	41-54	1122568	0.51	ECDA		12/31/10	

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So Cal	41-54	1122569	0.10	ECDA		12/31/10	
So Cal	41-54	1122570	0.10	ECDA		12/31/10	
So Cal	41-54	1122571	0.71	ECDA		12/31/10	
So Cal	41-54	3266879	0.34	ECDA		12/31/10	
So Cal	41-54	1122565	0.07	ECDA		12/31/10	
So Cal	41-54	1122547	0.11	ECDA		12/31/10	
So Cal	41-54	3266830	0.00	ECDA		12/31/10	
So Cal	41-54	3266828	0.01	ECDA		12/31/10	
So Cal	41-54	3266847	0.01	ECDA		12/31/10	
So Cal	41-54	3266807	0.01	ECDA		12/31/10	
So Cal	41-54	3266829	0.17	ECDA		12/31/10	
So Cal	41-54	1122548	0.46	ECDA		12/31/10	
So Cal	41-54	1122549	0.36	ECDA		12/31/10	
So Cal	41-54	1122556	0.20	ECDA		12/31/10	
So Cal	41-54	1122557	0.11	ECDA		12/31/10	
So Cal	41-54	1122558	0.11	ECDA		12/31/10	
So Cal	41-54	1122559	0.11	ECDA		12/31/10	
So Cal	41-54	1122560	0.11	ECDA		12/31/10	
So Cal	41-54	1122561	0.10	ECDA		12/31/10	
So Cal	41-54	1122562	0.10	ECDA		12/31/10	
So Cal	41-54	1122563	0.17	ECDA		12/31/10	
So Cal	41-54	1122544	0.14	ECDA		12/31/10	
So Cal	41-54	1122545	0.24	ECDA		12/31/10	
So Cal	41-54	1122546	0.51	ECDA		12/31/10	
So Cal	41-54	1122551	0.11	ECDA		12/31/10	
So Cal	41-54	1122552	0.10	ECDA		12/31/10	
So Cal	41-54	1122553	0.07	ECDA		12/31/10	
So Cal	41-54	1122554	0.10	ECDA		12/31/10	
So Cal	41-54	1122555	0.19	ECDA		12/31/10	
So Cal	42-12	1123584	0.09	ILI		12/31/10	
So Cal	42-12	1123583	0.78	ILI		12/31/10	
So Cal	42-12	1123585	0.22	ILI		12/31/10	
So Cal	42-12	1123581	0.44	ILI		12/31/10	
So Cal	42-12	1123580	0.26	ILI		12/31/10	
So Cal	42-12	3266725	0.17	ILI		12/31/10	
So Cal	42-12	3266726	0.00	ILI		12/31/10	
So Cal	42-12	1123578	0.00	ILI		12/31/10	
So Cal	42-12	3266977	0.07	ILI		12/31/10	
So Cal	42-12	1123577	0.16	ILI		12/31/10	
So Cal	42-12	3266727	0.25	ILI		12/31/10	
So Cal	42-12	3266796	0.16	ILI		12/31/10	
So Cal	42-46	2280507	0.65	ECDA		12/31/10	
So Cal	42-46	2280506	0.26	ECDA		12/31/10	
So Cal	42-46	2280509	0.22	ECDA		12/31/10	
So Cal	42-46	1122592	0.43	ECDA		12/31/10	
So Cal	42-46	1122593	2.12	ECDA		12/31/10	
So Cal	42-46	3266809	0.00	ECDA		12/31/10	
So Cal	42-46	1122596	0.55	ECDA		12/31/10	
So Cal	42-46	1122597	0.50	ECDA		12/31/10	
So Cal	42-46	1122598	0.87	ECDA		12/31/10	
So Cal	42-46	1122599	0.16	ECDA		12/31/10	
So Cal	42-46	1122591	0.13	ECDA		12/31/10	
So Cal	42-46	2280508	0.27	ECDA		12/31/10	
So Cal	42-46	1122602	0.14	ECDA		12/31/10	
So Cal	42-46	3094918	0.04	ECDA		12/31/10	
So Cal	42-46-F	3266953	0.39	ILI		12/31/10	
So Cal	42-46-F	3266954	0.11	ILI		12/31/10	
So Cal	42-46-F	3266955	0.32	ILI		12/31/10	

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So Cal	42-46-F	3266956	0.08	ILI		12/31/10	
So Cal	42-46-F	3266957	0.16	ILI		12/31/10	
So Cal	42-46-F	3266958	0.06	ILI		12/31/10	
So Cal	42-46-F	3266959	0.06	ILI		12/31/10	
So Cal	42-46-F	3266960	0.50	ILI		12/31/10	
So Cal	42-46-F	3266961	0.22	ILI		12/31/10	
So Cal	42-46-F	3266962	0.56	ILI		12/31/10	
So Cal	43-30	1122617	0.00	ECDA		12/31/10	
So Cal	44-720	1123059	0.09	ECDA		12/31/10	
SDGE	49-27	1121327	0.58	ECDA		12/31/10	
SDGE	49-27	3098625	0.19	ECDA		12/31/10	
SDGE	49-28	1121330	1.11	ECDA		12/31/10	
SDGE	49-28	3266819	0.86	ECDA		12/31/10	
SDGE	49-28	3266878	1.10	ECDA		12/31/10	
SDGE	49-28	1121329	2.37	ECDA		12/31/10	
So Cal	33-6258	3098776	0.00	ECDA		01/26/11	
So Cal	317	1122619	0.12	ILI		01/31/11	
So Cal	317	1122620	0.81	ILI		01/31/11	
So Cal	38-512	3266539	0.08	ECDA		01/31/11	
So Cal	38-512	3266540	0.07	ECDA		01/31/11	
So Cal	38-512	3266541	0.27	ECDA		01/31/11	
So Cal	38-512	3098664	0.11	ECDA		01/31/11	
So Cal	38-512	3266766	0.16	ECDA		01/31/11	
So Cal	38-512	3266542	0.06	ECDA		01/31/11	
So Cal	38-512	3266543	0.07	ECDA		01/31/11	
So Cal	3004	1121355	0.03	ECDA		01/31/11	
So Cal	6900	1122648	1.16	ECDA		01/31/11	
So Cal	6900	3098717	0.17	ECDA		01/31/11	
So Cal	36-9-06-E	1121552	0.06	ECDA		01/31/11	
So Cal	41-05-A	3266975	0.08	ECDA		01/31/11	
So Cal	1171	1121792	0.25	ILI		02/01/11	
So Cal	1171	1121793	0.80	ILI		02/01/11	
So Cal	30-6205	3098746	0.00	ECDA		02/04/11	
So Cal	1221	1122011	0.06	ECDA		02/23/11	
So Cal	37-04	1123047	0.03	ECDA		02/28/11	
So Cal	1171	3266880	0.09	ILI		02/28/11	
So Cal	1174	1121984	1.05	ILI		02/28/11	
So Cal	2007	1122094	0.05	ECDA		02/28/11	
SDGE	3600	1122849	0.01	ECDA		02/28/11	
So Cal	41-6557	1122586	0.31	ECDA		02/28/11	
So Cal	41-84-A	1122587	0.23	ECDA		02/28/11	
So Cal	8106	3098763	0.24	ILI		03/01/11	
So Cal	8106	3098764	0.15	ILI		03/01/11	
So Cal	8106	3098765	0.18	ILI		03/01/11	
So Cal	12	3266974	0.01	ECDA		03/31/11	
So Cal	775	1121773	0.10	ECDA		03/31/11	
So Cal	41-53	1122543	0.17	ECDA		04/10/11	
So Cal	1017	1121904	4.51	ILI		04/30/11	
So Cal	36-7-06	1121512	0.01	ILI		04/30/11	
So Cal	41-09	1122481	0.85	ECDA		04/30/11	
So Cal	41-09	1122482	0.61	ECDA		04/30/11	
So Cal	41-09	1122483	0.26	ECDA		04/30/11	
So Cal	41-55-C	3267054	0.06	ECDA		04/30/11	
So Cal	45-8036	1123075	0.04	ECDA		04/30/11	
So Cal	32-90	1121404	0.34	ECDA		05/10/11	
So Cal	36-6588	1121501	1.32	ECDA		05/31/11	
So Cal	36-6588	1121502	0.12	ECDA		05/31/11	
So Cal	36-6588	1121503	0.15	ECDA		05/31/11	

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So Cal	36-6588	1121504	0.21	ECDA		05/31/11	
So Cal	32-6521	1123021	0.02	ECDA		06/03/11	
So Cal	1218	3266992	1.05	ECDA		06/30/11	
So Cal	30-02	3267010	0.08	ECDA		06/30/11	
So Cal	30-02	3267011	0.00	ECDA		06/30/11	
So Cal	30-02	3267012	0.22	ECDA		06/30/11	
So Cal	30-02	3267013	0.12	ECDA		06/30/11	
So Cal	30-02	3267014	0.20	ECDA		06/30/11	
So Cal	30-02	3267015	0.12	ECDA		06/30/11	
So Cal	30-02	3267016	0.08	ECDA		06/30/11	
So Cal	30-02	3267017	0.72	ECDA		06/30/11	
So Cal	30-02	3267018	0.62	ECDA		06/30/11	
So Cal	30-02	3267019	0.15	ECDA		06/30/11	
So Cal	30-66	1121368	0.03	ECDA		06/30/11	
So Cal	30-73	3266770	0.00	ECDA		06/30/11	
So Cal	30-73	1123011	0.02	ECDA		06/30/11	
So Cal	36-8-01	1121520	2.10	ILI		06/30/11	
So Cal	36-8-01	1121522	0.27	ILI		06/30/11	
So Cal	36-8-01	1121519	0.13	ILI		06/30/11	
So Cal	36-8-01	1121513	0.18	ILI		06/30/11	
So Cal	36-8-01	1121514	1.04	ILI		06/30/11	
So Cal	36-8-01	1121515	0.15	ILI		06/30/11	
So Cal	36-8-01	1121516	0.19	ILI		06/30/11	
So Cal	36-8-01	3246370	0.42	ILI		06/30/11	
So Cal	36-8-01	3246371	1.02	ILI		06/30/11	
So Cal	36-8-01	3246373	0.55	ILI		06/30/11	
So Cal	36-8-01	3246374	0.62	ILI		06/30/11	
So Cal	36-8-01	3246375	0.41	ILI		06/30/11	
So Cal	36-8-01	3246376	0.10	ILI		06/30/11	
So Cal	36-8-01	3246377	0.07	ILI		06/30/11	
So Cal	36-8-01	3246378	0.24	ILI		06/30/11	
So Cal	36-8-01	3246379	0.15	ILI		06/30/11	
So Cal	44-8044	3266757	0.02	ECDA		06/30/11	
So Cal	119 North	1122706	0.25	Hydrotest		07/01/11	
So Cal	119 South	1123182	0.23	ILI		07/01/11	
So Cal	119 South	3098803	0.30	ILI		07/01/11	
So Cal	119 South	3098804	3.89	ILI		07/01/11	
So Cal	41-25-A1	3098768	0.00	ECDA		07/30/11	
So Cal	1207	1122003	0.12	ECDA		07/31/11	
SDGE	1600	2579965	0.14	ECDA		07/31/11	
SDGE	1600	2579977	0.20	ECDA		07/31/11	
SDGE	1600	2580005	0.26	ECDA		07/31/11	
So Cal	30-6295		0.01	ECDA		07/31/11	
So Cal	32-6523	1123023	0.09	ECDA		07/31/11	
So Cal	45-3205	1123071	0.00	ECDA		07/31/11	
SDGE	49-19	1122052	0.48	ECDA		07/31/11	
SDGE	49-16	1122033	2.27	ECDA		08/01/11	
SDGE	49-16	1122034	1.49	ECDA		08/01/11	
So Cal	1234	1122015	0.00	ECDA		08/12/11	
SDGE	1204	1122000	0.15	ECDA		08/12/11	
So Cal	30-6799	1121369	0.01	ECDA		08/30/11	
So Cal	5043	1122190	0.08	ILI		08/31/11	
So Cal	30-09	1123000	0.00	ECDA		08/31/11	
So Cal	30-09-A	1123001	1.00	ECDA		08/31/11	
So Cal	30-68	1123010	0.03	ECDA		08/31/11	
So Cal	32-8027	1121403	0.03	ECDA		08/31/11	
So Cal	32-8043	1123026	0.08	ECDA		08/31/11	
So Cal	36-7-04	1121510	0.03	ECDA		08/31/11	

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So Cal	43-1217	1123013	0.01	ECDA		08/31/11	
So Cal	1219	1122007	0.06	ECDA		09/30/11	
So Cal	1219	1122008	0.17	ECDA		09/30/11	
So Cal	1219	1122009	0.39	ECDA		09/30/11	
So Cal	1219	1122010	0.54	ECDA		09/30/11	
So Cal	30-6543	1121367	0.10	ECDA		09/30/11	
So Cal	45-3206	1123072	0.01	ECDA		09/30/11	
SDGE	801	1122664	0.98	ECDA		10/18/11	
SDGE	802	1122665	0.52	ECDA		10/18/11	
SDGE	804	1122668	0.09	ECDA		10/18/11	
SDGE	805	1122671	0.09	ECDA		10/27/11	
SDGE	1206	1122002	0.2	ECDA		10/31/2011	
SDGE	3601	1121483	0.10	ECDA		10/31/11	
So Cal	119 North	1122705	0.85	ILI		10/31/11	
So Cal	37-22	1122335	0.00	ECDA		10/31/11	
SDGE	49-20	1122055	0.04	ECDA		10/31/11	
So Cal	38-573	3266658	0.11	ILI		11/28/11	
So Cal	38-573	1122822	0.13	ILI		11/28/11	
So Cal	38-573	1122823	0.12	ILI		11/28/11	
So Cal	38-573	1122824	0.13	ILI		11/28/11	
So Cal	38-573	1122825	0.10	ILI		11/28/11	
SDGE	49-11	3129651	0.30	ECDA		11/30/11	
SDGE	49-11	1121974	2.03	ECDA		11/30/11	
SDGE	49-11	3267027	2.69	ECDA		11/30/11	
SDGE	49-5	1138986	0.93	ECDA		11/30/11	
SDGE	49-5	3267028	0.26	ECDA		11/30/11	
SDGE	49-5	3267029	0.32	ECDA		11/30/11	
SDGE	49-7	1122651	1.01	ECDA		11/30/11	
So Cal	32-91	1121405	0.15	ECDA		12/01/11	
So Cal	32-91	1121406	0.13	ECDA		12/01/11	
So Cal	32-91	1121407	0.20	ECDA		12/01/11	
So Cal	32-91	1121408	0.16	ECDA		12/01/11	
So Cal	32-91	1121409	0.15	ECDA		12/01/11	
So Cal	32-91	3267040	0.41	ECDA		12/01/11	
So Cal	32-91	1121410	0.29	ECDA		12/01/11	
So Cal	32-91	1121411	0.17	ECDA		12/01/11	
So Cal	32-91	1121412	0.14	ECDA		12/01/11	
So Cal	32-91	1121413	0.28	ECDA		12/01/11	
So Cal	32-91	1121414	0.27	ECDA		12/01/11	
So Cal	32-91	1121415	0.13	ECDA		12/01/11	
So Cal	32-91	1121416	0.15	ECDA		12/01/11	
So Cal	32-91	1121417	0.10	ECDA		12/01/11	
So Cal	32-91	1121418	0.55	ECDA		12/01/11	
So Cal	53	1121756	0.21	Hydrotest		12/31/11	
So Cal	1017	3208101	1.96	ILI		12/31/11	
So Cal	1031	1121973	0.78	ILI		12/31/11	
So Cal	129	1121758	0.18	ILI		12/31/11	
So Cal	156	1121759	0.20	ILI		12/31/11	
So Cal	404	1122133	0.24	ILI		12/31/11	
So Cal	404	1122134	0.37	ILI		12/31/11	
So Cal	404	1122135	0.75	ILI		12/31/11	
So Cal	404	1122836	0.23	ILI		12/31/11	
So Cal	404	1122837	0.33	ILI		12/31/11	
So Cal	404	1122838	0.26	ILI		12/31/11	
So Cal	404	1122839	0.28	ILI		12/31/11	
So Cal	4002		0.56	ILI		12/31/11	
So Cal	4002		0.60	ILI		12/31/11	
So Cal	4002		0.81	ILI		12/31/11	

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So Cal	4002		1.55	ILI		12/31/11	
So Cal	4002		0.72	ILI		12/31/11	
So Cal	4002		2.56	ILI		12/31/11	
So Cal	5009	1122914	0.04	Hydrotest		12/31/11	
So Cal	5026	1122627	0.25	ILI		12/31/11	
So Cal	5026	3098708	0.26	ILI		12/31/11	
So Cal	5027	1122628	0.10	Hydrotest		12/31/11	
So Cal	1003 LT 2	1123479	0.00	ECDA		12/31/11	
So Cal	1005 ID805-T	1123503	0.00	ECDA		12/31/11	
So Cal	1016ST1	1123504	0.00	ECDA		12/31/11	
So Cal	1016ST2	1123505	0.00	ECDA		12/31/11	
So Cal	1018 BR3 BO1	1123181	0.00	ECDA		12/31/11	
So Cal	1018BP3	3266933	0.00	ECDA		12/31/11	
So Cal	1171 ID502-T 5	3266934	0.00	ECDA		12/31/11	
So Cal	171 ID567-P 1	3266935	0.00	ECDA		12/31/11	
So Cal	171 ID567-P 1	3266936	0.01	ECDA		12/31/11	
So Cal	171 ID567-P 1	1123529	0.02	ECDA		12/31/11	
So Cal	1172 ID 2313 1	1123130	0.00	ECDA		12/31/11	
So Cal	1172 ID 2313 2	1123128	0.01	ECDA		12/31/11	
So Cal	1172 ID 2313 3	1123129	0.01	ECDA		12/31/11	
So Cal	172 ID 531-P	1123137	0.01	ECDA		12/31/11	
So Cal	172 ID 598-P	1123141	0.01	ECDA		12/31/11	
So Cal	172 ID 598-P	1123122	0.00	ECDA		12/31/11	
So Cal	1172 ID542-P 1	1123120	0.01	ECDA		12/31/11	
So Cal	1172BP3	1123133	0.03	ECDA		12/31/11	
So Cal	173 ID 571-T	1123147	0.01	ECDA		12/31/11	
So Cal	173 ID 571-T	1123146	0.00	ECDA		12/31/11	
So Cal	173 ID 571-T	1123145	0.00	ECDA		12/31/11	
So Cal	WEST ID241	1123152	0.10	ECDA		12/31/11	
So Cal	1205 ID436-T 1	1123537	0.00	ECDA		12/31/11	
So Cal	1205 ID436-T 3	1123539	0.01	ECDA		12/31/11	
So Cal	2002 ID465-T 4	1123509	0.00	ECDA		12/31/11	
So Cal	2007 ID629-T1	1123154	0.00	ECDA		12/31/11	
So Cal	2007 ID629-T2	1123153	0.02	ECDA		12/31/11	
So Cal	247 ID403-T 1	3098831	0.02	ECDA		12/31/11	
So Cal	247 ID403-T 2	1123562	0.01	ECDA		12/31/11	
So Cal	247 ID403-T 3	1123563	0.00	ECDA		12/31/11	
So Cal	247 ID403-T 4	1123564	0.00	ECDA		12/31/11	
So Cal	247 ID403-T 6	1123565	0.00	ECDA		12/31/11	
So Cal	293 ID1517-N	1123514	0.01	ECDA		12/31/11	
So Cal	3005-A	1610327	0.00	ECDA		12/31/11	
So Cal	3005-A1	1610336	0.00	ECDA		12/31/11	
So Cal	3005-B	1610330	0.00	ECDA		12/31/11	
So Cal	30-6799BR1	1123517	0.00	ECDA		12/31/11	
So Cal	325 ID5013-P	1123114	0.00	ECDA		12/31/11	
So Cal	325 ID562-T 1	1123540	0.00	ECDA		12/31/11	
So Cal	325 LT	1123113	0.00	ECDA		12/31/11	
So Cal	32-6523BR1	3266993	0.01	ECDA		12/31/11	
So Cal	32-8042BR1	3266994	0.01	ECDA		12/31/11	
So Cal	35-6405BR1	1123179	0.00	ECDA		12/31/11	
So Cal	365XO1	1123551	0.00	ECDA		12/31/11	
So Cal	36-9-21BR	1123156	0.00	ECDA		12/31/11	
So Cal	41-6903	3267038	0.53	ECDA		12/31/11	
So Cal	41-6903	3267039	0.21	ECDA		12/31/11	
So Cal	44-132	1123062	0.14	ECDA		12/31/11	
So Cal	44-132	1123063	2.57	ECDA		12/31/11	
So Cal	44-132	1123064	0.55	ECDA		12/31/11	
SDGE	49-14	1122039	1.53	ECDA		12/31/11	

SDGE	49-14	2670021	0.87	ECDA		12/31/11	
SDGE	49-17	1122040	0.84	ECDA		12/31/11	
SDGE	49-17	1122041	0.72	ECDA		12/31/11	
SDGE	49-17	1122042	1.04	ECDA		12/31/11	
SDGE	49-17	1122043	0.61	ECDA		12/31/11	
SDGE	49-17	1122044	1.43	ECDA		12/31/11	
SDGE	49-22	2428340	0.48	ECDA		12/31/11	
SDGE	49-22	3266806	0.36	ECDA		12/31/11	
SDGE	49-22	1122108	0.78	ECDA		12/31/11	
SDGE	49-22	3266810	0.21	ECDA		12/31/11	
SDGE	49-22	3266811	0.29	ECDA		12/31/11	
SDGE	49-22	1122110	0.49	ECDA		12/31/11	
SDGE	49-22	2428345	0.11	ECDA		12/31/11	
SDGE	49-22	7687	0.69	ECDA		12/31/11	
SDGE	49-23	3129659	1.91	ECDA		12/31/11	
SDGE	49-23	3266813	2.05	ECDA		12/31/11	
SDGE	49-25	3139254	2.28	ECDA		12/31/11	
SDGE	49-26	1121322	0.46	ECDA		12/31/11	
SDGE	49-26	1121323	0.97	ECDA		12/31/11	
SDGE	49-26	1121324	0.35	ECDA		12/31/11	
SDGE	49-26	1121325	0.33	ECDA		12/31/11	
SDGE	49-26	3266818	0.01	ECDA		12/31/11	
SDGE	49-31	1121387	0.99	ECDA		12/31/11	
So Cal	512 LT 2		0.03	ECDA		12/31/11	
So Cal	512BP1	1123168	0.01	ECDA		12/31/11	
So Cal	6904-A	3266716	0.02	ECDA		12/31/11	
So Cal	6904-A1	3266950	0.01	ECDA		12/31/11	
So Cal	6904-ABP	1123499	0.01	ECDA		12/31/11	
So Cal	6906 LT 2	1123502	0.01	ECDA		12/31/11	
So Cal	000 ID1517-N	1123542	0.01	ECDA		12/31/11	
So Cal	765 ID212-T 1	1123543	0.00	ECDA		12/31/11	
So Cal	765 ID212-T 2	1123544	0.00	ECDA		12/31/11	
So Cal	765 ID212-T 3	1123545	0.00	ECDA		12/31/11	
So Cal	765 ID212-T 4	1123546	0.01	ECDA		12/31/11	
So Cal	765 ID4016-N 1	1123547	0.02	ECDA		12/31/11	
So Cal	765 ID4016-N 2	1123548	0.00	ECDA		12/31/11	
So Cal	765 ID4021-N 1	1123567	0.01	ECDA		12/31/11	
So Cal	765 ID4021-N 2	1123568	0.00	ECDA		12/31/11	
So Cal	765 ID562-T 1	1123549	0.00	ECDA		12/31/11	
So Cal	765 ID562-T 7	1123555	0.00	ECDA		12/31/11	
So Cal	765 LT 1	1123556	0.03	ECDA		12/31/11	
So Cal	765 LT 2	1123557	0.00	ECDA		12/31/11	
So Cal	765 ST 1	1123558	0.00	ECDA		12/31/11	
So Cal	765BR2	1123554	0.00	ECDA		12/31/11	
So Cal	765BR3	1123553	0.00	ECDA		12/31/11	
So Cal	765ST1	1123550	0.01	ECDA		12/31/11	
So Cal	8045 ID2307-T	1123559	0.01	ECDA		12/31/11	
So Cal	8045 LT 1	1123560	0.00	ECDA		12/31/11	
So Cal	G001	1122990	0.02	Hydrotest		12/31/11	
So Cal	GNG001.01	1122243	0.01	Hydrotest		12/31/11	
So Cal	GNG001.02	1122244	0.00	Hydrotest		12/31/11	
So Cal	GNG001.02-B	1122245	0.00	Hydrotest		12/31/11	
So Cal	GNG001.03	1122249	0.01	Hydrotest		12/31/11	
So Cal	GNG001.04	1122250	0.01	Hydrotest		12/31/11	
So Cal	GNG001.04-A	1122251	0.00	Hydrotest		12/31/11	
So Cal	GNG001.05	1122247	0.01	Hydrotest		12/31/11	
So Cal	GNG001.05-A	1122248	0.00	Hydrotest		12/31/11	
So Cal	GNG001.06	1122246	0.02	Hydrotest		12/31/11	

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So Cal	GNG001.07	1122252	0.00	Hydrotest		12/31/11	
So Cal	GNG001.08	1122254	0.00	Hydrotest		12/31/11	
So Cal	GNG001.08-A	1122253	0.01	Hydrotest		12/31/11	
So Cal	GNG001.11	1122257	0.01	Hydrotest		12/31/11	
So Cal	GNG001.12	1122258	0.00	Hydrotest		12/31/11	
So Cal	GNG001.14	1122260	0.00	Hydrotest		12/31/11	
So Cal	GNG001.16	1122262	0.00	Hydrotest		12/31/11	
So Cal	GNG001.18	1122264	0.00	Hydrotest		12/31/11	
So Cal	GNG001-A1	1122265	0.01	Hydrotest		12/31/11	
So Cal	GNG001-A3	1122266	0.01	Hydrotest		12/31/11	
So Cal	GNG001-A4	1122267	0.01	Hydrotest		12/31/11	
So Cal	GNG002.01	1122269	0.00	Hydrotest		12/31/11	
So Cal	GNG002.01-B	1122288	0.00	Hydrotest		12/31/11	
So Cal	GNG002.02	1122270	0.00	Hydrotest		12/31/11	
So Cal	GNG002.02-B	1122291	0.00	Hydrotest		12/31/11	
So Cal	GNG002.03	1122271	0.00	Hydrotest		12/31/11	
So Cal	GNG002.03-B	1122295	0.00	Hydrotest		12/31/11	
So Cal	GNG002.04	1122272	0.01	Hydrotest		12/31/11	
So Cal	GNG002.05	1122273	0.01	Hydrotest		12/31/11	
So Cal	GNG002-A	1122279	0.02	Hydrotest		12/31/11	
So Cal	GNG002-A1	1122280	0.00	Hydrotest		12/31/11	
So Cal	GNG002-C2	1122284	0.00	Hydrotest		12/31/11	
So Cal	GNG003	1122992	0.04	Hydrotest		12/31/11	
So Cal	GNG003.01-B	1123415	0.00	Hydrotest		12/31/11	
So Cal	GNG003.01-B2	1123417	0.00	Hydrotest		12/31/11	
So Cal	GNG003.02-B	1123418	0.00	Hydrotest		12/31/11	
So Cal	GNG003.03	1123398	0.01	Hydrotest		12/31/11	
So Cal	GNG003.03-B	1123423	0.00	Hydrotest		12/31/11	
So Cal	GNG003.04	1123399	0.01	Hydrotest		12/31/11	
So Cal	GNG003.05	1123400	0.01	Hydrotest		12/31/11	
So Cal	GNG003.06	1123401	0.01	Hydrotest		12/31/11	
So Cal	GNG003.07	1123402	0.01	Hydrotest		12/31/11	
So Cal	GNG003.08	1123403	0.01	Hydrotest		12/31/11	
So Cal	GNG003.09	1123404	0.01	Hydrotest		12/31/11	
So Cal	GNG003.10	1123405	0.01	Hydrotest		12/31/11	
So Cal	GNG003.11	1123406	0.01	Hydrotest		12/31/11	
So Cal	GNG003-A	1123407	0.02	Hydrotest		12/31/11	
So Cal	GNG004	1122993	0.05	Hydrotest		12/31/11	
So Cal	GNG004.01	1123451	0.00	Hydrotest		12/31/11	
So Cal	GNG004.02	1123452	0.00	Hydrotest		12/31/11	
So Cal	GNG004.03	1123453	0.00	Hydrotest		12/31/11	
So Cal	GNG004.04	1123454	0.00	Hydrotest		12/31/11	
So Cal	GNG004.05	1123455	0.00	Hydrotest		12/31/11	
So Cal	GNG004.06	1123456	0.01	Hydrotest		12/31/11	
So Cal	GNG004.07	1123457	0.00	Hydrotest		12/31/11	
So Cal	GNG004.08	1123458	0.01	Hydrotest		12/31/11	
So Cal	GNG004.09	1123459	0.00	Hydrotest		12/31/11	
So Cal	GNG004-A	1123460	0.00	Hydrotest		12/31/11	
So Cal	GNG004-B	1123461	0.00	Hydrotest		12/31/11	
So Cal	GNG005	1122994	0.03	Hydrotest		12/31/11	
So Cal	GNG005.01	1123462	0.00	Hydrotest		12/31/11	
So Cal	GNG005.02	1123463	0.00	Hydrotest		12/31/11	
So Cal	GNG005.03	1123464	0.00	Hydrotest		12/31/11	
So Cal	GNG005.04	1123465	0.00	Hydrotest		12/31/11	
So Cal	GNG005.05	1123466	0.00	Hydrotest		12/31/11	
So Cal	GNG005.06	1123467	0.01	Hydrotest		12/31/11	
So Cal	GNG005.07	1123468	0.01	Hydrotest		12/31/11	
So Cal	GNG005.08	1123469	0.00	Hydrotest		12/31/11	

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So Cal	GNG005.09	1123470	0.01	Hydrotest		12/31/11	
So Cal	GNG005-A	1123471	0.01	Hydrotest		12/31/11	
So Cal	GNG005-B	1123472	0.00	Hydrotest		12/31/11	
So Cal	GNG005-B1	1123339	0.00	Hydrotest		12/31/11	
So Cal	GNG005-C	1123473	0.00	Hydrotest		12/31/11	
So Cal	GNG005-C1	1122967	0.00	Hydrotest		12/31/11	
So Cal	GNG005-D	1123474	0.00	Hydrotest		12/31/11	
So Cal	GNG005-E	1123475	0.01	Hydrotest		12/31/11	
So Cal	GNG005-F	1123476	0.00	Hydrotest		12/31/11	
So Cal	GNG005-G	1123477	0.00	Hydrotest		12/31/11	
So Cal	GNG247	1122996	0.03	Hydrotest		12/31/11	
So Cal	GNG247.01	1123487	0.02	Hydrotest		12/31/11	
So Cal	GNG247.03-A	1123340	0.00	Hydrotest		12/31/11	
So Cal	GNG247.04	1123491	0.01	Hydrotest		12/31/11	
So Cal	GNG247.05	1123495	0.01	Hydrotest		12/31/11	
So Cal	GNG247.06	1123493	0.00	Hydrotest		12/31/11	
So Cal	GNG247.07	1123494	0.00	Hydrotest		12/31/11	
So Cal	GNG257-A3	1123483	0.01	Hydrotest		12/31/11	
So Cal	GNG257-A5	1123485	0.00	Hydrotest		12/31/11	
So Cal	GV106A	1122997	0.00	Hydrotest		12/31/11	
So Cal	GV106B	1123497	0.00	Hydrotest		12/31/11	
So Cal	PC1	1122922	0.01	Hydrotest		12/31/11	
So Cal	PC13	1122925	0.11	Hydrotest		12/31/11	
So Cal	PC1-B	1123284	0.00	Hydrotest		12/31/11	
So Cal	PC1-C	1123285	0.00	Hydrotest		12/31/11	
So Cal	PC2	1123304	0.04	Hydrotest		12/31/11	
So Cal	PC23	1123295	0.02	Hydrotest		12/31/11	
So Cal	PC23-A	3266906	0.00	Hydrotest		12/31/11	
So Cal	PC26	1122929	0.01	Hydrotest		12/31/11	
So Cal	PC26-A	1123301	0.00	Hydrotest		12/31/11	
So Cal	PC26-B	1123300	0.00	Hydrotest		12/31/11	
So Cal	PC27	3266911	0.00	Hydrotest		12/31/11	
So Cal	PC28	1122930	0.00	Hydrotest		12/31/11	
So Cal	PC290	1122931	0.02	Hydrotest		12/31/11	
So Cal	PC290-A	1123302	0.00	Hydrotest		12/31/11	
So Cal	PC291	1122932	0.03	Hydrotest		12/31/11	
So Cal	PC291-A	1123303	0.03	Hydrotest		12/31/11	
So Cal	PC292	1122933	0.01	Hydrotest		12/31/11	
So Cal	PC2-A	1123306	0.01	Hydrotest		12/31/11	
So Cal	PC2-A1	1123307	0.00	Hydrotest		12/31/11	
So Cal	PC2-A2	1123308	0.00	Hydrotest		12/31/11	
So Cal	PC2-B	1122934	0.05	Hydrotest		12/31/11	
So Cal	PC2-C	1123305	0.01	Hydrotest		12/31/11	
So Cal	PC30	1122939	0.03	Hydrotest		12/31/11	
So Cal	PF12	1122915	0.02	Hydrotest		12/31/11	
So Cal	PF12-A	1123271	0.00	Hydrotest		12/31/11	
So Cal	PF12-B	1123272	0.00	Hydrotest		12/31/11	
So Cal	PF12-C	1123273	0.00	Hydrotest		12/31/11	
So Cal	PF13	1123274	0.02	Hydrotest		12/31/11	
So Cal	PF13-A	1122916	0.06	Hydrotest		12/31/11	
So Cal	PF13-B	1123275	0.00	Hydrotest		12/31/11	
So Cal	PF13-C	1123276	0.00	Hydrotest		12/31/11	
So Cal	PF302	1122935	0.01	Hydrotest		12/31/11	
So Cal	PF303	1122936	0.01	Hydrotest		12/31/11	
So Cal	PF305	1122937	0.01	Hydrotest		12/31/11	
So Cal	PF357	1122940	0.01	Hydrotest		12/31/11	
So Cal	PF358	1122941	0.01	Hydrotest		12/31/11	
So Cal	PF360	1122942	0.01	Hydrotest		12/31/11	

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So Cal	PF3-A	3098770	0.00	Hydrotest		12/31/11	
So Cal	PF3-B	3098812	0.00	Hydrotest		12/31/11	
So Cal	PF410	1122946	0.01	Hydrotest		12/31/11	
So Cal	PF411	1122947	0.01	Hydrotest		12/31/11	
So Cal	PF413	1122948	0.01	Hydrotest		12/31/11	
So Cal	PF4-A	1122950	0.00	Hydrotest		12/31/11	
So Cal	PF4-B	1123311	0.00	Hydrotest		12/31/11	
So Cal	PF4-C	1123310	0.00	Hydrotest		12/31/11	
So Cal	PF4-D	1123312	0.00	Hydrotest		12/31/11	
So Cal	PF5-A	1122952	0.00	Hydrotest		12/31/11	
So Cal	PF5-B	3266910	0.00	Hydrotest		12/31/11	
So Cal	PF6-A	1123315	0.00	Hydrotest		12/31/11	
So Cal	PF6-B	1122954	0.00	Hydrotest		12/31/11	
So Cal	PF7-A	1123323	0.00	Hydrotest		12/31/11	
So Cal	PF8-A	1122958	0.00	Hydrotest		12/31/11	
So Cal	PF8-B	3266923	0.00	Hydrotest		12/31/11	
So Cal	PF9-1	1122960	0.04	Hydrotest		12/31/11	
So Cal	PF9-2	1123325	0.02	Hydrotest		12/31/11	
So Cal	PF9-A	1123324	0.03	Hydrotest		12/31/11	
So Cal	PGR1	1122923	0.11	Hydrotest		12/31/11	
So Cal	PGR14-A	1122917	0.01	Hydrotest		12/31/11	
So Cal	PGR14-B	1123277	0.01	Hydrotest		12/31/11	
So Cal	PGR15-A	1122918	0.01	Hydrotest		12/31/11	
So Cal	PGR15-B	3098810	0.01	Hydrotest		12/31/11	
So Cal	PGR16-A	1122919	0.01	Hydrotest		12/31/11	
So Cal	PGR16-B	1123278	0.01	Hydrotest		12/31/11	
So Cal	PGR17-A	1122920	0.01	Hydrotest		12/31/11	
So Cal	PGR17-B	1123279	0.01	Hydrotest		12/31/11	
So Cal	PGR18-A	1122921	0.01	Hydrotest		12/31/11	
So Cal	PGR18-B	1123280	0.01	Hydrotest		12/31/11	
So Cal	PGR19-F	1123281	0.01	Hydrotest		12/31/11	
So Cal	PGR19-G	1123282	0.01	Hydrotest		12/31/11	
So Cal	PGR20	1122924	0.13	Hydrotest		12/31/11	
So Cal	PGR20-A	1123286	0.00	Hydrotest		12/31/11	
So Cal	PGR20-A1	1123287	0.02	Hydrotest		12/31/11	
So Cal	PGR21-D	1123290	0.00	Hydrotest		12/31/11	
So Cal	PGR21-D1	1123289	0.02	Hydrotest		12/31/11	
So Cal	PGR21-D1A	1123291	0.01	Hydrotest		12/31/11	
So Cal	PGR306	1122938	0.01	Hydrotest		12/31/11	
So Cal	PGR361	1122943	0.01	Hydrotest		12/31/11	
So Cal	PGR4	1122951	0.13	Hydrotest		12/31/11	
So Cal	PGR414	1122949	0.01	Hydrotest		12/31/11	
So Cal	PGR4-B	1123313	0.11	Hydrotest		12/31/11	
So Cal	PGR4-B1	1123314	0.02	Hydrotest		12/31/11	
So Cal	PGR7	1122957	0.60	Hydrotest		12/31/11	
So Cal	PGR8	1122959	0.17	Hydrotest		12/31/11	
So Cal	41-6001-2	3267055	0.36	ECDA		02/29/12	
So Cal	41-6001-2	1122174	0.30	ECDA		02/29/12	
So Cal	41-6001-2	1122175	0.15	ECDA		02/29/12	
So Cal	41-6001-2	1122176	0.31	ECDA		02/29/12	
So Cal	41-6001-2	1122177	0.12	ECDA		02/29/12	
So Cal	41-6001-2	1122178	0.30	ECDA		02/29/12	
So Cal	41-6001-2	1122179	0.18	ECDA		02/29/12	
So Cal	41-6001-2	1122180	0.25	ECDA		02/29/12	
So Cal	41-6001-2	3267056	0.61	ECDA		02/29/12	
So Cal	38-504	3536	0.20	ECDA		06/12/12	
So Cal	38-504	3532	0.22	ECDA		06/12/12	
So Cal	38-504	3528	1.19	ECDA		06/12/12	

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So Cal	38-504	3521	0.22	ECDA		06/12/12	
So Cal	38-504	3542	0.23	ECDA		06/12/12	
So Cal	38-504	3537	0.48	ECDA		06/12/12	
So Cal	38-504	3541	1.18	ECDA		06/12/12	
So Cal	38-504	3535	1.56	ECDA		06/12/12	
So Cal	38-504	3531	0.55	ECDA		06/12/12	
So Cal	38-504	3526	0.33	ECDA		06/12/12	
So Cal	38-504	3546	0.54	ECDA		06/12/12	
So Cal	38-504	3539	0.20	ECDA		06/12/12	
So Cal	38-504	3543	0.18	ECDA		06/12/12	
So Cal	38-504	3540	0.19	ECDA		06/12/12	
So Cal	38-504	3545	0.16	ECDA		06/12/12	
So Cal	38-504	3538	0.66	ECDA		06/12/12	
So Cal	38-504	3534	0.92	ECDA		06/12/12	
So Cal	145	3266980	0.63	ECDA		06/30/12	
So Cal	169	3266979	0.02	ECDA		06/30/12	
So Cal	207	3266433	0.14	ECDA		06/30/12	
So Cal	207	3266434	0.26	ECDA		06/30/12	
So Cal	1241	3266981	0.09	ECDA		06/30/12	
So Cal	5011	3266754	0.12	ECDA		06/30/12	
So Cal	6100		0.01	ECDA		06/30/12	
So Cal	6907		0.11	ECDA		06/30/12	
So Cal	6911		0.14	ECDA		06/30/12	
So Cal	1013ST1		0.01	ECDA		06/30/12	
So Cal	2002 ID465-T 2		0.01	ECDA		06/30/12	
So Cal	2002 ID465-T 3		0.00	ECDA		06/30/12	
So Cal	235 East		0.62	ILI		06/30/12	
So Cal	3000 EAST	3266783	0.31	ECDA		06/30/12	
So Cal	30-02-U	3266976	0.06	ECDA		06/30/12	
So Cal	30-38-X	3266747	0.25	ECDA		06/30/12	
So Cal	30-60		0.53	ECDA		06/30/12	
So Cal	30-60		0.09	ECDA		06/30/12	
So Cal	31-09	1121376	0.00	ECDA		06/30/12	
So Cal	31-09	3208624	0.47	ECDA		06/30/12	
So Cal	31-09	3208627	0.05	ECDA		06/30/12	
So Cal	31-09	3208628	0.14	ECDA		06/30/12	
So Cal	31-6134	1121385	0.04	ECDA		06/30/12	
So Cal	32-60	3099088	0.12	ECDA		06/30/12	
So Cal	36-07		0.54	ECDA		06/30/12	
So Cal	36-07		0.27	ECDA		06/30/12	
So Cal	36-07		0.08	ECDA		06/30/12	
So Cal	36-07		0.49	ECDA		06/30/12	
So Cal	36-07		0.84	ECDA		06/30/12	
So Cal	36-07		0.18	ECDA		06/30/12	
So Cal	36-07		0.16	ECDA		06/30/12	
So Cal	36-07		0.29	ECDA		06/30/12	
So Cal	36-07		0.43	ECDA		06/30/12	
So Cal	36-07		0.18	ECDA		06/30/12	
So Cal	36-07		0.08	ECDA		06/30/12	
So Cal	36-07		0.06	ECDA		06/30/12	
So Cal	36-07		0.04	ECDA		06/30/12	
So Cal	36-07		0.21	ECDA		06/30/12	
So Cal	36-1001	1122781	0.15	ILI		06/30/12	
So Cal	36-1001	1122779	0.23	ILI		06/30/12	
So Cal	36-1001	1122775	0.16	ILI		06/30/12	
So Cal	36-1001	1122776	0.16	ILI		06/30/12	
So Cal	36-1001	1122777	0.15	ILI		06/30/12	
So Cal	36-1001	1122773	0.19	ILI		06/30/12	

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So Cal	36-1001	1122774	0.04	ILI		06/30/12	
So Cal	36-1001	1122771	0.03	ILI		06/30/12	
So Cal	36-1001	3098747	0.01	ILI		06/30/12	
So Cal	36-1001	1122769	0.08	ILI		06/30/12	
So Cal	36-1001	1122770	0.24	ILI		06/30/12	
So Cal	36-37	3131402	0.16	ECDA		06/30/12	
So Cal	36-37	1610027	0.20	ECDA		06/30/12	
So Cal	36-8-01-C		0.06	ECDA		06/30/12	
So Cal	36-9-06-F	3267034	0.10	ECDA		06/30/12	
So Cal	36-9-06-F	3267035	0.06	ECDA		06/30/12	
So Cal	36-9-06-F	3267036	0.27	ECDA		06/30/12	
So Cal	36-9-06-F	3267037	0.08	ECDA		06/30/12	
So Cal	36-9-09-JJ	3266797	0.09	ECDA		06/30/12	
So Cal	36-9-09-JJ	3266798	0.03	ECDA		06/30/12	
So Cal	36-9-09-JJ	3266799	0.06	ECDA		06/30/12	
So Cal	36-9-09-JJ	3266800	0.07	ECDA		06/30/12	
So Cal	38-514		0.10	ECDA		06/30/12	
So Cal	38-539	3266548	0.08	ECDA		06/30/12	
So Cal	38-539	3266549	0.06	ECDA		06/30/12	
So Cal	41-05HH	3266991	0.00	ECDA		06/30/12	
So Cal	41-22	3266718	0.46	ECDA		06/30/12	
So Cal	41-22	3266719	0.10	ECDA		06/30/12	
So Cal	41-22	3266720	0.16	ECDA		06/30/12	
So Cal	41-22	3266374	0.07	ECDA		06/30/12	
So Cal	41-25	3266982	0.39	ECDA		06/30/12	
So Cal	41-25	3266984	0.07	ECDA		06/30/12	
So Cal	41-25	3266985	0.18	ECDA		06/30/12	
So Cal	41-25	3266986	0.12	ECDA		06/30/12	
So Cal	41-25	3266987	0.10	ECDA		06/30/12	
So Cal	41-25	3266988	0.33	ECDA		06/30/12	
So Cal	41-25	3266989	0.17	ECDA		06/30/12	
So Cal	41-48	3266920	0.49	ECDA		06/30/12	
So Cal	41-6505-A		0.03	ECDA		06/30/12	
So Cal	41-83-A	3266966	0.10	ECDA		06/30/12	
So Cal	42-89	3266967	0.13	ECDA		06/30/12	
So Cal	43-16	1123070	0.00	ECDA		06/30/12	
So Cal	43-34		0.13	ECDA		06/30/12	
So Cal	43-34		0.59	ECDA		06/30/12	
So Cal	43-34		0.07	ECDA		06/30/12	
So Cal	43-34		0.22	ECDA		06/30/12	
So Cal	43-34		0.10	ECDA		06/30/12	
So Cal	44-137	1121386	1.00	ECDA		06/30/12	
So Cal	44-151	3266964	0.33	ECDA		06/30/12	
So Cal	44-635	3266717	0.77	ECDA		06/30/12	
So Cal	44-675		0.03	ECDA		06/30/12	
So Cal	44-687	3266965	0.06	ECDA		06/30/12	
So Cal	44-702	3266918	0.03	ECDA		06/30/12	
So Cal	45-1109	3266625	0.03	ECDA		06/30/12	
SDGE	49-352		0.01	ECDA		06/30/12	
So Cal	1242	3266746	0.86	ECDA		07/01/12	
So Cal	1244	3267030	0.68	ECDA		07/02/12	
So Cal	1244	3267031	0.79	ECDA		07/03/12	
So Cal	324	1122759	0.72	ECDA		12/17/12	
So Cal	404	1122133	0.18	ILI		12/17/12	
So Cal	404	1122840	2.38	ILI		12/17/12	
So Cal	404	3098759	0.01	ILI		12/17/12	
So Cal	765	3098721	0.09	ILI		12/17/12	
So Cal	765	3098721	0.16	ILI		12/17/12	

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So Cal	767	1121712	0.08	ILI		12/17/12	
So Cal	1011	1121899	0.01	ECDA		12/17/12	
So Cal	1015	1121633	3.21	ECDA		12/17/12	
So Cal	1015	1121633	0.18	ECDA		12/17/12	
So Cal	1015	1122696	5.43	ECDA		12/17/12	
So Cal	1015	1122696	0.01	ECDA		12/17/12	
So Cal	1015	1122696	0.01	ECDA		12/17/12	
So Cal	1015	1122696	0.01	ECDA		12/17/12	
So Cal	1015	1122696	0.01	ECDA		12/17/12	
So Cal	1019	1121906	0.01	ILI		12/17/12	
So Cal	1024	3098568	0.02	ILI		12/17/12	
So Cal	1025	3266411	0.02	ECDA		12/17/12	
So Cal	1025	3266411	0.01	ECDA		12/17/12	
So Cal	1027	1121291	0.01	ILI		12/17/12	
So Cal	1167	1121293	0.04	ILI		12/17/12	
So Cal	1167	1121294	0.12	ILI		12/17/12	
So Cal	1172	3266412	0.41	ILI		12/17/12	
So Cal	1173	3266995	0.03	ILI		12/17/12	
So Cal	1176	3098584	0.01	ILI		12/17/12	
So Cal	1180	1121255	0.03	ILI		12/17/12	
So Cal	1181	1121299	0.03	ILI		12/17/12	
So Cal	1205	1121303	0.03	ILI		12/17/12	
SDGE	1600	3098836	0.03	ECDA		12/17/12	
SDGE	1600	3266743	0.11	ECDA		12/17/12	
SDGE	1600	2580005	0.07	ECDA		12/17/12	
SDGE	1600	2579986	0.04	ECDA		12/17/12	
SDGE	1600	2579986	0.05	ECDA		12/17/12	
SDGE	1600	2579991	0.12	ECDA		12/17/12	
SDGE	1601	1122210	0.01	ECDA		12/17/12	
SDGE	1601	1122210	0.05	ECDA		12/17/12	
SDGE	1601	1122212	0.02	ECDA		12/17/12	
SDGE	1601	1122844	0.04	ECDA		12/17/12	
SDGE	1602	1122030	0.10	ECDA		12/17/12	
SDGE	1604	3266430	0.01	ECDA		12/17/12	
SDGE	1604	3266430	0.09	ECDA		12/17/12	
SDGE	1604	3266430	0.01	ECDA		12/17/12	
So Cal	2000	3098589	0.19	ILI		12/17/12	
So Cal	2000	1121311	0.23	ILI		12/17/12	
So Cal	2000	3098613	0.06	ILI		12/17/12	
So Cal	2002	1155166	0.16	ILI		12/17/12	
So Cal	2003	1165326	0.00	ILI		12/17/12	
So Cal	2003	1165326	0.02	ILI		12/17/12	
SDGE	3010	1123175	0.13	ECDA		12/17/12	
SDGE	3010	1123175	0.07	ECDA		12/17/12	
SDGE	3010	1123176	0.44	ECDA		12/17/12	
SDGE	3010	3098802	0.05	ECDA		12/17/12	
SDGE	3010	1122687	0.03	ECDA		12/17/12	
SDGE	3010	1122689	1.54	ECDA		12/17/12	
SDGE	3010	1122689	1.54	ECDA		12/17/12	
SDGE	3600	3266675	2.32	ECDA		12/17/12	
SDGE	3600	1122848	0.10	ECDA		12/17/12	
SDGE	3600	3266883	0.00	ECDA		12/17/12	
SDGE	3600	3266883	0.08	ECDA		12/17/12	
SDGE	3600	3266883	0.05	ECDA		12/17/12	
SDGE	3600	3266883	0.02	ECDA		12/17/12	
SDGE	3600	3266883	0.11	ECDA		12/17/12	
SDGE	3600	3266882	0.03	ECDA		12/17/12	
SDGE	3600	3266882	0.01	ECDA		12/17/12	

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SDGE	3600	3266882	0.01	ECDA		12/17/12	
So Cal	4000	1155168	0.04	ILI		12/17/12	
So Cal	4000	1155168	0.01	ILI		12/17/12	
So Cal	6900	1122636	0.06	ECDA		12/17/12	
So Cal	6900	1122637	0.03	ECDA		12/17/12	
So Cal	6900	1122645	0.03	ECDA		12/17/12	
So Cal	6900	1122646	0.03	ECDA		12/17/12	
So Cal	8109	3098552	0.48	ILI		12/17/12	
So Cal	2001WEST	1121640	0.72	ILI		12/17/12	
So Cal	3000 WEST	1121724	0.02	ILI		12/17/12	
So Cal	30-18	1123007	0.13	ECDA		12/17/12	
So Cal	30-18	1123008	0.02	ECDA		12/17/12	
So Cal	30-18	1123008	0.01	ECDA		12/17/12	
So Cal	31-09	1121377	0.02	ECDA		12/17/12	
So Cal	31-09	1121377	0.00	ECDA		12/17/12	
So Cal	31-09	3098627	0.01	ECDA		12/17/12	
So Cal	31-09	3208621	0.01	ECDA		12/17/12	
So Cal	31-09	3208621	0.01	ECDA		12/17/12	
So Cal	32-25	1123016	0.14	ECDA		12/17/12	
So Cal	32-60	2308887	0.01	ECDA		12/17/12	
So Cal	32-60	2308891	0.01	ECDA		12/17/12	
So Cal	32-60	2308891	0.02	ECDA		12/17/12	
So Cal	33-37	1610039	0.05	ECDA		12/17/12	
So Cal	35-20-A	1121462	0.05	ECDA		12/17/12	
So Cal	35-20-A	1121464	0.01	ECDA		12/17/12	
So Cal	35-6416	1122204	0.10	ECDA		12/17/12	
So Cal	36-1007	1122787	0.02	ECDA		12/17/12	
So Cal	36-37	1610012	0.01	ECDA		12/17/12	
So Cal	36-37	1610012	0.03	ECDA		12/17/12	
So Cal	36-37	1610012	0.00	ECDA		12/17/12	
So Cal	36-37	1610012	0.01	ECDA		12/17/12	
So Cal	36-37	1610012	0.05	ECDA		12/17/12	
So Cal	36-37	3131393	0.00	ECDA		12/17/12	
So Cal	36-37	3131394	0.06	ECDA		12/17/12	
So Cal	36-37	1610035	0.01	ECDA		12/17/12	
So Cal	36-7-04BR1	3266990	0.01	ECDA		12/17/12	
So Cal	36-9-06	1121532	0.00	ECDA		12/17/12	
So Cal	36-9-06	1121532	0.01	ECDA		12/17/12	
So Cal	36-9-06	1121532	0.01	ECDA		12/17/12	
So Cal	36-9-06	1121532	0.02	ECDA		12/17/12	
So Cal	36-9-06-A	3266506	0.06	ECDA		12/17/12	
So Cal	36-9-06-A	3266506	0.01	ECDA		12/17/12	
So Cal	37-07	3266794	0.01	ECDA		12/17/12	
So Cal	37-18	1123051	0.01	ECDA		12/17/12	
So Cal	37-18	1123050	0.01	ECDA		12/17/12	
So Cal	37-18	1123048	0.02	ECDA		12/17/12	
So Cal	37-18-K	3266751	0.99	ECDA		12/17/12	
So Cal	37-18-K	3266752	0.01	ECDA		12/17/12	
So Cal	37-18-K	3266753	0.00	ECDA		12/17/12	
So Cal	41-05	1122470	0.02	ECDA		12/17/12	
So Cal	41-05	1122476	0.01	ECDA		12/17/12	
So Cal	41-05	3266554	0.02	ECDA		12/17/12	
So Cal	41-05	1122465	0.01	ECDA		12/17/12	
So Cal	41-05	1122442	0.02	ECDA		12/17/12	
So Cal	41-05	1122458	0.02	ECDA		12/17/12	
So Cal	41-05	1122458	0.04	ECDA		12/17/12	
So Cal	41-05	1122458	0.02	ECDA		12/17/12	
So Cal	41-05	2425509	0.02	ECDA		12/17/12	

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So Cal	41-19	2579899	0.01	ECDA		12/17/12	
So Cal	41-6000-2	1122166	0.01	ECDA		12/17/12	
So Cal	41-6501	1122584	0.02	ECDA		12/17/12	
So Cal	45-163	1122623	0.02	ECDA		12/17/12	
So Cal	45-163	1122623	0.00	ECDA		12/17/12	
So Cal	45-163	1122623	0.02	ECDA		12/17/12	
So Cal	45-163	1122625	0.03	ECDA		12/17/12	
SDGE	49-16	1122036	0.01	ECDA		12/17/12	
SDGE	49-16	1122038	0.08	ECDA		12/17/12	
SDGE	49-18	1122047	0.16	ECDA		12/17/12	
SDGE	49-18	1122047	0.01	ECDA		12/17/12	
SDGE	49-18	1122047	0.01	ECDA		12/17/12	
SDGE	49-18	1122049	0.05	ECDA		12/17/12	
So Cal	5000(1)	1596617	0.05	ILI		12/17/12	
So Cal	5000(1)	1596618	0.02	ILI		12/17/12	
So Cal	5000(1)	1596618	0.01	ILI		12/17/12	
So Cal	5000(1)	1596619	0.29	ECDA		12/17/12	
So Cal	1230	1122012	1.21	ECDA		12/31/12	
So Cal	45-120	1138993	0.12	ECDA		12/31/12	
So Cal	45-120	3266821	0.08	ECDA		12/31/12	
So Cal	45-120	3266822	0.03	ECDA		12/31/12	
So Cal	45-120	3266823	0.07	ECDA		12/31/12	
So Cal	45-120	3266824	0.57	ECDA		12/31/12	
So Cal	45-120	3266825	0.58	ECDA		12/31/12	
So Cal	45-120	1138995	0.25	ECDA		12/31/12	
SDGE	49-13	1122020	0.50	ECDA		12/31/12	
SDGE	49-13	1122018	1.60	ECDA		12/31/12	
So Cal	6916	3266739	0.19	ILI		01/01/18	
So Cal	6916	3266740	0.28	ILI		01/01/18	
So Cal	6916	3266737	0.54	ILI		01/01/18	
So Cal	6916	3266738	0.37	ILI		01/01/18	
So Cal	6916	3266735	0.53	ILI		01/01/18	
So Cal	6916	3266736	0.71	ILI		01/01/18	
So Cal	6916	3266733	0.74	ILI		01/01/18	
So Cal	6916	3266734	0.89	ILI		01/01/18	
So Cal	6916	3266732	0.17	ILI		01/01/18	
So Cal	6916	3266731	0.24	ILI		01/01/18	
So Cal	6916	3266730	0.36	ILI		01/01/18	

Based on GRC BAP367 20100423

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4. On page RKS-29, SCG states "SoCalGas must baseline assess approximately 1149 miles out of its 3989 miles of transmission pipeline." How many of the 1149 miles of pipelines are cased mains? How many miles of cased mains are part of SCG's transmission system?

SoCalGas Response:

Typically, only short segments of transmission pipeline are installed within casings. These installations are usually required where the line crosses (either over or under) structures such as railroad tracks, freeways and highways, rivers and flood control channels, etc. There are 106 segments of pipe installed within casings covered by the Pipeline Integrity Transmission program. This relates to approximately 2.38 miles of pipe.

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5. Please provide a nexus between the TIMP assessment summary in Table SCG-RKS-9, page RKS-30, and the workpapers titled: "Supplemental Workpaper Calculations for Costs related to TIMP Assessments," on pages 33 and 34 of the workpapers.

SoCalGas Response:

The Table SCG-RKS-9 represents the types and amounts of completed and forecasted integrity work within the utilities' integrity management program. Its inclusion in the testimony is to illustrate the evolution of activity in the TIMP program since inception and through the remaining two years of the Rules' initial baseline assessment mandate.

While the forecast in Table RKS-9 depicts the amount of work completed and remaining in the program, it does not necessarily coincide with the forecasted O&M activities on pages 33 and 34 of the workpapers. There are additional options that SoCalGas is pursuing to address specific individual pipe segments within the program. These options include pipe replacement, material testing, and operating pressure reduction. If successfully implemented, these alternative options would be performed in such a manner as to reduce the risk on the pipeline to levels that would transfer them from the transmission integrity management program to the distribution integrity management program. The O&M projects forecasted on pages 33 and 34 of the workpapers are those projects where there is virtual certainty that the indicated activity must be completed to meet the transmission integrity management requirements.

6. With regard to the workpapers pages 33-34, please provide the following:
    a. The timeframe in which the Supplemental Workpaper Calculations for Costs related to TIMP Assessments were developed;
    b. For each line item, provide the 2010YTD and the number of units completed for each work activity described within the line item.
    c. The calculations used and step-by-step instruction on how the 2012 forecasts for labor and non-labor expenses were developed for each line item in the Supplemental Workpaper Calculations on pages 33-34.
    d. For line item number 1, In-Line inspection and verification digs, provide a detailed explanation and all calculations used to determine that 73 assessment or reassessment projects are needed. For each of the 73 assessments planned, identify the beginning and ending date, as well as a copy of the project plans.
    e. For line item number 4, External Corrosion Direct Assessment of Department of Transportation defined Transmission Pipeline per Baseline Assessment Plan, provide a copy of all calculations and assumptions used to determine the number of miles needed to survey, and the number of digs needed, for each year from 2010-2012. Also, please provide a copy of all supporting documents and calculations used to determine the statement, "$32,000/mile to survey (with a minimum cost of $15,600 per project and 1.79 digs/mile (with a minimum of 4 digs per project) at a cost of $40,000 per dig for non-labor."
    f. For line item number 9, Conduct Tethered In-Line Magnetic Flux-Leakage Inspection of Cased Transmission Pipeline, provide a copy of all supporting documents and calculations used to determine 74 segments as the number of units to be assessed in 2012.

SoCalGas Response:

Note: To ensure the correct "Line Number" activity is referenced from the Supplemental workpaper on pages 33 and 34 of Exhibit SCG-05-WP, a copy of these two pages have been modified with Line numbers and included at the end of the response to question 6.

a. The development of the 2012 GRC forecast requirements for TIMP activities included in Mr. Stanford's testimony was prepared in the first quarter of 2010. The schedule and expense forecast were based on the most up-to-date information available at that time.

b. The 2010 expense data are not yet finalized. This data will be provided in the future.

Response to Question 6 (Continued)

c. The calculations and step-by-step instructions used in developing the 2012 expense forecast for each Item number are as follows:

<u>Line Item 1</u>: Typically the work to complete the retrofit, in-line inspection, and repair of a pipeline, in order to comply with Pipeline Safety and Improvement Act of 2002 (PSIA 2002), spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result, all project expenditures are forecast over a three-year period.

	Typical Schedule	Year 1	Year 2	Year 3	Sum
		% Work	% Work	% Work	
1	Retrofit costs	20%	80%		100%
2	Cost of launcher/receiver		100%		100%
3	ILI Fixed		100%		100%
4	ILI Variable		100%		100%
5	Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3, 4 and 5 above) from capital to expense.

<u>In-line Inspection Component:</u> The forecast for the "fixed" component is based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The "variable" component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component ($59,129 per project) from 2010 RFP.

Response to Question 6 (Continued)

Excavation Component: To forecast the excavation component of the assessments, it is assumed that there will be a minimum of 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per ILI run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor: The majority of work required to complete ILI projects is contractor work and materials which are pooled into the non-labor category. Based upon historical data from projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast these expenses in 2010-2012. ILI projects typically consist of five major steps that take place over a three-year period. The forecast represents the costs of forty individual projects that will take place in 2012, and accounts for the phase of the assessment and repair cycle each project will be in during 2012.

Line Item 2: There are no forecasted expenses for this item in 2012.

Line Item 3: The following expense schedule is based on a contractors bid for hydrostatic pressure testing at the Goleta storage field. As scheduled, 40% of the work will be performed in 2012 and therefore 40% of the bid ($36K Labor, $304K NL) was applied in 2012.

Goleta O&M L & NL Directs:			
Non-Labor	**Unit Rate**	**Days/Unit**	**Total**
Construction Vendor	6,200	57	353,400
Abatement Vendor	3,600	16	57,600
Materials	40,000	8	320,000
Misc. NL	10,000	3	30,000
		Total:	761,000
Labor	**Unit Rate**	**Hours**	**Total**
Team Lead	48	200	9,600
Project Manager	47	460	21,620
Construction Manager	42	600	25,200
Construction Labor	28	1,200	33,600
		Total:	90,020
		Total Direct Expense:	**851,020**

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Line Item 4: The calculation for labor was prepared as follows. For non-labor, see response to Question 6e.

Labor was calculated by taking the forecasted spending for 2010 and adding 1 associate engineer for ½ of 2010 at $60,000 per year, 2 project managers at an average salary of $87,500, and one tech advisor at an average salary of $82,500. The "current spending" for 2010 is the cost for existing labor used for ECDA without adding personnel. It was calculated by using 2009 labor rates and FTEs.

Labor	2010	2011	2012
Current spending	389,584	389,584	389,584
+ 1 Associate Engineer	30,000	60,000	60,000
+ 2 Project Managers	175,000	175,000	175,000
+ 1 Tech Advisor	82,500	82,500	82,500
	677,084	**707,084**	**707,084**

Line Item 5: The cost estimate for this line item is based on a contractual agreement with the 3rd party vendor. To date, 19 of 20 short line studies have been completed for a total of approximately $323,000, and 3 of 15 long line studies have been completed for a total of approximately $210,000. Total for 2010 YTD is approximately $534,000.

Line Item 6: There are no forecasted expenses for this item in 2012.

Line Item 7: There are no forecasted expenses for this item in 2012.

Line Item 8: As stated in the Forecast Methodology section of the TIMP O&M workpaper, Exhibit SCG-05-WP, page 28, "The activities and operational support provided by this workgroup are project specific and as such are provided as a zero-based forecasting methodology." This line item reflects the ongoing operational support functions for the in-line inspection and metallurgical analysis activities and as such is forecasted within this line based on the 2009 actual expense incurred. The Labor expense is for 3.6 FTEs at an average salary of $70,300. Non-Labor expense includes project-specific travel expenses for personnel, metallurgical testing, and contract labor expense for consultation and project support.

Response to Question 6 (Continued)

Line Item 9: 74 cased pipeline segments are to be assessed using tethered In-Line MFL in 2012. The O&M component is $103,600 per project. This amount is derived from historical expense values which show the total O&M costs of a typical tethered ILI project is approximately 40% of the total project cost. See below for the Labor/Non-Labor split and description of each.

O&M Per Project Breakdown				
	% of Total Cost	% Labor	% Non-Labor	Description of O&M Charges
Tethered-ILI	40	8.5	91.5	The per project O&M estimate is broken down into **NL:** The inspection run charges (tether vender costs, mobilization, MFL tool cost, report) and **Labor:** In-house run analysis and programmatic documentation.

Line Item 10: 11 casings are to be removed in 2012. The O&M component is estimated at approximately $942 per project. Casing removals are primarily a capital expense activity. Project management, supervision, data analysis, and reporting activities are expected to account for approximately 7% of the total project cost. See below for the Labor/Non-Labor split and description of each.

O&M Per Project Breakdown				
	% of Total Cost	% Labor	% Non-Labor	Description of O&M Charges
Casing Removals	0.7	8.5	91.5	The per project O&M estimate is broken down into **NL:** A portion of the bell hole inspection vender charges and **Labor:** In-house analysis and programmatic documentation.

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d. All DOT Transmission Pipeline Integrity baseline assessments, and reassessments, are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with 49 CFR Part 192 Subpart O. Under this rule, operators of gas transmission pipelines are required to identify threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns as prescribed by the rule.

The BAP is the utilities' summary of these activities and depicts which lines have already been assessed and which lines are scheduled for future assessment. All baseline assessments must be completed by Dec 17, 2012. The pipeline segments identified within this line item must be assessed by this date. The response to Question 6c-Line Item1 of this data request details the O&M expense activities as part of a capital project. The project beginning and ending dates as well as project plans for each are included in the capital workpapers associated with Mr. Stanford's testimony.

e. The cost to perform indirect inspection surveys was determined using the average survey cost per mile for 2008-2010 projects that had been completed. The estimated cost used was $32,000 per mile which has been consistently used for internal planning. The actual average survey cost per mile was $35,420 per mile.
The cost per dig was determined using the average cost per direct examination bell hole ("dig") for completed 2008-2009 projects which was $40,000. The actual average direct examination cost was $39,885.

<u>ECDA Projects from 2008 – 2009</u>

ECDA Project	Miles Surveyed	No. Digs	Total Survey Costs	Survey Cost per mile	Total Direct Exam cost	DE Cost/Dig
L 32-24 &44-725	1.26	4	$ 42,581	$ 33,754	$ 289,791	$ 72,448
Line 41-05	13.85	18	$ 338,069	$ 24,415	$ 523,084	$ 29,060
Line 32-60	5.94	8	$ 154,014	$ 25,927	$ 306,000	$ 38,250
Line 36-1007	2.73	4	$ 50,523	$ 18,540	$ 96,167	$ 24,042
Line 36-6593	0.99	4	$ 52,987	$ 53,785	$ 157,687	$ 39,422
Line 32-25	1.18	4	$ 35,729	$ 30,364	$ 62,471	$ 15,618
Line 35-10	3.47	4	$ 105,769	$ 30,505	$ 233,503	$ 58,376
Line 36-9-09S	1.23	5	$ 37,065	$ 30,201	$ 121,740	$ 24,348
Line 36-9-09N	7.08	11	$ 336,524	$ 47,500	$ 567,832	$ 51,621
Line 36-9-21	11.04	6	$ 144,449	$ 13,083	$ 322,931	$ 53,822
L 43/45-1106	1.03	8	$ 64,319	$ 62,393	$ 284,765	$ 35,596
Line 44-1008	1.12	4	$ 40,317	$ 35,971	$ 166,500	$ 41,625
Line 38-501	1.36	10	$ 73,444	$ 54,027	$ 342,821	$ 34,282
			Average>>	**$ 35,420**	**Average>>**	**$ 39,885**
			Used>>	**$ 32,000**	**Used**	**$ 40,000**

Response to Question 6 (Continued)

Estimating Survey Costs

For planning, $32,000 per mile for survey costs was used. However, short mileage projects have a fixed cost no matter the length because it takes a set amount of time for the survey crews to mobilize and demobilize on each project. So regardless of length, each and every project requires a minimum of three days of crew time. Crew time costs $5,200 per day.

For projects less than one mile in length, the following was used:

- 0.01 - 0.50 miles requires a minimum of 3 days for the survey crew. The cost is $5,200 per day = a minimum of $15,600 for the three days
- 0.50 - 1.00 miles requires a minimum of 5 days for survey crew. The cost is $5,200 per day = a minimum of $26,000 for the 5 days
- 1.00 + miles uses the $32,000 per mile for the surveys

The greater of "mileage based cost" or "project minimum" was used.

Example:

Project	Total HCA Miles	Cost/Mile	Mileage-based Cost	Project Minimum	Estimated Survey Cost
Project 408-RA	0.14	$ 32,000	$ 4,480	$ 15,600	$ 15,600
Project 41-17A	0.71	$ 32,000	$ 22,720	$ 26,000	$ 26,000
Project 38-504	10.32	$ 32,000	$330,240	--------	$ 330,240

Estimating Direct Examination Costs

There have been 67 completed projects for a total of 279 HCA miles. Associated with these projects, 500 direct examination digs were conducted. This equates to an average of 1.79 digs per HCA mile. This factor was applied to the number of HCA miles planned per project per year from the March 2010 baseline assessment plan per project.

Additionally, 49 CFR 192, Subpart O, references the NACE SP0502 standard for ECDA which requires a minimum of 4 digs per project so the total number of "Project Minimum Digs" was entered as 4. If the project's HCA mileage is low, the project minimum digs must be used.

The "Estimated Minimum Digs" is the greater of "Mileage-based digs" or "Project Minimum digs". Note that actual field data results could require more than the "Estimated Minimum Digs."

DRA DATA REQUEST
DRA-SCG-022-DAO
SOCALGAS 2012 GRC
SOCALGAS RESPONSE
DATE RECEIVED: DECEMBER 8, 2010
DATE RESPONDED: JANUARY 13, 2011

Response to Question 6 (Continued)

Example

Project	Total HCA Miles	Digs/Mile	Mileage-based Digs	Project Minimum Digs	Estimated Minimum Digs
Project 1023	0.86	1.79	1.54	4	4.00
Project 41-17	2.84	1.79	5.08	4	5.08
Project 38-504	10.32	1.79	18.47	4	18.47

This calculation was performed for each project by year to forecast the "Estimated Minimum Digs".

GRC Survey and Dig Estimates – Summary

Using the methodologies outlined above and the cost averages from ECDA projects performed and completed from late year 2008 through early 2010, the cost estimates listed below were generated. Because of project minimums for surveys and minimum dig requirements discussed above, the survey costs listed below are not a simple multiplication of HCA miles times $32,000/mile and the dig costs listed below are not a simple multiplication of digs times $40,000 per dig. As described in the sections above, the costs were estimated for each project using the methods described and the table below is a summary of those individual estimates.

	2010			
Category	Miles of HCA	Survey Cost	Digs	Dig Cost
SoCal Distribution HCA	39.82	$1,321,680	107.92	$ 4,316,732
SoCal Transmission HCA	11.64	$ 400,320	44.00	$ 1,760,000
Total		$1,722,000		$ 6,076,732

	2011			
Category	Miles of HCA	Survey Cost	Digs	Dig Cost
SoCal Distribution HCA	11.43	$ 404,640	38.47	$ 1,538,860
SoCal Transmission HCA	3.77	$ 144,800	20.00	$ 800,000
Total		$ 549,440		$ 2,338,860

	2012			
Category	Miles of HCA	Survey Cost	Digs	Dig Cost
SoCal Distribution HCA	11.94	$ 625,200	110.93	$ 4,437,092
SoCal Transmission HCA	4.17	$ 225,680	44.00	$ 1,760,000
Total		$ 850,880		$ 6,197,092

Response to Question 6 (Continued)

f. All DOT Transmission Pipeline Integrity baseline assessments, and reassessments, are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with 49 CFR Part 192 Subpart O. Under this rule, operators of gas transmission pipelines are required to identify threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns as prescribed by the rule.

The BAP is the utilities' summary of these activities and depicts which lines have already been assessed, which lines are scheduled for future assessment, and which assessment method is planned to be used. The 74 pipeline segments identified in this line item are scheduled to be assessed by the ILI method. However, due to various physical and/or operational aspects of these projects, traditional ILI cannot be used due to lack of sufficient volumetric gas flow, lack of sufficient length, or lack of sufficient geometric configuration to allow use of traditional ILI tools. In these cases, tethered ILI inspection has been chosen for the baseline inspection. All baseline assessments must be completed by December 17, 2012.

Response to Question 6 (Continued)

GRC Supplemental Workpaper pages 33 and 34

Southern California Gas Company -- Gas Engineering -- Witness Raymond K. Stanford

Supplemental Workpaper Calculations for Costs related to TIMP Assessments (Page 1 of 2)

		Forecast								
	Description of upward pressure/ additional activities	2010			2011			2012		
Line Number		Labor	Non Labor	FTE	Labor	Non Labor	FTE	Labor	Non Labor	FTE
1	In-line inspection (ILI) and verification digs - 73 assessment or reassessment projects. Costs include minimum of two tool runs to complete ILI, follow-on verification excavations, and any minor pipeline repairs that may be required. These projects can be very complicated, must be completed in sequence, and span multiple years. 2200-0256	$350	$3,765	3.7	$655	$7,056	7.1	$718	$7,726	7.7
2	Hydrostatic pressure testing of the injection and withdrawal piping in the Playa Del Rey storage field. Costs include piping isolation, purging operations, and hydrostatic testing. Current system operation allows removal of various sized intake and discharge piping in lieu of future mandated reassessment. 2200-0256	$117	$1,007	1.3	$14	$112	0.1	$0	$0	0.0
3	Hydrostatic pressure testing of the injection and withdrawal piping in the Goleta storage field. Costs include piping isolation, purging operations, and hydrostatic testing. 2200-0256	$18	$153	0.2	$36	$304	0.4	$36	$304	0.4
4	External Corrosion Direct Assessment of Department of Transportation defined Transmission Pipeline per Baseline Assessment Plan is 51.46 miles in 2010, 15.20 miles in 2011, and 16.11 miles in 2012 @ $32,000/mile to survey (with a minimum cost of $15,600 per project and 1.79 digs/mile (with a minimum of 4 digs per project) at a cost of $40,000 per dig for non-labor. 152 digs are forecasted for 2010, 59 in 2011, and 155 in 2012.	$678	$7,799	7.5	$707	$2,888	7.7	$707	$7,048	8.0
5	3rd party vendor to prepare detailed feature studies of 35 pipelines prior to integrity assessment. 20 of these projects are characterized as short lines at a flat rate of $16,000/line, and the 15 remaining projects are longer lines totaling 894.7 miles, at a cost of $3400/mile. 10% charge or $336,198 for scanning and indexing the work product. 2200-2290	$0	$3,698	0.0	$0	$0	0.0	$0	$0	0.0
6	Reduce line pressure due to shifting operational needs in lieu of conventional integrity assessment of 2 pipelines, 36-1002 and 36-8-01. Excavate 36-1002 and acquire 4 pipeline samples for analysis to confirm pipeline wall thickness and grade, at cost of $55,000 per sample. Install pressure limiting station to separate 36-8-01 from 36-8-06 at a cost of $150,000. 2200-2290	$10	$278	0.1	$3	$93	0.0	$0	$0	0.0

Southern California Gas Company -- Gas Engineering -- Witness Raymond K. Stanford

Supplemental Workpaper Calculations for Costs related to TIMP Assessments (Page 2 of 2)

		Forecast								
	Description of upward pressure/ additional activities	2010			2011			2012		
Line Number		Labor	Non Labor	FTE	Labor	Non Labor	FTE	Labor	Non Labor	FTE
7	CP Survey of 32 miles of pipeline that have been ILI inpsected ($32,000 /mile)		$1,024							
8	In-line inspection and metalurgical analysis support team. Team Lead, staff engineers, technical advisors, administrative support. Provide analytical support during assessment phase of projects to determine severity of anomolies discovered in field, provide calcualtion for remaining life estimates, evaluate data to determine pipeline return-to-service status.	$ 253	$ 291	3.6	$ 253	$ 291	3.6	$ 253	$ 291	3.6
9	Conduct tethered In-Line Magnetci Flux-Leakage (MFL) inspection of cased transmission pipeline to comply with the PHMSA baseline assessment and future re-assessment requirements. These segments of cased pipeline can not be inspected using the appropriate assessment method, External Corrosion Direct Assessment, because it is ineffective on pipelines that are shielded and can not be physically accessed to perform direct assessment validations. 3 cased pipeline segments assessed in 2010, 43 in 2011, and 74 in 2012 at $103,600 per project for the MFL tool cost, inspection analysis, and program documentation. 2290	$26	$284	0.3	$379	$4,076	4.1	$652	$7,015	7.1
10	Remove casing assembly from transmission pipeline segment to enable required assessment. Segments of cased pipeline can not be inspected using the appropriate assessment method, ECDA, because it is ineffective on pipelines that are shielded and can not be physically accessed to perform direct assessment validations. For these projects, it has been determined that the casing is superfluous (original conditions that required a cased crossing are no longer present). Casing will be excavated and removed to allow direct examination of the carrier pipe to comply with required baseline assessment and future re-assessment efforts. 12 casings removed in 2010, 12 in 2011, and 11 in 2012. The expense component is $942 per project for vendor bellhole inspection, analysis, and program documentation. 2200-2290	$1	$10	0.0	$1	$10	0.0	$1	$9	0.0
		$1,453	$18,309	16.7	$2,048	$14,830	23.0	$2,367	$22,393	26.8

SoCalGas 2010 ANNUAL REPORT FOR CALENDAR YEAR 2010
NATURAL OR OTHER GAS TRANSMISSION and
GATHERING SYSTEMS
(FORM PHMSA F7100.2-1)

SoCalGas 2010 ANNUAL REPORT FOR CALENDAR YEAR 2010

NATURAL OR OTHER GAS TRANSMISSION and GATHERING SYSTEMS (FORM PHMSA F7100.2-1)

U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration	**ANNUAL REPORT FOR CALENDAR YEAR 2010 NATURAL OR OTHER GAS TRANSMISSION and GATHERING SYSTEMS**	**Report Submission Type** **ORIGINAL**

Important: Please read the separate instructions for completing this form before you begin.

PART A - OPERATOR INFORMATION	DOT USE ONLY	**20110764 - 22828**

1. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (OPID)

18484

2. NAME OF COMPANY OR ESTABLISHMENT:

SOUTHERN CALIFORNIA GAS CO

IF SUBSIDIARY, NAME OF PARENT:

SEMPRA ENERGY

3. INDIVIDUAL WHERE ADDITIONAL INFORMATION MAY BE OBTAINED:

Name: **JEFF W. KOSKIE**

Title: **PIPELINE SAFETY ADVISOR**

Email Address: **WKoskie@semprautilities.com**

Telephone Number: **(661) 775-8770**

4. HEADQUARTERS ADDRESS:

SEMPRA ENERGY
Company Name

555 WEST FIFTH STREET
Street Address

State: **CA** Zip Code: **90013-1011**

(800) 427-2200
Telephone Number

5. THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP: *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)*

Natural Gas

6. CHARACTERIZE THE PIPELINES AND/OR PIPELINE FACILITIES COVERED BY THIS OPID AND COMMODITY GROUP WITH RESPECT TO COMPLIANCE WITH PHMSA'S INTEGRITY MANAGEMENT PROGRAM REGULATIONS (49 CFR 192 Subpart O).

Portions of SOME OR ALL of the pipelines and/or pipeline facilities covered by this OPID and Commodity Group are included in an Integrity Management Program subject to 49 CFR 192. If this box is checked, complete all PARTs of this form in accordance with PART A, Question 8.

7. FOR THE DESIGNATED "COMMODITY GROUP", THE PIPELINES AND/OR PIPELINE FACILITIES INCLUDED WITHIN THIS OPID ARE: *(Select one or both)*

INTERstate pipeline - List all of the States in which INTERstate pipelines and/or pipeline facilities included under this OPID exist: etc.

INTRAstate pipeline - List all of the States in which INTRAstate pipelines and/or pipeline facilities included under this OPID exist: **CALIFORNIA** etc.

8. DOES THIS REPORT REPRESENT A CHANGE FROM LAST YEAR'S FINAL REPORTED NUMBERS FOR ONE OR MORE OF THE FOLLOWING PARTs: PART B, D, E, H, I, J, K, or L? *(For calendar year 2010 reporting or if this is a first-time Report for an operator or OPID, Commodity Group(s), or pipelines and/or pipeline facilities, select the first box only. For subsequent years' reporting, select either No or one or both of the Yes choices.)*

- [x] This report is **FOR CALENDAR YEAR 2010** reporting **or is a FIRST-TIME REPORT** and, therefore, *the remaining choices in this Question 8 do not apply*. Complete all remaining PARTS of this form as applicable

- [ ] NO, there are **NO CHANGES** from last year's final reported information for PARTs B, D, E, H, I, J, K, or L. Complete PARTs A, C, M, and N, along with PARTs F, G, and O when applicable.

- [ ] YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for one or more of PARTs B, D, E, H, I, J, K, or L ***due to corrected information****; however, the pipelines and/or pipeline facilities and operations are the same* as those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable).

- [ ] YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for one or more of PARTs B, D, E, H, I, J, K, or L ***due to corrected information****; however, the pipelines and/or pipeline facilities and operations are the same* as those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable)

  - [ ] Merger of companies and/or operations, acquisition of pipelines and/or pipeline facilities
  - [ ] Divestiture of pipelines and/or pipeline facilities
  - [ ] New construction or new installation of pipelines and/or pipeline facilities
  - [ ] Conversion to service, change in commodity transported, or c change in MAOP (maximum allowable operating pressure)
  - [ ] Abandonment of existing pipelines and/or pipeline facilities
  - [ ] Change in HCA's identified, HCA Segments, or other changes to Operator's Integrity Management Program
  - [ ] Change in OPID

  Other – Describe: ,

For the designated Commodity Group, complete PARTs B, C, D, and E one time for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate - included within this OPID.

PART B – TRANSMISSION PIPELINE HCA MILES	
	Number of HCA Miles in the IMP Program
Onshore	1178
Offshore	0
Total Miles	1178

PART C - VOLUME TRANSPORTED IN TRANSMISSION PIPELINES (ONLY) IN MILLION SCF PER YEAR (excludesTransmission lines of Gas Distribution systems)	**Check this box and proceed to PART D without completing this PART C if this report only includes gathering pipelines or transmission lines of gas distribution systems.**	
	Onshore	**Offshore**
Natural Gas	0	
Propane Gas		
Synthetic Gas		
Hydrogen Gas		
Other Gas - Name:		

PART D - MILES OF STEEL PIPE BY CORROSION PROTECTION					
	Cathodically protected		Cathodically unprotected		Total Miles
	Bare	Coated	Bare	Coated	
Transmission					
Onshore	5	3749	3	0	*3757*
Offshore	0	0	0	0	*0*
Subtotal Transmission	*5*	*3749*	*3*	*0*	*3757*
Gathering					
Onshore Type A	0	0	0	0	*0*
Onshore Type B	0	0	0	0	*0*
Offshore	0	0	0	0	*0*
Subtotal Gathering	*0*	*0*	*0*	*0*	*0*
Total Miles	*5*	*3749*	*3*	*0*	*3757*

PART E - MILES OF non-STEEL PIPE BY TYPE AND LOCATION					
	Cast Iron Pipe	Wrought Iron Pipe	Plastic Pipe	Other Pipe	Total Miles
Transmission					
Onshore	0	0	0	0	*0*
Offshore	0	0	0	0	*0*
Subtotal Transmission	*0*	*0*	*0*	*0*	*0*
Gathering					
Onshore Type A	0	0	0	0	*0*
Onshore Type B	0	0	0	0	*0*
Offshore	0	0	0	0	*0*
Subtotal Gathering	*0*	*0*	*0*	*0*	*0*
Total Miles	*0*	*0*	*0*	*0*	*0*

For the designated Commodity Group, complete PARTs F and G <u>one time for all INTERstate pipelines and/or pipeline facilities</u> included within this OPID and multiple times as needed for the designated Commodity Group <u>for each State in which INTRAstate pipelines and/or pipeline facilities</u> included within this OPID exist. Each time these sections are completed, designate the State to which the data applies for INTRAstate pipelines and/or pipeline facilities, or that it applies to all INTERstate pipelines included within this Commodity Group and OPID.

PARTs F and G

The data reported in these PARTs F and G applies to: *(select only one)*

Interstate pipelines/pipeline facilities

PARTs F and G

The data reported in these PARTs F and G applies to: *(select only one)*

Intrastate pipelines/pipeline facilities in the State *(complete for each State)*

PART F - INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION
Intrastate pipelines/pipeline facilities in the State - **CALIFORNIA**

1. MILEAGE INSPECTED IN CALENDAR YEAR USING THE FOLLOWING IN-LINE INSPECTION (ILI) TOOLS	
a. Corrosion or metal loss tools	540
b. Dent or deformation tools	540
c. Crack or long seam defect detection tools	422
d. Any other internal inspection tools	0
e. Total tool mileage inspected in calendar year using in-line inspection tools. (Lines a + b + c + d)	*1502*
2. ACTIONS TAKEN IN CALENDAR YEAR BASED ON IN-LINE INSPECTIONS	
a. Based on ILI data, total number of anomalies excavated in calendar year because they met the operator's criteria for excavation.	369
b. Total number of anomalies repaired in calendar year that were identified by ILI based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment.	148
c. Total number of conditions repaired WITHIN AN HCA SEGMENT meeting the definition of:	58
1. "Immediate repair conditions" [192.933(d)(1)]	2
2. "One-year conditions" [192.933(d)(2)]	1
3. "Monitored conditions" [192.933(d)(3)]	52
4. Other "Scheduled conditions" [192.933(c)]	3
3. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON PRESSURE TESTING	
a. Total mileage inspected by pressure testing in calendar year.	1
b. Total number of pressure test failures (ruptures and leaks) repaired in calendar year, both within an HCA Segment and outside of an HCA Segment.	0
c. Total number of pressure test ruptures (complete failure of pipe wall) repaired in calendar year WITHIN AN HCA SEGMENT.	0
d. Total number of pressure test leaks (less than complete wall failure but including escape of test medium) repaired in calendar year WITHIN AN HCA SEGMENT.	0
4. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON DA (Direct Assessment methods)	
a. Total mileage inspected by each DA method in calendar year.	*26*
1. ECDA	26
2. ICDA	0
3. SCCDA	0
b. Total number of anomalies identified by each DA method and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment.	*4*
1. ECDA	4
2. ICDA	0
3. SCCDA	0
c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of:	*3*
1. "Immediate repair conditions" [192.933(d)(1)]	3
2. "One-year conditions" [192.933(d)(2)]	0
3. "Monitored conditions" [192.933(d)(3)]	0
4. Other "Scheduled conditions" [192.933(c)]	0
5. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON OTHER INSPECTION TECHNIQUES	
a. Total mileage inspected by inspection techniques other than those listed above in calendar year.	0

b. Total number of anomalies identified by other inspection techniques and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment.	0
c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of:	*0*
1. "Immediate repair conditions" [192.933(d)(1)]	0
2. "One-year conditions" [192.933(d)(2)]	0
3. "Monitored conditions" [192.933(d)(3)]	0
4. Other "Scheduled conditions" [192.933(c)]	0
6. TOTAL MILEAGE INSPECTED (ALL METHODS) AND ACTIONS TAKEN IN CALENDAR YEAR	
a. Total mileage inspected in calendar year. (Lines 1.e + 3.a + 4.a.1 + 4.a.2 + 4.a.3 + 5.a)	*1529*
b. Total number of anomalies repaired in calendar year both within an HCA Segment and outside of an HCA Segment. (Lines 2.b + 3.b + 4.b.1 + 4.b.2 + 4.b.3 + 5.b)	*152*
c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT. (Lines 2.c.1 + 2.c.2 + 2.c.3 + 2.c.4 + 3.c + 3.d + 4.c.1 + 4.c.2 + 4.c.3 + 4.c.4 + 5.c.1 + 5.c.2 + 5.c.3 + 5.c.4)	*61*

PART G– MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS COMPLETED IN CALENDAR YEAR (HCA Segment miles ONLY)	
a. Baseline assessment miles completed during the calendar year.	55
b. Reassessment miles completed during the calendar year.	50
c. Total assessment and reassessment miles completed during the calendar year.	*105*

For the designated Commodity Group, complete PARTs H, I, J, K, L, and M covering INTERstate pipelines and/or pipeline facilities for each State in which INTERstate systems exist within this OPID and again covering INTRAstate pipelines and/or pipeline facilities for each State in which INTRAstate systems exist within this OPID.

PART H - MILES OF TRANSMISSION PIPE BY NOMINAL PIPE SIZE (NPS)

Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

Onshore	NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
	9	138	247	323	247	1	384	51	184
	22"	24"	26"	28"	30"	32"	34"	36"	38"
	79	184	129	0	1087	0	269	398	0
	40"	42"	44"	46"	48"	50"	52"	54"	56"
	0	0	0	0	0	0	0	0	0
	58" and over	Additional Sizes and Miles (Size – Miles;): 15 - 27; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0; 0 - 0;							
	0								
3757	Total Miles of Onshore Pipe – Transmission								
Offshore	NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
	22"	24"	26"	28"	30"	32"	34"	36"	38"
	40"	42"	44"	46"	48"	50"	52"	54"	56"
	58" and over	Additional Sizes and Miles (Size – Miles;): - ; - ; - ; - ; - ; - ; - ; - ; - ;							
	Total Miles of Offshore Pipe – Transmission								

PART J – MILES OF PIPE BY DECADE INSTALLED
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

Decade Pipe Installed	Pre-40 or Unknown	1940 - 1949	1950 - 1959	1960 - 1969	1970 - 1979	1980 - 1989
Transmission						
Onshore	189	554	1121	809	290	309
Offshore	0	0	0	0	0	0
Subtotal Transmission	189	554	1121	809	290	309
Gathering						
Onshore Type A	*0*	*0*	*0*	*0*	*0*	*0*
Onshore Type B	*0*	*0*	*0*	*0*	*0*	*0*
Offshore	*0*	*0*	*0*	*0*	*0*	*0*
Subtotal Gathering	0	0	0	0	0	0
Total Miles	*189*	*554*	*1121*	809	290	*309*

Decade Pipe Installed	1990 - 1999	2000 - 2009	2010 - 2019			Total Miles
Transmission						
Onshore	*337*	*147*	*1*			*3757*
Offshore	*0*	*0*	*0*			*0*
Subtotal Transmission	*337*	*147*	*1*			*3757*
Gathering						
Onshore Type A	*0*	*0*	*0*			*0*
Onshore Type B	*0*	*0*	*0*			*0*
Offshore	*0*	*0*	*0*			*0*
Subtotal Gathering	*0*	*0*	*0*			*0*
Total Miles	*337*	*147*	*1*			*3757*

PART K- MILES OF TRANSMISSION PIPE BY SPECIFIED MINIMUM YIELD STRENGTH
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

ONSHORE	CLASS LOCATION				Total Miles
	Class I	Class 2	Class 3	Class 4	
Less than 20% SMYS	4	0	12	0	16
Greater than or equal to 20% SMYS but less than 30% SMYS	270	62	238	0	570
Greater than or equal to 30% SMYS but less than or equal to 40% SMYS	171	27	398	0	596
Greater than 40% SMYS but less than or equal to 50% SMYS	514	89	553	0	1156
Greater than 50% SMYS but less than or equal to 60% SMYS	415	56	169	0	640
Greater than 60% SMYS but less than or equal to 72% SMYS	745	32	2	0	779
Greater than 72% SMYS but less than or equal to 80% SMYS	0	0	0	0	0
Greater than 80% SMYS	0	0	0	0	0
Unknown percent of SMYS	0	0	0	0	0
All Non-Steel pipe	0	0	0	0	0
Onshore Totals	2119	266	1372	0	3757
OFFSHORE	Class I				
Less than or equal to 50% SMYS	0				
Greater than 50% SMYS but less than or equal to 72% SMYS	0				
Offshore Total	0				0
Total Miles	2119				3757

PART L - MILES OF PIPE BY CLASS LOCATION

Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

	Class Location				Total Class Location Miles	HCA Miles in the IMP Program
	Class I	Class 2	Class 3	Class 4		
Transmission						
Onshore	2119	266	1372	0	*3757*	*1178*
Offshore	0	0	0	0	*0*	*0*
Subtotal Transmission	2119	266	1372	0	3757	*1178*
Gathering						
Onshore Type A	0	0	0	0	*0*	
Onshore Type B	0	0	0	0	*0*	
Offshore	0	0	0	0	*0*	
Subtotal Gathering	0	0	0	0	0	
Total Miles	2119	266	1372	0	*3757*	*1178*

PART M – INCIDENTS, FAILURES, LEAKS, AND REPAIRS
Intrastate Pipelines/pipeline facilities in the State of: **CALIFORNIA**

PART M1 – ALL LEAKS ELIMINATED/REPAIRED IN CALENDAR YEAR; INCIDENTS & FAILURES IN HCA SEGMENTS IN CALENDAR YEAR

Cause	Transmission Incidents, Leaks, and Failures						Gathering Leaks		
	Incidents in HCA Segments	Leaks				Failures in HCA Segments	Onshore Leaks		Offshore Leaks
		Onshore Leaks		Offshore Leaks					
		HCA	Non-HCA	HCA	Non-HCA		Type A	Type B	
External Corrosion	0	0	0	0	0	0	0	0	0
Internal Corrosion	0	0	1	0	0	0	0	0	0
Stress Corrosion Cracking	0	0	0	0	0	0	0	0	0
Manufacturing	0	0	0	0	0	0	0	0	0
Construction	0	1	1	0	0	0	0	0	0
Equipment	0	0	0	0	0	0	0	0	0
Incorrect Operations	0	0	1	0	0	0	0	0	0
Third Party Damage/Mechanical Damage									
Excavation Damage	0	1	1	0	0	0	0	0	0
Previous Damage (due to Excavation Activity)	0	0	0	0	0	0	0	0	0
Vandalism (includes all Intentional Damage)	0	0	0	0	0	0	0	0	0
Weather Related/Other Outside Force									
Natural Force Damage (all)	0	0	0	0	0	0	0	0	0
Other Outside Force Damage (excluding Vandalism and all Intentional Damage)	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0
Total	*0*	*2*	*4*	*0*	*0*	*0*	*0*	*0*	*0*

PART M2 – KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR

Transmission	0	**Gathering**	0

PART M3 – LEAKS ON FEDERAL LAND OR OCS REPAIRED OR SCHEDULED FOR REPAIR

Transmission		**Gathering**	
Onshore	0	Onshore Type A	0
		Onshore Type B	0
OCS	0	OCS	0
Subtotal Transmission	*0*	Subtotal Gathering	*0*
Total	*0*		

For the designated Commodity Group, complete PART N one time for all of the pipelines and/or pipeline facilities included within this OPID, and then also PART O if any portion(s) of the pipelines and/or pipeline facilities covered under this Commodity Group and OPID are included in an Integrity Management Program subject to 49 CFR 192.

PART N - PREPARER SIGNATURE (applicable to all PARTs A - M)

ROBERT W. CONAWAY
Preparer's Name(type or print)

(213) 244-5429
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PART O - CERTIFYING SIGNATURE (applicable only to PARTs B, F, G, and M1)

RICHARD M. MORROW
Senior Executive Officer's signature certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

(213) 244-3650
Telephone Number

RICHARD M. MORROW
Senior Executive Officer's name certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

VICE PRESIDENT - ENGINEERING & OPERATIONS STAFF
Senior Executive Officer's title certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

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Senior Executive Officer's E-mail Address

ATTACHMENT-B - AL Riser

AL RISER INSPECTION PROGRAM

SoCalGas Response to Data Request DRA-SCG-040-DAO

DRA DATA REQUEST
DRA-SCG-040-DAO
SOCALGAS 2012 GRC – A.10-12-006
SOCALGAS RESPONSE
DATE RECEIVED: FEBRUARY 9, 2011
DATE RESPONDED: MARCH 1, 2011

Exhibit Reference: SCG-5, Engineering

Subject: DIMP-Driven Activities, Anodeless Riser Program

Please provide the following:

1. Please state if the Anodeless Riser Program, as discussed on page RKS-43 to page RKS-44, is work that is being planned in addition to the inspections, repairs, and replacements of anodeless risers currently performed by Distribution. If not, please identify the current and TY cost tracking of this program.

SoCalGas Response:

Yes, the DIMP-Driven, Anodeless (AL) Riser Replacement Program is being implemented as an Accelerated Action, in accordance with the DIMP regulations. This program is incremental to the inspections, repairs, and replacements of AL risers currently performed by Distribution.

2. Is SoCalGas requesting additional expenses for anodeless risers under Distribution? If so, please provide a citation to the testimony.

SoCalGas Response:

No, Gas Distribution is not requesting incremental funding for the repair of AL risers. Included within the base forecast presented by witness Ms. Orozco-Mejia (SCG-02) is funding sufficient only to sustain the level of repairs SoCalGas has been completing in the past. This funding is included within the workgroup 2GD000.004 - Pipeline O&M - Service Maintenance (SCG-02, page GOM- 29-30, Workpapers page 93).

3. With regard to the statement on page RKS-44, "Based on a preliminary analysis, SoCalGas estimates that approximately 15% of the risers will ultimately qualify for replacement, while the remaining units will be effectively mitigated with the Trenton Wax Tape", please provide the following:
   a. A copy of all calculations and supportive documents relied on to determine that 15% of the risers will need to be replaced.
   b. The 2005-2010 recorded expenses of mitigating anodeless risers and identify the account used to track these expenses.
   c. The number of anodeless risers processed each year from 2005-2010. Please break down the annual number of anodeless risers repaired versus replaced and include the unit cost of each.
   d. When did SoCalGas first begin using the Trenton Wax Tape solution?
   e. How did SoCalGas repair anodeless risers before the implementation of the Trenton Wax Tape solution? Please also provide the unit cost of repair using this solution.
   f. Please compare the cost and benefits of using the Trenton Wax Tape method versus the method identified in question 1(e) above. Please provide copies of any cost-benefit analyses performed by or for SoCalGas.

SoCalGas Response:

a. The attached report, *DIMP-Driven AL Riser Program Report*, details SoCalGas' engineering study to mitigate the threat to anodeless risers. Included in the report is a background discussion of the issues, explanation of the methodology used in the study, and results. Also included is a cost-benefit analysis for the program. The second attachment, *AL Riser Pilot Survey*, shows the data developed in the study for which the recommendations were based.

The report included below is labeled interim due to on-going work and materials testing in progress. The report will be updated and finalized once this additional work is completed.

b. Anodeless riser mitigation consists of two options, Inspect and Repair, or Inspect and Replace. Please see the expense columns in the table associated with Question No. 3c, below. This data represents the historical expense incurred for mitigating AL risers. These expenses are tracked by FERC account 892.005.

DIMP-Driven Anodeless Riser Inspection Project
Pilot Research Survey
Final Report

Report Date: November 12, 2010 (interim)

Report Prepared By: Name: Ed Newton
Title: DIMP Team Leader
Pipeline Integrity/ Gas Engineering

Southern California Gas Company Project Team: **Gilbert Ching**
Steve Hammer
Mel Tufto
Steve Anderson

Revised: 11/23/2011

Legal Notice

Table of Contents

Background

In compliance with the recent DOT/PHMSA issuance of the Distribution Integrity Management Program and incorporation into the Code of Federal Regulations (CFR), Subpart P - Gas Distribution Pipeline Integrity Management (IM), Southern California Gas Company (SoCalGas) continues to research new and reasonable solutions to mitigate existing and potential threats to our system.

Anodeless risers are pipe assemblies fabricated for the purpose of transitioning plastic Distribution Main or Service lines from below to above ground. Prior to the development of "anodeless" risers, plastic lines were transitioned from plastic pipe to steel pipe underground and the riser portion was fabricated using steel pipe. However, this approach resulted in stranded sections of buried steel pipe that required cathodic protection, along with all of the operating and maintenance activities that go along with properly managing those types of installations. Since cathodic protection was typically achieved for these types of installations using anodes the term "anodeless" was coined for a riser design that eliminated the need for cathodic protection. Anodeless Risers utilize a non-gas carrying steel casing bent 90 degrees and connected to a gas-carrying steel nipple set above ground level. The plastic pipe enters the steel casing below ground and continues above ground level within the casing where it transitions from plastic to steel within the casing. The casing provides for protection of the above-ground plastic pipe and transition joint, and results in all gas-carrying steel associated with the installation to be above ground and therefore not subject the various corrosion threats associated with buried steel facilities. These types of riser designs have been in use in the Natural Gas Industry since the early 1970's. Within SoCalGas these facilities now span over 4 decades of installation dates from numerous manufacturers with various product designs. Anodeless risers are installed across the entire service territory consisting of coastal areas, inland regions, and deserts.

Over the years SoCalGas has conducted various investigations into the performance of certain anodeless riser designs in response to failure analysis and operational concerns. Historically the focus was on certain riser designs from the 1970s and 1980s where factory applied coatings resulted in an area that trapped moisture and created a corrosion cell. These designs were attributed to the shortened service life experienced with some anodeless risers. In response, various approaches and procedures were implemented to address these concerns and to mitigate the associated leakage threat. Formal policies and procedures were developed and are in place today to perform riser inspection and maintenance activities during routine maintenance of meter-set assemblies. Through these procedures roughly 40,000 to 50,000 risers are currently inspected annually for excessive metal loss and re-painted.

Inspection Survey Results and Finding

This research project was initiated early 2010 to conduct a pilot survey of the SoCalGas service territory to determine the state of the system and to investigate if other potential problems exist with anodeless risers. This limited survey covered 7 operating Districts representing the coastal, inland and desert regions.

Approximately 650 anodeless risers were inspected and their conditions were documented. An inspection criteria described in the company's Anodeless Riser Inspection Program was used to determine if the riser "passed" or "failed". An average failure rate was calculated for each of the 3 geographic regions. This failure rate was then statistically applied across the company's service territory, comprising of 44 operating Districts based on the population density of anodeless risers for each geographic area.

Based on this analysis, the failure rate was calculated to be 19%. Since this pilot research survey covered a relatively small sampling of the company's total anodeless risers, a conservative failure rate of 15% can be applied. The total number of anodeless risers installed since the 1970s is in excess of 2,040,000. A failure rate of 15% would result in the replacement of over 300,000 anodeless risers.

The work identified that such failures can be categorized into three major types; Corrosion of above-ground gas-carrying steel nipple; 2) Corrosion of the steel casing above or below ground causing loss of structural integrity; and 3) Corrosion of the gas-carrying steel nipple below ground due to low-set risers.

The first cause of accelerated failure is from above ground corrosion of the gas-carrying steel nipple. Anodeless risers have a demonstrated propensity toward accelerated atmospheric corrosion just below the stopcock in the gas-carrying steel nipple portion of the assembly. The root cause of such corrosion is usually due to environmental conditions that result in a constant or frequent presence of moisture. The environmental moisture factor can be compounded in some riser designs by the presence of shrink sleeves and ID tags that can trap and retain moisture against the surface of the steel making them less tolerant to moisture exposure. Since leaks from this failure mode are above ground the risks associated with this type of failure mode is considered to be moderate, however the consequence can be high.

The second cause of accelerated failure is from corrosion of the steel casing above or below the ground causing loss of structural integrity. Compromised MSA installations can result in movement of the MSA, loosening threaded connections, and thus causing possible thread leaks. Although the risks associated with this type of failure mode is considered to be low, the consequence can be high.

The third cause of accelerated failure is below-ground leakage due to corrosion from low-set risers. A low-set riser can result if an anodeless riser becomes buried to a depth that causes the gas-carrying steel portion of the riser to be buried. When risers become buried too deep the corrosion threat must be mitigated by raising or replacing the riser. A myriad of events can result in the riser becoming buried too deep over time even though risers are set at the proper depth at the time of installation. Activities such as grade changes, paving, landscaping, or even natural causes can all result in compromising the proper burial depth of a riser. The risks associated with this type of failure mode are considered to be high because it can result in below ground leakage, and the consequence can be high.

SoCalGas has been involved in research to develop an effective means of mitigating the above-ground and ground-level corrosion on anodeless risers. This effort has lead to the implementation of the Trenton Wax Tape solution, which provides an effective protective barrier of the above-ground section of the riser in the severe environmental conditions that are typical of riser installations. The previous method of re-coating risers was approached with the assumption that the above ground corrosion inspection activity would result in re-coating of the exposed riser every three years, or as necessary. The coating specified was a robust spray paint that was found to be effective when used over a rusty surface; however, the endurance of the coating was only expected to last 3-5 years. Comparative laboratory testing of this coating to the Trenton Wax tape coating demonstrates a significant improvement in performance over the spray paint previously specified. In salt fog testing conducted for over 2000 hours the Trenton Wax Tape performed without developing any corrosion product, while the spray paint provided minimal protection and corrosion continued at the riser nipple.

This approach enables SoCalGas to arrest the active corrosion. This effective mitigation measure will accomplish two goals. First, it will minimize the corrosion threat upon application, and second it will prolong the life of the riser without the added expense of replacement. Risers that do not pass the evaluation and those found leaking will be replaced. Based on a preliminary analysis, SoCalGas estimates that approximately 15% of the risers will ultimately qualify for replacement, while the remaining units will be effectively mitigated with the Trenton Wax Tape.

Cost Benefit Analysis

The cost benefit of a systematic approach to mitigating the corrosion threat on Anodeless risers within the Distribution system is best explained using a qualitative approach due to the subjective nature of the relevant data. Many factors have been identified that impact the life expectancy of these facilities, resulting in wide variations in performance from one riser to the next. Along with the age of the riser, quality of factory applied coatings and climate conditions, other variables listed below all influence the overall performance of anodeless risers.

- The amount of sun exposure, which is influenced by the side of the building the riser is installed, walls, plants, etc.
- Exposure to moisture from rain and condensation, influenced by whether or not the riser is under the eves of the structure, splash zones, etc.
- Exposure to moisture from irrigation spray or other sources
- Exposure to various chemical substances such as fertilizers, urine, pool maintenance chemicals, etc.
- Frequency and degree of mechanical damage from activities such as construction, lawn care, etc.
- Risers that have subsequently been buried too deep

For the purpose of the cost benefit, the difference in cost between the spray paint coating and the Wax Tape or comparable coating methods is easily demonstrated. The time and skill required to perform the different coatings are comparable, leaving only the cost and performance of the two coatings as the variables remaining for consideration. The performance of the paint option is estimated to be 3 to 5 years, while the duration of the Wax Tape is estimated to be in excess of 30 years. The cost of applying the spray paint is estimated to be $0.70 per riser, compared with a cost of $1.00 per riser for the Wax Tape.

The **historic routine riser inspection and maintenance program** is performed in conjunction with other work needing to be performed on the Meter Set Assembly. In contrast the new DIMP-Driven Anodeless Riser Program takes a holistic and programmatic approach toward the total population of over 2 million anodeless risers installed in the system. This program is based on an enhanced understanding of the severity of the environment achieved through additional research, physical inspections and studying the overall performance statistics of the population. It is now understood that the old shrink sleeve coating design is only one factor impacting the service life of anodeless risers in general, and that other designs are also being influenced by the many other factors mentioned above.

In addition, through the process of implementing the Distribution Integrity Management Program more detailed analysis of leak data has resulted in identifying anodeless risers as a top contributor behind the cause of hazardous leaks. As can be seen in ***Figure 1*** the number of anodeless riser leaks is being managed through the historic **routine riser inspection and maintenance program** which is helping keep the rate of leakage fairly flat. However, when viewed as a percentage compared to overall system leak repairs the relative percentage is increasing due to the overall decreasing number system leak repairs.

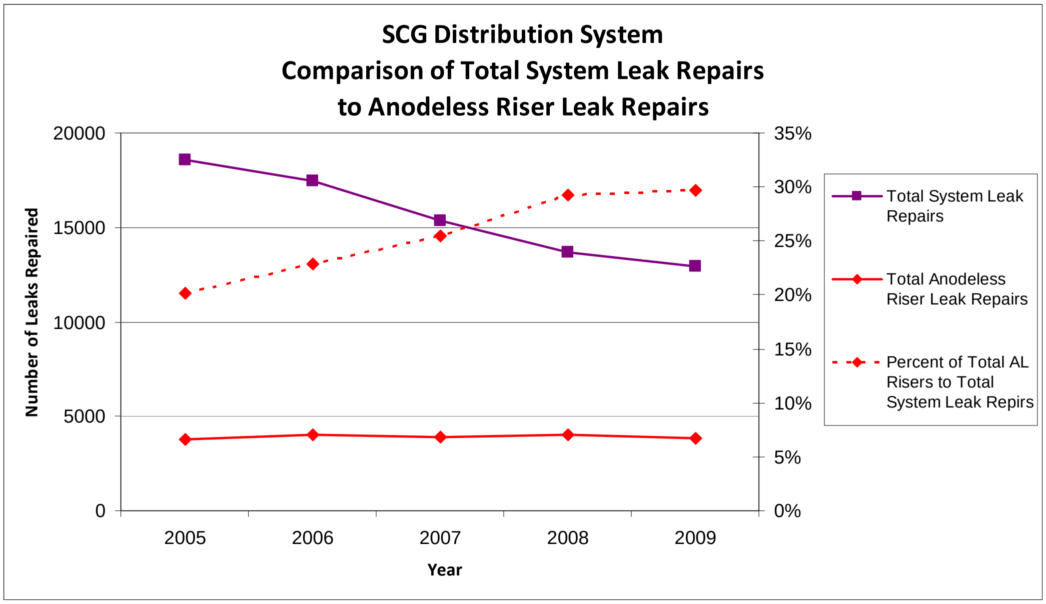


Figure 1
Comparison of System to Anodeless Riser Leak Repairs

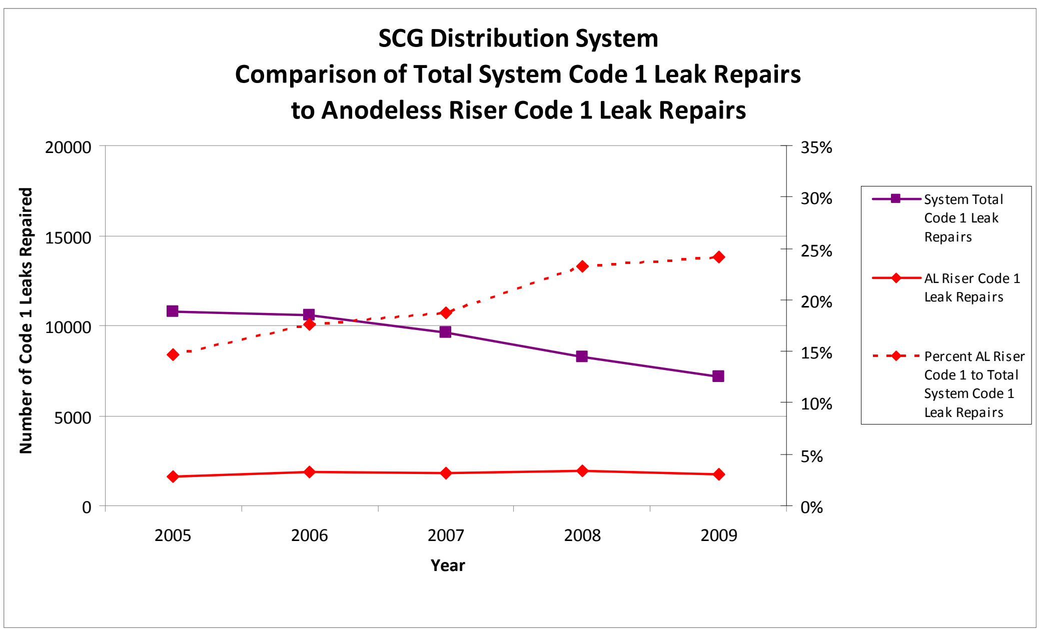


Figure 2
Comparison of System Code 1 Leaks Repairs
to Anodeless Riser Code 1 Leak Repairs

In addition, a similar trend emerges when viewing the trend of hazardous; code 1 leak repairs (see ***Figure 2***). Because anodeless riser leak repairs represent 30% of all system leaks and nearly 25% of all system hazardous leak repairs it was identified as a key candidate for implementing additional accelerated action through the efforts for our Distribution Integrity Management Program.

As stated in § 192.1007(c)

> *(c) An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure.*

In evaluating the likelihood of failure, anodeless riser hazardous leaks were found to be second only to 3rd party damage. Because these leaks are almost always next to a structure the probability for gas to migrate into a structure and result in an incident is significant. Fortunately a number of other circumstances must coincide with the leak at the riser for this to occur, but the greater the number of leaks that exist the higher the probability for such circumstances to develop, and an incident to happen.

As stated in § 192.1007(d)

> *(d) Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline.*

This program is designed to significantly reduce the risk from failure of anodeless risers. In 2009 for example approximately 43,500 riser inspections were performed, 3,836 leaks were repaired on anodeless risers, and 1,728 of those repaired leaks were reported as being hazardous. With the addition of the new program an additional 300,000 risers will be inspected per year (for years 2012-2015), with inspections focused in the areas that are most likely to have risers of concern. This is anticipated to yield a discovery rate of 15% and result in the removal of approximately 45,000 risers from the system annually. These will be risers that have the potential to leak, and that could have conceivably resulted in a future incident. In addition, all risers inspected will be re-coated using the Wax Tape coating solution that will arrest the advancement of the corrosion process and provide for greater confidence that future degradation of the riser will not continue.

To estimate the cost benefit between the two programs the future replacement rate of anodeless risers was projected using the combination of historic replacement rates and a population model based on the annual installation rates of anodeless risers. **Figure 3** below graphically depicts these two trends along with the additional accelerated DIMP – Driven program proposed. As can be seen from **Figure 3** the accelerated action results in inspection, replacement or repair of the entire riser population over the course of the next 7 years, which in turn drops the riser failure rate to near zero. Doing so accelerates the approximate $70,000,000 dollars that would have been spent over a 16 year period into the 7 year projected program period, and subsequently eliminates the estimated $6,000,000+ replacement costs that would have been incurred from using the old paint method every year thereafter. More importantly, and what the graph cannot depict, are the hazardous leaks that will be prevented from occurring, and the potential incidents that may be avoided both during the program years subsequent to the program's completion.

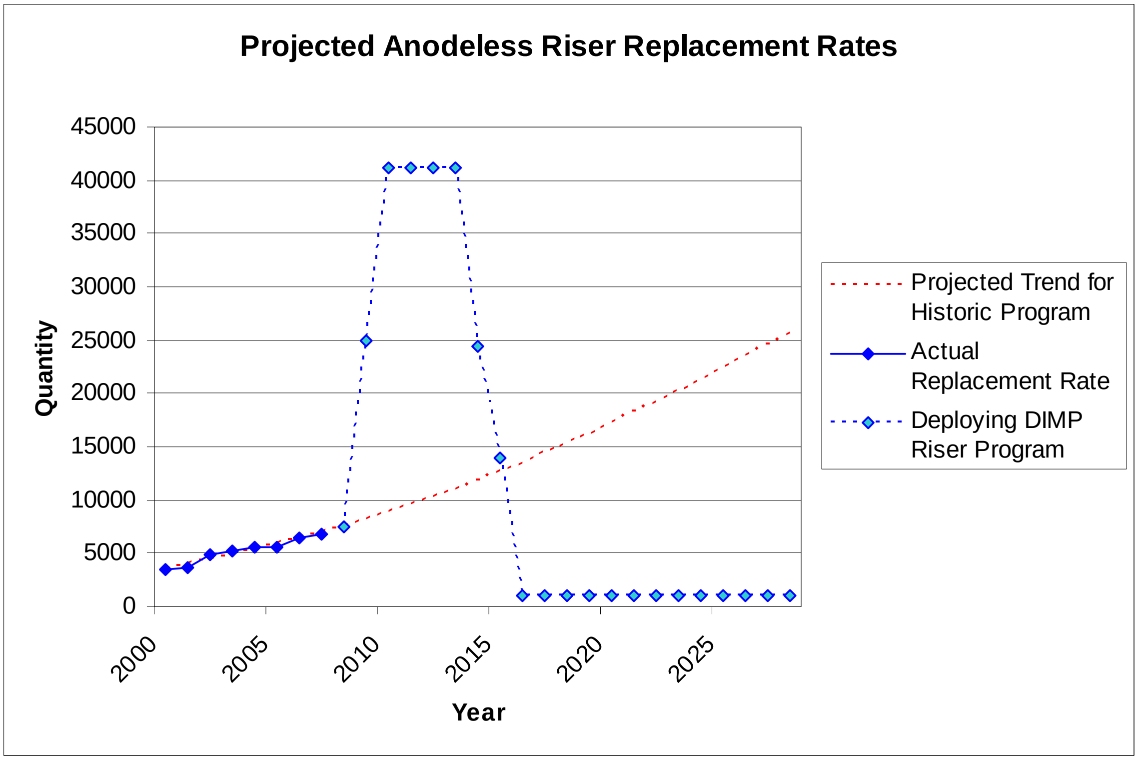


Figure 3
Historic Anodeless Riser Replacement Rate
Projected Future Trend Doing Nothing New
Projected Future Trend Deploying the DIMP-Driven Program

[redacted]

[redacted]	Riser Type	As Found Condition					
		Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
	Blk Sleeve/FBE	Fail	Poor	Medium	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Fail	Poor	Medium	Light to Medium	Isolated & Shallow	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Fail	Poor	Medium	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Paint/FBE	Fail	Poor	None	Medium to Heavy	Frequent & Deep	None
	Paint/FBE	Pass	Poor	None	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/X-Tru Coat	Pass	Fair	Low	Light to Medium	Isolated & Shallow	None
	Blk Sleeve/X-Tru Coat	Pass	Fair	Low	Light to Medium	None	None
	Blk Sleeve/X-Tru Coat	Pass	Fair	Low	Light to Medium	None	None
	Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
	Paint/FBE						
	Paint/FBE		Good	None	None	None	None
	New Riser	Fail	Good	None	None	None	None
	Paint/FBE	Pass	Good	None	None	None	None
	Paint/FBE		Good	None	None	None	None
	New Riser	Fail	Good	None	None	None	None
	Paint/FBE		Fair	None	Light to Medium	None	None
	Paint/FBE	Pass	Good	None	None	None	None
	Paint/FBE		Good	None	None	None	None
	Paint/FBE		Good	None	None	None	None
	Paint/FBE		Good	None	None	None	None
	Paint/FBE		Good	None	None	None	None
	Paint/FBE		Good	None	None	None	None
	New Riser	Fail	Good	None	None	None	None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Isolated & Deep	None
	Blk Sleeve/FBE	Pass	Good	None	Light to Medium	None	None
	New Riser	Fail	Poor	Excessive	Light to Medium	Frequent & Deep	None
	New Riser	Fail	Poor	Excessive	Light to Medium	Frequent & Deep	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	New Riser	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	New Riser	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/X-Tru Coat	Fail	Poor	Excessive	Medium to Heavy		
	Blk Sleeve/FBE	Pass	Fair	None	Light to Medium	Isolated & Shallow	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	Light to Medium	None	None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Isolated & Deep	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Fail	Poor	Medium	Light to Medium	Isolated & Deep	None
	Blk Sleeve/FBE	Fail	Poor	Medium	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	Medium	Light to Medium	Isolated & Shallow	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Isolated & Shallow	None
	Blk Sleeve/FBE	Fail	Poor	Medium	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Green Sleeve/X-tru Co	Fail	Poor	Medium	Medium to Heavy	Frequent & Deep	None
	Green Sleeve/X-tru Co	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Green Sleeve/X-tru Co	Pass	Good	None	None	None	None
	Green Sleeve/X-tru Co	Pass	Good	None	None	None	None
	New Riser	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Green Sleeve/X-tru Co	Pass	Good	None	None	None	None
	Green Sleeve/X-tru Co	Fail	Poor	Excessive	Medium to Heavy	Isolated & Deep	None
	Green Sleeve/X-tru Co	Fail	Poor	Excessive	Medium to Heavy	Isolated & Deep	None
	Green Sleeve/X-tru Co	Pass	Good	None	None	None	None
	Green Sleeve/X-tru Co	Pass	Good	None	None	None	None
	Green Sleeve/X-tru Co	Pass	Good	None	None	None	None

[redacted]

[redacted]	Riser Type	As Found Condition					
		Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
	Green Sleeve/X-tru Co	Pass	Good	None	None	None	None
	Green Sleeve/X-tru Co	Pass	Poor	Medium	Light to Medium	None	None
	Green Sleeve/X-tru Co	Pass	Good	None	None	None	None
	Green Sleeve/X-tru Co	Pass	Good	None	None	None	None
	New Riser	Fail	Poor	Medium	Medium to Heavy	Isolated & Deep	None
	New Riser	Fail	Poor	Medium	Medium to Heavy	Isolated & Deep	None
	Green Sleeve/X-tru Co	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Fail	Poor	Medium	Medium to Heavy	Isolated & Deep	None
	Blk Sleeve/FBE	Fail	Poor	Medium	Medium to Heavy	Isolated & Deep	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	Light to Medium	Isolated & Shallow	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Paint/FBE	Fail	Poor	Medium	Medium to Heavy	Isolated & Deep	None
	Paint/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	Light to Medium	None	None
	Blk Sleeve/FBE	Fail	Poor	Low	Medium to Heavy		None
	Blk Sleeve/FBE	Pass	Poor	Low	Light to Medium		None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy		None
	Blk Sleeve/FBE	Pass	Good	None	None		None
	Blk Sleeve/FBE	Pass	Good	None	None		None
	Blk Sleeve/FBE	Pass	Good	None	None		None
	Blk Sleeve/FBE	Pass	Good	None	None		None
	Blk Sleeve/FBE	Fail	Poor	Low	Medium to Heavy		None
	Blk Sleeve/FBE						None
	Blk Sleeve/FBE	Fail	Poor	Low	Medium to Heavy		None
	Blk Sleeve/FBE	Pass	Poor	Low	Light to Medium		None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Pass	Fair	None	Light to Medium	Isolated & Shallow	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	Fizz
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Green Sleeve/X-tru Co	Pass					
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	New Riser	Fail	Poor				None
	New Riser	Fail	Poor				None
	New Riser	Fail	Poor				None
	New Riser	Fail	Poor				None
	New Riser	Fail	Poor				None
	New Riser	Fail	Poor				None
	New Riser	Fail	Poor				None
	New Riser	Fail	Poor				None
	New Riser	Fail					None
	Blk Sleeve/FBE	Pass					None
	New Riser	Fail					None
	New Riser	Fail					None
	New Riser	Fail					None
	New Riser	Fail					None
	New Riser	Fail					None
	Blk Sleeve/FBE	Pass					None
	Blk Sleeve/FBE	Pass					None
	New Riser	Fail					None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Pass	Fair	Low	Light to Medium	Isolated & Shallow	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	New Riser	Fail					None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Good	None	None	None	None

[redacted]

[redacted]			Riser Type	As Found Condition					
				Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
			Blk Sleeve/FBE	Pass	Good	None	None	None	None
			Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
			New Riser	Fail					None
			Blk Sleeve/FBE	Pass	Poor	Medium	Light to Medium	Frequent & Shallow	None
			Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
			Blk Sleeve/FBE	Pass	Poor	Medium	Medium to Heavy	Isolated & Deep	None
			Blk Sleeve/FBE	Fail	Poor	Medium	Light to Medium	Frequent & Deep	None
			Blk Sleeve/FBE	Pass	Good	Low	Light to Medium	Isolated & Shallow	None
			Blk Sleeve/FBE	Pass	Fair	Low	Light to Medium	None	None
			Blk Sleeve/FBE	Fail	Poor	Excessive	Light to Medium	Frequent & Shallow	None
			Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	Code 1
			Blk Sleeve/FBE	Fail	Poor	Medium	Light to Medium	Isolated & Deep	None
			New Riser	Fail					None
	# Inspected =	**154**	**# Failed =**	**66**					

[redacted]

[redacted]	Riser Type	As Found Condition					
		Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Isolated & Deep	Code 1
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	New Riser	Fail	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	None	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Isolated & Deep	None
	New Riser	Fail	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	Medium	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Medium	Light to Medium	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Medium	Medium to Heavy	Isolated & Deep	None

[redacted]

[redacted]			Riser Type	As Found Condition					
				Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			New Riser	Fail	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	# Inspected =	**90**	**# Failed =**	**8**					

[redacted]

	Riser Type	As Found Condition					
		Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
[redacted]	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Blk Sleeve/FBE	Fail	Poor	Excessive	Medium to Heavy	Isolated & Deep	None
	Blk Sleeve/X-Tru Coat	Pass	Fair	None	Light to Medium	None	None
	New Riser	Fail	Good	None	None	None	None
	Blk Sleeve/FBE	Pass	Poor	Low	Medium to Heavy	Frequent & Shallow	None
	New Riser	Fail	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Blk Sleeve/FBE	Pass	Fair	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	Isolated & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Medium	Medium to Heavy	Isolated & Shallow	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	New Riser	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Medium	Medium to Heavy	Isolated & Deep	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Isolated & Deep	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Shallow	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Fair	Low	Medium to Heavy	Frequent & Shallow	None
	Blk Sleeve/X-Tru Coat	Pass	Fair	None	Light to Medium	None	None
	Blk Sleeve/X-Tru Coat	Pass	Good	Low	Light to Medium	Isolated & Shallow	None
	Blk Sleeve/X-Tru Coat	Pass	Fair	None	Light to Medium	Isolated & Shallow	None
	Blk Sleeve/X-Tru Coat	Pass	Good	Low	None	None	None
	Blk Sleeve/X-Tru Coat	Pass	Good	Low	None	None	None
	Blk Sleeve/X-Tru Coat	Pass	Fair	None	Light to Medium	None	None
	Blk Sleeve/X-Tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
# Inspected = 63	**# Failed =**	**11**					

[redacted]

[redacted]	Riser Type	As Found Condition					
		Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
	Grn Sleeve/X-tru Coat	Pass	Poor	Medium	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	Medium	Light to Medium	Isolated & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	New Riser	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	New Riser	Fail	Poor	Medium	Light to Medium	Isolated & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	New Riser	Fail	Poor	Medium	Medium to Heavy	Isolated & Deep	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	New Riser	Fail	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Medium	Medium to Heavy	Isolated & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Medium	Medium to Heavy	Frequent & Deep	None
	New Riser	Fail	Good	None	None	None	None
	New Riser	Fail	Good	None	None	None	None
	New Riser	Fail	Good	None	None	None	None
	New Riser	Fail	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Medium	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	New Riser	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Low	Light to Medium	Frequent & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Low	Medium to Heavy	Isolated & Deep	None
# Inspected = 60		**# Failed = 11**					

[redacted]

[redacted]	Riser Type	As Found Condition					
		Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Low	Light to Medium	Isolated & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Low	Medium to Heavy	Isolated & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Fair	Low	Medium to Heavy	Frequent & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Low	Medium to Heavy	Frequent & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Low	Light to Medium	Isolated & Shallow	None
	New Riser	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	New Riser	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	New Riser	Fail	Poor	Excessive	Medium to Heavy	None	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Medium	Medium to Heavy	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None

[redacted]

[redacted]			Riser Type	As Found Condition					
				Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
			Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	None	None
			Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
			Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	None	None
			Grn Sleeve/X-tru Coat	Pass	Poor	Medium	Medium to Heavy	None	None
			Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
			New Riser	Fail	Poor	Excessive	Light to Medium	None	None
			Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
			Blk Sleeve/X-Tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
			New Riser	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
			Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
			Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
			Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
			Blk Sleeve/X-Tru Coat	Fail	Poor	Low	Medium to Heavy	Frequent & Deep	None
			Grn Sleeve/X-tru Coat	Fail	Poor	None	Medium to Heavy	Isolated & Deep	None
			Blk Sleeve/X-Tru Coat	Fail	Poor	None	Medium to Heavy	Frequent & Deep	None
			Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	
			Blk Sleeve/X-Tru Coat	Fail	Poor	Medium	Medium to Heavy	Frequent & Deep	None
			New Riser	Fail	Poor	Medium	Medium to Heavy	Frequent & Deep	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
			Blk Sleeve/X-Tru Coat	Fail	Poor	Medium	Medium to Heavy	Frequent & Deep	None
			Blk Sleeve/X-Tru Coat	Pass	Poor	Medium	None	None	None
			Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
	# Inspected =	**94**	**# Failed =**	**13**					

[redacted]

[redacted]

Riser Type	As Found Condition					
	Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
New Riser	Fail	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
New Riser	Fail	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Poor	Low	Light to Medium	Isolated & Deep	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
Blk Sleeve/X-Tru Coat	Pass	Fair	Low	Light to Medium	None	None
Blk Sleeve/X-Tru Coat	Pass		None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Fair	Low	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	None	None
Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	Frequent & Shallow	None
Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	None	None
Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	None	None
New Riser	Fail					None
Grn Sleeve/X-tru Coat	Pass	Poor	Medium	Medium to Heavy	Isolated & Deep	None
Grn Sleeve/X-tru Coat	Pass	Poor	Low	Medium to Heavy	Isolated & Deep	None
Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
New Riser	Fail					None
New Riser	Fail					None
New Riser	Fail					None
Blk Sleeve/X-Tru Coat	Fail	Poor	Medium	Light to Medium	Isolated & Deep	None
Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
Blk Sleeve/X-Tru Coat	Pass	Good	None	None	None	None
Blk Sleeve/X-Tru Coat	Pass	Fair	Low	Light to Medium	Isolated & Shallow	None
Blk Sleeve/X-Tru Coat	Pass	Poor	Medium	Light to Medium	Isolated & Deep	None
Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None

[redacted]

[redacted]	Riser Type	As Found Condition					
		Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None		None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None		None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None		None
# Inspected = 95	**# Failed = 7**						

[redacted]

[redacted]	Riser Type	As Found Condition					
		Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Poor		Light to Medium	Frequent & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Poor		Medium to Heavy	Isolated & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Poor		Medium to Heavy	Isolated & Shallow	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Isolated & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Isolated & Deep	None
	New Riser	Fail					None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	New Riser	Fail					None
	New Riser	Fail					None
	New Riser	Fail					None
	New Riser	Fail					None
	New Riser	Fail					None
	New Riser	Fail					None
	Grn Sleeve/X-tru Coat	Pass	Good	Medium	Light to Medium	Isolated & Shallow	None
	New Riser	Fail					None
	Grn Sleeve/X-tru Coat	Pass	Good	Low	Light to Medium	None	None
	New Riser	Fail					None
	New Riser	Fail					None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	Code 1
	Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Frequent & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Low	Medium to Heavy	Isolated & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Poor	None	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Low	Light to Medium	Isolated & Shallow	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Frequent & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Low	Light to Medium	Isolated & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Poor	Low	Light to Medium	Isolated & Shallow	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Poor	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	Isolated & Shallow	None
	New Riser	Fail					None
	New Riser	Fail					None
	New Riser	Fail					None
	New Riser	Fail					None
	New Riser	Fail					None
	Grn Sleeve/X-tru Coat	Pass	Poor	Low	Light to Medium	None	None
		Pass	Fair	None	Light to Medium	Isolated & Shallow	None
	New Riser	Fail					None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	Frequent & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Poor	None	Light to Medium	Isolated & Shallow	None
	Grn Sleeve/X-tru Coat	Pass	Poor	None	Light to Medium	Isolated & Shallow	None
	New Riser	Fail					None
	Grn Sleeve/X-tru Coat	Pass	Fair	None	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Pass	Good	None	None	None	None
	Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	Isolated & Shallow	None
	New Riser	Fail					None
	Grn Sleeve/X-tru Coat	Pass	Fair	Low	Light to Medium	None	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	Bubble
	Grn Sleeve/X-tru Coat	Fail	Poor	Medium	Light to Medium	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Medium	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Medium	Medium to Heavy	Frequent & Deep	None
	New Riser	Fail					None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	New Riser	Fail					None
	New Riser	Fail					None
	Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	New Riser	Fail					
	Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	New Riser	Fail					

[redacted]

[redacted]			Riser Type	As Found Condition					
				Pass/Fail	Paint/Wrap	Swelling	Rust/Scale	Pitting	Leak
			Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
			Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Frequent & Shallow	None
			Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Light to Medium	Isolated & Shallow	None
			New Riser	Fail					None
			New Riser	Fail					None
			Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Isolated & Deep	None
			New Riser	Fail					None
			Grn Sleeve/X-tru Coat	Pass	Poor	Medium	Light to Medium	Isolated & Shallow	None
			Grn Sleeve/X-tru Coat	Pass	Poor	Low	Light to Medium	None	None
			Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
			New Riser	Pass		Low	Light to Medium	Isolated & Shallow	None
			New Riser	Fail					None
			Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
			Grn Sleeve/X-tru Coat	Fail	Poor	Excessive	Medium to Heavy	Frequent & Deep	Bubble
			New Riser	Fail					None
			Grn Sleeve/X-tru Coat	Pass	Poor	Excessive	Medium to Heavy	Frequent & Deep	None
	# Inspected =	**91**	**# Failed =**	**46**					

Summary Report

Anodeless Riser Inspection Project

Pilot Research Survey

	Inspection Results		Coastal Region			Inland Region			Desert Region		
[redacted]	# Risers Inspected	# Risers Failed	% in Regon	# Inspected	# Failed	% in Regon	# Inspected	# Failed	% in Regon	# Inspected	# Failed
	154	66	80%	123	53	20%	31	13	0%	0	0
	91	46	60%	55	28	40%	36	18	0%	0	0
	90	8	0%	0	0	100%	90	8	0%	0	0
	95	7	0%	0	0	30%	29	2	70%	67	5
	63	11	10%	6	1	90%	57	10	0%	0	0
	60	11	0%	0	0	100%	60	11	0%	0	0
	94	13	30%	28	4	70%	66	9	0%	0	0
	647	**162**		**212**	**85**		**368**	**72**		**67**	**5**
				Coastal			**Inland**			**Desert**	
Regional Failure Rates				**40.2%**			**19.5%**			**7.4%**	

Revised: 11/23/2011

AL Riser Data
(Company-Wide)

[redacted]	# AL Risers	Coastal Region		Inland Region		Desert Region	
		% in Region	# in Region	% in Region	# in Region	% in Region	# in Region
[redacted]	42,310	75%	31,733	25%	10,578	0%	0
[redacted]	43,354	0%	0	100%	43,354	0%	0
[redacted]	99,647	80%	79,718	20%	19,929	0%	0
[redacted]	19,923	0%	0	100%	19,923	0%	0
[redacted]	31,490	0%	0	100%	31,490	0%	0
[redacted]	55,500	0%	0	50%	27,750	50%	27,750
[redacted]	6,131	0%	0	50%	3,066	50%	3,066
[redacted]	18,043	0%	0	100%	18,043	0%	0
[redacted]	41,996	0%	0	100%	41,996	0%	0
[redacted]	51,987	0%	0	100%	51,987	0%	0
[redacted]	86,018	0%	0	100%	86,018	0%	0
[redacted]	33,643	0%	0	100%	33,643	0%	0
[redacted]	9,693	0%	0	80%	7,754	20%	1,939
[redacted]	28,169	10%	2,817	90%	25,352	0%	0
[redacted]	36,529	0%	0	100%	36,529	0%	0
[redacted]	26,069	0%	0	0%	0	100%	26,069
[redacted]	66,981	0%	0	100%	66,981	0%	0
[redacted]	30,641	60%	18,385	40%	12,256	0%	0
[redacted]	40,840	0%	0	100%	40,840	0%	0
[redacted]	24,779	0%	0	100%	24,779	0%	0
[redacted]	32,112	0%	0	100%	32,112	0%	0
[redacted]	35,539	0%	0	100%	35,539	0%	0
[redacted]	19,090	0%	0	100%	19,090	0%	0
[redacted]	39,869	0%	0	100%	39,869	0%	0
[redacted]	85,340	0%	0	30%	25,602	70%	59,738
[redacted]	21,858	0%	0	40%	8,743	60%	13,115
[redacted]	48,239	30%	14,472	70%	33,767	0%	0
[redacted]	115,950	0%	0	0%	0	100%	115,950
[redacted]	49,109	0%	0	100%	49,109	0%	0
[redacted]	143,999	0%	0	0%	0	100%	143,999
[redacted]	11,861	0%	0	100%	11,861	0%	0
[redacted]	106,639	0%	0	40%	42,656	60%	63,983
[redacted]	77,387	0%	0	50%	38,694	50%	38,694
[redacted]	40,902	50%	20,451	50%	20,451	0%	0
[redacted]	16,903	100%	16,903	0%	0	0%	0
[redacted]	57,088	50%	28,544	50%	28,544	0%	0
[redacted]	18,234	90%	16,411	10%	1,823	0%	0
[redacted]	32,669	30%	9,801	70%	22,868	0%	0
[redacted]	31,711	100%	31,711	0%	0	0%	0
[redacted]	43,954	0%	0	100%	43,954	0%	0
[redacted]	54,678	10%	5,468	90%	49,210	0%	0
[redacted]	53,122	0%	0	100%	53,122	0%	0
[redacted]	86,186	0%	0	50%	43,093	50%	43,093
[redacted]	23,938	0%	0	100%	23,938	0%	0
Total	**2,040,120**	**13.5%**	**276,411**	**60.1%**	**1,226,314**	**26.3%**	**537,395**

Company-Wide Failure Rate						
		Coastal Region		**Inland Region**		**Desert Region**
Regional Failure Rate		40.2%		19.5%		7.4%
Company-Wide Riser Population Distribution		13.5%		60.1%		26.3%
Failure Rate		**19.1%**				

Response to Question 3 (Continued)

c. Historically, the number of AL risers mitigated (repaired or replaced), and the associated expenses incurred are recorded in different systems and by different processes. The expenses are recorded by activity-type on an employee's time card and are consolidated and tracked by account number based on the amount of time allotted to the activity, in this case AL Riser repair or replacement.

The number of AL risers mitigated have been tracked differently. The process for replacing an AL riser requires that there first be a replacement work order generated. These work orders are tracked in the Construction Management System. The number of units mitigated by replacement is reflected in the "Units Replaced" column in the table below.

The process of tracking the number of units inspected/repaired has evolved since 2005. When reviewing the most recent data, it became apparent that there were inconsistencies in the tally of the number of units inspected/repaired. After lengthy discussions with staff and field supervision personnel and detailed review of the data it was determined that the legacy systems were not capturing all of the data. To provide a more accurate accounting of the historical number of units inspected an estimate has been developed based on the 2009 values for inspection expenses and data for number of units replaced. It was the conclusion of both staff and field supervision personnel that the historical expenses charged to both activities were correct. The 2009 data for number of units inspected/repaired is also considered accurate due to changes in data collection practices on the mobile data terminals used by the field personnel to log their work activities.

Therefore, the estimated number of units inspected/repaired for the timeframe of 2005 through 2008 was based on the following calculation.

<u>2009 Cost per Unit Inspected/Repaired</u>:
$380,176 (Inspection/Repair expense) ÷ 43,524 (Units completed) = $8.73 Repair cost per Unit

This value was then applied to the inspect/repair expense column for each year from 2005 through 2008 to provide an estimated number of units Inspected/repaired.

Additional data validation was achieved by performing a comparison between the number of estimated inspection/repairs and the number of recorded replacement units. This comparison demonstrated that the ratio between the two values is consistent with the assumptions used in developing the estimates.

Response to Question 3 (Continued)

Year	Units Inspect/ Repaired	Inspect/ Repair Expense (2009$)	Unit Cost for Inspect/ Repair		Units Replaced	Replacement Expense (2009$)	Unit cost for Replacement
2005	23,487*	$205,155	$8.73*		5,229	$1,589,053	$303.89
2006	29,648*	$258,972	$8.73*		5,643	$2,023,846	$358.65
2007	38,542*	$336,658	$8.73*		5,622	$2,069,637	$368.13
2008	48,793*	$426,202	$8.73*		6,368	$2,275,811	$357.38
2009	43,524	$380,176	$8.73		6,796	$2,478,508	$364.70

(*) These values estimated based on the discussion included in response to Question No. 3c.

d. The Trenton Wax Tape solution was tested and first utilized at SoCalGas in June 2010 when the new procedure was first piloted. This procedure is detailed in the attached Gas Standard 184.0122 – *Anodeless Riser Integrity Inspection Program*.

e. Prior to use of the Trenton Wax Tape solution risers were spray painted according to the attached Gas Standard 184.0121 - *Anodeless Riser Inspection Program*.

f. The Cost-Benefit analysis is included in the attachment to SoCalGas' response to Question No. 3a, above.

Southern California Gas Company

A Sempra Energy utility

GAS STANDARD

ANODELESS RISER INTEGRITY INSPECTION PROGRAM	SCG: 184.0122

PURPOSE: To document the process for the inspection, repair, or replacement for aging anodeless risers.

1. POLICY AND SCOPE

1.1. Field employees who have been qualified to participate in this riser inspection program shall conduct the riser inspection in accordance with this Gas Standard.

1.2. Employees not trained in this Standard will continue to use Gas Standard **184.0121** *Anodeless Riser Inspection Program*.

1.3. When working a Integrity Riser Inspection order, All anodeless risers should be inspected per this Gas Standard;

- With or without a shrink sleeve, and regardless of sleeve color,
- FBE coated,
- With or without a painted riser nipple.

1.4. Risers that will be replaced within two weeks of discovery date do not require application of approved coating found in section 4.3 of this Gas Standard.

1.5. Risers that will be replaced beyond two weeks will require application of approved coating found in section 4.3 of this Gas Standard.

2. RESPONSIBILITIES & QUALIFICATIONS

2.1. Gas Engineering/Pipeline Integrity is responsible for establishing policy specified in this Gas Standard.

2.2. Trained company or contracted field employees shall adhere to this Gas Standard instructions and requirements. Field employees are responsible for adhering to this company procedure and shall wear appropriate personal safety equipment during any and all duties performed.
See Injury and Illness Prevention Program, **IIPP.4**, *Employee's Responsibilities*.

3. DEFINITIONS

3.1. Anodeless Riser (AL Riser): gas service risers used for transitioning from underground polyethylene (PE) piping systems to above ground steel piping systems, which do not require cathodic protection by eliminating buried gas-carrying steel piping. Some Anodeless risers will have shrink sleeves and others

Revised: 11/23/2011

will have FBE coating or other painted coating just below the stopcock on the riser nipple.

3.2. Riser Nipple: the gas carrying steel nipple that the stopcock is attached to on the riser. This nipple extends to approximately 5 inches below the bottom of the stopcock on a 3/4” riser and must be above ground. See Table 1 for estimated riser nipple lengths.

3.3. Riser Casing: the steel portion below the riser nipple extending to riser pigtail.

3.4. Service Valve Stopcock: a type of valve used to stop the flow of gas through a gas service piping system.

3.5. Plastic Service ID Ring: a metal identifier with two extended vertical tabs, located just below the stopcock valve.

3.6. Shrink Sleeve: a plastic sleeve tightly formed around the riser nipple, located just below the stopcock valve. Typically green, black, or gray in color.

3.7. FBE (Fusion Bonded Epoxy): a pipe coating designed for underground corrosion protection of the steel riser casing, typically gray and sometimes green in color.

3.8. Vertical Protective Sleeve: a loose fitting slotted plastic tube installed over the vertical leg of the riser to protect against external damage.

3.9. 3/4” Riser Inspection Tool: a no-go type gauge device used to assess metal loss of the gas carrying 3/4” steel nipple. (code number N658506)

4. PROCEDURE

4.1. IDENTIFICATION OF ANODELESS RISERS:

CAUTION:	Always use good judgment when stripping off shrink sleeves, I.D. Rings, rust and scale. On severely corroded nipples these actions can result in the creation of leaks. Hazardous leaks must be addressed immediately and the employee must ALWAYS stand-by and keep the area safe until handed-off to a Distribution Crew.


Green Sleeve
X-True Coat PE


Black Sleeve
X-True Coat PE


Black Sleeve
Fusion Bonded Epoxy


Painted or FBE
Coating

4.2. RISER NIPPLE INSPECTION:

4.2.1. Start with visual inspection of the exposed above-ground portion of the riser. If the riser is buried too deep remove the soil if possible to expose the depth burial limit line, or use table #1 for proper riser nipple length. An AL Riser comes with a redline mark above which it should not be buried. If this mark is not visible it may be buried too deep. Use the following exposed riser length (see Table #1) to judge proper burial depth.

4.2.1.1. If riser is buried too deep and cannot be corrected as stated in 4.2.1, an order must be issued to have the condition corrected within 6 months.

4.2.1.2. If stopcock is not accessible see **184.0090** *Valve Selection and Installation* – Services, for corrective action.

NOTE: Distances in Table #1 are measured from the bottom of the stopcock.

Anodeless Riser Size	Minimum Exposed Length
¾ x ½ CTS	5 Inches
¾ x ½ IPS	5 Inches
1” x 1” IPS (W/By-pass) 1” x 1” IPS (W/O By-pass)	7-3/4 Inches 5 Inches
2 x 2 IPS (W/By-pass	5 Inches

Table #1

4.2.2. Soap test the riser nipple. If leakage is found from the initial soap test, DO NOT ATTEMPT TO MAKE REPAIRS use the criteria in (Table 2) for scheduling the riser replacement.

4.2.2.1. During the inspection AL risers found leaking above ground must be replaced using criteria in Table 2.

4.2.2.2. Below ground leak indications found at the riser location must be investigated per Gas Standard **223.0125** *Leakage Priority Classification*

	Small Bubbles (Cotton Ball/ Snow)		Medium Bubbles (Fizzer)		Large Bubble		Can't Hold Bubble/Audible	
	Hazard	No Hazard	Hazard	No Hazard	Hazard	No Hazard	Hazard	No Hazard
Work Immediately	N/A	Code 2	N/A	Code 2	Code 1	Code 2	Code 1	N/A
Work Same Day/ Next Business Day	N/A	Code 2	N/A	Code 2	N/A	Code 2	N/A	N/A
Work Within two Weeks	N/A	Code 2	N/A	Code 2	N/A	Code 2	N/A	N/A
								

Table #2

NOTE; Code 1 Leak; A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous. Code 2 Leak; A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.

4.2.2.3. If a severely swollen non leaking riser nipple is found and cleaning may cause further damage or leakage, issue an order to have riser replaced per the Inspection Report criteria.

NOTE; if the situation listed in section 4.2.2, or 4.2.2.3, do not exist, proceed with the ID ring and sleeve removal process as described below in section 4.2.3

4.2.3. If AL Riser Identification Ring exists, remove ring below the stopcock valve by making a cut with a hack saw or other approved Company tool, and then using a twisting motion, break and remove the ID ring off the riser.

4.2.4. If shrink sleeve exists, remove sleeve by cutting through the sleeve with a sharp linoleum knife.

4.2.5. Clean off the exposed riser nipple with a wire brush and soap test.

4.2.5.1. If leakage is found, DO NOT ATTEMPT TO MAKE REPAIRS, issue an order to have the riser replaced using criteria in Table 2)

4.2.6. Inspect the exposed portion of the riser nipple for pitting. For 3/4" nipples use the No-Go Riser Inspection Tool Gauge, (stock code N658506) to determine if riser has excessive metal loss and needs to be replaced. See Figure #1 for No-Go Riser Inspection Tool Gauge.

FIGURE #1

4.2.6.1. If the gauge can slide over the nipple portion of the 3/4" riser, this is an indication of metal loss. Issue an order to have the riser replaced.

- AL risers found that do not pass inspection, and are considered to be structurally weak (i.e. at risk of breakage) should be replaced same day or by the next Business day.

- AL risers found that do not pass inspection and are not leaking or not considered structurally weak, can be deferred up to two years with application of the approved coating found in section 4.3 of this Gas Standard.

4.2.6.2. For risers 1” and larger visually inspect for excessive corrosion or pitting. If either of the above conditions exist, issue an order to replace the riser.

4.2.6.3. If riser needs to be replaced see **184.0120**, *Service Risers for PE Installations*. Only trained and qualified personnel are permitted to perform riser replacements.

4.3. RISER CASING INSPECTION:

4.3.1. Inspect the above ground portion of Riser Casing.

- If corrosion has resulted in a hole completely through the casing wall, issue an order to have the riser replaced.
    - AL riser casings found that are considered to be structurally weak (i.e. at risk of breakage) should be replaced same day or next Business day.
    - Structurally weak casings that can be supported with a stainless steel clamp or some other supporting device, replacement of riser may be deferred up to two weeks.

4.4. COATING PROCEDURE

4.4.1. Apply small amount of Trenton Temcoat primer from the bottom of stopcock to 1” below the existing coating. (primer. stock code N444809).

4.4.2. Apply the 6”x6” Trenton #2A wax pad to the area that has been primered. (Wax pad stock code N449010).

> Note; if area to be coated exceeds the 6”x6” wax pad, additional pads will be required. Apply wax pads from the lowest portion of primered area, maintaining a 1” minimum overlap until the wrap has reached the bottom of the stopcock.

4.5. DOCUMENT INSPECTION FINDINGS

4.5.1. Log all inspection information on the Anodeless Riser Integrity Inspection Report . All sections A through K must be filled in with the appropriate criteria selected. WR# numbers for all identified work must be entered in the order issued section.

4.5.2. If the riser will need to be replaced within the next two weeks, make the appropriate customer notification.

4.6. REFERENCES

4.6.1. For riser installation design specifications, see **182.0060** *Service Risers*.

4.6.2. For the current Material Specification for anodeless risers, refer to MSP **56-70.1**.

4.6.3. For a complete listing of SAP stock code numbers with full descriptions on anodeless risers, refer to **MSP 56-70.1AM**.

5. OPERATOR QUALIFICATION COVERED TASKS
(See **167.0100**, *Operator Qualification Program, Appendix A, Covered Task List)*

- Task 2.1 49 CFR 192.459 – Examining buried pipeline when exposed
- Task 2.2 49 CFR 192.461 – Properly applying external protective coatings for corrosion control
- Task 2.13 49 CFR 192.481 – Monitoring for atmospheric corrosion
- Task 2.15 49 CFR 192.487 – Recognizing general and localized corrosion, taking action: Distribution
- Task 3.1 49 CFR 192.503(d) – Leak Testing non-welded joints
- Task 9.4 49 CFR 192.703, 192.723(b) - Distribution systems: Leakage Investigations
- Task 9.5 49 CFR 192.703, 192.723(b) - Leakage Assessment

6. RECORDS

6.1. DOCUMENTING INSPECTION (REPAIR) OR INITIATING RISER REPLACEMENT.

6.1.1. Field personnel will complete the Riser Integrity Inspection report indicating repaired or “Replace AL riser.” The order is then forwarded to Gas Engineering ML GT24H3 to be imputed into the Exigen riser data base.

6.2. DISTRIBUTION ACCOUNT NUMBER FOR ANODELESS RISER INTEGRITY INSPECTION PROGRAM:

6.2.1. Inspections, data entry, and anodeless riser replacement costs specific to this Pipeline Integrity program should be charged to **MWO 25019.000, IO 300636321.**

NOTE all activities related to the routine AL Riser inspection program outlined in Gas Standard **184.0121** and AL Riser replacements resulting from the routine inspection program may not be charged to this MWO.

■

SUMMARY OF DOCUMENT CHANGES & FILING INSTRUCTIONS	
Brief: This new Gas Standard documents the process for the inspection, repair, and replacement of anodeless risers during the **ANODELESS RISER INTEGRITY INSPECTION PROGRAM**.	
Circulation Code	**Filing Instructions**
DIST	File numerically

DOCUMENT PROFILE SUMMARY NOTE: Do not make any changes to this table. Data in this table is automatically posted during publication.	
Document Number:	**184.0122**
Document Title:	**Anodeless Riser Integrity Inspection Program**
Contact Person:	**Reinhold Mueller**
Current Revision Date:	**12/9/2010**
Last Full Review Completed On:	**12/9/2010**
Document Status:	
Document Type:	**GAS**
Category (FCD Only):	
If Merged, Merged to:	
Incoming Materials Inspection Required (MSP only):	
Company:	**SoCalGas**
Impacts the Integrity Management Program:	**No**
Contains OPQUAL Covered Task:	**Yes**
Common Document (if applicable):	
Part of SoCalGas O&M Plan (reviewed annually):	**No**
Part of SDG&E O&M Plan (reviewed annually):	**No**
O&M Plan 49 CFR Codes Covered by This Document & Sections Therein Where Compliance is Documented:	
Common Document (if applicable):	
Additional 49 CFR Codes) Covered by Document:	

Southern California Gas Company

A Sempra Energy utility

GAS STANDARD

ANODELESS RISER INSPECTION PROGRAM	SCG: 184.0121

PURPOSE: **To document the process for the inspection, repair, or replacement for aging anodeless risers with shrink sleeves.**

1. POLICY AND SCOPE

   1.1. Field employees working Tools Type Orders at the MSA shall conduct a riser inspection in accordance with this Gas Standard.

2. RESPONSIBILITIES & QUALIFICATIONS

   2.1. **Gas Engineering/Pipeline Integrity** is responsible for establishing policy specified in this Gas Standard.

   2.2. **Trained company or contracted field employees** shall adhere to this Gas Standard instructions and requirements.

   2.3. **All shrink sleeve anodeless risers** should be inspected regardless of the shrink sleeve color.

   2.4. **Field employees** are responsible for adhering to this company procedure and shall wear appropriate personal safety equipment during any and all duties performed. See Injury and Illness Prevention Program, **IIPP.4**, *Employee's Responsibilities.*

3. DEFINITIONS

   3.1. **Anodeless (AL) Riser:** gas service risers used for transitioning from underground polyethylene (PE) piping systems to above ground steel piping systems, which do not require cathodic protection by eliminating buried gas-carrying steel piping.

   3.2. **Service Valve Stopcock:** a type of valve used to stop the flow of gas through a gas service piping system.

   3.3. **AL Riser ID Ring:** a metal identifier with two extended vertical tabs, located just below the stopcock valve.

   3.4. **Shrink Sleeve:** a plastic sleeve tightly formed around the riser nipple, located just below the stopcock valve. Typically green, black, or gray in color.

   3.5. **FBE** (Fusion Bonded Epoxy): a pipe coating designed for underground corrosion protection of the steel riser casing.

   3.6. **Vertical Protective Sleeve:** a loose fitting slotted plastic tube installed over the vertical leg of the riser to protect against external damage.

3.7. **Tools Type Order:** a service order issued anytime an employee is required to use tools at the MSA

3.8. **Riser Inspection Tool:** a go-no-go type gauge device used to assess metal loss of the gas carrying ¾" steel nipple. (code number N658506)

4. PROCEDURE

4.1. **IDENTIFICATION OF ANODELESS RISERS**:

CAUTION: STOPCOCKS ON CORRODED ANODELESS RISERS CAN BREAK OFF.

Note: Anodeless risers involved in this program can be identified typically by a **green, black, or gray plastic shrink sleeve** located just below the stopcock. When corrosion under the sleeve occurs, the shrink sleeve sometimes swells or bulges due to the corrosion activity underneath. Anodeless risers without shrink sleeves may also be subject to corrosion in some environments. This procedure is appropriate to use on all Anodeless riser types.

Green Sleeve

X-True Coat PE

Black Sleeve

X-Tru Coat PE

Black Sleeve

Fusion Bonded Epoxy

No Sleeve

Paint or FBE coating

4.2. **INSPECTION PROCEDURE:** Observe all company personal safety precautions while inspecting anodeless risers (See **IIPP.4 ,** *Employees Responsibilit*y).

4.2.1. Start with visual inspection of the exposed above-ground portion of the riser. If the riser is buried too deep remove soil to expose the top few inches of the riser nipple. An AL Riser comes with a redline mark above which it should not be buried. If this mark is not visible it may be buried too deep. Use the following exposed riser length **(see Table #1)** to judge proper burial depth.

NOTE: Distances in Table #1 are measured from the bottom of the stopcock.

Anodeless Riser Size	Minimum Exposed Length
¾ x ½ CTS	5 Inches
¾ x ½ IPS	5 Inches
1” x 1” IPS (W/By-pass) 1” x 1” IPS (W/O By-pass)	7-3/4” Inches 5 Inches
2 x 2 IPS (W/By-pass	5 Inches

Table #1

4.2.2. Soap test the top of the riser. If leakage is found by an initial soap test of the riser, **DO NOT ATTEMPT TO MAKE REPAIRS,** call dispatch to request Distribution to inspect that day. Code type will be assigned after distribution assesses the severity of the leak.

4.2.3. If no leakage is found, but visual inspection determines that cleaning may cause further damage or leakage, issue order to have riser replaced.

4.2.4. If the first two situations do not exist, proceed with the ID ring and sleeve removal process as described below:

4.2.4.1. If AL Riser Identification Ring exists, remove ring below the stopcock valve by making a cut with a hack saw or other approved Company tool, and then using a twisting motion, break and remove the ID ring off the riser.

4.2.4.2. If shrink sleeve exists, remove sleeve by cutting through the sleeve with a sharp linoleum knife.

4.2.5. Clean off the exposed riser piping with a wire brush and re-soap test below the stopcock valve.

4.2.5.1. If leakage is found, **DO NOT ATTEMPT TO MAKE REPAIRS,** call dispatch to request a distribution crew to work that day. Code type will be assigned after the distribution crew assesses the severity of the leak.

4.2.6. Inspect the exposed portion of the riser for pitting and/or structural damage. Use the *Go-No-Go Riser Inspection Tool Gauge*, (code number N658506) to determine if riser has excessive metal loss and needs to be replaced. See Figure #1 for *Go-No-Go Riser Inspection Tool Gauge*.

FIGURE #1

4.2.6.1. Issue an electronic order, or if not working off an MDT a Multi-Purpose Order (3081) for Distribution to replace the riser if the Go-No-Go Riser Inspection Tool gauge (code number N658506) can slide over this portion of the riser, indicating loss of metal. Note: This is not a Code 1 situation and Distribution will work at a later date.

4.2.6.2. If riser needs to be replaced *see* **184.0120**, *Service Risers for PE Installations.* Only Distribution Operations trained personal is permitted to perform riser replacements.

4.2.7. If deep pitting is verified see **186.02**, *Cathodic Protection – Inspection of Exposed Pipe* or structural damage is observed on the riser, issue an electronic order, or if not working off an MDT, a Multi-Purpose Order (3081) and send to dispatch to have the riser replaced. Note: This is not a Code 1 situation and Distribution will work at a later date.

4.2.7.1. Tent Fumigation - AL Risers shall be inspected prior to tent fumigation. Risers that fail inspection shall be replaced prior to tent fumigation. Field personnel should contact Dispatch immediately in order to have risers replaced in a timely manner.

4.2.8. If the AL Riser does not need to be replaced, clean and thoroughly paint the exposed steel portion of the riser with Zero-Rust black paint (code N308136) for the primary rust protection.

4.2.8.1. Steel gas carrying portion of the riser can be covered with gray meter paint (code N302318 light gray brush-on, or N308135 dark gray spray can) for cosmetics if desired.

4.2.9. Log all inspection information on the electronic order in the MDT or issue a Multi-Purpose Order (3081) and send to dispatch. See section 6 in this Gas Standard.

4.3. REFERENCES

4.3.1. For riser installation design specifications, see **182.0060** *Service Risers.*

4.3.2. For the current *Material Specification* for anodeless risers, refer to MSP **56-70.1**.

4.3.3. For a complete listing of SAP stock code numbers with full descriptions on anodeless risers, refer to MSP **56-70.1AM**.

5. OPERATOR QUALIFICATION COVERED TASKS
(See **167.0100**, *Operator Qualification Program*, Appendix A, *Covered Task List*)

- **Task 2.1** 49 CFR 192.459 – Examining buried pipeline when exposed
- **Task 2.2** 49 CFR 192.461 – Properly applying external protective coatings for corrosion control
- **Task 2.13** 49 CFR 192.481 – Monitoring for atmospheric corrosion
- **Task 2.15** 49 CFR 192.487 – Recognizing general and localized corrosion, taking action: Distribution
- **Task 3.1** 49 CFR 192.503(d) – Leak Testing non-welded joints

6. RECORDS

6.1. **DOCUMENTING INSPECTION/REPAIR, OR INITIATING RISER REPLACEMENT USING MDT:**

6.1.1. Within the order, access the “Incidental” tab and select either 15-Riser Insp-Pass or 16-Riser Insp-Fail from the Survey Code dropdown arrow.

6.1.1.1. Enter the total number of inspections.

6.1.1.2. If a Riser Inspection fails due to metal loss determined by the Go-No-Go Tool and is not leaking; send a Request for Assistance while clocked into the order. Note that further inspection by Distribution is required.

6.1.1.3. If the riser requires replacement due to leakage, contact Distribution Dispatch to issue a same-day order for further inspection.

6.1.1.4. If the customer is home, inform them someone will return later in the day. If the customer is not home, leave **Form 30**, *Sorry We Missed You Tag* informing the customer that further repairs are needed and someone will return later the same day

6.2. **DOCUMENTING INSPECTION (REPAIR) OR INITIATING RISER REPLACEMENT USING MULTI-PURPOSE ORDER:**

6.2.1. Field personnel not using an MDT, will manually issue **Form 3081**, *Multi-Purpose Order* (Form 3081) stating either "AL riser was painted" indicating repaired or "Replace AL riser." The order is then forwarded to the dispatch office to be tallied and, if necessary, the riser is scheduled for replacement.

6.3. **TAKING CREDIT FOR INSPECTIONS (REPAIR):**

6.3.1. MDT Timesheet - Tally the time for completed inspections in the "Miscellaneous Time" screen. Select "Add Misc. Time" then "OA04-Riser Inspections." Enter time allowance for inspections under "Total-Time." Select Base Location from dropdown menu. In "Remarks" enter Account Number **"892.005"**

6.3.2. Paper Timesheet – Tally the time for completed inspections in the top section of the DTAR under "Other Accounts". Enter account number **"892.005** and (the number of) AL Inspections" as the reason in the "Other Describe" section.

6.4. **TIME CREDITED FOR INSPECTIONS:**

6.4.1. Each order that requires an anodeless riser inspection (repair) will be allowed 7 additional minutes to complete. The order will be tracked to ensure multiple credits for the repair is not mistakenly given to the same location. Inspection time should be rounded off to the nearest quarter hour as shown on Table #2 below:

1-2 Insp.	3-5 Insp.	6-7 Insp.	8-9 Insp.	10-11 Insp.	12-13 Insp.	14-16 Insp.	17-18 Insp.	19-20 Insp.	21-22 Insp.
.25	.50	.75	1.00	1.25	1.50	1.75	2.00	2.25	2.50

Table #2

6.5. **DISTRIBUTION ACCOUNT NUMBER FOR ANODELESS RISER INSPECTION PROGRAM:**

6.5.1. Inspections and anodeless riser replacement activities by Distribution are charged to **892.005** account number (FG8920052200). Shrink Sleeve Riser replacements are planned in CMS.

■

SUMMARY OF DOCUMENT CHANGES & FILING INSTRUCTIONS	
Brief: This new Gas Standard documents the process for the inspection, repair, and replacement of shrink sleeves found on older anodeless risers.	
Circulation Code	**Filing Instructions**
CSF	File numerically behind Meters and MSA's Tab
DIST	File numerically

DOCUMENT PROFILE SUMMARY NOTE: Do not make any changes to this table. Data in this table is automatically posted during publication.	
Document Number:	**184.0121**
Document Title:	**Anodeless Riser Inspection Program**
Contact Person:	**Reinhold Mueller**
Current Revision Date:	**2/6/2009**
Last Full Review Completed On:	**2/6/2009**
Document Status:	
Document Type:	**GAS**
Category (FCD Only):	
If Merged, Merged to:	
Incoming Materials Inspection Required (MSP only):	**No**
Company:	**SoCalGas**
Impacts the Integrity Management Program:	**No**
Contains OPQUAL Covered Task:	**Yes**
Common Document (if applicable):	
Part of SoCalGas O&M Plan (reviewed annually):	**No**
Part of SDG&E O&M Plan (reviewed annually):	**No**
O&M Plan 49 CFR Codes Covered by This Document & Sections Therein Where Compliance is Documented:	
Common Document (if applicable):	
Additional 49 CFR Codes) Covered by Document:	

4. SoCalGas states on page RKS-44 that it plans to mitigate the anodeless riser threat over a 7-year period. Please provide a detailed explanation and include all supportive documents and/or calculations used to determine that this program needs to be completed in 7 years.

SoCalGas Response:

NOTE: The time frame of a seven year program was established during the initial development phase of this program. Included in the workpapers for this program are the costs estimated to be incurred through 2015, or a six-year time frame. The reference in testimony to a seven-year program is an editing oversight and should be corrected to reflect a six-year time frame. This will be corrected if there is an opportunity for additional errata filing.

Due to the development and pending implementation of the DIMP rules, SoCalGas is applying the directive that operators need to implement their integrity management program to "promote continuous improvement in pipeline safety by requiring operators to identify and invest in risk control measures beyond core regulatory requirements."[1]

Based on the analysis discussed in testimony, workpapers, and within this data request, SoCalGas is addressing a known threat to the distribution system, AL risers, by applying the additional and accelerated actions of the DIMP-driven AL riser program to mitigate this threat.

Page 64 of the workpaper as well as the additional explanation provided in the responses to this data request provide details on the number of AL risers included in the program. Based on the volume of AL risers to be inspected and SoCalGas' experience with program development, such as resource identification, training, and implementation, six years was determined to be a reasonable and prudent time-frame to responsibly address the threat.

[1] Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Final Rule, 74 Fed. Reg. 63,906 (posted Dec. 4, 2009)(codified 49 C.F.R. pt. 192).

5. On page 64 of the workpapers, SoCalGas presents a table entitled, "Estimated Repair and Replacement Risers". Please provide the following with regard to this table:
   a. The 2010 recorded number of inspections, repairs, replacements and the expenses of each as tracked by Distribution and Engineering. Please also identify the accounts used to track the anodeless riser activities for Distribution and for Engineering.
   b. Prior to 2010, did SoCalGas charge the cost of inspecting, repairing and/or replacing anodeless risers to Engineering? If so, please provide the amount(s) and identify the tracking account.
   c. On page RKS-44 of the testimony SoCalGas states that it plans to process an average of 193,000 anodeless risers per year. Yet, on page 64 of the workpapers, SoCalGas shows 9,600 as the inspection rate per year under the "Assumptions" table, and 300,000 inspections and 41,250 replacements under the "Estimated Repair and Replacement risers" table. Please provide a step by step showing of how the numbers in the workpapers tie to the number identified in the testimony.
   d. Please identify all assumptions used to estimate the number of inspections, replacements, and replacement costs in the "Estimated Repair and Replacement Risers" table.
   e. Please provide a copy of all calculations, including all supportive documents, used to estimate the number of inspections, replacements, and replacement costs in the "Estimated Repair and Replacement Risers" table.

SoCalGas Response:

a. The number of DIMP-driven AL riser activities recorded for 2010 are as follows: 5944 Inspected; 5277 Repaired; 636 Replaced; 31 Identified for replacement, carried over to 2011. All of these activities were tracked by Engineering through DIMP-specific accounts.

b. No. The DIMP-driven AL riser program was not in place prior to 2010. All riser work was managed and tracked within the Operations organizations as routine maintenance work.

c. As mentioned in the response to Question 4 of this data request, the time frame of a seven year program was established during the initial development phase of this program. Subsequent data analysis and the actual reference on page 64 of the workpaper indicate a six-year time frame (2010 – 2015) for this phase of the anodeless riser program. The reference in testimony to a seven-year program is an editing oversight and should be corrected to reflect a six-year time frame. This will be corrected if there is an opportunity for additional errata filing.

   The statement referencing 193,000 AL risers on page RKS-44 is an annual average for the proposed seven-year program. (1,350,000 risers ÷ 7 years = 193,000 risers/year).

Response to Question 5 (Continued)

Due to the modification to a six-year program this statement should be changed from an average of 193,000 to 225,000 (1,350,000 risers ÷ 6 years = 225,000 risers/year).

On page 64 of the workpapers in the "Assumptions" table, the assumed inspection rate for AL risers is 9600 risers per year per FTE. On the same workpaper in the "Cost Schedule" table for 2012, it is proposed that SoCalGas will have 31.3 FTEs working on this AL riser inspection program.
For 2012: (9600 risers/year/FTE x 31.3 FTE = approx. 300,000 risers/year)

The testimony and workpaper numbers tie together at the total number of risers in this program of 1,350,000 risers. This value is shown in testimony as the average amount of 193,000 risers/year x 7 years = 1,350,000 risers (should be 225,000 x 6 =1,350,000). This value of 1,350,000 risers is also reflected in the "totals" row of the "Estimated Repair and Replacement risers" table on page 64 of the workpapers.

d. The "Assumptions" table on page 64 serves as the initial collection of assumptions used in creating the values in the "Estimated Repair and Replacement Risers" table.

- The total number of risers to be inspected in the program, 1,350,000, is based on the estimated number of AL risers in SoCalGas' system that due to their design, have the potential to be an integrity threat due to premature failure.
- The number of inspections shown for each year (# Insp column) is based on the program initiating in 2010 and ramping up to full implementation in 2012. These numbers are based on available resources and estimated requirements for additional hiring and training of the necessary resources to complete the program.
- The number of "# Don't Pass (Replace)" units is expected to be higher during the early years of the program. The program will initially be focused on areas of known historical failures. Based on experience, the initial "Don't pass" rate is estimated at 25% of the number of risers inspected for years 2010 and 2011 and reduces to approximately 14% for the remainder of the program.
- The Replacement costs in the final column of the "Estimated Repair and Replacement Risers" table is simply the product of the number of replacements in the (# Don't Pass – Replace) column multiplied by the Average Riser replacement cost of $307.93, as shown in the "Assumptions" table. This replacement cost value is based on the historical average system-wide cost to replace an AL riser.

e. Please see the response to question 5d above. The costs and calculations are detailed along with the explanation of the assumptions used in defining the program.

DRA DATA REQUEST
DRA-SCG-040-DAO
SOCALGAS 2012 GRC – A.10-12-006
SOCALGAS RESPONSE
DATE RECEIVED: FEBRUARY 9, 2011
DATE RESPONDED: MARCH 1, 2011

6. Please provide a copy of all calculations, including all supportive documents, used to determine each of the numbers under the "Assumptions" table presented on page 64 of the workpapers.

SoCalGas Response:

The following are explanations for the information shown in the "Assumptions" table as presented on page 64 of the workpapers:
Labor Rate: The activities of riser inspection and wax repair are performed by company personnel in the classifications of Grade 4 and Grade 5. This practice is expected to continue throughout this program. The hourly base rate for each Grade, effective 10/1/2009, was $29.92 for Grade 4 and $32.17 for Grade 5. Assuming 2080 work hours per year, a 50/50 blend of these two classifications provides an average annual salary of approximately $65,000.

Inspection Rate: Based on company experience it is estimated that a fully trained worker can inspect approximately 40 risers per day.

Work Days: Taking into account vacation and holidays, it is estimated that the average worker will work 48 weeks out of the year. Given 5 work days per week: 48 x 5 = 240 work days

Inspection Rate: 40 risers per day x 240 days per year = 9,600 risers per year.

NL Material Cost: Based on field experience, it is estimated that approximately $1 worth of Trenton Wax tape will be used for each riser repair.

Avg. Riser Replacement Cost: Based on recorded companywide expenses, the average cost to replace an AL riser is approximately $307.93.

DRA DATA REQUEST
DRA-SCG-040-DAO
SOCALGAS 2012 GRC – A.10-12-006
SOCALGAS RESPONSE
DATE RECEIVED: FEBRUARY 9, 2011
DATE RESPONDED: MARCH 1, 2011

7. Please provide a copy of all calculations, along with all supportive documents relied on, to determine the annual cost of wax repair for years 2010-2012, as presented on page 64 of the workpapers.

SoCalGas Response:

Based on the information provided on page 64 of the workpapers, the following tables focus on the information used to calculate the estimated expenses for the Trenton Wax tape repair activities:

	Item	Units	2010	2011	2012	Assumption Source
Assumptions	**# Inspections**	risers	50,000	100,000	300,000	From "Estimated Repair and Replacement risers" table
	Inspection Rate	risers/yr/ FTE	9,600	9,600	9,600	From "Assumptions" Table
	Labor Rate	$/year	$65,000	$65,000	$65,000	From "Assumptions" Table
	NL Material Costs per Riser	$/riser	$1.00	$1.00	$1.00	From "Assumptions" Table

	Item					Calculation Description
Calculations	**Required # FTEs**	FTEs	**5.2**	**10.4**	**31.3**	(# Inspections) ÷ (Inspection Rate)
	Labor Expense	Labor $'s	**$338,542**	**$677,083**	**$2,031,250**	(Required # FTEs) x (Labor Rate)
	NL expense	NL $'s	**$50,000**	**$100,000**	**$300,000**	(# Inspections) x (NL Material Costs)

ATTACHMENT-C - GIPP

<u>GAS INFRASTRUCTURE PROTECTION PROGRAM (GIPP)</u>

Risk Algorithm Description

Introduction

As a part of the development of the Gas Infrastructure Protection Program (GIPP), a study was performed to analyze approximately 1000 instances where a moving vehicle damaged pressurized aboveground gas facilities. Based on the results of this analysis, it was determined that a number of factors influence the risk of damage to aboveground facilities. An algorithm was developed that quantifies this risk which is now being used as a part of the GIPP inspection process, the results of this algorithm help to determine which facilities are subject to mitigative efforts under the GIPP.

The Algorithm

Risk, in general is the likelihood of harmful incidents multiplied by the consequences of the same incidents.

Risk = Likelihood of Failure * Consequence of Failure

For the purposes of the GIPP, an incident is generally defined as a failure of system integrity resulting in a release of gas resulting from a motor vehicle impact. For purposes of our survey, we separated the incidents caused by low speed, driveway type impacts and the damages caused by high speed impacts. The total likelihood of an incident is therefore the sum of the likelihoods of low and high speed impacts. Considering this, then:

Risk = (Likelihood of Low Speed Collision + Likelihood of High Speed Collision) * Consequence

The likelihood of an incident and the consequence of that incident are in turn influenced by a number of factors, incorporating these the complete GIPP algorithm is therefore:

Risk =([TRV * INT * DRD * MITH] + [TRL * DPK * MITL]) * (DEN * FSD * PRS * SIZ2 * MITC)

With the individual factors described below.

Algorithm Factors:

TRV – Traffic Volumes. We use roadway type as a general proxy for traffic volumes since exact counts are not universally available. Roads are divided into primary, secondary and local.

INT – Intersection. Risk is increased slightly within 100’ of the intersection of two streets.

DRD – Distance to Road. The distance from the gas facility to the nearest roadway.

TRL – Low Speed Traffic Volumes. Again, exact traffic counts are not available so we use customer type (Commercial/Industrial/Residential) as a proxy to substitute for the absence of exact traffic volumes.

DPK – Distance to Parking. The distance from the gas facility to the nearest low speed traffic. This could be from a driveway, parking lot, alley etc.

DEN – Density. Again, we use customer type as an indication of the "density", or complexity and cost of adjacent customer facilities. In addition, commercial and industrial customers tend to have more complex gas facilities. Incidents at Commercial and Industrial facilities therefore tend to have higher consequences.

FSD – Facility to Structure Distance. If a facility is a yard set and is not attached to a building consequences are generally lower.

PRS – Pressure. When a service is broken, volume of gas released is related to the pressure.

SIZ – Size. Likewise, when a service is broken, volume of gas released is related to the cross sectional area of the break.

MIT – Mitigation. Mitigative factors can be applied to the facility risk where protective devices have been installed. The mitigative factor can be applied to the likelihood of low and/or high speed incidents, or, in the case of an excess flow valve, the consequence of an incident is mitigated by stopping the uncontrolled release of gas when a line is broken.

GIPP Implementation Plan

[Place Attachment C here]

Implementation Plan for the Gas Infrastructure Protection Program at SoCalGas and SDG&E

Revision 1

May 16, 2011

Table of Contents

Executive Summary

A. Background

The Gas Infrastructure Protection Program (GIPP) was established to address aboveground pressurized natural gas facilities that are susceptible to third party damage caused by vehicle collisions.

49 CFR 192 regulations prescribe the minimum requirements for pipeline safety, including the prevention of damage to gas carrying pipelines and related facilities from vehicular damage. A meter guard program has been in place to comply with this regulation. This existing meter guard program is designed to identify and protect gas facilities from impact forces caused by slow moving passenger vehicles and light trucks. Existing design standards are intended to protect gas facilities from the most common impact occurrences, rather than the very infrequent incidents involving higher vehicular speeds or heavy commercial vehicles. Although SoCalGas has existing design standards to address the protection of facilities due to vehicular impact under 49 CFR 192.317(b) and 49 CFR 192.353(a), they are not always sufficient to protect facilities for vehicular damage where the vehicle leaves the road at elevated rates of speed.

Specifically CFR sections, 192.917 and 192.1007, and the SEu Transmission Integrity Management Program (TIMP) and the Distribution Integrity Management Program (DIMP), requires the Company to:

i. *Identify threats*
ii. *Evaluate and rank the risk of the threat*
iii. *Identify and implement measures to address the risk*
iv. *Measure performance, monitor results, and evaluate effectiveness*
v. *Perform periodic re-evaluation and improvement*
vi. *Report results*

Thus, all potential threats to each pipeline segment must be identified including time independent threats such as third party damage and outside force damage. Vehicular impacts to aboveground gas facilities were identified as an "outside force damage" threat.

An in-depth investigation of historical claims data where aboveground facilities were impacted by vehicular traffic was utilized to determine the characteristics for an algorithm that ranks the probability of occurrence.

The results of the investigation indicate that Commercial, Industrial and High Pressure Residential gas facilities are the most vulnerable. There are over 352,000 Commercial, Industrial and HP Residential customers in the system of which 122,000 are estimated to require some type of mitigation. It is estimated that approximately 95,600 of these facilities will require mitigation through the existing meter guard program, while 26,500 of them will be mitigated under the GIPP.

In addition to C&I and HP Residential gas facilities, a previous assessment identified 2,100 potentially at risk Distribution and Transmission facilities[1]. Seventy of these sites were evaluated as being at high/moderate risk of vehicle collision should a vehicle leave the road and strike the facility at high speed[2].

[1] Risk defined as being located within 50 ft. of an street intersection.
[2] Factors affecting the level of risk involved proximity to the intersection, speed & volume of traffic and the design and quality of existing barriers.

To date the GIPP does not include pipe spans, pressure monitoring devices, facilities related to Storage Operations or residential Meter Set Assemblies operating <60 psig.

B. Program Purpose

The GIPP will identify, evaluate, recommend and implement damage prevention solutions for at risk above-ground pressurized gas facilities that are exposed to vehicular impacts. The solutions will reduce the potential consequences caused from escaping natural gas after vehicular collisions by:

1. An in-depth investigation of historical claims data where aboveground facilities were impacted by vehicular traffic was utilized to determine the characteristics for an algorithm that will risk rank the probability of occurrence. (Completed)

2. Conducting a records review and performing on-site investigations to identify SEu aboveground pressurized natural gas facilities located within a predefined proximity from traffic on a roadway, driveway or other intersecting transportation pathways intended for routine vehicular traffic. (In-progress)

3. Documenting and reporting the results of record reviews, physical inspections and mitigation actions. (In-Progress)

4. Categorizing the potential risk exposure of third party vehicular impacts on aboveground pressurized natural gas facilities using established criteria. (Complete)

5. Identifying and implementing mitigation actions including the removal or relocation of facilities, the construction of protective barriers, or the installation of safety devices such as Excess flow Valves (EFV). (In-Progress)

6. Updating Company policies and practices to ensure detailed methodologies exist for locating, protecting, and installing aboveground gas facilities. (In-Progress)

7. Developing and monitoring performance measures from an established baseline to evaluate the effectiveness of the GIPP program. (In-Progress)

8. Providing Best Practices solutions to Field Operations for future facility evaluations and mitigation of vehicle collision risks. (In-Progress)

9. Providing a mechanism to report program results on an annual basis as required by §191.11. (In-Progress)

C. Potential Solutions

The following options have been identified as potential risk mitigating actions for existing above ground facilities:

1. <u>The Installation of Excess Flow Valves on Residential Services</u>. Installed at the main & service connection (SMC), these devices would protect individuals and facilities from escaping gas at the service and MSA after vehicular impacts. Currently only medium pressure EFV's are approved

for installation, a study to investigate the potential utilization of EFV's on High Pressure Residential Services is underway.

2. The Installation of No-Hole Excess Flow Valves on Residential Services. Inserted from the riser, no excavation is required for installation, These devices are much less costly than valves placed at the service to main connection. However, they do not provide protection from damages to the service that might occur from the main to the riser.[3]

3. The Installation of Excess Flow Valves on Risers
Installed on the riser just below the stop-cock, no excavation is required for installation. However, they do not provide protection from damages to the service that might occur upstream of the EFV[4]

4. The Installation of Excess Flow Valves on Pressure Monitoring Devices
Installed on mechanical and electronic pressure monitoring equipment at Regulator Stations or other locations where the riser supplying gas to the device is aboveground and exposed to vehicular damage.

5. Installation of Traffic Barriers. Facilities such as bollards, meter guards, K-rails and block/concrete walls can be economical to moderately expensive to install and highly effective at protecting gas facilities. Standard designs utilized on facilities exposed to slow moving vehicular threats that are within 10-ft.

6. Facility Relocations, Replacements, or Removal. Construction related modifications can be effective at reducing the risk of vehicle collisions, but, high costs are typically associated with these actions.

7. Convert Aboveground Facilities to Underground Facilities. Underground vaults or curb boxes can effectively reduce the potential exposure from vehicle collisions. However, they are costly to install and require more routine maintenance than aboveground facilities.

8. Install Warning Signs. Raising the public's level of awareness with signage and reflective near streets or highways turns where gas facilities exist might be an appropriate action under some circumstances.

9. High Pressure Excess Flow Valves (HP EFV). The current approved mitigation measure for HP residential services exposed to street traffic is to relocate the First Stage Regulator (FSR) set underground into a curb meter box, and then install a medium pressure EFV. An Engineering study is underway to prove the feasibility for an HP EFV that can be installed upstream of the FSR, in order to stop the escape of natural gas in the event of vehicular damage.

[3] The current manufacturer only has options for 3/4" and 1" IPS service risers. They do not have anything available for 1/2 CTS risers, which is the majority of the residential services in existence at SEu. A project to help develop a 1/2 inch device is being pursued by the Research Department.
[4] A study is underway to determine if installing an EFV on the riser will be an effective method to prevent the escape of natural gas when impacted by a vehicle. Since this EFV is installed aboveground there is the potential that the damage may occur upstream (below) the location of the valve.

D. GIPP Cost Estimates

The cost to design and implement the GIPP is estimated at $35.8 million at SoCalGas and $7.5 million at SDG&E over five years.[5]

GIPP Forecast (SCG)										
	2011		2012		2013		2014		2015	
Project	O&M	Capital	O&M	Capital	O&M	Capital	O&M	Capital	O&M	Capital
Project Management	$ 506,000		$ 315,000		$ 315,000		$ 315,000		$ 315,000	
C&I Inspections	$ 194,800		$ 300,000		$ 300,000		$ 300,000		$ 300,000	
Standard Protection	$ 16,000	$1,393,200	$1,662,904	$3,296,914	$1,662,904	$3,296,914	$1,662,904	$3,296,914	$1,662,904	$3,296,914
HP Relocations	$1,320,000	$ 110,000	$ 925,978	$ -	$ 925,978	$ -	$ 694,484		$ 462,989	$ 65,190
HP EFV			$1,500,000		$1,560,000		$1,770,000		$2,100,000	
Total Forecast	$2,036,800	$1,503,200	$4,703,882	$3,296,914	$4,763,882	$3,296,914	$4,742,388	$3,296,914	$4,840,893	$3,362,104

SDG&E GIPP Forecast										
	2011		2012		2013		2014		2015	
Description	O&M	Capital	O&M	Capital	O&M	Capital	O&M	Capital	O&M	Capital
Inspections	$ 496,003									
Standard Barriers	$ 284,900	$ 552,000	$ 408,775	$ 822,000	$ 408,775	$ 822,000	$ 408,775	$ 822,000	$ 408,775	$ 822,000
Relocations	$ -	$ -	$ 160,000	$ 40,000	$ 160,000	$ 40,000	$ 160,000	$ 40,000	$ 160,000	$ 40,000
PM	$ 93,125	$ 20,833	$ 21,250	$ 63,750	$ 21,250	$ 63,750	$ 21,250	$ 63,750	$ 21,250	$ 63,750
Total	**$ 874,028**	**$ 572,833**	**$ 590,025**	**$ 925,750**	**$ 590,025**	**$ 925,750**	**$ 590,025**	**$ 925,750**	**$ 590,025**	**$ 925,750**
Mitigated Sites	285	552	409	822	409	822	409	822	409	822

The estimates that were included in the TY 2012 GRC were $12.9 million at SoCalGas and $1.1 million at SDG&E over five years.

E. Estimated Number of Sites to be Mitigated[6]

Customer Type	Pressure	Road Type	Location	GIPP Inspection?		GIPP Field Assessment		Is Mitigation Recommended?	Estimated # of Meters		
				Yes/No	Estimated # of Meters	Is MSA Protected Adequately	Is MSA exposed to Traffic?		By GIPP	By MGP	TOTAL
Commercial	All	All	Any	Yes	296,928	No	Yes	Yes	18,262	85,663	103,925
							No	No			115,802
						Yes	No	No			77,201
Industrial	All	All	Any	Yes	33,583	No	Yes	Yes	1,484	9,934	11,418
							No	No			12,762
						Yes	No	No			9,403
Residential	High	All	Any	Yes	21,588	No	Yes	Yes	6,692	0	6,692
							No	No			14,896
	Medium	Primary / Secondary	PL	No	44,268						
			House	No	398,410						
		Local	Any	No	5,213,998						

Total # of MSA's: 6,008,775
# of MSA's to Inspect: 352,000
Estimated # of MSA's to Mitigate: 122,000 (26,500 by the GIPP)

[5] Cost estimates are based on a 30% reduction from the total estimated number of facilities requiring mitigation. The costs for HP Residential Services is based on the approval of the HP EFV for mitigation, which is pending.
[6]Transmission and Large Distribution facilities were removed from the original implementation plan version 0 in order to address the higher priority facilities (C&I and Residential HP) within the original 5 year budgeted amount for the program.

F. Project Approach

The GIPP will initially focus on Commercial, Industrial and High Pressure Residential Gas Facilities. The schedule will be split into 3 general phases, which includes: 1.) *Facility Identification, Evaluation and Risk Categorization, 2.) Determination of Mitigation Measures, and 3.) Implementation of Mitigation Measures.*

The program will begin with the identification of aboveground gas facilities that are exposed to vehicular damage[7]. Facilities will then be addressed based on the level of risk; higher risk facilities will be given priority for mitigation.

For Commercial and Industrial Gas facilities the most likely mitigation solution will be the installation of meter guards or guard posts per System Instruction 185.0008. In some occasions where the facility is exposed to high speed traffic, the solution might be to relocate the facility away from traffic or the installation of special design protective devices which will be determined on a case-by-case basis.

For High Pressure Gas Facilities serving residential customers the current mitigation method is to relocate the HP FSR below ground in a curb meter box, install an excess flow valve downstream of the FSR. In the occurrence that the Meter Set Assembly (MSA) is within 20-ft of the roadway, it will be relocated away from the roadway a minimum of 40-ft. Some services will require alterations, while others complete replacements depending on the condition of the existing service and the location of the MSA.

<u>Pilot Project – HP Residential Facilities</u>

A Pilot Project was conducted that focused on high pressure residential gas facilities where the facilities were located near the property line, and consequently near high speed traffic. The pilot project targeted a geographic area in the Northern and Inland Regions where the majority of these types of facilities are predominant.

Currently there are EFVs that are approved for installation as part of a requirement on replacements and new services that are designed for medium pressure applications (<60 psig). For instances where a High Pressure (>60psig) service is encountered, the FSR was relocated below ground into a curb meter box, with the EFV installed between the FSR and MSA. In addition, each site was assessed to determine if a meter guard was required to protect from exposure to slow speed vehicular damage (farm equipment, lawn-mowers or driveways).

[7] This includes all Commercial, Industrial and HP Residential Gas Facilities only.

G. GIPP Schedule and Timeline

Please refer to the program implementation timelines in Figure 1 below.

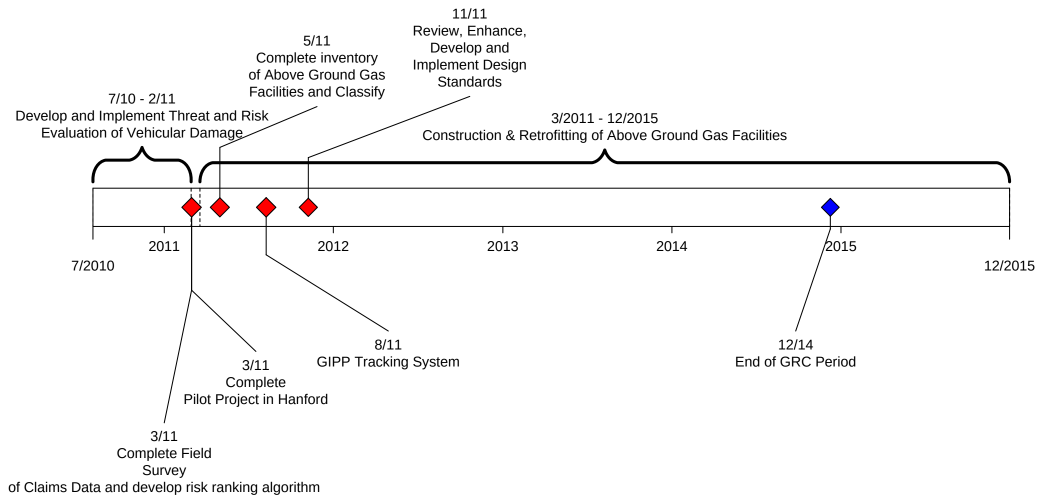


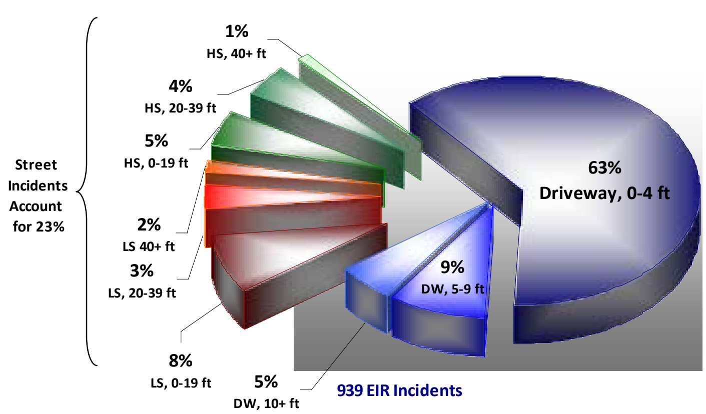
Figure 1. Implementation Timeline for the Gas Infrastructure Inspection Program

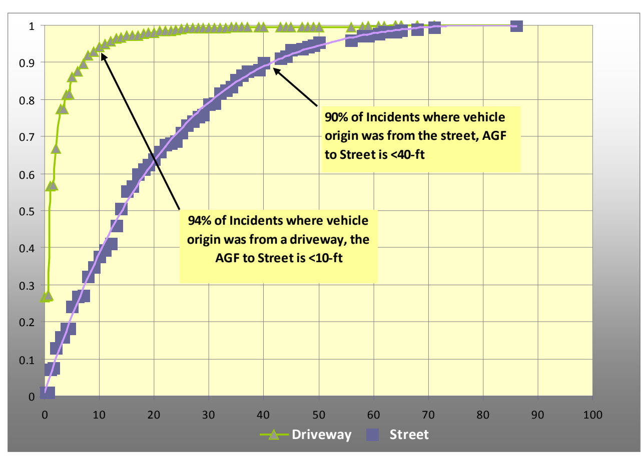
The projected overall program timeline for the GIPP is 5 years (2010-2015).

H. Gas Risk Algorithm

The development of a risk algorithm is a challenging process and unique to Southern California Gas Company and San Diego Gas & Electric's above ground gas facilities infrastructure. An in-depth evaluation of past incidents was conducted to identify all of the threats and consequences associated with exposure of above ground gas facilities exposed to vehicular impact. The process includes categorize factors in a way that results in a meaningful risk score for any given facility at any proximity to vehicular traffic.

The Emergency Incident Reporting (EIR) system identified 2,115 3rd party damages to SCG facilities caused by vehicular impacts[8]. Field surveys of identified incidents were conducted and data from 939 incidents was utilized to develop risk factors and their weighting in the risk algorithm.



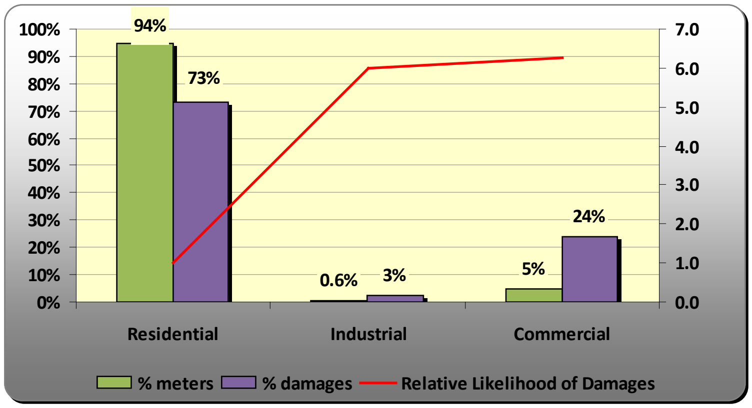


[8] Data from EIR system was polled through 12/31/2010, with "caused by = vehicle" filter.

Revised: 11/23/2011

The pie graph above illustrates the breakdown of incidents relative to the distance of the facility from the travelled roadway. The blue wedges on the graph shows that 77% of all incidents occurred where the vehicle involved originated in a driveway or parking lot. These facilities are candidates that can be mitigated with existing standard protection (meter guards and bollards). The remaining 23% (orange and green wedges) are of incidents where the origin of the vehicle was from a public "high-speed" roadway. The chart on the right illustrates the relative Probability Distribution of Incidents by Distance to Traffic. The data shows that 94% of "driveway" incidents occurred to facilities located within 10-ft of the driveway, and over 80% occurred within 5-ft. The data also shows for incidents involving a vehicle originating on a public roadway that 90% occurred to facilities that were located within 40-ft of the roadway.

The graph to the right shows the relative likelihood of damages by facility type. Residential meters constitute 94% of all meters in the system yet they are responsible for 73% of the incidents, while commercial meters make up 24% of the system, but are responsible for 5% of the incidents. Similarly, Industrial customers only make up 0.6% of our customer base, but are responsible for 3% of the incidents. The relative likelihood is 6 times higher for Industrial and Commercial customers compared to residential customers.



The following is a listing of all of the risk factors and their contributing weight factor for each.

Likelihood Factors

Roadway Type (Proxy for high-speed traffic volumes)

Primary	25
Secondary	10
Local	1
Alley, Parking, etc.	1

Rate Code (Proxy for low-speed traffic volumes)

Commercial	3
Industrial	3
Residential	1

Distance to Intersection (ft)

<100	1.1
>100	1.0

Distance to Driveway/Parking/Alley (ft)

0-4	25
4-9	9
>9	2

Distance to Street/Highway (ft)

- 0-19 10
- 20-39 3
- >40

Mitigation	Low Speed	High Speed
Meter guard (res. Only)	0.2	1.0
Bollards	0.1	0.8
Block Wall + Clearance	0	0.5
Block Wall no Clearance	0.1	0.9
Rail + Clearance	0	0.2
Rail no Clearance	0.1	0.8
Fence (wood, chain link)	0.5	0.95
Natural (Elev., trees, rocks)	0.5	0.75
Structure	0	0.1
Curb	0.5	0.9
EFV	0.5	0.5

Consequence Factors

Customer Type		Distance from Structure		Pressure
Residential	1.0	On building	1.2	Trans – 4.0
Industrial	1.2	Yard Set	1.0	Dist HP – 2.0
Commercial	1.0			<60psig – 1.0

Risk is equal to the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF). LOF is comprised of two main components, the Likelihood of High Speed (LHS) failure and the Likelihood of Low Speed Failure (LLS). The LHS factors include the type of roadway, distance to the intersection, distance to the street and mitigation, where:

LHS = Roadway Type * Distance to Intersection * Distance to Street * Mitigation
LLS = Type of Customer * Distance to Driveway * Mitigation
COF = Density (rate code) * Distance to Structure * Pressure^2

I. Current State of Industry Practices

A. AGA White Paper

A survey of other Gas Utilities was conducted to understand what the industry standards are in regards to protection of gas facilities from vehicular damage. The survey results indicate that SEu standards match or exceed those of other gas utilities.

B. Assessment of Vehicle Barrier Designs for Aboveground Facility Protection

The Gas Technology Institute (GTI) has been contracted by SEu to conduct a thorough investigation into structural barriers designed to protect various aboveground facilities from vehicular damage. Results from this study are expected June 2011 2010.

II. Project Success Factors

A. Key Performance Indicators and Reporting Metrics

The initial metrics that will be used to track the progress and efficiency of the GIPP are listed below. These metrics will be reported on a system wide basis and for each region.

1. Budget: Actual vs. Planned

2. A listing of facilities that have been cleared or mitigated and scheduled

3. Numerical metrics include:

   - Number of facility records reviewed by type

   - Number of high/medium/low risk category locations identified

   - Number of high/medium locations field inspected

   - Number of facilities mitigated by:

     a. EFVs on the service at the service-to-main-connection or near riser
     b. EFVs at the riser
     c. EFVs at Pressure Monitoring Devices
     d. Block/Concrete walls
     e. Relocations/Removal
     f. Barriers (wall, K-rail, other)
     g. Signage
     h. Meter Guards
     i. Retrofitted to meet current company standards
     j. No mitigation necessary

III. Resource Requirements

A. Company and Contractor Workforce Requirements

Workforce requirements for this project are extensive. In addition to the Project Manager labor resources required to implement the GIPP include:

1. A Project Engineer to lead the records management effort, records review, facility clearing documentation and establishment of project plans

    - Implement procedures for ranking and documenting facilities
    - Provide work direction and support to field planners
    - Produce and monitor project schedules and KPIs
    - Manage project data
    - Provide technical and planning related support for the Field Inspectors

2. A Field Inspection Supervisor to manage the Field Inspectors and contractors performing the on-site facility mitigation work.

    - Develop and manage work schedules for the Field Inspections
    - Provide work direction and manage contractors
    - Primary liaison with field operations
    - Manage Field Inspectors
    - Establish field protocols, processes and procedures

3. Field Inspectors

    - Supervise contractors and Company Crews.
    - Field Inspections of identified facilities
    - Evaluate existing facilities for compliance with current company standards
    - Recommend mitigation actions for "at-risk" facilities

4. Distribution/Transmission Planners

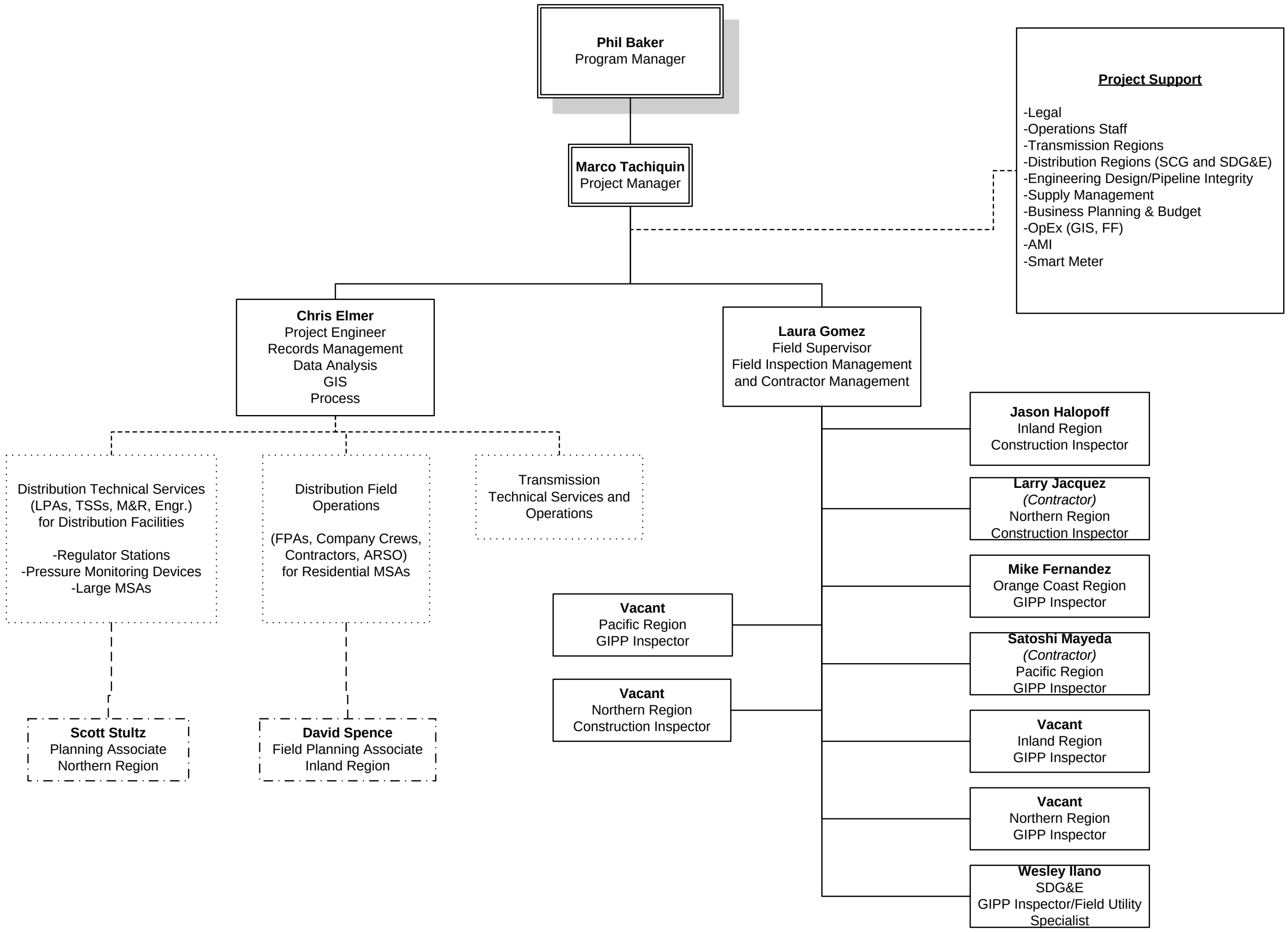
    - Gather field data
    - Assist with field inspections of identified facilities
    - Perform Planning mitigation functions for "at-risk" facility modifications

5. Pipeline contractors and Company crews to perform mitigation construction work.

6. Dispatch and ARSO, personnel to support the work initiated

7. Engineering – Associate Engineer or Intern to support the Project Engineer/Project Manager with data analysis, tracking, reporting, design reviews, RER's, Civil/Structural designs.

B. Organizational Chart



Project Support

a. *Legal* – Provide legal review and counsel
b. *Operations Staff* - Provide input and revisions for Gas Standards; establish field procedures; training support; Field Technology support
c. *Transmission Regions* – Provide Subject Matter Expertise
d. *Distribution Regions* – Provide Subject Matter Expertise
e. *Engineering & Pipeline Integrity* – Risk Criteria; mitigation options; Gas Standards; special studies; DIMP & TIMP
f. *Supply Management* – Contract support; tools/materials; bidding strategy
g. *Business Planning* – Budget & Financial support
h. *OpEx* – Integrations of tactical plans with OpEx initiatives
i. *AMI/Smart Meter/GIS* – Facility location data

III. Policy and Practice Revisions

A. Gas Standard Revisions

SoCalGas and SDG&E have facility standards in place that require review. As a minimum the following standards that will be examined and revised as appropriate.

Document No.	Utility	Type	Document Title
49 CFR Part 192.183(a)			
180.01	SoCalGas	GAS	Prefabricated Vaults - Design and Selection Guide
76-94	SoCalGas/SDG&E	MSP	Vault, Prefabricated, Concrete
76-94.1	SoCalGas/SDG&E	MSP	Vault - Prefabricated, RPM
76-94.2	SoCalGas/SDG&E	MSP	Vault - Prefabricated, FRP
D7465	SDG&E	GAS	Prefabricated Vaults - Design and Selection Guide
49 CFR Part 192.199(g)			
180.005	SoCalGas	GAS	Control Piping
184.0035	SoCalGas	GAS	Regulator Station Design and Planning
184.0275	SoCalGas	GAS	Inspection Schedule - Regulator Station, Power Generating Plant Regulation Equipment Requirements
185.001	SoCalGas	GAS	MSA Standard Designs and Selection Chart
185.0287	SoCalGas	GAS	Over-Pressure/Under-Pressure Protection - Maintenance, Installation and Settings
223.0345	SoCalGas	GAS	Pressure Relief/Pressure Limiting Devices, Testing/Inspection
D7711	SDG&E	GAS	Regulator Station Design and Planning
56-40	SoCalGas/SDG&E	MSP	Stop Cocks
58-96.6	SoCalGas/SDG&E	MSP	Valve - Relief, Large
70-45	SoCalGas/SDG&E	MSP	Regulator - Service, Standard Pressure
70-47	SoCalGas/SDG&E	MSP	Regulators - High Pressure Spring Loaded
49 CFR Part 192.317(b)			
182.001	SoCalGas	GAS	Request for Pipeline Design Assistance
184.0035	SoCalGas	GAS	Regulator Station Design and Planning
184.005	SoCalGas	GAS	General Construction Requirements for Distribution Mains
184.12	SoCalGas	GAS	Inspection of Pipelines on Bridges, Spans and in Unstable Earth
185.0008	SoCalGas	GAS	Meter Guard - Installation Requirements
223.0003	SoCalGas	GAS	General Construction Requirements- Steel Transmission System
223.0001/G8171	SoCalGas/SDG&E	SHRD	New and Uprated Pipelines - CPUC Notification
D7241	SDG&E	GAS	Direct Burial of Polyethylene
D7303	SDG&E	GAS	General Requirements - Steel Distribution System
D7415	SDG&E	GAS	Trench Paralleling Foundations
D7417	SDG&E	GAS	Joint Trench Gas Facilities Near Underground Structures
D7425	SDG&E	GAS	Utility Locations in Local and Collector Streets in S.D. County
G8142	SDG&E	GAS	Inspection of Pipelines on Bridges, Spans and in Unstable Earth
G8605	SDG&E	GAS	Request for Pipeline Design Assistance
49 CFR Part 192.353(a)			
140.04	SoCalGas	GAS	Condition/Location of Meter Installations and Report of Inaccessible/Removed Meters
185.0001	SoCalGas	GAS	Meter Locations
D7103	SDG&E	GAS	Gas Meter Location
D7105	SDG&E	GAS	Gas Meter Location Behind Wing Wall
D7115	SDG&E	GAS	Barricades for Gas Meter Sets
D9103	SDG&E	GAS	Terms and Definitions
49 CFR Part 192.355(c)			
142.0275	SoCalGas	GAS	Back Flow Protection - Regulators and Check Valves
185.0005	SoCalGas	GAS	Curb Meter Box - Installation Requirements
185.056	SoCalGas	GAS	Pressure Regulation Overpressure Protection
D7103	SDG&E	GAS	Gas Meter Location
D7105	SDG&E	GAS	Gas Meter Location Behind Wing Wall
D7123	SDG&E	GAS	Service Regulator Vent Extensions
D7125	SDG&E	GAS	Service Regulators in Curb Meter Boxes
D7461	SDG&E	GAS	Gas Facilities Box (Inside Dimensions 2' X 3')
49 CFR Part 192.739(a)(4)			
184.0275	SoCalGas	GAS	Inspection Schedule - Regulator Station, Power Generating Plant Regulation Equipment Requirements
223.0345	SoCalGas	GAS	Pressure Relief/Pressure Limiting Devices, Testing/Inspection
D7709	SDG&E	GAS	Services of Regulator Technicians for Gas Construction - Distribution
G8159	SDG&E	GAS	Distribution Pressure Regulating and Monitoring Station & Vault - Inspection, Maintenance and Settings
T8149	SDG&E	GAS	Compressor Station Relief Valves
T8165	SDG&E	GAS	Gas Transmission System Relief Valves
49 CFR Part 192.749(d)			
184.0275	SoCalGas	GAS	Inspection Schedule - Regulator Station, Power Generating Plant Regulation Equipment Requirements
223.021	SoCalGas	GAS	Vault Maintenance and Inspection
D7709	SDG&E	GAS	Services of Regulator Technicians for Gas Construction - Distribution
D8167	SDG&E	GAS	Major Distribution System Valve Inspection Requirements
G8159	SDG&E	GAS	Distribution Pressure Regulating and Monitoring Station & Vault - Inspection, Maintenance and Settings

IV. Action Steps

a. Identify Threat Characteristics

Using the data from the field survey, establish specific characteristics that distinguish an "at-risk" facility. These characteristics may include proximity to traffic, type and speed of traffic, level of protection or any other as determined from the study.

b. Identify Mitigation Measures

Develop mitigation measure criteria for each type of aboveground gas facility exposed to vehicular traffic. Examples include installation of standard meter guards for MSAs exposed to low-speed traffic, installing EFVs in vaulted Distribution Regulator stations where the pressure monitoring device is installed aboveground, or installing barricades or block/concrete walls at Transmission/Distribution facilities located at T-Intersections.

c. Bundle Common Facility Types

Establish "profiles" of common aboveground gas facilities exposed to similar traffic threats. (E.g. residential MSAs located in rural/farm areas are located within a few feet of a high speed roadway in unpaved parkways.) and attach a recommended mitigation measure to each "profile" to maintain consistency across the entire system.

d. Locate "at-risk" Facilities

A challenge will be identifying where the "at-risk" facilities are located in the SEu service territory, specifically small MSAs. A strategy will be developed to find and build an inventory of "at-risk" facilities to be mitigated. GIS, AMI (GPS), Smart Meter, Meter Reading and other SEu programs are potential systems/tools that will be leveraged to accomplish this task.

e. Review Current Standards and Practices

Besides retrofitting existing facilities to lower the threat of vehicular damage, the GIPP will also identify current gas standards and procedures to ensure that future installations comply with the GIPP requirements.

f. Implementation of Mitigation Measures

Partner with the affected SEu organizations (Distribution, Transmission, Storage, OpEx, Meter Reading, AMI, Gas Engineering, and others) to roll out mitigation activities to bring "at-risk" facilities to within established standards. This task may utilize company resources to perform the work, or may require contracts to achieve desired goals. Sub-projects may be initiated to efficiently mitigate "bundled" facilities.

g. Monitoring Program Progress

A strategy will be developed to track which facilities have been cleared, either by identifying that no-action is necessary or documenting what action was implemented. The GIPP will partner with OpEx Field Force to ensure that the tracking of these facilities is covered in future asset records. This will allow progress monitoring of the GIPP, help determine forecasts for future work, and eliminate repeat inspection cycles for cleared facilities.

h. Establishing Best Practices for Re-evaluations in the Future

Training programs will be developed for company personnel who work on above ground facilities to understand how to identify at –risk threats as the surroundings change. M&R, ETRs, LCTs and other company personnel who inspect, maintain and perform various types of work on these facilities on a regular basis (PMCs, Turn-on/Turn-offs, corrosion inspections and others) will learn what to look for and identify new threats.

Key Activities & Deliverables	Responsible Party	Target Dates	Current Status
Implement Vehicular Damage Prevention Program as part of DIMP (Subpart P).	Pipeline Integrity	8/02/2011	In Progress
Develop and Implement Threat and Risk Evaluation of Vehicular Damage in accordance with 192.1007(c). This task will include the segmenting of the facilities into groupings with similar characteristics such as location and facility type (DIMP).	Pipeline Integrity	2/28/2011	Complete
Review and add Preventative and Mitigative Measures for Vehicular Damage in accordance with 192.917(a3) and ASME B31.8S (TIMP).	Pipeline Integrity	12/31/2011	In Progress
Review, Enhance, Develop and Implement Design Standards for the protection of gas carrying facilities based upon segments location (environment) and facility type. Validate policies are consistent and complete.	Engineering Design	8/02/2011	In Progress
Complete an inventory of aboveground gas facilities and classify by DOT Transmission (HCA, Non-HCA), Distribution and other attributes that will assist with prioritization and determination if additional protection is appropriate. Data will be placed in the GIS or other appropriate repository (TIMP & DIMP).	Gas Operations Support	12/31/2011	In Progress
Review inventory completed to date and identify facilities requiring additional damage prevention measures.	Gas Operations Support and Engineering Design	Continual	In Progress

V. Communications Strategy

A. Communications Strategy

A communication strategy intended to provide program background and information to stakeholders has been implemented. The objectives of the communications strategy are:

- Increase awareness of the risk mitigation strategy.
- Reinforce our commitment to safety and service.

The communications strategy will be completed in a phased program to coordinate with the Implementation Plan.

Presentations will be provided at stakeholder meetings such as FOT and Peer Teams ahead of the program and throughout to communicate progress.

Regular updates about the GIPP will be communicated to the Public Affairs organization.

Appendix A

The following table identifies the SoCalGas and SDG&E supporting the GIPP.

Activity	Lead(s)
Executive Sponsor	Rick Morrow
Legal Support	Randy Morrow/Larry Davis
Management and Implementation of the Program	Phil Baker Marco Tachiquin
Communications Plan	Public Affairs
Updating Gas Standard and Field Procedures	Reinhold Mueller Ed Newton
EFVs for M&R	Bruce Davis/John Pedroza
Data Analysis and Tracking	Chris Elmer Ed Newton Victor Romero
Inspection of Facilities	Inspectors
Product Testing and QC	Chun Yeh
Pipeline Integrity and Engineering Design	Doug Schneider Ray Stanford
Liaison with AGA	Ed Newton
Liaison with Field Operations	David Schiller Paul Smith Chris Roady Jim Smith
Liaison with Distribution Technical Services	Zandra Marrero Rick Chiapa Jorge Aspa Bill Kostelnik Jim Smith
Liaison with Transmission	Jon Garcia Claus Langer Ed Wiegman
Liaison with CPUC Safety Branch	Jeff Koskie
Claims Support	Mike Moreno Michael Cummings

ATTACHMENT-D - SLIP

SEWER LATERAL INSPECTION PROGRAM (SLIP)

FAQ located on the U.S Department of Transportation's Distribution Integrity Management website: http://primis.phmsa.dot.gov/dimp/faqs.htm

C.4.b.3 - ***The DIMP requirements include knowing the condition of facilities that are at risk for potential damage from external sources. Cross bores of gas lines in sewers have been reported at 2-3 per mile in high risk areas – predominately where trenchless installation methods were used for gas line installs and where sewers and gas lines are in the proximity of each other. Does the potential for cross bore of sewers resulting in gas lines intersecting with sewers need to be determined?***

Yes, the threat of excavation damage includes consideration of potential or existing cross bore of sewers which have resulted in gas lines intersecting with sewers. Pursuant to § 192.1007(a)(2), the operator must consider information gained from past design, operations, and maintenance. If operators used trenchless technologies without taking measures to locate sewer laterals and other unmarked facilities during construction, there may be a risk that their facilities were installed through the foreign facility. If this excavation damage threat applies to the operator, they must evaluate its risk to their system. Depending on the results of the risk evaluation, they may need to identify and implement measures to reduce this risk to existing and future facilities.

SLIP Detailed Calculation

Table 1 Calculations

Testimony Component	Original GRC TY2012 Estimates	Revised Estimates Derived from Independent Assessment and Actual 2010 SLIP Data
Number of conflicts that exist	410	3,400
Cost to resolve conflicts	$820,000	$4.29 million
Number of services to review and clear	361,000	361,000
Number of field or video inspections required	144,000	162,000
Conflict rate	0.1% per mile	0.8% per mile
Cost of records review	$50 per service	$53 per service
Combined cost of video inspections and field inspection	$300 per service	$398 per service

<u>2010 Calculations</u>

2010 Conflict Rate

Number of Conflicts Found and Repaired in 2010	Number of Records Reviewed in 2010	Rate of Conflicts Found in 2010
23	2,420	1.0%

2010 Conflict Repair Costs

Number of Conflicts Found and Repaired	Average Cost for Conflict Repair	Cost of Repairs for 2010
23	$1,250	$28,750

The estimate for the total number of records to review at SoCalGas was determined by reviewing Service History files that date back to 1994. This review revealed the following number of gas installations that used cut and bore installation methods:

Pipe Size	Miles of Pipe	Number of Services
1"-2" main	950	65,000
3" main	90	7,000
Services under 3"	1,000	108,000
3" service	10	500
Sub-Total	2,050	180,500
Installed Since 1970[47]	**4,100**	**361,000**

2010 Video and Field Inspections

Number of Records Reviewed in 2010	Laterals Cleared By Field Inspections in 2010	Percent of Total That Were Field Inspected
2,420	1,088	45%

2010 Records Review Costs

Total Number of Records Reviewed in 2010	Total 2010 Labor Costs	Cost to Review Each Record
2,420	**$127,830**	**$53**

2010 Video and Field Inspections Costs

Total Laterals Cleared By Field Inspections	Total Labor and Contractor Costs	Cost for Video and Field Inspections
1,088	**$433,484**	**$398**

2010 Conflict Rate: 410 conflicts / 4,100 miles = 0.1%

Invoice Amounts and Dates for Sewer Lateral Camera Inspections for 2010:

[47] The CMS data covers the period since 1994. However, the Company started using trenchless construction methods to install PE pipe in 1970. Therefore, the Sub-Total amount above was doubled to calculate the entire period estimate.

Amount	Posting Date	Vendor Name	Project Name
3,430	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,625	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,625	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,430	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
822	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
4,485	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,310	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,310	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,800	9/9/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,060	9/9/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
4,485	9/9/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,510	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,505	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
1,785	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
4,485	9/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,035	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
343	10/4/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
182	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,035	10/4/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,035	10/4/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,035	10/4/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,035	10/4/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
4,010	10/4/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,393	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,750	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,750	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,255	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,180	10/4/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,035	10/4/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,395	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,395	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,750	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
5,320	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,035	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,310	10/4/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,035	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,360	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,035	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,035	10/4/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,395	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
5,720	10/7/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,770	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,770	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,065	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
4,995	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,115	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,395	10/11/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
489	10/6/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
6,505	11/1/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,505	11/1/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project

6,505	11/1/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,795	11/1/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
7,840	11/1/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
221	11/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
388	11/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
2,495	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,065	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
1,780	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
4,170	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
4,846	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,065	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
4,160	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
4,170	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
6,115	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,495	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,065	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	11/15/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
71	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
99	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
85	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
122	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
303	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
416	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
71	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
303	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
113	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
303	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
303	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
388	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
402	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
518	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
1,785	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,205	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
4,170	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,955	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,485	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,625	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project

2,625	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
4,020	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
1,720	12/16/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/29/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
3,590	12/29/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,625	12/29/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/29/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/29/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/29/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,520	12/29/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
2,345	12/29/2010	Advanced Sewer Technologies	DIMP - Sewer Lateral Inspection Project
503	12/7/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
275	12/1/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
1,753	12/29/2010	Jack's All-American Plumbing	DIMP - Sewer Lateral Inspection Project
613	12/7/2010	Acuren Inspection	DIMP - Sewer Lateral Inspection Project
275	12/7/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
99	12/7/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
392	12/7/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
12	12/7/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
275	12/6/2010	Chris J Plumbing & Heating Inc.	DIMP - Sewer Lateral Inspection Project
$377,260	**Total**		

5 Year Program Calculations

Number of Conflicts for the 5 Year Program

Total Number of Services in Program	Rate of Conflicts Found	Number of Conflicts for 5 Year Program
361,000	1.0%	3,431

Conflict Repair Costs for 5 Year Program

Number of Conflicts for 5 Year Program	Average Cost for Repair	Cost of Repairs for 5 Year Program
3,431	$1,250	$4,288,740

Number of Field Inspections for 5 Year Program

Number of Records Reviewed in 2010	Percent of Total that Were Field Inspected	Total Number of Field Inspections for the 5 Year Program
361,000	45%	162,301

5 Year Program Conflict Rate: 3,431 / 4,100 = 0.8%

Record Review Costs for 5 Year Program

Number of Records to be Reviewed	Cost for Records Review	Total Cost for 5 Year Program
361,000	$53	$19,068,866

Camera and Field Inspection Costs for 5 Year Program

Total Number of Services to be Camera and Field Inspected	Cost for Video and Field Inspection	Total Cost for 5 Year Program
162,301	$398	$64,664,392

CITY of PALO ALTO

For Immediate Release
April 26, 2011

For Immediate Release

Contact: Mary Coady
Communications Manager, Utilities
650.329.2479
mary.coady@cityofpaloalto.org

CITY OF PALO ALTO LAUNCHES NEW GAS SAFETY INITIATIVE

Palo Alto, CA – The City of Palo Alto Utilities Department (CPAU) has announced a new gas safety initiative, launched as an important component in its ongoing gas safety activity.

Under this initiative, the Utilities Department will visually inspect sewer laterals throughout the city at homes and businesses to identify and repair any situation where a gas line passes through or intersects a sewer line, a condition known as a crossbore. Palo Alto is a leader in implementing this program, which addresses an issue that occurs in communities throughout the nation.

Crossbores typically are not a risk if left undisturbed. However, a safety risk exists in cases when a homeowner or plumber attempts repair work to a sewer line using a mechanical cleaning device such as a cutter or snake machine. The cleaning device may sever a gas line and cause a resulting gas leak, which could result in a dangerous situation.

As part of the city-wide, comprehensive inspection process, crews will use video technology to run cameras from sewer mains through customers' sewer lines. The City will repair any crossbore occurrences by rerouting gas lines, as well as replacing or repairing affected customers' sewer lines. In the course of this examination, the City may find non-crossbore related problems with a sewer line. The City will inform customers if their sewer lines appear to need repair, and, upon request, will provide customers with a digital copy of the video for their personal use.

In the event of a sewer emergency, the City will have crews available on a round-the-clock basis for quick response. "The key message for our customers is this: if you believe you have a sewer blockage problem, call the City of Palo Alto Utilities Department first at (650) 496-6995. We will have trained staff available to respond 24x7. They will assess the area for crossbore and determine additional precautions or next steps," said Javad Ghaffari, Manager of Water, Gas and Wastewater Operations.

"CPAU conducts on-going maintenance and upgrade programs to assure the integrity of its gas system. In reviewing our operations and best practices and in response to heightened concerns around gas system safety, we recently conducted an intensive review of current system conditions to determine the existence of potential hazards to our customers. Although the issue of crossbore safety is a national one, CPAU is among the first utilities in the country to undertake a very aggressive crossbore safety program," said Greg Scoby, Water, Gas and Wastewater Engineering Manager.

The Utilities Department has begun inspecting schools, places of worship and other large gathering sites. Following that, it will begin inspection of other sites throughout the city. This program is expected to be completed by January 2013.

Industry data shows that crossbores exist in a rare number of cases. The occurrence of crossbore began with the use of trenchless underground utility construction methods. These methods, including horizontal directional drilling and pneumatic boring, eliminated the disarray caused by the older method of digging trenches across property and through yards. The trenchless techniques involve creation of a small underground tunnel through the soil, through which a new utility line is pulled.

In using these trenchless methods, generally in the period between 1970 and 2000, the industry undertook all standard precautions to place new pipes in areas removed from other underground utilities, including water and sewer lines. However, not all sewer lines follow the expected alignments, as a result of remodeling, re-landscaping or other activity. In those cases, the boring equipment operator could inadvertently bore through a sewer lateral while installing another utility line at intersection with the sewer pipe. Because the boring equipment is designed to cut through hard materials, these crossbores could be undetected during construction.

Improvements in technology and construction practices have reduced the possibility of crossbore during the past decade. In 1999, the CPAU began installing safety devices known as excess flow valves, which restrict gas flow in the event of a service line severance. CPAU has employed advances in video technology to efficiently inspect sewer lines both before and after installing another utility line. As a result, in 2001, CPAU began a practice of video inspecting sewer lines on properties where gas lines were replaced.

"I support taking an aggressive stance in addressing the issue of crossbore," said City Manager James Keene. "We believe that adoption of a program that resolves any crossbore situations is a necessary investment in the safety and well-being of our community."

For more information, visit www.cityofpaloalto.org/safety

About the City of Palo Alto Utilities

CPAU is the only publicly-owned utility in California that provides a full complement of utilities services, including electric, fiber optic, natural gas, water and wastewater. The City of Palo Alto Utilities has been delivering quality services to the citizens and businesses of Palo Alto since 1896. For more information, visit us on the web at www.cityofpaloalto.org/utilities.

ATTACHMENT-E Annual DOT Distribution Report

Annual Report for Calendar Year 2010

Gas Distribution System

FORM PHMSA 7100.1-1

NOTICE: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the violation continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

OMB No. 2137-0522
Expiration Date 01/31/2014

U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

ANNUAL REPORT FOR CALENDAR YEAR 2010
GAS DISTRIBUTION SYSTEM

INITIAL REPORT X
SUPPLEMENTAL REPORT ☐

PART A – OPERATOR INFORMATION

DOT USE ONLY

1. NAME OF OPERATOR
Southern California Gas Company

2. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED
555 West Fifth Street
Number and Street
Los Angeles Los Angeles
City and County
California 90013-1011
State and Zip Code

3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER
/ 1 / 8 / 4 / 8 / 4 /

4. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT

Number and Street

City and County

State and Zip Code

5. STATE IN WHICH SYSTEM OPERATES: / C / A / (provide a separate report for each state in which system operates)

PART B – SYSTEM DESCRIPTION

Report miles of main and number of services in system at end of year.

1. GENERAL

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	SYSTEM TOTAL
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED						
MILES OF MAIN	5574	2493	0	17909	22892	0	0	0	0	48868
NO. OF SERVICES	129	893092	18	758504	2707778	0	0	206	0	4359727

2. MILES OF MAINS IN SYSTEM AT END OF YEAR

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"	SYSTEM TOTALS
STEEL	0	14413	7003	3571	608	381	25976
DUCTILE IRON	0	0	0	0	0	0	0
COPPER	0	0	0	0	0	0	0
CAST/WROUGHT IRON	0	0	0	0	0	0	0
PLASTIC 1. PVC	0	0	0	0	0	0	0
2. PE	0	17740	4578	574	0	0	22892
3. ABS	0	0	0	0	0	0	0
4. OTHER PLASTIC	0	0	0	0	0	0	0
OTHER	0	0	0	0	0	0	0
SYSTEM TOTALS	0	32153	11581	4145	608	381	48868

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR — AVERAGE SERVICE LENGTH 59 FEET

Revised: 11/23/2011

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"	TOTAL
STEEL	0	1604632	45175	1717	177	42	1651743
DUCTILE IRON	0	0	0	0	0	0	0
COPPER	0	202	4	0	0	0	206
CAST/WROUGHT IRON	0	0	0	0	0	0	0
PLASTIC 1. PVC	0	0	0	0	0	0	0
2. PE	0	2687953	18933	850	31	11	2707778
3. ABS	0	0	0	0	0	0	0
4. OTHER PLASTIC	0	0	0	0	0	0	0
OTHER	0	0	0	0	0	0	0
SYSTEM TOTALS	0	4292787	64112	2567	208	53	4359727

4. MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

	UN-KNOWN	PRE-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009	2010-2019	TOTAL
MILES OF MAIN	0	2811	2763	8034	7033	7155	9654	5158	6135	125	48868
NUMBER OF SERVICES	0	51317	135531	623375	610305	711157	1074729	539180	596648	17485	4359727

PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING YEAR

CAUSE OF LEAK	Mains		Services	
	Total	Hazardous	Total	Hazardous
CORROSION	1320	432	3150	2681
NATURAL FORCES	102	65	192	123
EXCAVATION DAMAGE	447	443	1995	1972
OTHER OUTSIDE FORCE DAMAGE	23	22	20	15
MATERIAL OR WELDS	545	254	950	329
EQUIPMENT	0	0	0	0
INCORRECT OPERATIONS	0	0	0	0
OTHER	391	118	1224	618

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR **3424**

PART D – EXCAVATION DAMAGE

Number of Excavation Damages **2253**

Number of Excavation Tickets **287969**

PART E – EXCESS FLOW VALVE (EFV) DATA

Total Number Of EFVs on Single-family Residential Services Installed During Year **11489**

Estimated Number of EFVs In System At End Of Year **28912**

PART F - TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED FOR REPAIR

PART G - PERCENT OF UNACCOUNTED FOR GAS

8	Unaccounted for gas as a percent of total input for the12 months ending June 30 of the reporting year. [(Purchased gas + produced gas) minus (customer use + company use + appropriate adjustments)] divided by (purchased gas + produced gas) equals percent unaccounted for. Input for year ending 6/30 **0.89** %.

PART H - ADDITIONAL INFORMATION

PART I - PREPARER AND AUTHORIZED SIGNATURE

Robert W. Conaway Technical Advisor II
(Type or print) Preparer's Name and Title

(213) 244-5429
Area Code and Telephone Number

Rconaway@semprautilities.com
Preparer's email address

(213) 244-8242
Area Code and Facsimile Number

Barry Kerns Safety and Health Manager
Name and Title of Person Signing

(714) 634-5024
Area Code and Telephone Number

Barry Kerns
Authorized Signature

Revised: 11/23/2011