No. S246669

IN THE SUPREME COURT OF THE STATE OF CALIFORNIA

SOUTHERN CALIFORNIA GAS COMPANY,
Respondent to Petition for Review,

v.

THE SUPERIOR COURT OF LOS ANGELES COUNTY,
Respondent to Petition for Writ of Mandate.

SUPREME COURT
FILED

AUG 6 2018

Jorge Navarrete Clerk

Deputy

FIRST AMERICAN WHOLESALE
LENDING CORPORATION et al.,
Real Parties in Interest, Petitioners.

After a Decision by the Court of Appeal,
Second Appellate District, Division Five, Case No. B283606

The Superior Court of Los Angeles County,
Judicial Council Coordination Proceeding No. 4861,
The Hon. John Shepard Wiley, Jr., Judge

MOTION REQUESTING JUDICIAL NOTICE

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MOTION REQUESTING JUDICIAL NOTICE

Pursuant to California Evidence Code §§ 452, 453, and 459, and Rules of Court, Rule 8.252(a), Plaintiffs and Petitioners respectfully request that this Court take judicial notice of the following documents:

1. The First Amended Consolidated Complaint of Porter Ranch Development Co. and Toll Brothers, Inc. in the Coordinated Pre-Trial Proceeding below filed on July 20, 2018, entitled *Toll Brothers, Inc. and Porter Ranch Development Company v. Sempra Energy, Southern California Gas Company, et al.*, Case No. BC674622, JCCP No. 4861. Dunlavey Decl., ¶ 2, Ex. A.

2. Testimony to the Public Utility Commission by Phillip E. Baker entitled *SoCalGas Direct Testimony of Phillip E. Baker Underground Storage (November 2014).* Dunlavey Decl., ¶ 3, Ex. B.

3. The Department of Conservation, Division of Oil, Gas, and Geothermal Resources' Annual Report to the California Legislature from 2015, entitled *Department of Conservation, Division of Oil, Gas, and Geothermal Resources Report to the Legislature on the Underground Injection Control Program Pursuant to SB 855, 2011 Through 2014.* Dunlavey Decl., ¶ 4, Ex. C.

3. A federal interagency task force's final report on natural gas storage safety, titled *Ensuring Safe and Reliable Underground Natural Gas*

Storage: Final Report of the Interagency Task Force on Natural Gas Storage Safety (Oct. 2016). Dunlavey Decl., ¶ 5, Ex. D.

4. Sempra Energy's 2016 Form 10-K, submitted to and filed with the United States Securities and Exchange Commission, a government agency. Dunlavey Decl., ¶ 6, Ex. E.

Dated: August 6, 2018

By: ____________________

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(Petitioners) Plaintiffs' Steering Committee for the Class Action Track

MEMORANDUM OF POINTS AND AUTHORITIES

A reviewing court may take judicial notice of any matter specified in Evidence Code section 452. "In determining the propriety of taking judicial notice of a matter, or the tenor thereof, the reviewing court has the same power as the trial court under section 454." (Cal. Evid. Code § 459(b).)

The purpose of this request for judicial notice is to provide the Court with documents relevant to application of Civil Code § 1714(a) and the factors set forth in *Rowland v. Christian* (1968) 69 Cal. 2d 108, 112–13.

Judicial notice of these documents was not sought from the trial court, though Petitioners did seek judicial notice of an earlier Sempra 10-K filing, which the trial court granted. (*In re Coordination Proceedings Special Title Rule (3.550) S. California Gas Leak CA*, No. JCCP486 (Cal. Super. Ct. 2017) 2017 WL 2361919.)

Exhibit A is a court filing properly subject to judicial notice pursuant to California Evidence Code § 452(d). Exhibits B, C, and D are government documents properly subject to judicial notice pursuant to California Evidence Code §§ 452(c), 452(g), and 452(h). Exhibit E is a submission to a government agency properly subject to judicial notice pursuant to California Evidence Code §§ 452(g) and 452(h).[1]

[1] California courts regularly take judicial notice of company filings with government agencies. *See, e.g., Cody F. v. Falletti* (2001) 92 Cal.App.4th 1232, 1236 (holding that grant deeds and articles of incorporation filed with the Secretary of State are properly subject to judicial notice); *Intengan v.*

Exhibit A post-dates the decision below. Exhibits B through E pre-date the decision below. Petitioners respectfully request this Court take judicial notice of a court filing, various government documents, and a filing to a government agency, which are attached as **Exhibits A-E** to the declaration of Wilson M. Dunlavey.

Dated: August 6, 2018

By: ____________________

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BAC Home Loans Servicing LP (2013) 214 C.A.4th 1047, 1057 (holding that the existence of defendant bank's declaration of compliance is subject to judicial notice); *Santa Barbara County Coalition Against Automobile Subsidies v. Santa Barbara County Assn. of Governments* (2008) 167 Cal.App.4th 1229, 1234 n.3 (taking judicial notice of articles of incorporation and campaign disclosure forms).

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(Petitioners) Plaintiffs' Steering Committee for the Class Action Track

DECLARATION OF WILSON M. DUNLAVEY

I, Wilson M. Dunlavey, declare:

1. I am a member in good standing of the State Bar of California, duly admitted to practice before the courts of the State of California. I am an attorney with the law firm Lieff Cabraser Heimann & Bernstein, LLP, attorney of record for plaintiffs. I submit this Declaration in opposition to Defendants' Demurrer to the Second Amended Consolidated Master Class Action Business Complaint. I have personal knowledge of the facts stated in this Declaration. I believe all facts stated in this Declaration are true, and I would testify to these facts if called upon to do so.

2. Attached hereto as **Exhibit A** is a true and correct copy of the First Amended Consolidated Complaint of Porter Ranch Development Co. and Toll Brothers, Inc. in the Coordinated Pre-Trial Proceeding below filed on July 20, 2018, titled *Toll Brothers, Inc. and Porter Ranch Development Company v. Sempra Energy, Southern California Gas Company, et al.*, Case No. BC674622, JCCP No 4861.

3. Attached hereto as **Exhibit B** is a true and correct copy of testimony to the Public Utility Commission by Phillip E. Baker, titled *SoCalGas Direct Testimony of Phillip E. Baker Underground Storage Before the Public Utilities Commission of the State of California* (November 2014).

4. Attached hereto as **Exhibit C** is a true and correct copy of The California Department of Conservation, Division of Oil, Gas, and Geothermal Resources' annual report to the California Legislature from 2015, titled *Department of Conservation, Division of Oil, Gas, and Geothermal Resources Report to the Legislature on the Underground Injection Control Program Pursuant to SB 855, 2011 Through 2014.*

5. Attached hereto as **Exhibit D** is a true and correct copy of a federal interagency task force's final report on natural gas storage safety, titled *Ensuring Safe and Reliable Underground Natural Gas Storage: Final Report of the Interagency Task Force on Natural Gas Storage Safety* (Oct. 2016).

6. Attached hereto as **Exhibit E** is a true and correct copy of Sempra Energy's 2016 Form 10-K submitted to the United States Securities and Exchange Commission.

I declare under penalty of perjury under the laws of the State of California that the forgoing is true and correct. Executed this 6th day of August, 2018, at San Francisco, California.

Wilson M. Dunlavey

[PROPOSED] ORDER

Petitioners' Motion Requesting Judicial Notice is hereby GRANTED.

Dated: ______________________ By: ______________________________
Chief Justice

PROOF OF SERVICE

I am employed in the County of San Francisco, State of California. I am over the age of eighteen (18) years and not a party to the within action. My business address is 275 Battery Street, San Francisco, California 94111-3339. I am readily familiar with Lieff, Cabraser, Heimann & Bernstein, LLP's practices for collection and processing of documents for mailing with the United States Postal Service and for transmission via facsimile machine. On the date listed below, I served copies of the following document(s):

PETITIONERS' MOTION REQUESTING JUDICIAL NOTICE

upon the parties and attorneys listed below via U.S. Mail as follows:

Second District California Court of Appeal
Ronald Reagan State Building
300 S. Spring Street
Los Angeles, CA 90013

Superior Court of Los Angeles
600 Commonwealth Avenue
Los Angeles, CA 90005

upon the parties and attorneys listed below via U.S. Mail and email as follows:

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I declare under penalty of perjury under the laws of the State Bar of California that the foregoing is true and correct and that this proof of service was executed on August 6, 2018, at San Francisco, California.

Wilson M. Dunlavey

WILSON M. DUNLAVEY

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EXHIBIT A

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CONFORMED COPY
ORIGINAL FILED
Superior Court of California
County of Los Angeles

JUL 20 2018

Sherri R. Carter, Executive Officer/Clerk of Court
By: Brittny Smith, Deputy

SUPERIOR COURT OF THE STATE OF CALIFORNIA

FOR THE COUNTY OF LOS ANGELES

COORDINATION PROCEEDING SPECIAL TITLE [RULE 3.550]

SOUTHERN CALIFORNIA GAS LEAK CASES

THIS FILING RELATES TO:

Toll Brothers, Inc. and Porter Ranch Development Company v. Sempra Energy, Southern California Gas Company, et al. (Case No. BC674622)

JUDICIAL COUNCIL COORDINATION PROCEEDING NO. 4861

Case Assigned for All Purposes to the Honorable John Shepard Wiley, Jr. Department 9

FIRST AMENDED COMPLAINT FOR:

1. **STRICT LIABILITY**
2. **NEGLIGENCE PER SE**
3. **NEGLIGENCE (CORPORATE)**
4. **NEGLIGENCE (INDIVIDUALS)**
5. **CONTINUING PUBLIC NUISANCE**
6. **CONTINUING PRIVATE NUISANCE**
7. **PERMANENT PUBLIC NUISANCE**
8. **PERMANENT PRIVATE NUISANCE**
9. **TRESPASS**
10. **VIOLATION OF CALIFORNIA BUSINESS & PROFESSIONS CODE §§ 17200, et seq.**

JURY TRIAL DEMANDED

Plaintiffs Porter Ranch Development Company ("PRDC") and Toll Brothers, Inc. ("Toll" and, with PRDC, "Plaintiffs") sue Defendants Southern California Gas Company ("SoCalGas"), Sempra Energy ("Sempra" and, together with SoCalGas, "Utility Defendants"), Dennis Arriola, J. Bret Lane, Martha B. Wyrsch, G. Joyce Rowland, Jessie Knight, Joseph A. Householder, and Steven D. Davis (collectively, the "Individual Defendants" and, together with the Utility Defendants, the "Defendants"), and Does 1-100, and allege as follows:

I. INTRODUCTION

1. This case arises out of extensive damage to Plaintiffs' development of the Porter Ranch community ("Porter Ranch") resulting from a gas blowout caused by Defendants' failure to properly construct, maintain, and operate their Aliso Canyon natural gas storage well field ("Aliso Canyon"), which lies adjacent to Porter Ranch.

2. Porter Ranch is the largest master-planned community in the Los Angeles area, with approximately 6,000 home sites, over 1500 of which were still being developed by Plaintiffs at the time of the gas blowout. Perched on a scenic promontory high above Los Angeles, just south of the Santa Susana Mountains, Porter Ranch has been described as a model for upscale California suburban living. Prior to the Blowout, the Porter Ranch development had been very successful over many years due to the high quality of the homes, the great location and views, the many parks and amenities, and Toll's outstanding reputation as a builder and developer.

3. On October 23, 2015, SoCalGas claims it discovered a catastrophic blowout of the Standard Sesnon No. 25 natural gas injection well (the "SS-25 Well") that is owned, controlled, maintained, and operated by the Utility Defendants at Aliso Canyon (the "Blowout"). Between that date and February 2016 when the SS-25 Well was capped, the Blowout ejected natural gas, chemicals, and other pollutants. The Blowout not only upended the lives of those already living and doing business in Porter Ranch, with residents uprooted from their homes and children sent to new schools, but it also had a serious impact on Plaintiffs' remaining development of Porter Ranch.

4. Following the Blowout, the sale of new homes at Porter Ranch essentially came to a stop. As a result, Plaintiffs' development plans for Porter Ranch have been set back years.

Plaintiffs are committed to completing the development of Porter Ranch, and a fully developed community of excellence will eventually exist there. However, due to the Blowout, it will now exist years after it otherwise would have. The results are dramatically higher costs, which combined with years of delay in homes sales and completion of the community, have caused hundreds of millions of dollars in damages to Plaintiffs.

5. Defendants knew that the well blowout was a catastrophe waiting to happen—and that when it did happen it would have dire consequences to the residents, businesses, and property owners in and around Aliso Canyon, including Porter Ranch. Since the Blowout, it has become publicly known that Defendants negligently operated the Aliso Canyon facility. Defendants failed to implement appropriate safeguards, conduct required maintenance, and perform necessary repairs for the SS-25 Well prior to its catastrophic Blowout. Indeed, the SS-25 Well had no safety valve—a basic piece of safety equipment—because Defendants removed it in 1979 and never replaced it.

6. Information made public revealed that Defendants took a reckless attitude toward the operation of Aliso Canyon, and the SS-25 Well in particular. Rather than designing, implementing, and operating a repair and maintenance protocol that would minimize the possibility of a well blowout, Defendants designed a so-called maintenance and repair plan that was reactive instead of proactive: Defendants' maintenance plan relied on the occurrence of problems as a trigger for repair, rather than requiring that known and expected problems be addressed before they escalated to the type of catastrophe that occurred when the SS-25 Well blew out. It was this fundamental failure by Defendants to properly maintain and operate Aliso Canyon that caused the Blowout.

7. The Blowout was thus not unforeseeable to Defendants. Defendants knowingly implemented their deficient maintenance and repair plan despite the fact they knew that their activities at Aliso Canyon risked a blowout that posed an inherent and significant danger to the surrounding communities, including Porter Ranch. For example, in testimony before California's Public Utilities Commission in 2014, the Utility Defendants admitted that aging wells in Aliso

Canyon had "integrity" problems and that their "reactive" policy and practices exposed the public to the risk of "uncontrolled well-related situations."

8. Similarly, in Sempra's 10-K for the year 2014, filed with the Securities and Exchange Commission ("SEC") on February 26, 2015—just eight months before the Blowout—the Utility Defendants acknowledged that, "Because we are in the business of ... storing ... highly flammable and explosive materials ... and operating highly energized equipment, the risks such incidents may pose to our facilities and infrastructure, as well *as the risks to the surrounding communities* are substantially greater than the risks such incidents may pose to a typical business."[1] In the same document, the Utility Defendants admitted that one of the activities posing that substantially greater risk is "storage" of natural gas. The Utility Defendants further conceded that "any such incident also could cause catastrophic ... leaks, ... explosions, spills or other significant damage to ... property belonging to third parties, or cause personal injuries or fatalities," which "could lead to significant claims against us."

9. In short, Defendants failed to take the necessary steps to prevent a catastrophe. As a direct consequence of Defendants' malfeasance, the catastrophe happened, causing hundreds of millions of dollars in damage to Plaintiffs.

II. NATURE OF THE ACTION

10. Plaintiffs sue the Utility Defendants for strict liability; for negligence *per se* for violating, *inter alia*, California Health and Safety Code § 41700 and South Coast Air Quality Management District Rule 402 in operating the SS-25 Well; for negligence pursuant to California Civil Code § 1714; for nuisance pursuant to California Civil Code § 3479; for trespass in violation of California Civil Code § 3334; and for violating California Business & Professions Code §§ 17200, *et seq*. Plaintiffs sue the Individual Defendants for negligence, pursuant to California Civil Code § 1714.

III. JURISDICTION AND VENUE

11. This Court has personal jurisdiction over the Utility Defendants because SoCalGas and Sempra are headquartered in California and do business in the County of Los Angeles,

[1] In this complaint, all emphasis in quoted material is added, unless otherwise stated.

California. Moreover, their actions giving rise to the claims against them were taken in California and caused Plaintiffs' injury in California. Plaintiffs' damages exceed the jurisdictional minimum for this Court.

12. This Court has personal jurisdiction over the Individual Defendants because each of them does business in the County of Los Angeles as a director of Defendant SoCalGas and, on information and belief, reside in California. Moreover, their actions giving rise to the claims against them were taken in California and caused Plaintiffs' injury in California.

13. Venue in Los Angeles County and in this judicial district is proper pursuant to California Code of Civil Procedure §§ 395 and 395.5 because Defendants are located in and/or perform business in this County, and a substantial part of the events, acts, omissions, transactions, and injury complained of herein occurred in and/or originated within Los Angeles County.

IV. <u>PARTIES</u>

14. Plaintiff PRDC is a corporation with its principal place of business in Los Angeles, California. PRDC owns properties in California, including in Porter Ranch, which it is developing into a master-planned community of homes. PRDC is a wholly owned subsidiary of Toll.

15. Plaintiff Toll is a Delaware corporation with its principal place of business in Pennsylvania. Toll has developed communities in 20 states, including California. In 2017, Toll was named the World's Most Admired Home Building Company by *Fortune* magazine, the third year in a row that it has been so honored.

16. Defendant SoCalGas is a California corporation with its principal place of business in Los Angeles, California. SoCalGas is a natural gas distribution utility that owns and operates Aliso Canyon, the natural gas distribution, transmission, and storage system located in Los Angeles County, California. SoCalGas is the nation's largest gas distribution utility provider, serving more than 20 million natural gas consumers throughout Southern and Central California. In 2015, SoCalGas had natural gas revenues of over $3.4 billion. SoCalGas is both a "Gas Corporation" and a "Public Utility" pursuant to California Public Utilities Code §§ 222 and 216(a), respectively.

17. Defendant Sempra is a California corporation with its principal place of business in San Diego, California. Defendant SoCalGas is a wholly-owned subsidiary of Sempra. Sempra is a Fortune 500 energy services holding company with revenues of more than $10 billion in 2015.

18. At all material times, SoCalGas was Sempra's agent with respect to the operation, repair, and maintenance of Aliso Canyon, including the SS-25 Well. Sempra is liable for the acts of SoCalGas that give rise to the claims asserted in this complaint, as it has enacted a corporate structure that has placed it in control of SoCalGas's operation of Aliso Canyon. In 2001, Sempra filed with the Public Utilities Commission a Petition to Modify Decision, in which it sought a "declaratory order affirming that its proposed reorganization of its California utility subsidiaries, SoCalGas and San Diego Gas & Electric Company ("SDG&E") is within the authority granted by the Commission in D.98-03-073." The basis for the reorganization was to create efficiencies and savings by integrating certain functions at the two utilities. The reorganization served to "integrate most gas and electric operations at the senior leadership level" of the two subsidiaries, requiring that "most officers would carry responsibility for their function in both corporate utility entities," so that "[s]uch integrated operations would report to the President or CEO of Sempra's Regulated Utilities Group." In structuring itself in this manner, Sempra gained day-to-day control of SoCalGas's "gas operations," thus establishing an agency relationship with SoCalGas. Sempra is thus liable for the acts of SoCalGas that give rise to the claims asserted in this complaint.

19. Sempra is also liable for SoCalGas's conduct alleged herein because there is such unity of interest and ownership between Sempra and SoCalGas that the separate personalities of those entities no longer exist with respect to the operation of Aliso Canyon, rendering SoCalGas the alter ego of Sempra. For that reason, Sempra, the entity operating Aliso Canyon as a practical matter, should be held responsible for its actions related to the Blowout. The alter ego nature of the relationship between the two companies is evidenced by, upon information and belief, the following:

a. SoCalGas and Sempra as a practical matter operate as a single business enterprise for the purpose of effectuating and carrying out Sempra's business and operations for the benefit of Sempra.

b. Defendants do not operate as completely separate entities, but rather, integrate their operations under direction to achieve a common business purpose. Sempra's public filings with the SEC describe SoCalGas as one of its "principal operating units." On its website, SoCalGas describes itself as a "Sempra Energy, regulated California utility."

c. Consistent with its description of SoCalGas as an "operating unit," the corporate structure set in place by Sempra provides that Sempra will sit as the *de facto* decision-maker with respect to the integrated operations of its gas operations.

d. SoCalGas's income contribution results from function integration, centralization of management, and economies of scale with Sempra.

e. SoCalGas's and Sempra's officers and management are intertwined and do not act completely independently of one another.

f. The integrated operations of SoCalGas and SDG&E "report to the President or CEO of Sempra's utility group."

g. SoCalGas is so organized and controlled, and its decisions, affairs, and business so conducted as to make it a mere instrumentality, agent, conduit, or adjunct of Sempra.

h. Sempra has control and authority to choose and appoint SoCalGas's board members as well as its other top officers and managers. The majority of SoCalGas's board is comprised of Sempra executive officers. Other members of the board were previously employed by Sempra in leadership positions.

i. Sempra's officers, directors, and other management make policies and decisions to be effectuated by SoCalGas or otherwise provide direction and make decisions for SoCalGas both in setting and implementing policies.

j. Sempra's officers, directors, and other management direct certain financial decisions for SoCalGas, including the amount and nature of capital outlays.

k. Sempra maintains unified personnel and administrative control over SoCalGas. For example:

i. Sempra and SoCalGas have unified personnel policies and practices and/or a consolidated personnel organization or structure.

ii. Sempra's written guidelines, policies, and procedures control SoCalGas, its employees, policies, and practices.

iii. Sempra and SoCalGas have unified accounting policies and practices dictated by Sempra and/or common or integrated accounting organizations or personnel.

iv. Sempra and SoCalGas are insured by the same carriers and provide uniform or similar health, life, and disability insurance plans for employees.

v. Sempra and SoCalGas have unified 401(k) plans, pensions and investment plans, bonus programs, vacation policies, and paid time off from work schedules and policies. They invest these funds from their programs and plans by a consolidated and/or coordinated Benefits Committee controlled by Sempra and administered by common trustees and administrators.

l. Sempra and SoCalGas are generally represented jointly by the same legal counsel.

m. Sempra files consolidated earnings statements factoring all revenue and losses from SoCalGas as well as consolidated tax returns, including those seeking tax relief.

n. Despite both being Gas Companies and Public Utilities, SoCalGas and Sempra have been structured and organized so as to create an integrated single enterprise.

o. Sempra generally directs and controls SoCalGas's relationship with the California Public Utilities Commission, including in the making of requests to, and responding to inquiries from, the Commission.

20. Sempra's control over, and the nature of its unitary operations with, SoCalGas are illustrated by its enactment of a corporate structure under which it controls the operations of its subsidiaries, SDG&E and SoCalGas, including with respect to the operation of Aliso Canyon. In 2001, Sempra filed with the Public Utilities Commission a "Petition to Modify Decision," in which it sought a "declaratory order affirming that its proposed reorganization of its California utility subsidiaries, Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E)" was within the scope of the approved merger of those entities. The stated basis for the reorganization was to create efficiencies and savings by "grouping gas and electric distribution operations together *under common leadership and management*." To accomplish that purpose, Sempra requested from the Public Utilities Commission "authorization to integrate core utility functions at the leadership level by *appointing common officers who would lead integrated functions for both SDG&E and SoCalGas*." As a result, "Sempra [was] authorized to *integrate core utility functions* as set forth in this decision *at the leadership level by appointing common officers who would lead integrated functions for both SDG&E and SoCalGas*." The reorganization served to "*integrate most gas and electric operations at the senior leadership level*" of the two subsidiaries, requiring that "*most officers would carry responsibility for their function in both corporate utility entities*," so that "*such integrated operations would report to the President or CEO of Sempra's Regulated Utilities Group*." In structuring its operations in this manner, Sempra positioned itself as the senior decision-maker with respect to the day-to-day operations of SoCalGas's "gas operations," thus establishing its direct control over SoCalGas's natural gas operations at Aliso Canyon.[2]

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[2] Although the decision of the Public Utilities Commission required that "Sempra must obtain the approval of the Commission before it may transfer any operational or managerial responsibilities from the utility level to the holding company beyond the holding company responsibilities that were set forth in Sempra's original merger proposal," as a matter of fact the restructuring placed the operational control of the "integrated" gas operations upon a Sempra officer.

21. The totality of the circumstances bearing on the relationship between Sempra and SoCalGas, as alleged above, establish that at all times material to Plaintiffs' claims there was such unity of interest and ownership as between Sempra and SoCalGas that the separate personalities of the companies ceased to exist with respect to the operation, maintenance, and repair of Aliso Canyon, including the SS-25 Well, and, therefore, actions of either Sempra and SoCalGas relating to Aliso Canyon should be treated as those of both Sempra and SoCalGas.

22. Dennis Arriola was Chairman of the Board of Directors from November 2015 until December 2016, and was the Chief Executive Officer of SoCalGas from March 2014 until December 2016. In these positions, he was involved in overseeing all of the operations of SoCalGas, including, but not limited to, its gas storage facilities at Aliso Canyon and its statements to the California Public Utilities Commission. In those positions, Arriola knew or should have known about the dangerous operating conditions at the Aliso Canyon facility, including the deficient maintenance and repair program and the safety problems Defendants acknowledged before the California Public Utilities Commission in 2014. Yet he failed to take appropriate actions to redress these conditions.

23. J. Bret Lane is the President and Chief Operating Officer of SoCalGas. Lane has been the President since September 2016 and the Chief Operating Officer since January 2014. Lane has also been a member of the Board of Directors of SoCalGas since March 2014. In these positions, he was involved in overseeing the day-to-day operations of SoCalGas, including, but not limited to, its gas storage facilities and its statements to the California Public Utilities Commission. In those positions, Lane knew or should have known about the dangerous operating conditions at the Aliso Canyon facility, including the deficient maintenance and repair program and the safety problems Defendants acknowledged before the California Public Utilities Commission in 2014. Yet he failed to take appropriate actions to redress the conditions.

24. Martha Wyrsch is a member of the Board of Directors of SoCalGas. Wyrsch became a director in September 2013. As a director, Wyrsch knew or should have known about the dangerous operating conditions at the Aliso Canyon facility, including the deficient maintenance and repair program and the safety problems Defendants acknowledged before the

California Public Utilities Commission in 2014. Yet she failed to take appropriate actions to redress the conditions.

25. G. Joyce Rowland is a member of the Board of Directors of SoCalGas. Rowland became a director in September 2015. As a director, Rowland knew or should have known about the dangerous operating conditions at the Aliso Canyon facility, including the deficient maintenance and repair program and the safety problems Defendants acknowledged before the California Public Utilities Commission in 2014. Yet she failed to take appropriate actions to redress the conditions.

26. Jessie Knight was a member of the Board of Directors of SoCalGas from March 2014 to November 2015. As a director, Knight knew or should have known about the dangerous operating conditions at the Aliso Canyon facility, including the deficient maintenance and repair program and the safety problems Defendants acknowledged before the California Public Utilities Commission in 2014. Yet he failed to take appropriate actions to redress the conditions.

27. Joseph A. Householder was a member of the Board of Directors of SoCalGas from April 2010 to September 2015. As a director, Householder knew or should have known about the dangerous operating conditions at the Aliso Canyon facility, including the deficient maintenance and repair program and the safety problems Defendants acknowledged before the California Public Utilities Commission in 2014. Yet he failed to take appropriate actions to redress the conditions.

28. Steven D. Davis is a member of the Board of Directors of SoCalGas. Davis became a director in November 2015. As a director, Davis knew or should have known about the dangerous operating conditions at the Aliso Canyon facility, including the deficient maintenance and repair program and the safety problems Defendants acknowledged before the California Public Utilities Commission in 2014. Yet he failed to take appropriate actions to redress the conditions.

29. DOES 1 through 50 inclusive are the partners, agents, employees, contractors, principals, officers, directors, affiliates, and/or subsidiaries of the named Defendants, and of each other whose true names and capacities are currently unknown to Plaintiffs. Plaintiffs are informed

and believe, and thereupon allege, that each of the DOES 1 through 50 is legally responsible, negligently or in some other actionable manner, for the events and happenings alleged herein, and proximately caused the injuries described below. DOES 1 through 50 are liable to Plaintiffs to the extent of the liability of the named Defendants. Plaintiffs will amend this Complaint to assert the true names and/or capacities of the DOES 1 through 50 when ascertained. DOES 51 through 100, inclusive are the manufacturers, distributors, and contractors responsible for the manufacture, distribution, and installation of the materials and equipment associated with the SS-25 Well, and whose true names and capacities are currently unknown to Plaintiffs. Plaintiffs are informed and believe, and thereupon allege, that each of the DOES 51 through 100 is legally responsible, negligently or in some other actionable manner, for any product failure that contributed to events and happenings alleged herein, and proximately caused the injuries described below. Plaintiffs will amend this Complaint to assert the true names and/or capacities of the DOES 51 through 100 when ascertained.

V. FACTUAL ALLEGATIONS

A. Plaintiffs' Porter Ranch Development

30. Since 1967, Toll has been in the business of developing residential communities across the country. In order to bolster its footprint in desirable California locations that fit its existing operations in the state, on February 4, 2014, Toll acquired Shapell Industries, Inc.'s residential property holdings for approximately $1.6 billion.

31. Nearly a third of that purchase price related to the purchase of PRDC and its holdings in Porter Ranch, which included the future development of approximately 1,734 additional home sites. At the time of the Blowout, 1,530 of those lots remained to be developed by Plaintiffs and, as of today, almost 1,400 remain to be developed. Since the acquisition, Plaintiffs have spent more than $100 million developing Porter Ranch and anticipate spending hundreds of millions of dollars more to develop the community over the coming years.

32. Porter Ranch consists of luxury homes and communities with superior design options, excellent amenities, and the highest-quality construction. The Blowout's impact on Plaintiffs' development of Porter Ranch was immediate. At the time of the Blowout, 61 buyers

were under contract to purchase homes in Porter Ranch. Of those pending sales, 21 were cancelled, dozens more were delayed, and Plaintiffs were obligated to provide significant financial concessions to avoid losing dozens more contracted sales.

33. But the impact did not end with these contracted sales. New sales came to a screeching halt following announcement of the Blowout. In the six months following the announcement, Plaintiffs managed only 18 sales. During that same six month period, 19 buyers cancelled their pre-Blowout contracts (and two more contracts were cancelled after that). Thus, during the six months after the Blowout, Toll had net sales of -1 home in Porter Ranch. By comparison, during the same six-month period the prior year, Plaintiffs had net sales of 74 homes in Porter Ranch. The impact of the Blowout on Plaintiffs' sales continues today, and the development of Porter Ranch is years away from a full recovery.

34. In addition to the property under development, Plaintiffs own another 410 acres of undeveloped or partially undeveloped land in Porter Ranch. Before the Blowout, Plaintiffs had embarked upon a detailed plan and schedule to develop this land, with the intent of completing the development of existing communities and creating an additional eight communities, including building on approximately 1,530 undeveloped home sites and establishing large nature areas. At the time of the Blowout, Plaintiffs had made substantial progress in the execution of their development plan, having already sold more than 200 homes, and begun work on developing the eight new communities. Due to the long and successful track record of development at Porter Ranch, Toll's experience and reputation as a developer and builder, and the strong demand for homes in Porter Ranch before the Blowout, Plaintiffs' plans for the existing and new communities in Porter Ranch were both well substantiated and conservative. The Blowout significantly impeded the planned development of these properties, setting back Plaintiffs' development plans by years, with the attendant loss of hundreds of millions of dollars in profits.

B. <u>The Utility Defendants' Aliso Canyon Underground Storage Field</u>

35. SoCalGas is the nation's largest natural gas distribution utility. It owns and operates a natural gas storage, distribution, and transmission system throughout its approximately 20,000 square miles of service territory in Southern and Central California.

36. In addition to Aliso Canyon, SoCalGas operates three underground storage fields in converted oil fields in Los Angeles County. SoCalGas pipes in and stores billions of cubic feet of natural gas in these four storage facilities, which have a combined working capacity of approximately 136 billion cubic feet. To store natural gas at these facilities, SoCalGas injects gas into underground reservoirs using injection wells. These injection wells require substantial pressure to force natural gas down into the reservoir.

37. In 1971, SoCalGas bought the depleted Aliso Canyon oil field, which lies adjacent to Porter Ranch, and converted it into a natural gas storage field. The Aliso Canyon storage field began natural gas storage operations in 1973, although many of the converted oil wells date back to the 1940s.

38. Aliso Canyon is SoCalGas's largest underground natural gas storage facility and is the largest underground storage facility in the Western United States. Aliso Canyon can hold more than 166 billion cubic feet of natural gas, of which 86 billion cubic feet is usable natural gas and another 80 billion cubic feet is used as "cushion gas," which is gas that is supposed to remain underground to keep the reservoir's pressure high enough so that gas can be moved in and out. SoCalGas has estimated that, within Aliso Canyon, there are approximately 38 miles of gas injection, withdrawal, and liquid-handling pipelines that connect the storage wells to processing and compression facilities.

39. At the time of the blowout, the Aliso Canyon storage field had approximately 115 active injection wells. More than 40 of the 115 injection wells—including the SS-25 Well—are over 50 years old. The average depth of the wells is approximately 8,500 feet. SoCalGas pipes in natural gas and then uses the wells to inject the natural gas into the Sesnon-Frew reservoir for later distribution. SoCalGas also relies upon the wells to dispose of toxic wastewater from oil and natural gas operations and to inject water to force oil and gas from one part of the field to another part.

40. SoCalGas's operation of these aging injection wells at Aliso Canyon is an ultrahazardous activity. As detailed below, SoCalGas pumped natural gas through both the inner and outer casing of the SS-25 Well, which did not have a subsurface safety valve or a protective

cemented casing that went all the way to the surface. These factors rendered the SS-25 Well even more hazardous than the rest of Aliso Canyon.

C. **<u>The Well Blowout</u>**

41. The October 2015 Blowout was caused by unrepaired damage to the casing of the SS-25 Well at approximately 500 feet underground. SoCalGas claims it discovered the uncontrolled Blowout on October 23, 2015. The SS-25 Well was originally drilled as an oil well in 1953. In 1973, SoCalGas converted the SS-25 Well from an oil well into a natural gas injection well, which extends over 8,700 feet below the surface. At the time of the Blowout, the SS-25 Well was over 60 years old. As discussed below, although the SS-25 Well originally had a downhole safety valve, SoCalGas removed this critical safety feature and never replaced it, enhancing the danger posed by this aging well.

42. The Blowout dispersed natural gas, and other pollutants into the adjacent Porter Ranch community. Natural gas is a hydrocarbon gas mixture that consists primarily of methane. Methane is a highly flammable and combustible gas. On November 20, 2015, the California Air Resources Board ("CARB") released a report showing that the SS-25 Well was leaking a tremendous amount of methane. According to that report, methane was being released at a rate of 50,000 kilograms (or 50 metric tons) an hour. According to the final report issued by the CARB on October 21, 2016, entitled "Determination of Total Methane Emissions from the Aliso Canyon Natural Gas Leak Incident" (the "CARB Report"), "[t]he emissions were a major public nuisance, and resulted in more than 2,300 odor complaints during the leak from the nearby communities.... In addition to the leak's many effects on local residents, the methane emissions from Aliso Canyon exacerbated statewide greenhouse gas emissions which contribute to climate change.... [The leak] alone was responsible for approximately 20 percent of statewide methane emissions, which is double the statewide fugitive emissions from oil and gas production."

43. According to the CARB Report, between October 23, 2015, and February 18, 2016, the SS-25 Well released approximately 100,000 metric tons of methane, which effectively doubled the methane emission rate of the entire Los Angeles area during that period. The leaking methane gas created a significant risk of fire and/or explosions. Because of this risk, the Federal Aircraft

Administration prohibited flights below 2,000 feet within a half-mile radius of the leaking SS-25 Well.

44. The Blowout continued without interruption for approximately four months. According to the Final Report of the Interagency Task Force on Natural Gas Storage Safety, published on October 18, 2016 (the "Interagency Task Force Report"), the Blowout resulted in "the largest methane leak from a natural gas storage facility in United States history." The South Coast Air Quality Management District found that the air contaminants released as a result of the Blowout "created a public nuisance by discharging such quantities of natural gas into the surrounding communities ... in violation of Health & Safety Code Section 41700 and SCAQMD Rule 402." The governor and the County Board of Supervisors declared a state of emergency. The Los Angeles County Department of Public Health ordered the implementation of a temporary relocation program for surrounding communities, including Porter Ranch.

45. As a result of the Blowout, approximately 15,000 people (residents of 8,000 homes) were displaced from their homes for months, and two schools were relocated for the remainder of the 2015-2016 school year.

D. Utility Defendants Knowingly Operated Aliso Canyon in a Manner That Increased the Risks of a Blowout

46. The Utility Defendants knowingly operated the injection wells at Aliso Canyon, and, in particular, the SS-25 Well, in a manner that increased the likelihood of an uncontrolled blowout. For example:

a. The SS-25 Well was not equipped with a working safety valve. A 1976 SoCalGas application to the State Department of Oil and Gas to increase storage pressure at Aliso Canyon touted the facility's modern safety features. Based on that application, the State approved the request to increase storage pressure. Yet, in 1979, SoCalGas removed one of those safety features, the downhole safety valve for the SS-25 Well. The valve had "failed to test," and, according to a SoCalGas executive, the company decided against replacing it because the well was not deemed "critical."

b. As reflected in the October 18, 2016, Interagency Task Force Report, SoCalGas knowingly increased the risk of a massive blowout by drawing gas through *both* the inner metal tubing and the larger outer casing of the SS-25 Well in order to increase well production at the expense of safety. This weakened and eroded the SS-25 Well's outer casing and eliminated its purpose, which is to act as a safety barrier in case of a leak in the inner metal tubing. As a result, the long casing string functioned as a single barrier to the environment. SoCalGas waited until after the Blowout to implement a policy of "[w]ithdrawal and injection only through each well's tubing." When it announced this policy change, SoCalGas admitted that the "physical barrier [of the outer casing] provides another layer in the well to protect against leaks" if gas is withdrawn and injected only through the well's tubing. Rodger Schwecke, a Vice President of SoCalGas, admitted that the Utility Defendants waited until after the Blowout before they stopped using the casing "for flow." Defendant Lane similarly admitted that because of "the other safety measure that we have ... now going forward for Aliso [but did not have before the Blowout], they will only flow through the tubing." "So now there's an extra barrier of safety around it, as well." That extra barrier should have existed before the Blowout.

c. The SS-25 Well, like many other injection wells operated by SoCalGas, did not have cemented casing all the way to the surface. The October 18, 2016, Interagency Task Force Report explained that this meant the SS-25 Well was "uncemented in the uppermost critical sections." In the event of a blowout, gas could escape due to the absence of this casing.

d. Despite knowing that there had been corrosion and leaks detected on several wells at Aliso Canyon, Defendants designed and implemented a maintenance and repair plan that was reactive rather than proactive, meaning that Defendants waited until potential problems became actual problems before they were addressed. Thus, for example, SoCalGas did not implement a Storage Integrity Management Program or any other comprehensive safety plan at Aliso Canyon, which would have proactively addressed the known safety risks associated with the aging injection wells, including the SS-25 Well. In 2014, SoCalGas admitted that such a program was necessary to operate its storage facilities prudently. But it only began implementing aspects of such a program after the Aliso Canyon disaster occurred. The Department of Conservation, Division of Oil, Gas and Geothermal Resources ("DOGGR") found that SoCalGas's failure to implement such a Storage Integrity Management Program before the Blowout "raises concerns about the integrity and safety of the wells in the gas storage injection project." DOGGR's concerns were warranted, as the vast majority of the Aliso Canyon wells have since been taken out of operation or plugged. Defendant Lane has admitted that the Utility Defendants only began designing a "comprehensive safety plan that is directly for Aliso Canyon" after the Blowout occurred. He further admitted that the Utility Defendants waited until after the Blowout before "really want[ing] to make sure that all the wells have been thoroughly assessed to ensure their safety and integrity as we move forward with the facility." Similarly, Mr. Schwecke recently admitted that the Utility Defendants waited until after the Blowout before taking precautions to "give us those early indicators, if there could be a problem."

e. The Utility Defendants also failed to properly maintain and test the SS-25 Well. State Department of Conservation files contain no record of any pressure tests conducted on the SS-25 Well after 2006 or of any structural integrity tests conducted after 1991. The October 18, 2016, Interagency Task Force Report found that "[l]ogs that could be used to assess the risk of the well system (e.g., metal loss in the casing) were not located." This is consistent with how SoCalGas operated Aliso Canyon generally. For example, according to the same report, "there are preliminary indications that the practices for monitoring and assessing leaks (temperature and noise) and leak potential (cement bond, metal thickness, and pressure testing) at the Aliso Canyon facility were inadequate to maintain safe field operating pressures." And "before the 2015 leak event, the vast majority of the wells remained unevaluated for cement integrity along the production casing." Despite this failure to test, in 2014 Defendants chose to install powerful new turbine compressors, reportedly costing more than $200 million, to boost the amount of gas that can be compressed for injection in a single day at Aliso Canyon. This significantly increased Defendants' ability to force natural gas into storage, albeit without addressing the significant safety problems of which they were aware.

47. Just as they failed to take appropriate action before the Blowout, the Utility Defendants were wholly unprepared to stop the Blowout once it occurred. For example, they failed to have effective contingency plans in place for such an event and failed to pre-position mechanical and technical resources that would be needed in the event of such a blowout. Indeed, the Utility Defendants only began creating such plans for Aliso Canyon after the Blowout occurred. This lack of preparation resulted in substantial delays in the Utility Defendants' efforts to stop the Blowout and mitigate its damaging effects.

48. To make matters worse, Defendants also delayed reporting the Blowout. Despite discovering it on October 23, they failed to report it until October 25. Even then, the report was cryptic and designed to downplay the severity of the Blowout: "Leak from an existing Aliso Canyon gas storage well. No ignition, no injury. No media. Notification due to operator judgment only."

49. Defendants also delayed providing regulators with important information about the Blowout. As of November 18, 2015, Defendants still had not provided DOGGR with "information about, and results from, some of the tests and/or remedial work" being performed, even though the Utility Defendants' efforts had "not yet remedied the uncontrolled flow of fluids or stop[ped] the waste of gas." DOGGR therefore had to issue an emergency order requiring SoCalGas to provide such information. On December 10, 2015, DOGGR again had to issue an emergency order, "[f]inding that an emergency exists, and in order to protect life, health, property, and natural resources, the Supervisor needs immediate access to data to monitor and address the uncontrolled flow of fluids and current and future remedial work."

50. As the result of their lack of appropriate planning, the Utility Defendants' initial attempts to stop the Blowout were ill-conceived and unsuccessful. According to the October 18, 2016, Interagency Task Force Report, the "leak was exacerbated by repeated (eight) top kill attempts over the course of the first two months of the event." The many problems with these kill attempts were exacerbated by "limitations caused by concerns for the structure of the wellhead." These ill-conceived, unsuccessful and poorly executed top kill efforts caused particulates, compounds and other materials to be sprayed and deposited throughout the Porter Ranch community, including on Plaintiffs' property.

51. Moreover, despite the enormity of the Blowout, SoCalGas did not immediately construct a relief well in parallel with those top kill attempts, which eventually proved to be the only way to effectively stop the Blowout. On or about November 25, 2015—more than a month after SoCalGas claims it discovered the Blowout—SoCalGas finally determined it needed to drill such a relief well. SoCalGas did not begin drilling the relief well until December 4, 2015.

52. On February 12, 2016, the relief well intercept occurred, which finally stopped the Blowout—113 days after SoCalGas claims it began. On February 18, 2016, DOGGR certified that the SS-25 Well was sealed.

E. <u>Defendants Knew There Were Widespread Problems with Their Gas Injection Wells Long before the Aliso Canyon Disaster Occurred</u>

53. Defendants' actions described above were all the more egregious because they long knew that Aliso Canyon's aging wells were deteriorating and posed a serious safety risk. Yet, despite the risk of a blowout, Defendants did not take reasonable steps to prevent or diminish such a blowout from occurring. This, despite the Utility Defendants' public acknowledgment before the Blowout that such risks could cause "significant damages to natural resources or property belonging to third parties, or cause personal injuries or fatalities. Any of these consequences could lead to significant claims against us."

54. When SoCalGas sought a rate increase in December 2010, it recognized that "many valves (block well site, safety, etc.) in the [Aliso Canyon] Storage Field are leaking." Yet the Defendants did not take reasonable action to address these ongoing problems.

55. In 2014, SoCalGas sought another rate increase, purportedly to address the significant safety concerns posed by its aging wells. At that time, SoCalGas gave sworn testimony through Philip E. Baker before the Public Utilities Commission, in which it admitted there were significant safety problems associated with its aging wells, including those at Aliso Canyon, that needed to be addressed proactively. For example, in that sworn testimony, Defendants admitted:

a. "[A] negative well integrity trend seems to have developed since 2008," with an "increasing number of safety and integrity conditions." SoCalGas attributed this negative integrity trend "primarily to the frequency of use, exposure to the environment, and length of time the wells have been in service."

b. There was a history of gas leaks at Aliso Canyon that predate the Blowout. In 2008, SoCalGas discovered a well with an amount of pressure that was "indicative of production casing leaks from either internal or external corrosion where high pressure gas can migrate to the surface in a matter of hours." In 2013, SoCalGas identified at least two wells that were found to have leaks in the production casing. "External corrosion had also been observed in other wells" in the Aliso Canyon field. In addition to external casing corrosion, SoCalGas observed mechanical wear in production casings and external tubing corrosion.

c. All of SoCalGas's storage facilities had aging wells that were leaking. From 2008 to 2013, SoCalGas identified internal/external casing corrosion or mechanical damages in 15 wells that were part of a survey. During that same period, there were another 36 wells identified as having significant integrity problems, including casing leaks, tubing leaks, wellhead leaks, casing shoe leaks, and sub-surface safety valve issues. In 2014, there were at least 26 existing mechanically unsound, unproductive, or aging storage wells located in environmentally-sensitive areas.

d. The Aliso Canyon facility had numerous aging wells. "Aging wells, compressors, and gas and liquid piping systems are susceptible to unpredictable failures or preemptive repair situations."

56. In the same sworn testimony, Defendants, again through Mr. Baker, further admitted that it was "critical that we adopt a more proactive and in-depth approach" to safety and risk consideration and had identified the steps that needed to be taken to implement such an approach in a Storage Integrity Management Program. SoCalGas admitted that a "proactive, methodical, and structured approach, using state-of-the-art inspection technologies and risk management disciplines to address well integrity issues before they result in unsafe conditions, or become major situational or media incidents, is a *prudent* operating practice."

57. In the testimony, SoCalGas also admitted that "[t]his concern is further amplified by the age, length, and location of wells. Some SoCalGas wells are more than 80 years old with an average age of 52 years. Well depths can exceed 13,000 feet. In addition, *some wells are located within close proximity to residential dwellings or high consequence areas*." Defendants knew how to implement such a proactive approach because, as was admitted in the 2014 sworn testimony and in recent comments by Defendant Lane during a Joint Agency Workshop on Aliso Canyon Action Plan, such a safety program would be similar to SoCalGas's existing pipeline risk mitigation programs.

58. However, as the 2014 sworn testimony reflects, Defendants chose not to take this proactive approach. Instead, their corporate policy was to take a "reactive" approach. Consequently, SoCalGas did not have a Storage Integrity Management Program, and Defendant Lane recently admitted that the Utility Defendants waited until after the Blowout to begin formulating a "comprehensive safety plan that is directly for Aliso Canyon." In the 2014 testimony, the Utility Defendants admitted that, without a Storage Integrity Management Program, "SoCalGas will continue to operate in a reactive mode (with the potential for even higher costs to ratepayers) to address sudden failures of old equipment. In addition, SoCalGas and customers could experience major failures and service interruptions from potential hazards that currently remain undetected." The Utility Defendants further admitted that their "reactive" policy and practices exposed the public to the risk of "uncontrolled well-related situations."

59. Defendants stuck to their "reactive" mode of operating Aliso Canyon even though they knew that "[r]eactive-type work in response to identified safety-related conditions observed

as part of routine operations has increased in recent years. In fact, a negative well-integrity trend seems to have developed since 2008." "[M]ost major O&M and capital funded activities conducted on storage wells are typically reactive-type work, in response to corrosion or other problems identified through routine pressure surveillance and temperature surveys." Furthermore, Defendants acknowledged that, "[g]iven the fact that many of the wells have not been worked on in recent years, and the mature age of some wells, major problems and fixes of unknown costs are *anticipated*."

60. It was thus foreseeable to Defendants that the unattended well integrity issues would eventually result in a major blowout at the Aliso Canyon facility that would harm nearby communities, including Plaintiffs' properties. However, despite knowing the probable dangerous consequences of its "reactive" approach, Defendants continued to implement this approach that delayed assessments, maintenance, and repairs for the sole purpose of improving the company's financial performance and production capacity.

61. The consequences of this approach were further emphasized by DOGGR's conclusions during well inspections that began in March 2016. DOGGR ordered these inspections not only because of the Blowout, but also because the Utility Defendants' testimony about the need for a Storage Integrity Management Program "raises concerns about the integrity and safety of the wells" at Aliso Canyon.

62. The inspections have demonstrated that DOGGR's concerns were warranted: 79 wells failed mechanical integrity tests or otherwise needed to be taken out of service and isolated. In a January 17, 2017 report, the California Public Utilities Commission "noted that a significant number of wells may need to be plugged and abandoned." It also observed that the wells that successfully completed the required testing needed repair and remediation, indicating that even those wells were in disrepair at the time of the Blowout. According to DOGGR's website reporting on the status of the required well testing program, 58 of the Aliso Canyon wells have been taken out of service or plugged and abandoned as a result of the inspection process as of June 12, 2018. Only 56 wells passed the required tests. Of those 56 wells, 23 required well casing repairs before they could pass, indicating that 81 wells at the Aliso Canyon facility had serious

problems caused by SoCalGas's failure to properly inspect, maintain, and repair the wells at the facility.

63. As detailed above, beyond its hands-off approach to maintaining Aliso Canyon, SoCalGas also chose to operate the SS-25 Well, in particular, in a reckless manner by, for example: (i) failing to have a working safety valve in the SS-25 Well, which would have prevented the Blowout; (ii) pumping gas through both the tubing and casing of the SS-25 Well, thereby eliminating a safety barrier; and (iii) failing to have cemented casing all the way to the surface of the SS-25 Well.

64. Defendants were obviously capable of implementing a reasonable and necessary Storage Integrity Management Program before the Aliso Canyon disaster, but they did not implement any of the reasonable safety measures needed to address the foreseeable risks associated with the operation of Aliso Canyon until after the Blowout. Now—after the fact—the Utility Defendants perform: "[a]round-the-clock monitoring of the tubing, production casing, and surface casing of every well"; "[d]aily patrols to visually examine every well at Aliso Canyon"; "[d]aily scanning of each well using sensitive infrared thermal imaging cameras that can detect even the smallest leak"; and "[w]ithdrawal and injection only through each well's tubing." These measures plainly could have and should have been—but were not—taken before the Aliso Canyon disaster occurred.

65. SoCalGas recently acknowledged that major safety upgrades were needed before natural gas injection activities could resume at Aliso Canyon. In a January 13, 2017, letter to the California Public Utilities Commission, SoCalGas argued that it should be allowed to resume injection activities because it had "made extensive physical, technological, and safety enhancements at the Aliso Canyon facility." These enhancements included "the replacement of the inner metal tubing of every well approved for injection," "introduc[ing] real-time pressure monitoring of each well," "install[ing] a fence-line methane monitoring system," and "launch[ing] a new community notification system."

66. The Individual Defendants, by virtue of their positions as directors of SoCalGas, either authorized, directed, consented to, or otherwise participated in SoCalGas's "reactive" policy

of risk management at Alison Canyon, including the SS-25 Well, and in the policy and decision to forego implementation of a proactive Storage Integrity Management Program. By virtue of their positions as directors of SoCalGas, the Individual Defendants also knew or should have known of the hazardous conditions at Aliso Canyon, but failed to take or order appropriate action to avoid the Blowout.

F. The Blowout Damaged Plaintiffs

67. As detailed above, at the time of the Blowout, Plaintiffs had a comprehensive plan and schedule to continue development of the Porter Ranch community, which included finishing the development of then-existing communities and developing an additional eight communities that would include, among other things, approximately 1,530 home sites, trails, and parks. The Blowout resulted in months-long ejection of gas and other materials.

68. Immediately following the Blowout, the once-vibrant Porter Ranch real estate market dried up. In the six months following the announcement of the Blowout, Plaintiffs' Porter Ranch net sales were -1 (meaning there was one more cancellation than there were sales), compared to 74 net sales the same period the year before the Blowout. Even today—22 months after the Blowout—the Porter Ranch development has not fully recovered, and its completion (and Plaintiffs' economic return) has been delayed for years.

69. As a direct consequence of Defendants' egregious conduct, home sales dropped precipitously and have yet to fully recover. In addition, 21 purchase contracts executed prior to the Blowout were cancelled following the Blowout. The reduced pace of sales and cancellations, along with other substantial impacts of the Blowout, have delayed for years Plaintiffs' ability to sell out their Porter Ranch development. The combination of, *inter alia,* delayed absorption and increased costs to carry the project for many additional years has resulted in damages to Plaintiffs in the hundreds of millions of dollars.

G. The Defendants Owed a Duty to Plaintiffs

70. The Plaintiffs are members of a foreseeable class to which Defendants owed a duty of care, particularly in view of the type of activity in which Defendants were engaged and the proximity of that activity to Porter Ranch. Plaintiffs are the largest landowners adjacent to the

Facility. Defendants knew or should have known of Plaintiffs' extensive property ownership and development activities immediately adjacent to the Facility, that Plaintiffs are in the business of developing and selling homes in the Porter Ranch Community, and that Plaintiffs' property and sales efforts would be damaged by a well blowout or other environmental catastrophe at the Facility.

71. The hazard the operation of Aliso Canyon posed to Plaintiffs and other neighbors of the well field was foreseeable to the Utility Defendants, as they have admitted. As noted above, Sempra's 10-K for the year 2014 acknowledged that, "[b]ecause we are in the business of … storing … highly flammable and explosive materials … and operating highly energized equipment, the risks such incidents may pose to our facilities and infrastructure, as well *as the risks to the surrounding communities* are substantially greater than the risks such incidents may pose to a typical business." Sempra further conceded that "any such incident also could cause catastrophic … leaks, … explosions, spills or other significant damage to … property belonging to third parties, or cause personal injuries or fatalities," which "could lead to significant claims against us."

72. Similarly, in their 2014 testimony before the Public Service Commission, where they discussed the concerns attendant to the aging Aliso Canyon wells, the Utility Defendants similarly recognized that those concerns were particularly exigent because "*some wells are located within close proximity to residential dwellings or high consequence areas.*" As their own words make plain, Defendants were well aware of the risks their activities carried for Porter Ranch.

73. As alleged in detail in paragraphs 53 through 66, above, Defendants were aware of the deteriorated and dangerous condition of Aliso Canyon and, in particular, the SS-25 Well, and consequently were aware of the risks and hazards that the well field posed to the Plaintiffs and other neighbors. Yet Defendants made business decisions not to internalize the cost of preventing the Blowout by investing appropriate amounts to prevent the avoidance or minimization of those risks and hazards.

74. California law and public policy provide that "everyone is responsible, not only for the result of his or her willful acts, but also for an injury occasioned to another by his or her want

of ordinary care or skill in the management of his or her property or person" and that the injured party is entitled to recover "the amount which will compensate for all the detriment proximately caused" by a defendant's negligence. Accordingly, California law requires that Defendants bear all damages caused by the Blowout, including "tangible and conventionally measurable economic losses" suffered by Plaintiffs.

VI. CAUSES OF ACTION

FIRST CAUSE OF ACTION

(Strict Liability – Against SoCalGas and Sempra)

75. Plaintiffs incorporate the allegations set forth in Paragraphs 1 through 74.

76. The Utility Defendants were engaged in the activity of operating and maintaining aging injection wells for the storage of natural gas at Aliso Canyon. That activity was an ultrahazardous activity because it carried a high degree of risk of harm to the property of Plaintiffs and, more generally, to the communities surrounding Aliso Canyon. In addition, the manner in which SoCalGas operated the wells, piping and other equipment at Aliso Canyon, including the aging SS-25 Well, constituted an ultrahazardous activity, which included pumping high-pressure natural gas through both the tubing and casing of the Aliso Canyon wells, including the SS-25 Well, and operating some or all of those wells without appropriate safety valves or cemented casings all the way to the surface.

77. It was very likely, indeed almost certain, that the harm that would result from a leak from a natural gas well at Aliso Canyon would be great. It is not possible to wholly eliminate that risk by the exercise of reasonable care. The Utility Defendants were therefore required to exercise extreme care in their construction, maintenance, and operation of the Facility, and are to be held strictly liable for any accidents or blowouts at the Facility. Had the Utility Defendants exercised even reasonable care, the Blowout either would not have occurred or its magnitude and effect would have been significantly reduced.

78. The operation and maintenance of a natural gas well field such as Aliso Canyon—which contains aging wells that were converted from oil wells into natural gas injection wells—is not a matter of common usage, particularly near a populated area such as Porter Ranch. The risk

of operating Aliso Canyon was and is so great that it is not outweighed by the value the gas-storage activity brings to the community, particularly if the risk is not ameliorated by the use of extreme care, as was the case at Aliso Canyon. The Utility Defendants are therefore strictly liable for the Blowout and its impacts.

79. As a proximate cause of the blowout of the well, Plaintiffs suffered injury to their property and to their business.

80. The Utility Defendants acted with conscious disregard of the probable injurious consequences of their conduct that resulted in the blowout of the SS-25 Well, and deliberately failed to avoid those consequences.

81. The Utility Defendants knowingly acted with wanton and reckless disregard of the consequences of their misconduct alleged herein.

SECOND CAUSE OF ACTION

(Negligence *Per Se* – Against SoCalGas and Sempra)

82. Plaintiffs incorporate the allegations set forth in Paragraphs 1 through 74.

83. California Health and Safety Code § 41700 and South Coast Air Quality Management District Rule 402 provide, in relevant part, that:

> [A] person shall not discharge from any source whatsoever quantities of air contaminants or other material that cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or that endanger the comfort, repose, health, or safety of any of those persons or the public, or that cause, or have a natural tendency to cause, injury or damage to business or property.

84. The Utility Defendants violated California Health and Safety Code § 41700 and South Coast Air Quality Management District Rule 402.

85. The violation of California Health and Safety Code § 41700 and South Coast Air Quality Management District Rule 402 proximately caused injury to Plaintiffs.

86. Plaintiffs' injury resulted from an occurrence that California Health and Safety Code § 41700 and South Coast Air Quality Management District Rule 402 were designed to prevent.

87. Plaintiffs are within the class of persons for whose protection California Health and Safety Code § 41700 and South Coast Air Quality Management District Rule 402 were adopted.

88. As these statutes demonstrate, the Utility Defendants owed Plaintiffs a *per se* duty to use due care in the operation and maintenance of Aliso Canyon and, in particular, the SS-25 Well.

89. As the Utility Defendants' violations of these statutes demonstrate, the Utility Defendants have committed *per se* breaches of that duty by failing to use due care in the operation and maintenance of Aliso Canyon resulting in the blowout of the SS-25 Well.

90. As a proximate cause of the blowout of the well, Plaintiffs suffered injury to their property and to their business.

91. The Utility Defendants acted with conscious disregard of the probable injurious consequences of their conduct that resulted in the blowout of the SS-25 Well, and deliberately failed to avoid those consequences.

92. The Utility Defendants knowingly acted with wanton and reckless disregard of the consequences of their misconduct alleged herein.

<u>THIRD CAUSE OF ACTION</u>

(Negligence – Against SoCalGas and Sempra)

93. Plaintiffs incorporate the allegations set forth in Paragraphs 1 through 74.

94. Defendants owed Plaintiffs a duty to use due care in the operation and maintenance of Aliso Canyon and, in particular, the SS-25 Well.

95. Defendants breached that duty by failing to use due care in the operation and maintenance of Aliso Canyon, resulting in the blowout of the SS-25 Well.

96. As a proximate cause of the blowout of the SS-25 Well, Plaintiffs suffered injury to their property and to their business.

97. The Utility Defendants acted with conscious disregard of the probable injurious consequences of their conduct that resulted in the blowout of the SS-25 Well, and deliberately failed to avoid those consequences.

98. Defendants knowingly acted with wanton and reckless disregard of the consequences of their misconduct alleged herein.

FOURTH CAUSE OF ACTION

(Negligence – Against All Individual Defendants)

99. Plaintiffs incorporate the allegations set forth in Paragraphs 1 through 74.

100. The Individual Defendants had a duty to use due care in the operation and maintenance of Aliso Canyon and, in particular, the SS-25 Well, so as to not cause injury to third parties such as Plaintiffs.

101. In their capacities as directors of the Utility Defendants, the Individual Defendants specifically authorized, directed, or participated in the tortious conduct that is the subject of this action, or they specifically knew or reasonably should have known about the dangerous conditions at Aliso Canyon and at the SS-25 Well in particular, and negligently failed to take or order appropriate action to avoid the harm. An ordinarily prudent person, knowing what the Individual Defendants knew at the time, would not have acted similarly under the circumstances.

102. The Individual Defendants—all of whom were directors of SoCalGas—knew or should have known the contents of the testimony and statements described above, including the admissions described therein.

103. The Individual Defendants breached their duties by failing to use due care in the operation and maintenance of Aliso Canyon, resulting in the blowout of the SS-25 Well.

104. As a proximate cause of the blowout of the SS-25 Well, Plaintiffs suffered injury to their property and injury to their business.

105. The Individual Defendants acted with conscious disregard of the probable injurious consequences of their conduct that resulted in the blowout of the SS-25 Well, and deliberately failed to avoid those consequences.

106. The Individual Defendants knowingly acted with wanton and reckless disregard of the consequences of their misconduct alleged herein.

FIFTH CAUSE OF ACTION

(Continuing Public Nuisance – Against SoCalGas and Sempra)

107. Plaintiffs incorporate the allegations set forth in Paragraphs 1 through 74.

108. Plaintiffs own the Porter Ranch property near Aliso Canyon and have a right to the use and enjoyment of their property without interference by the Utility Defendants, including Plaintiffs' right to develop and sell homes in the Porter Ranch community.

109. The Utility Defendants owe Plaintiffs a duty not to interfere with Plaintiffs' use and enjoyment of their property. The Utility Defendants also have a public duty to operate in a manner that does not cause a nuisance to the public.

110. The improper maintenance and operation of Aliso Canyon and the Blowout substantially and unreasonably interfered with Plaintiffs' use and enjoyment of their property.

111. Plaintiffs did not consent to the Utility Defendants' interference with Plaintiffs' right to the use and enjoyment of their property.

112. The nuisances that were caused by the Utility Defendants have affected the entire community surrounding Aliso Canyon, and also specially injured Plaintiffs. As alleged herein, Plaintiffs have been injured and suffered damages, including without limitation damage to their property, lost business and lost profits.

113. The Utility Defendants acted with conscious disregard of the probable injurious consequences of their conduct regarding the operation of the SS-25 Well, and deliberately failed to avoid those consequences.

114. The Utility Defendants knowingly acted with wanton and reckless disregard of the consequences of their misconduct alleged herein.

SIXTH CAUSE OF ACTION

(Continuing Private Nuisance – Against SoCalGas and Sempra)

115. Plaintiffs incorporate the allegations set forth in Paragraphs 1 through 74.

116. Plaintiffs own the Porter Ranch property near Aliso Canyon and have a right to the use and enjoyment of their property without interference by the Utility Defendants, including Plaintiffs' right to develop and sell homes in the Porter Ranch community.

117. The Utility Defendants owe Plaintiffs a duty not to interfere with Plaintiffs' use and enjoyment of their property. The Utility Defendants also have a public duty to operate in a manner that does not cause a nuisance to the Plaintiffs.

118. The improper maintenance and operation of Aliso Canyon and the Blowout substantially and unreasonably interfered with Plaintiffs' use and enjoyment of their property.

119. Plaintiffs did not consent to the Utility Defendants' interference with Plaintiffs' right to the use and enjoyment of their property.

120. The nuisances that were caused by the Utility Defendants have specifically impacted Plaintiffs. As alleged herein, Plaintiffs have been injured and suffered damages, including without limitation damage to their property, lost business and lost profits.

121. The Utility Defendants acted with conscious disregard of the probable injurious consequences of their conduct regarding the operation of the SS-25 Well, and deliberately failed to avoid those consequences.

122. The Utility Defendants knowingly acted with wanton and reckless disregard of the consequences of their misconduct alleged herein.

SEVENTH CAUSE OF ACTION

(Permanent Public Nuisance – Against SoCalGas and Sempra)

123. Plaintiffs incorporate the allegations set forth in Paragraphs 1 through 74.

124. Plaintiffs own the Porter Ranch property near Aliso Canyon and have a right to the use and enjoyment of their property without interference by the Utility Defendants, including Plaintiffs' right to develop and sell homes on their property.

125. The Utility Defendants owed, and continue to owe, Plaintiffs a duty not to interfere with Plaintiffs' use and enjoyment of their property. The Utility Defendants also have a public duty to operate in a manner that does not cause a nuisance to the public.

126. The Aliso Canyon well field and the Utility Defendants' improper maintenance and operation of the wells and equipment at Aliso Canyon constitute a substantial and unreasonable interference with Plaintiffs' use and enjoyment of their property. The manner in which Defendants continue to operate the Aliso Canyon facility constitutes a permanent nuisance.

127. Plaintiffs did not consent to the Utility Defendants' interference with their right to the use and enjoyment of Plaintiffs' property.

128. The nuisances created by the Utility Defendants affect the entire community, and have also specially injured Plaintiffs. As alleged herein, Plaintiffs have been injured and suffered damages, including without limitation physical damage to their property and economic damages that include lost sales and lost profits resulting from the Aliso Canyon nuisance.

129. The Utility Defendants acted with conscious disregard of the probable injurious consequences of their conduct regarding the operation of the wells and equipment at Aliso Canyon, and deliberately failed to avoid those consequences.

130. The Utility Defendants knowingly acted with wanton and reckless disregard of the consequences of their misconduct alleged herein.

EIGHTH CAUSE OF ACTION

(Permanent Private Nuisance – Against SoCalGas and Sempra)

131. Plaintiffs incorporate the allegations set forth in Paragraphs 1 through 74.

132. Plaintiffs own the Porter Ranch property near Aliso Canyon and have a right to the use and enjoyment of their property without interference by the Utility Defendants, including Plaintiffs' right to develop and sell homes on their property.

133. The Utility Defendants owed, and continue to owe, Plaintiffs a duty not to interfere with Plaintiffs' use and enjoyment of their property. The Utility Defendants also have a public duty to operate in a manner that does not cause a nuisance to the public.

134. The Aliso Canyon well field and the Utility Defendants' improper maintenance and operation of the wells and equipment at Aliso Canyon constitute a substantial and unreasonable interference with Plaintiffs' use and enjoyment of their property. The manner in which

Defendants continue to operate the Aliso Canyon facility constitutes a permanent nuisance.

135. Plaintiffs did not consent to the Utility Defendants' interference with their right to the use and enjoyment of Plaintiffs' property.

136. The nuisances created by the Utility Defendants have specifically impacted Plaintiffs. As alleged herein, Plaintiffs have been injured and suffered damages, including without limitation physical damage to their property and economic damages that include lost sales and lost profits resulting from the Aliso Canyon nuisance.

137. The Utility Defendants acted with conscious disregard of the probable injurious consequences of their conduct regarding the operation of the wells and equipment at Aliso Canyon, and deliberately failed to avoid those consequences.

138. The Utility Defendants knowingly acted with wanton and reckless disregard of the consequences of their misconduct alleged herein.

NINTH CAUSE OF ACTION

(Trespass – Against SoCalGas and Sempra)

139. Plaintiffs incorporate the allegations set forth in Paragraphs 1 through 74.

140. Plaintiffs owned and were in possession of their Porter Ranch property when the Blowout occurred, which caused gas and other materials to enter Plaintiffs' property.

141. The entry of gas and other materials onto Plaintiffs' property occurred without Plaintiffs' consent and caused damage to Plaintiffs.

142. The Utility Defendants acted with conscious disregard of the probable injurious consequences of their conduct that resulted in the Blowout and deliberately failed to avoid those consequences.

143. The Utility Defendants knowingly acted with wanton and reckless disregard of the consequences of their misconduct alleged herein.

TENTH CAUSE OF ACTION

(Violation of Cal. Bus. & Prof. Code §§ 17200, et seq. – Against SoCalGas and Sempra)

144. Plaintiffs incorporate the allegations set forth in Paragraphs 1 through 74.

145. The Utility Defendants have engaged in the unlawful, fraudulent, and unfair business acts and practices described throughout this Complaint in violation of California's Unfair Competition Law (the "UCL"), California Business and Professions Code §§ 17200, et seq.

146. The Utility Defendants' business acts and practices have been unlawful under the UCL because they resulted in the violations of law described herein, including acts and practices that violated California Health and Safety Code § 41700, South Coast Air Quality Management, District Rule 402, California Civil Code § 1714, California Civil Code § 3479, California Civil Code § 3334, and because they constituted negligence *per se* and strict liability in connection with an ultrahazardous activity.

147. The Utility Defendants' business acts and practices have been fraudulent because a reasonable person would likely be deceived or misled by the Utility Defendants' false statements and claims regarding their safety, repair, maintenance, and emergency response programs prior to the Blowout and their false statements and claims about the severity of the Blowout.

148. The Utility Defendants' business acts and practices have been unfair because they have not had adequate safety, maintenance, repair, emergency response, or community notification programs in place at the Aliso Canyon facility and did not take adequate safety, maintenance, repair, emergency response, or community notification measures prior to, during, and after the Blowout. The harm suffered by Plaintiffs outweighs any justification that the Utility Defendants may assert for engaging in those acts and practices. Plaintiffs could not have avoided the harm they suffered as a result of the Utility Defendants' unfair acts and practices.

149. The Utility Defendants' unlawful, unfair, and fraudulent business acts and practices were carried out and effectuated in California and injured Plaintiffs in California.

150. Plaintiffs have suffered damages as herein alleged as a direct and proximate result of the Utility Defendants' unlawful, unfair, and fraudulent business acts and practices.

151. Upon information and belief, the Utility Defendants have received substantial revenues and substantial profits arising out of their acts of unfair competition to which they are not entitled, and Plaintiffs have also suffered an injury in fact, and lost money or property as a result

of the Utility Defendants' acts of unfair competition, for which the Utility Defendants are responsible.

PRAYER FOR RELIEF

Based on the foregoing, Plaintiffs respectfully request that the Court enter judgment in their favor and against Defendants, awarding as follows:

(a) A judgment in favor of Plaintiffs on all claims;

(b) Compensatory and general damages;

(c) An award of all amounts to which Plaintiffs are entitled under Cal. Civil Code § 3334;

(d) Costs;

(e) Attorney's fees;

(f) Exemplary and/or punitive damages;

(g) Injunctive Relief;

(h) Pre- and post-judgment interest; and

(i) All other relief the Court may deem just and proper.

Respectfully submitted,

Dated: July 6, 2018

BOIES SCHILLER FLEXNER LLP

By: [signature]

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DEMAND FOR JURY TRIAL

To the extent permitted by law, Plaintiffs demand a trial by jury in this action of all issues so triable.

Respectfully submitted,

Dated: July 6, 2018

BOIES SCHILLER FLEXNER LLP

By: [signature]

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PROOF OF SERVICE

STATE OF CALIFORNIA, COUNTY OF LOS ANGELES

At the time of service, I was over 18 years of age and **not a party to this action**. I am employed in the County of Los Angeles, State of California. My business address is 725 South Figueroa Street, 31st Floor, Los Angeles, CA 90017-5524.

On July 20, 2018, I served true copies of the following document(s) described as **FIRST AMENDED COMPLAINT** on the interested parties in this action as follows:

SEE ATTACHED SERVICE LIST

BY MAIL: I enclosed the document(s) in a sealed envelope or package addressed to the persons at the addresses listed in the Service List and placed the envelope for collection and mailing, following our ordinary business practices. I am readily familiar with Boies Schiller Flexner LLP's practice for collecting and processing correspondence for mailing. On the same day that the correspondence is placed for collection and mailing, it is deposited in the ordinary course of business with the United States Postal Service, in a sealed envelope with postage fully prepaid.

BY ELECTRONIC SERVICE: Pursuant to Court Order Authorizing Electronic Service, dated November 30, 2015, I provided the document(s) listed above electronically on the CASE ANYWHERE Website to the parties on the Service List maintained on the CASE ANYWHERE Website for this case, or on the attached Service List. Case Anywhere is the on-line e-service provider designated in this case.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on July 20, 2018, at Los Angeles, California.

Wendy M. Carpenter

SERVICE LIST

BY FIRST-CLASS MAIL Kyung Hee Kim 611 S. Catalina Street, #212 Los Angeles, CA 90005	Pro Se Plaintiff
BY FIRST-CLASS MAIL Stacy Choi 611 S. Catalina Street, #212 Los Angeles, CA 90005	Pro Se Plaintiff
BY FIRST-CLASS MAIL Jesse S. Salas Law Office of Jesse S. Salas 1721 W. Fern Avenue Redlands, CA 92373	Attorney for Plaintiff re Case No. BC621933

EXHIBIT B

Company: Southern California Gas Company (U 904 G)
Proceeding: 2016 General Rate Case
Application: A.14-11-XXX
Exhibit: SCG-06

SOCALGAS

DIRECT TESTIMONY OF PHILLIP E. BAKER

UNDERGROUND STORAGE

November, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Southern
California
Gas Company

A Sempra Energy utility®

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SUMMARY

UNDERGROUND STORAGE O&M	Thousands of 2013 Dollars		
	2013 Adjusted Recorded	**TY2016 Estimated**	**Change**
Total Non-Shared	$30,995	$40,181	$9,186
Total Shared Services (Incurred)	$0	$0	$0
Total O&M	**$30,995**	**$40,181**	**$9,186**

UNDERGROUND STORAGE CAPITAL	Thousands of 2013 Dollars		
	2014	**2015**	**2016**
Total Capital	**$71,429**	**$74,270**	**$90,523**

The funding summarized above and described in my testimony is reasonable and represents the required Operations and Maintenance (O&M) expenses and capital investments for Southern California Gas Company's (SoCalGas or the Company) underground storage facilities to:

- Maintain the safety, integrity, and effective operations of the natural gas storage system;
- Provide a reliable and economic supply of gas for customers throughout the service territory, especially during periods of high demand;
- Achieve compliance with operating and environmental regulations; and
- Allow gas deliveries to be efficiently balanced throughout the overall transmission and distribution system.

Incremental O&M and capital funding associated with a new safety, system integrity, and risk management initiative, the Storage Integrity Management Program (SIMP), is proposed for underground storage wells. This program is modeled after SoCalGas' Transmission Integrity Management Program (TIMP), and a similar two-way balancing account process is requested.

The driving force behind the expenditure plan for Underground Storage is the objective of SoCalGas and its employees to provide safe, reliable deliveries of natural gas to customers at reasonable rates. O&M and capital investments also enhance and maintain the efficiency and responsiveness of operations, extend the life of assets, and facilitate compliance with governmental regulations.

The O&M forecast was established using a five-year trend, with the addition of costs for the new safety and integrity management program for underground storage wells.

The capital forecast was established using a five-year average. Added to the average are remediation costs for the new safety and well integrity management program, plus costs to drill new wells.

To understand this Test Year (TY) 2016 forecast in the proper context, the following factors should be considered:

- Storage facilities consist of large complex interconnected industrial equipment that continues to age. The increasing volume, frequency and complexity of above-ground and below-ground maintenance work, and the declining availability of replacement components for older assets exposed to demanding field conditions, all continue to push operating costs higher.

- Costs for storage activities have been increasing at a relatively consistent rate in recent years in support of safety, system integrity, maintenance, reliability, deliverability, and regulatory compliance objectives. Most increases have been driven by the intensity of traditional operating functions and routine work efforts across the board that are required to safely operate and maintain the aging infrastructure of the fields. As a result, there are very few "big ticket items" one can single out as primary contributors for the increasing O&M trend.

- Problems associated with operating equipment, aging wells, compressors, and gas and liquid process/piping systems are difficult to predict. When unpredictable failures or preemptive repair situations occur, the associated mitigation costs for such occurrences can vary from year to year. This potential for peaks and valleys in spending trends supports a longer-term (five-year) trending methodology to forecast O&M costs.

- In the future, pipeline integrity inspection requirements, the frequency and depth of regulatory audits and resulting compliance activities, additional focus on employee training, operator and supervisory qualification, employee turnover, expanded permitting and reporting requirements of regulatory agencies from new and existing environmental regulations such as storm water requirements, security enhancements, and chemical costs are all expected to increase operating expenses. These upward pressures further support the five-year trending methodology used to forecast O&M costs.

- Capital costs for routine storage functions have been relatively consistent over the past five years. This supports the five-year methodology used to forecast costs for traditional baseline capital expenditures.

- Underground storage reservoirs are dynamic geological assets where gas injection and withdrawal capabilities can change over time. These changes, which include natural well degradation and storage volume variability due to fluid extraction or intrusion, require ongoing studies and significant capital investments in new or replacement wells to maintain historical storage deliverability rates. The small number of new or replacement wells planned, the high cost of constructing these assets, along with an inconsistent historical trend for this particular sub-activity supports a zero-based approach to forecasting the capital costs for new wells.

SOCALGAS DIRECT TESTIMONY OF PHILLIP E. BAKER
UNDERGROUND STORAGE

I. INTRODUCTION

A. Summary of Costs

I sponsor the TY2016 forecasts of O&M costs for non-shared services, and forecasts of capital costs for years 2014, 2015, and 2016, associated with Underground Storage for SoCalGas.[1] My cost forecasts support the Company's goals of maintaining and enhancing public and employee safety, as well as providing reliable supplies of gas for service delivery. Underground Storage's support of SoCalGas' safety, integrity and reliability goals is discussed in greater detail within this testimony. Tables PEB-1 and PEB-2 below summarize my sponsored costs.

Table PEB-1
Southern California Gas Company
Test Year 2016 Summary of Total O&M Costs

UNDERGROUND STORAGE O&M	Thousands of 2013 Dollars		
	2013 Adjusted Recorded	TY2016 Estimated	Change
Total Non-Shared	$30,995	$40,181	$9,186
Total Shared Services (Incurred)	$0	$0	$0
Total O&M	**$30,995**	**$40,181**	**$9,186**

Table PEB-2
Southern California Gas Company
Test Year 2016 Summary of Total Capital Costs

UNDERGROUND STORAGE CAPITAL	Thousands of 2013 Dollars		
	2014 Estimated	2015 Estimated	2016 Estimated
Total Capital	**$71,429**	**$74,270**	**$90,523**

In addition to this testimony, please also refer to my workpapers, Exhibits SCG-06-WP (O&M) and SCG-06-CWP (capital), for additional information on the activities described herein.

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1 Pursuant to CPUC Decision (D) 01-06-081, issued June 28, 2001, the costs forecast in TY2016 do not include costs associated with the operation and maintenance of the Montebello underground storage field or any costs associated with salvage operations. This decision directs that all costs associated with the Montebello underground storage field operation be removed from rates as of August 29, 2001, which has been done. Also, as of April 2009, the East Whittier storage field was removed from rate base. Therefore, costs associated with maintaining this field are also excluded from this case.

B. Summary of Activities

SoCalGas operates four underground storage fields with a combined working capacity of approximately 136 Bcf.[2] These fields are: Aliso Canyon (86.2 Bcf), La Goleta (21.5 Bcf), Honor Rancho (26.0 Bcf), and Playa del Rey (2.4 Bcf). Underground Storage is responsible for the safety, system integrity, design, operations, maintenance, and gas injection/withdrawal activities, along with environmental and regulatory compliance functions, within the four storage fields. It plans and constructs the capital investments necessary to provide value-added storage services for SoCalGas customers. The critical goals for storage are safety, system integrity, gas availability, reliability, and value, which are achieved in full compliance with governmental regulations.[3]

Gas storage fields can only be constructed in areas with unique underground geological characteristics. Their proximity to local gas consumers and transmission and distribution pipelines make them even more valuable assets. The unique underground geology of SoCalGas' storage fields, all former hydrocarbon-producing fields, and their location with respect to gas loads make them ideally suited for storage operations within the SoCalGas system. More information about what determines a good storage field is provided in Appendix B: Underground Storage of Natural Gas, and incorporated here by reference.

By their nature, gas storage fields occupy large open areas of land and require the continual installation, maintenance, refurbishment, and replacement of heavy industrial equipment such as engines, compressors, electrical systems, wells and piping, gas processing components, and instrumentation.

Natural gas is compressed onsite to very high pressures (up to 3,600 psig) and injected underground into the field reservoirs through piping networks and storage wells, typically during seasonal periods when gas consumption is low and supplies are ample.

Storage gas is usually withdrawn and delivered to customers through the transmission and distribution system when gas consumption is seasonally high during winter months. At the beginning of the withdrawal season in November, the combined storage capacity of the four storage fields is enough to supply all of SoCalGas' customers for approximately six weeks, if one assumes an average daily consumption rate.

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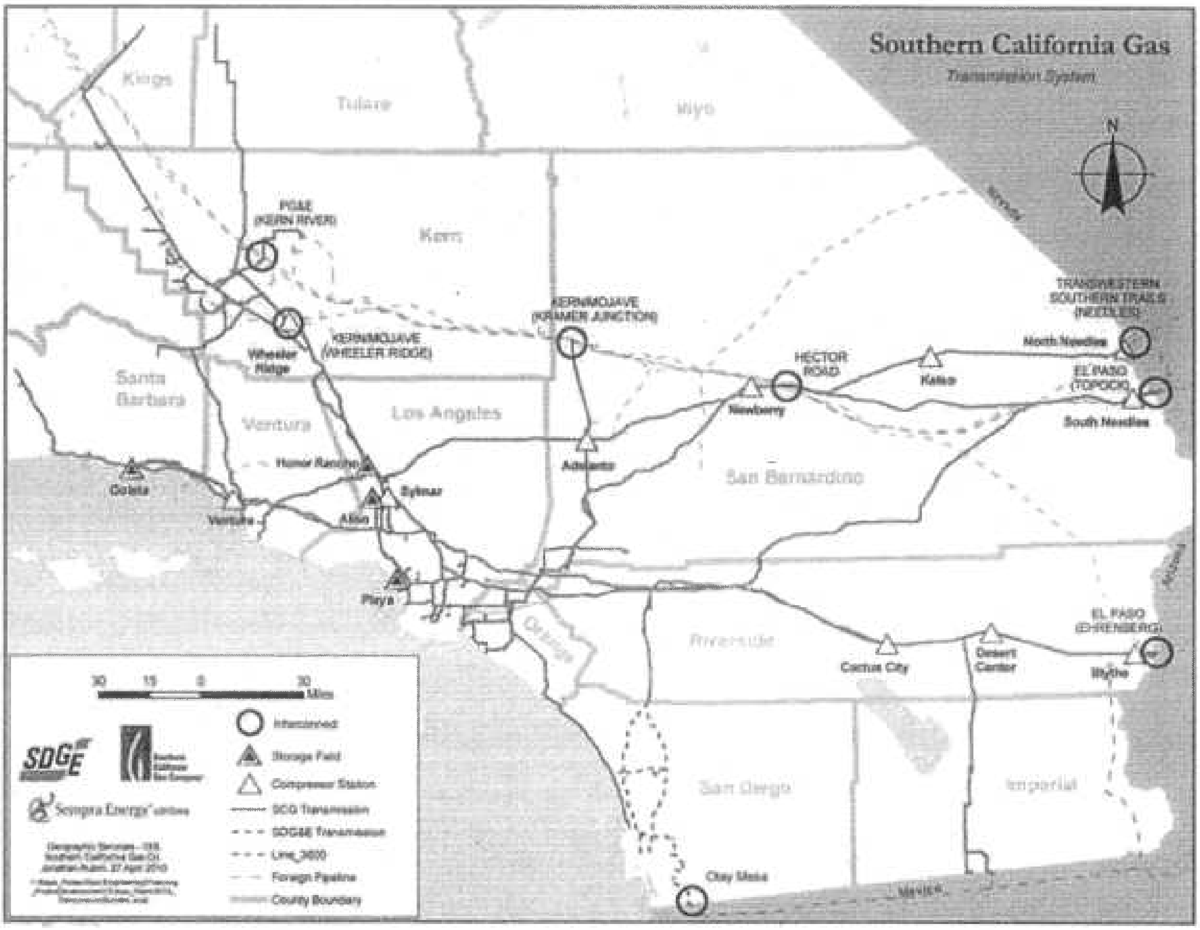
[2] The volumetric capacity of a natural gas storage field reservoir is measured in units of billion cubic feet (Bcf).

[3] Additional information on storage operations can be found in Appendix B.

A diagram/map of the SoCalGas/SDG&E gas transmission system, including the location of the four storage fields is shown in Figure PEB-1 below.

Figure PEB-1
Southern California Gas Company
Transmission and Storage System



The four storage facilities are an integrated part of the energy infrastructure required to provide southern California businesses and residents with safe and reliable energy and gas storage services at a reasonable cost.

<u>Aliso Canyon</u>

Aliso Canyon is located in Northern Los Angeles County and is the largest of the four gas storage fields, with a working capacity of approximately 86 Bcf and deliveries to the Los Angeles pipeline loop. Aliso Canyon began storage operations in 1973, although many of its wells date back to the 1940s. Aliso Canyon has 115 injection/withdrawal/observation wells and is designed for a maximum withdrawal rate of approximately 1.8 Bcf per day at full-field inventory. Within the field, it is estimated there are approximately 38 miles of gas injection, withdrawal, and liquid-handling pipelines that connect the storage wells to processing and compression facilities.

Honor Rancho

Honor Rancho is also located in Northern Los Angeles County, approximately ten miles north of Aliso Canyon, with a working capacity of approximately 26 Bcf and deliveries to the Los Angeles pipeline loop. Honor Rancho began storage operations in 1975, although many of its wells date back to the 1940s. Honor Rancho has 40 gas injection/withdrawal wells and is designed for a maximum withdrawal capability of 1.0 Bcf per day. It is estimated that approximately 12 miles of pipelines connect the storage wells to processing and compression facilities.

La Goleta

La Goleta is located in Santa Barbara County near the Santa Barbara Airport and the University of California–Santa Barbara campus and provides service to the northern coastal area of the SoCalGas territory. La Goleta, the oldest of the four fields, began storage operations in 1941 and has a working capacity of approximately 21 Bcf. Most of its wells date back to the 1940s. La Goleta has 20 gas injection/withdrawal/observation wells and is designed for a maximum withdrawal capability of 0.4 Bcf per day. It is estimated that approximately eight miles of pipelines connect the storage wells to processing and compression facilities.

Playa Del Rey

Playa Del Rey, located in central Los Angeles County, near the Los Angeles International Airport, was placed into storage service in 1942. It is the smallest of the storage fields, yet, due its location, is a very critical asset with a design working capacity of approximately 2.4 Bcf. Playa Del Rey has 54 gas injection/withdrawal/observation wells. It is estimated that approximately 11 miles of pipeline connect the storage wells to processing and compression facilities.

Playa Del Rey is designed for a maximum withdrawal rate of 0.4 Bcf per day to meet residential, commercial and industrial loads throughout the western part of Los Angeles, including oil refineries and power generators.

Table PEB-3 below further summarizes the descriptive characteristics of all four storage fields.

Table PEB-3
Southern California Gas Company
Descriptive Statistics of Storage Fields

Descriptive Statistic	Aliso Canyon	La Goleta	Honor Rancho	Playa del Rey	Total All Fields
Year Field Placed in Service	1973	1941	1975	1942	-
Injection/Withdrawal/Observation Wells (number)	115	20	40	54	229
Gas Compressor Units (number)	8	8	5	3	24
Compression Horsepower (bhp)	42,000	5,700	27,500	6,000	81,000
Maximum Reservoir Pressure (psig)	3,600	2,050	4,400	1,700	-
Working Gas (Bcf)	86.2	21.5	26.0	2.4	136.1
Maximum Withdrawal Rate (MMcfd)	1,860	420	1,000	400	3,760
Maximum Injection Rate (MMcfd)	600	140	300	75	1,115
Maximum Well Depth (feet)	10,691	6,912	13,300	6,575	-
Minimum Well Depth (feet)	6,997	4,247	9,165	6,049	-
Average Well Depth (feet)	8,146	4,886	9,959	6,339	-

C. Risk Management Practices in Storage

The risk policy witnesses, Diana Day (Exhibit SCG-02) and Doug Schneider (Exhibit SCG-03), describe how risks are assessed and factored into cost decisions on an enterprise-wide basis. Several of my costs address safety risks associated with the storage system. Most specifically, I propose to establish a new SIMP, described and discussed below in the O&M and Capital cost sections, to mitigate safety-related risks.

While we have historically managed risk at our storage facilities by relying on more traditional monitoring activities and identification of potential component failures, we believe that it is critical that we adopt a more proactive and in-depth approach. Historically, safety and risk considerations for wells and their associated valves and piping components have not been addressed in past rate cases to the same extent that distribution and transmission facilities have been under the Distribution and Transmission integrity management programs. As a prudent storage operator, SoCalGas proposes to manage and approach the integrity of its storage well assets, which all fall under the jurisdiction of the California Department of Oil, Gas and Geothermal Resources (DOGGR), in a manner consistent with the approach adopted for distribution and transmission systems. Risk management activities, processes, and procedures for well integrity should have a focus similar to those employed under the Company's pipeline risk mitigation programs.

Accordingly, in this rate case, we propose to establish a highly proactive approach to evaluating and managing risks associated with wells in our storage system through a new SIMP, modeled after the successes of our pipeline integrity management programs (TIMP and DIMP). Through the implementation of the SIMP, better storage well system data will be collected, maintained and modeled to identify the top risks throughout Storage. Comprehensive plans to mitigate those risks will be developed and implemented.

1. Risk Assessment

Currently, risk assessment of our storage system is of a qualitative nature and is based on our long experience in operating and managing SoCalGas' storage facilities. During routine system assessments, we monitor the condition of our assets and consider the risks they may pose on safety, reliability, and the environment.

The future of risk assessment for our storage system is moving towards a more robust and quantitative approach that will help us capture more information on the condition of our storage wells and develop models that will assist in prioritizing risk mitigation activities. The details of this new risk assessment are captured in further sections of my testimony describing the SIMP.

2. Risk Mitigation Alternatives Evaluation

Well risk mitigation is evaluated on a case-by-case basis. Whenever a well may pose a safety risk, we act immediately to address the problem. Alternatives, such as plugging and abandoning the well, versus a major repair or well replacement, are evaluated based on conditions, including the age of the well, prior repair or maintenance history, performance during withdrawal or injection periods, and surface considerations, such as susceptibility to landslides. These various conditions, and their associated costs, are evaluated to determine the safest, most cost-effective mitigation option. Another consideration that may influence repair decisions is the age and condition of certain well components that may have become obsolete and are no longer supported by the original equipment manufacturer and cannot be readily replaced or maintained.

At a very high level, alternatives to mitigate risks posed by deteriorating, aging, obsolete or failed storage equipment include:

- Replacement of equipment / storage wells
- Overhaul of equipment / storage wells

- Repair of equipment / storage wells
- Abandonment of a storage well / equipment
- Installation of additional equipment

3. Risk Reduction Benefits

The proposed mitigation activities are expected to address safety, reliability and environmental risks by either maintaining a certain acceptable level of control over those risks, or by further reducing the potential impacts of the risks. While there are no current means to provide a quantitative risk reduction forecast, it is my belief that the proposed mitigation activities will greatly assist in controlling and reducing the risks in our storage system.

In addition to establishing a more quantitative risk analysis of our storage wells as discussed below, the SIMP will result in a more effective prioritization of required capital expenditures that address risks that impact safety, reliability and the environment.

4. Integration of Risk Mitigation Actions and Investment Prioritization

The implementation of the proposed SIMP will establish an integrated risk management and investment prioritization process for storage management at SoCalGas. Storage wells are an integral gas delivery component, and an unanticipated safety concern could interrupt access to the working gas asset and potentially lead to a complete shutdown of a storage field.

Models to be developed from captured well data will evaluate threats and risks that exist in our storage system. This will allow for a prioritization of those storage well threats, based on their location, age, condition and other factors, thereby establishing a robust methodology for prioritizing storage management investments.

5. Investment Included in Request to Support Risk Mitigation

Investments related to the SIMP are necessary to establish a risk management program. Future mitigation activities that will result from the implementation of the SIMP will be risk-driven and will address identified and prioritized risks. SoCalGas forecasts $5.676 million annually in O&M and $24.272 million annually in capital costs for the implementation of the SIMP. It is anticipated that the SIMP will last for six years, the estimated length of time required to inspect all of the wells and mitigate any identified conditions. After this six-year period, when the program is complete, future inspection and mitigation costs will be addressed through routine operations.

D. Support To/From Other Witnesses

In addition to sponsoring my own organization's costs, I also provide sponsorship of the New Environmental Regulatory Balancing Account (NERBA) cost forecast for the reporting requirements under Subpart W for Gas Engineering, Gas Transmission and Underground Storage for witnesses Raymond Stanford (Exhibit SCG-07), John Dagg (Exhibit SCG-05), and myself. The costs associated with Subpart W reporting requirements are illustrated in the cost detail in section II.C of my testimony. Policy testimony in support of NERBA and storm water regulations is provided by Environmental Services witness Jill Tracy (Exhibit SCG-17).

II. NON-SHARED COSTS

A. Introduction

Table PEB-4 below summarizes the total non-shared O&M forecasts for the listed cost categories.

Table PEB-4
Southern California Gas Company
Non-Shared O&M Summary of Costs

UNDERGROUND STORAGE	Thousands of 2013 Dollars		
Categories of Management	**2013 Adjusted Recorded**	**TY2016 Estimated**	**Change**
Underground Storage – Routine	$30,681	$34,101	$3,420
New Environmental Regulatory Balancing Account (NERBA) (Existing Balancing Account)	$314	$404	$90
Storage Integrity Management Program (Proposed New Balancing Account)	$0	$5,676	$5,676
Total	**$30,995**	**$40,181**	**$9,186**

B. Underground Storage – Routine O&M

Table PEB-05 below summarizes the non-shared O&M forecasts for routine storage operations.

Table PEB-05
Southern California Gas Company
Non-Shared Routine O&M Costs

UNDERGROUND STORAGE	Thousands of 2013 Dollars		
Categories of Management	2013 Adjusted Recorded	TY2016 Estimated	Change
Underground Storage - Routine	$30,681	$34,101	$3,420

1. Criticality of Storage and Underlying Activities

The use of the four underground storage fields is an essential component of the energy delivery system within California that works in conjunction with the SoCalGas transmission pipeline and distribution delivery network. This interconnected system consists of high-pressure pipelines, compressor stations, and underground storage fields, designed to receive natural gas from interstate pipelines and local production sources. The integrated system enables deliveries of natural gas to customers or into storage field reservoirs, depending on market demands. SoCalGas uses its storage assets to efficiently meet seasonal, as well as daily, gas balancing requirements.[4] To satisfy these needs, the individual storage facilities act as "gas suppliers" or "consumers," depending upon the withdrawal or injection requirements as managed by Gas Control. Fluctuating demands may require Storage Operations to perform gas injection or withdrawal functions at any hour of the day, 365 days per year. Storage fields are continually staffed with operating crews and on-call personnel to support these critical 24/7 operations.

Figure PEB-2 below illustrates the crucial role of storage in the delivery of reliable gas service for energy consumers within southern California during the fall and winter heating season.

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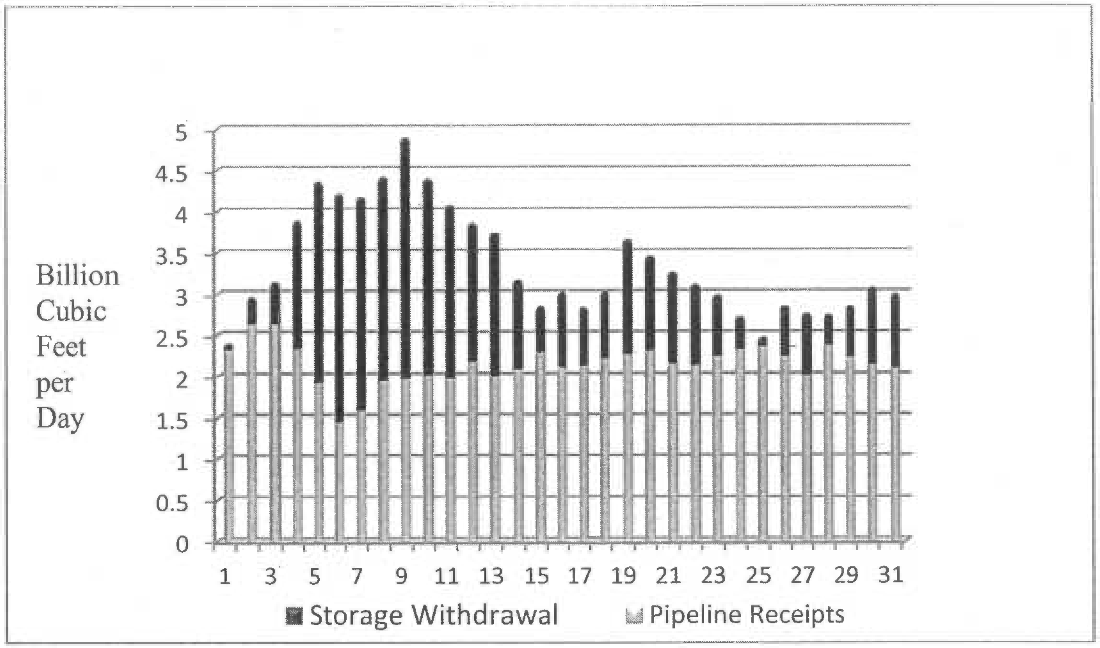
[4] In order to maintain operational stability of the gas system, smaller changes in supply and demand are typically met by "increasing" and/or "pulling" on the inventory of pressurized gas contained within the transmission pipelines. This process known as "packing and drafting," is an efficient way to deal with minor changes in load. As the system load increases, and can no longer be satisfied using pack and draft, the system is balanced by either injecting natural gas into the storage fields when pipeline delivery supply exceeds customer demand, or withdrawing natural gas from storage when service requirements exceeds out-of-State pipeline supplies.

Figure PEB-2
Southern California Gas Company
System Send-out December 2013



From the bar chart in Figure PEB-2, it can be observed that SoCalGas underground storage provided approximately 58% of the system send-out, or 17.7 Bcf, for a seven-day period beginning on December 5, 2013. On December 6, 2013, storage actually delivered 2.8 Bcf or 66% of the gas consumed by residential, commercial and industrial customers on this cold day. Had underground storage not been available and reliable for this extended period of high demand, widespread curtailments may have been necessary, and potentially significantly impacted millions of Southern California customers.

The reliance/dependency on underground storage to supply the SoCalGas system with such enormous volumes of gas over short period of times due to extreme weather conditions occurring locally or out of state, or from the temporary reduction of interstate supplies for other reasons, places significant strains on the wells, pipelines, and other aging storage facilities that must support the heavy withdrawal demands. The expected instant availability of storage gas requires continuous maintenance activities and ongoing investments to satisfy these immediate and longer-term customer demands.

Storage is responsible for the operation, maintenance, integrity, and engineering functions associated with the use of facilities within the perimeter of the fields. This responsibility also extends beyond the plant perimeter in some areas, where gas injection and withdrawal pipelines and storage wells exist outside of the storage field property. As an example, Figure PEB-3 below is an aerial view of the Playa del Rey storage field that plots the location of its wells inside and outside of the plant perimeter.[5]

Figure PEB-3
Southern California Gas Company
Aerial View of Playa Del Rey Underground Storage Field

The Storage department presently consists of approximately 175 employees. It is organized with both operational and technical support groups that provide cost-effective delivery of services essential to operating and maintaining the safety, integrity, security, and reliability of its crucial gas delivery assets. While each storage field has its own unique operating issues and characteristics, there are common support activities performed on a regular basis that make up the bulk of historical expenses presented in this testimony.

In general, the activities performed in compliance with increasing regulatory requirements that drive the historical and future O&M costs for storage can be summarized as follows:

[5] Some wells are plotted on the graphic as a single dot, due to their close proximity of each other.

Management, Supervision, Training, and Engineering

These activities cover the administrative salaries and engineering costs associated with the operation of the underground storage fields. This includes funding for studies in connection with reservoir operations and wells necessary to maintain the integrity of the storage system. Leadership, safety, technical training, operator qualification and quality assurance functions are other critical components of this grouping.

Wells and Pipelines

These costs include salaries and expenses associated with routinely operating storage reservoirs such as: turning wells on and off, well testing and pressure surveys, and wellhead[6] and down-hole activities for contractors that perform subsurface leakage surveys on injection/withdrawal facilities. Other expenses include the costs associated with patrolling field lines, lubricating valves, cleaning lines, disposing of pipeline drips, injecting corrosion inhibitors, pressure monitors, and maintaining alarms and gauges.

Equipment Operation and Maintenance

These costs include salaries and expenses for maintenance work performed on gas compressors and other mechanical equipment. The work ranges from the basic repair of an oil leak to a major time consuming overhaul of a compressor engine. Other maintenance functions include: work on measurement and regulating equipment, starting and monitoring engines, lubricating machinery, environmental compliance, checking pressures, work on equipment used for conditioning extracted gas, and wastewater disposal systems. Lastly, this area includes costs for chemicals, consumables, fuel, and electrical power used to operate storage reservoirs and compressors.[7]

Structural Improvements, Rents, Royalties

These costs include salaries and expenses for maintenance work performed on compressor station structures at underground storage facilities along with property rental costs. Royalty payments associated with gas wells and land acreage located at underground storage properties is also included.

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6 An illustrative diagram of a wellhead is provided as Appendix C, Wellhead Diagram and Down-hole Schematic.

7 The cost of natural gas used as fuel for the compressors and other equipment necessary to operate the storage fields has been adjusted out and excluded from this testimony because these costs are included in the Triennial Cost Allocation Proceeding (TCAP). In the same manner, all unaccounted for quantities of gas associated with field operation activities are similarly excluded from this general rate case due to cost recovery in the TCAP.

Records Management

These activities are associated with maintaining records related to storage assets and operations. Typical types of work performed include: work orders, surveys and documentation of wells, pipelines, topography, roads, rights-of-way, various infrastructure and easements boundary verification, and creation and maintenance of maps related to underground zones/rights. Audit related activities are also included.

2. Cost Forecast Methodology

A five-year trending methodology using 2009 to 2013 adjusted-recorded expenses for labor and non-labor was used to forecast the TY2016 O&M for routine Storage operations, since historical O&M costs have been increasing at a relatively consistent rate. Storage facilities consist of large heavy duty equipment located above and below ground that continues to wear and age, due to operating demands and the environment. The volume of maintenance work, along with its complexity and the limited availability of replacement components, continues to push costs consistently higher on an annual basis. Increasingly stringent governmental regulations, operator qualification requirements, enhanced employee training, chemical consumables, records management functions and enhanced audit activities also contribute to the upward trend.

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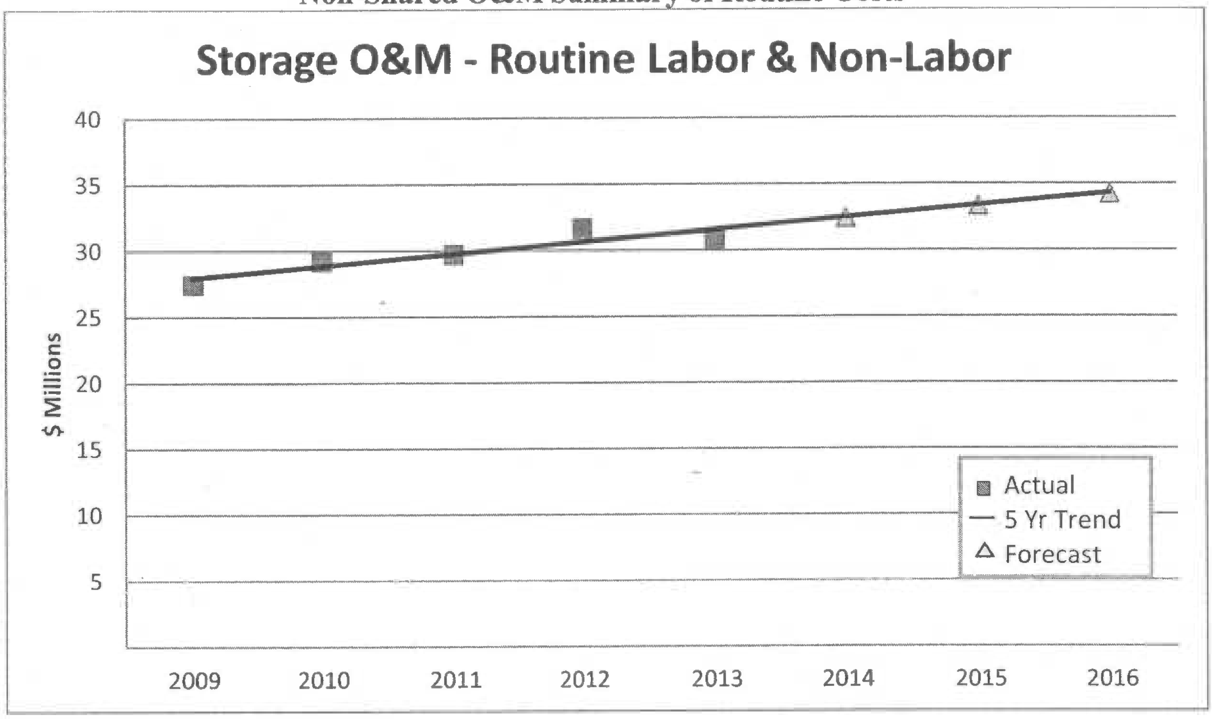
Figure PEB-4 below illustrates the historical and future projected costs (excluding NERBA and SIMP in 2016) for the routine labor and non-labor expenses based on a five-year trending methodology.

Figure PEB-4
Southern California Gas Company
Non-Shared O&M Summary of Routine Costs



The five-year trend establishes a TY2016 forecast of $34.101 million for routine O&M expenses.

3. Cost Drivers

Most increases in costs for storage over the five-year trend period are driven by the intensity of traditional operating functions and routine work efforts across the board that are required to safely operate and maintain the aging infrastructure of the fields, and costs associated with a larger volumetric storage capacity and throughput.[8]

Aging wells, compressors, and gas and liquid piping systems are susceptible to unpredictable failures or preemptive repair situations. The associated mitigation costs for such

[8] Over the five-year period of 2009 through 2013, SoCalGas increased the capacity of its storage fields by 5 Bcf, from approximately 131 Bcf to 136 Bcf. In CPUC Decision (D) 10-04-034, SoCalGas was authorized to increase the capacity of Honor Rancho from 23 to 28 Bcf. This expansion is expected to result in a total storage capacity of 138 Bcf by 2016, an inventory increase of 5.3% over 2009 volumes.

occurrences can vary from year to year. Thus, single events among relatively few facilities can have a significant impact on expense history. This "peak and valley" potential is another reason that a long-term horizon, such as the five-year historical trending methodology utilized, is appropriate for forecasting O&M costs.

In the future, pipeline integrity inspection requirements, the frequency and depth of regulatory audits and resulting compliance activities, additional focus on employee training and supervisory qualification, chemical consumables, increased permitting and reporting to regulatory agencies, along with new and existing environmental regulations are expected to add to operating expenses. Thus, O&M costs are expected to continue to increase, if not exceed, the annual historical rate of approximately 3.1%.

Another cost driver that varies from year to year is the amount of gas throughput (injection volume plus withdrawal volume) for the storage fields. This cycled volume is dependent on external factors such as the weather, the economy, and the gas markets. Over the five-year period of 2009 through 2013, the annual volume of gas cycled through the storage fields varied from a high of 228 Bcf to a low of 162 Bcf. The storage throughput in 2013 was 197 Bcf, 4% higher than the five year average of 189 Bcf. Higher gas throughput causes more wear on the compressors and equipment, and requires additional use of consumables such as engine oil, glycol, chemicals, odorant, etc.

There are few "big ticket items" one can point to as a primary cause for the increasing trend. Those few identifiable items that tend to stand out beyond the routine trend include the increasing costs of environmental compliance and hazardous waste disposal along with chemical consumables such as lubricating oil or glycol.

C. New Environmental Regulatory Balancing Account O&M Costs

The NERBA is a two-way balancing account established to record costs associated with specified new and proposed environmental regulations. Table PEB-6 below summarizes the costs for Storage, Transmission and Gas Engineering that are balanced in the NERBA.

Table PEB-6
Southern California Gas Company
NERBA Costs for Storage, Transmission and Gas Engineering

UNDERGROUND STORAGE	Thousands of 2013 Dollars		
Categories of Management	**2013 Adjusted Recorded**	**TY2016 Estimated**	**Change**
New Environmental Regulatory Balancing Account (NERBA)	$314	$404	$90

1. Description of Costs and Underlying Activities

The NERBA costs in my testimony are limited to the Environmental Protection Agency Subpart W reporting requirement costs for Gas Engineering, Gas Transmission, and Underground Storage. This forecast is to comply with the Subpart W requirements for fugitive emission monitoring, as supported by Environmental Services witness Jill Tracy (Exhibit SCG-17), that address facilities downstream of major equipment, such as compressors, regulator stations, and valves.

2. Cost Forecast Method

The forecast method for this cost category is the base year plus anticipated incremental costs. This method is appropriate because it identifies specific environmental regulatory changes and their related costs impacting the company in 2013, and during the next forecast period that cannot be represented using an average or trending forecast. Due to the uncertainty of the scope and anticipated costs related to future reporting, incremental funding was added to the base year recorded costs.

3. Cost Drivers

The cost drivers behind this forecast are the anticipated upper pressures from air quality agencies requiring more emission reporting during the next forecast period.

D. Storage Integrity Management Program

SoCalGas proposes to implement a new SIMP to proactively identify and mitigate potential storage well safety and/or integrity issues before they result in unsafe conditions for the public or employees. Table PEB-7 below summarizes the projected O&M costs for implementation of the SIMP.

Table PEB-7
Southern California Gas Company
Storage Integrity Management Program O&M Costs

UNDERGROUND STORAGE	**Thousands of 2013 Dollars**		
Categories of Management	**2013 Adjusted Recorded**	**TY2016 Estimated**	**Change**
Storage Integrity Management Program (SIMP)	$0	$5,676	$5,676

1. Introduction

SoCalGas proposes to implement a new six-year SIMP to proactively identify and mitigate potential storage well safety and/or integrity issues before they result in unsafe conditions for the public or employees. A proactive, methodical, and structured approach, using state-of-the-art inspection technologies and risk management disciplines to address well integrity issues before they result in unsafe conditions, or become major situational or media incidents, is a prudent operating practice. Without a robust program to inspect underground storage wells to identify potential safety and/or integrity issues, problems may remain undetected within the high pressure above-ground wellheads, pipe laterals (up to 3,600 psig) and below-ground facilities (up to 4,400 psig) among the 229 storage field wells. This situation is evidenced by an increase in recent years in the type of work related to safety conditions observed as part of routine operations. This concern is further amplified by the age, length, and location of wells. Some SoCalGas wells are more than 80 years old with an average age of 52 years. Well depths can exceed 13,000 feet. In addition, some wells are located within close proximity to residential dwellings or high consequence areas, as shown in Figure PEB-3.

The SIMP is intended to:

- Identify threats and perform risk assessment for all wells
- Develop an assessment plan for all wells
- Remediate conditions
- Develop preventative and mitigation measures
- Maintain associated records

The primary threats to the SoCalGas well facilities that SIMP will address are internal and external corrosion, and erosion.[9] Once an issue is identified, the initiation of critical repair work identified will immediately minimize safety risks. Lesser-risk integrity work will be prioritized to plan and efficiently execute mitigation or preventative actions.

SoCalGas proposes to establish detailed baseline assessments on its underground assets that are complete, verifiable, and traceable to a much greater degree than it has done in the past.[10] This risk management approach will enhance the proactive assessment, management, planning, repair, and replacement of below-ground facilities to eliminate situations that could potentially expose the public or employees to uncontrolled well-related situations.

The SIMP would launch an accelerated and robust assessment of the inspected storage well facilities (approximately 50% of the SoCalGas wells) over the rate case period. The initial SIMP work, which will likely target wells older than fifty years of age, would enhance ongoing safety, system integrity, support reliability of service, and provide additional confidence that wells, down-hole equipment, and associated pipe laterals maintain their compliance with DOGGR regulations. While SoCalGas currently meets existing requirements under DOGGR regulations, the possibility of a well related incident still exists, given the age of the wells and their heavy utilization. A SIMP will further decrease risks always present in these types of operations, provide a higher level of safety for its customers and employees, and further protect the environment.

Presently, most major O&M and capital funded activities conducted on storage wells are typically reactive-type work, in response to corrosion or other problems identified through routine pressure surveillance and temperature surveys. For example in 2008 at Aliso Canyon, it was discovered during routine weekly pressure surveillance that the surface annulus of well Porter 50A had a pressure of over 400 psig.[11] In most cases, situations like this can be indicative of production casing leaks from either internal or external corrosion where high pressure gas can

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9 The gas withdrawn from storage formations typically contains water, sand, and reactive gas constituents such as carbon dioxide that can corrode or erode storage well components especially during periods of high demand.

10 The goals and objectives of SIMP are similar to those of the TIMP for transmission pipelines. SIMP would be focused on vertical casing pipe and components (wells) and associated above-ground facilities.

11 The well was immediately taken out of service and work began to isolate and blow-down the surface casing. Eventually a workover rig moved onto the well and an ultrasonic inspection revealed external production casing corrosion from 450 ft. to 1050 ft.

migrate to the surface in a matter of hours. External corrosion has also been observed in other wells at the field.

Routine surveillance and temperature survey work identifies problems that have already occurred, and well integrity may have already been severely compromised requiring immediate attention to maintain safety, integrity and reliability. For example in 2013, again at Aliso Canyon, two wells were found to have leaks in the production casing at depths adjacent to the shallower oil production sands. In these situations, there was no evidence of the leaks at the surface or surface casing.

Reactive-type work in response to identified safety-related conditions observed as part of routine operations has increased in recent years. In fact, a negative well integrity trend seems to have developed since 2008. The increasing number of safety and integrity conditions summarized in Table PEB-8 below is attributed primarily to the frequency of use, exposure to the environment, and length of time the wells have been in service.

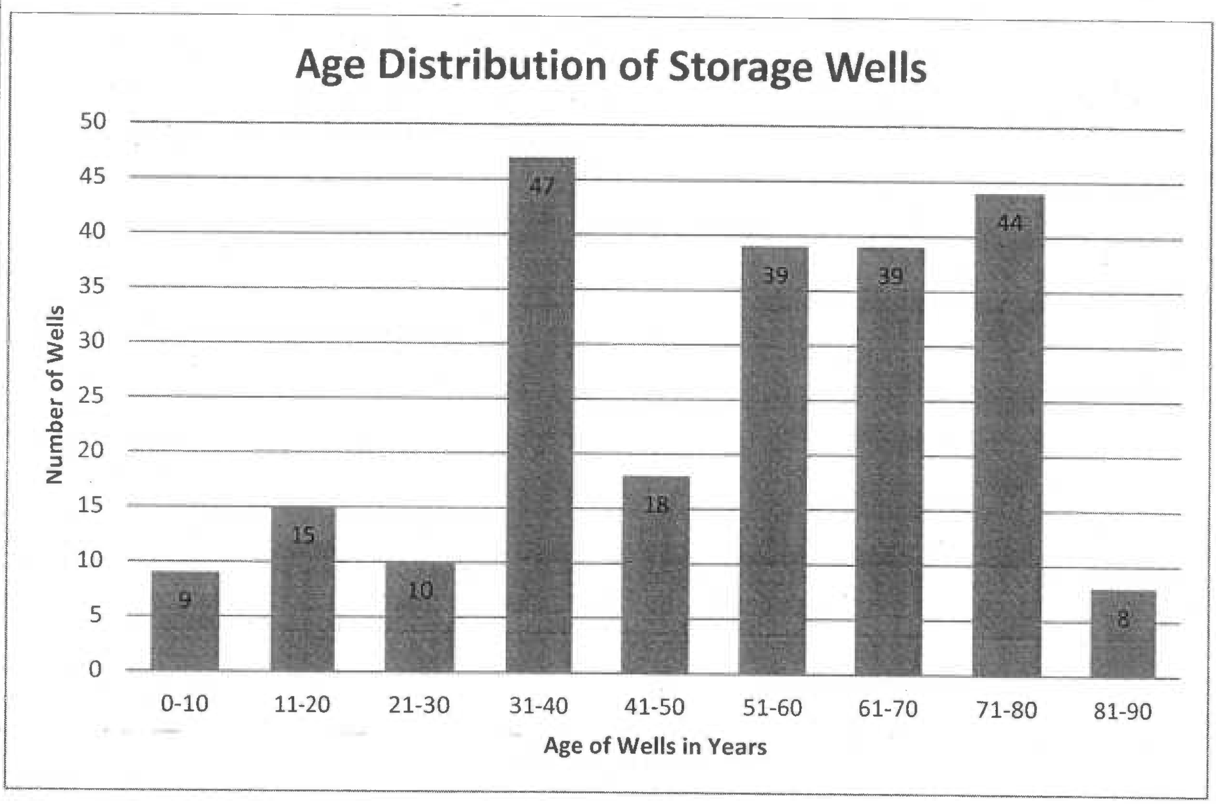
Table PEB-8
Southern California Gas Company
Number of Major Well Integrity Workovers by Year

Well Integrity Category	Year					
	2008	2009	2010	2011	2012	2013
Casing Leak	-	-	-	2	3	2
Tubing Leak	1	1	5	3	3	4
Wellhead Leak	-	-	1	2	-	2
Casing Shoe Leak	-	1	-	1	-	-
Sub-surface Safety Valve	2	-	-	-	2	1
Total	3	2	6	8	8	9

Ultrasonic surveys conducted in storage wells as part of well repair work from 2008 to 2013 identified internal/external casing corrosion, or mechanical damage in 15 wells. External casing corrosion has been observed at relatively shallow depths in the production casing, and at deeper intervals near the Aliso Canyon shallow oil production zone at which is being water-flooded. Internal mechanical wear has been observed in production casings, likely as a result of drilling operations that took place when the well was originally drilled. In addition, external tubing corrosion has been observed on tubing in the joint above the packer most likely as a result of stagnant fluid.

In addition to the 36 well-related conditions presented in Table 8, and the corrosion or mechanically damaged wells that were previously identified, SoCalGas has 52 storage wells in service that are more than 70 years old. Half of the 229 storage wells are more than 57 years old as of July 2014. Figure PEB-5 below displays the age distribution visually.

Figure PEB-5
Southern California Gas Company
Age Distribution of Storage Wells



Given the increasing trend in well integrity repairs, the corrosion threats that have been detected on some wells, the increasing age of the wells, and the success of the California Public Utilities Commission (CPUC)-approved TIMP, which has been established to maintain the safety of horizontal high pressure pipelines that are subject to less harsh conditions than storage wells, the SIMP is certainly justified. Without the SIMP, SoCalGas will continue to operate in a reactive mode (with the potential for even higher costs to ratepayers) to address sudden failures of old equipment. In addition, SoCalGas and customers could experience major failures and service interruptions from potential hazards that currently remain undetected.

Some of the inspection techniques, components, and practices planned for the SIMP are currently conducted on a limited basis as part of on-going operations performed to address maintenance issues. The intensity of routine inspections is expected to continue at historical levels. The more advanced SIMP inspections will be performed in addition to routine reactive inspections, as there is currently no indication that the rate of reactive maintenance work will decrease over the period of the next rate case. By establishing the additional and more robust SIMP inspections, and creating baseline assessments of well conditions, the severity and extent of reactive maintenance may be reduced in the future, and the time necessary to respond to indications of breaches in reservoir integrity and safety should be greatly improved.

To take advantage of economy of scale, accelerate problem solving and knowledge continuity, and best utilize the limited resources of qualified personnel and specialized equipment in the oil and gas industry required for this type of program, SoCalGas plans to conduct this program over a six-year period. Economic rig availability and quality supervision is highly dependent on overall demands of the industry. A continuous program implemented over a reasonable period of time will help secure efficient and effective specialty resources. After the six-year baseline assessment period of the SIMP, it is expected that well assessments performed on a regular frequency would become part of routine operations.

SoCalGas proposes that these O&M costs receive two-way balancing treatment due to the highly unpredictable nature of inspection costs. Factors contributing to the uncertainty include the unknown number of at-risk wells and their integrity status, the highly variable nature of well inspection strategies, the uncertainty surrounding the volume and degree of repair work to be performed, the variable cost of consulting experts when required, specialty equipment and skillful operators to be procured, and erratic field conditions typically encountered once inspection work is initiated. Since there are many uncertainties with regards to the number and integrity condition of the wells, and down hole inspection activities can become enormously costly and unpredictable when problems occur which is increasingly frequent, and follow-up mitigation actions whether they be O&M or capital is so variable due to the unique situation of each well, a two-way interest bearing balancing account treatment is requested for this work as sponsored by Regulatory Accounts witness Reginald Austria (Exhibit SCG-35).

2. General Description of Work

The safety and integrity-related work will be conducted in parallel at all four Storage Fields (Aliso Canyon, Honor Rancho, Playa del Rey, and La Goleta). A project manager, with other support personnel, will be used to conduct detailed internal well inspections and to develop the threat identification, risk assessment, well assessment plan, plan to remediate the conditions found, preventive and mitigative measures, and record keeping requirements for the SIMP. The assessment portion of the process will include contract workover rigs that will be used to evaluate downhole casing and tubing. Surface equipment such as valves, wellheads, and well laterals will be evaluated using different methods.

A threat assessment and risk assessment matrix will be developed and populated, and a priority inspection guide established, from existing well data that includes but is not limited to: age of the well, proximity to sensitive areas or populations, workover history, inspection data, historical withdrawal rates (energy release potential), known reservoir and geologic conditions, and surrounding geological characteristics (fault lines, landslide potential, etc.). In summary, it is expected that the oldest wells in closest proximity to the public, located in environmentally or safety-sensitive areas that have not had recent downhole inspections or work would likely be prioritized for inspection. Other wells may be added to this list, where deemed appropriate, based on subject matter expertise.

The first order of work would include the detailed inspection of all surface valves and above ground lines on the wellheads and laterals (both kill and injection/withdrawal lines), since surface failures, should they occur, could potentially have the most immediate impact on operating personnel and the public.

The majority of O&M costs to perform the noise and temperature surveys, pressure tests, visual camera tests, and casing/tubing inspections to assess well integrity risks associated with internal/external corrosion and erosion are associated with workover rig usage and well control activities. A typical week-long inspection process is summarized at a high level with the following ten steps:

1. Move in the workover rig and fill the well with brine.
2. Install well Blow-out Prevention Equipment.
3. Remove the tubing and down-hole completion equipment.
4. Scrape and prepare the casing, set the bridge plug and sand.

5. Run casing inspection equipment (Ultrasonic, magnetic flux, calipers, cameras etc.).
6. Run the test packer and pressure test production casing.
7. Remove the sand and retrievable bridge plug.
8. Re-install the production tubing and completion equipment, then pressure test.
9. Rig down the Blow-out Prevention Equipment, reinstall the production tree, and move the workover rig off the well.
10. Replace laterals, instrumentation, unload the workover brine from the wellbore and return the well to service.

This type of inspection operation typically requires six to eight days to complete, assuming no difficulties are encountered. If difficulties are encountered, which are not unusual with well work, the duration of the inspection and associated costs could easily double.

Follow-up preventative mitigation and remediation work will most likely be capitalized. The remediation plan will depend on the evaluation of the inspection data, and further pressure testing of the casing may be conducted. If no damage is observed or questionable conditions identified, the tubing will be re-run, the wellheads and laterals reinstalled, and the well will be returned to normal operations. If any significant deficiencies or unacceptable operating situations are found during the evaluation, the well will not be returned to service. Rather, it will be idled for an indefinite period of time while a detailed work prognosis is prepared and further work scheduled. Preventative and mitigative measures could include actions such as running inner liners, new tubing, cement squeezing of holes, or possible abandonment of the well. A complete abandonment would likely require the drilling of a replacement well in order to maintain storage field deliverability requirements. The details of the SIMP capital plan are included in section III-C.C13 of this testimony.

The record keeping requirements will include a written Storage Integrity Management Plan, traceable, verifiable and complete documentation of the results of the assessments that are completed, and the results of the remediation completed.

The company labor required for the inspection process is one individual at each of the four fields to oversee the workover/inspection contractors, plus 1.5 FTEs to manage the inspection program, interpret the complex data, and develop follow-up mitigation plans.

3. Cost Forecast Methodology

The forecast method used for SIMP O&M activities is zero-based. This approach is most appropriate because this is a new program and the assumed units of work, estimated cost per unit, and support labor needs are identifiable. Unit costs for the ten step inspection process previously described and the lateral inspections are based on historical prices of similar type work. Labor FTEs to support the program based on experience and practicality consist of one Contract Administrator for each of the fields (4), a Well Inspection Project Manager (1), and 0.5 clerical support. These costs are presented in Table PEB-9 below.

Table PEB-9
Southern California Gas Company
SIMP O&M Cost Detail

Description	Annual Number	Cost Per Inspection	Estimated Total
		(Thousands of $2003)	
Well Inspections and Mitigation	40	$390	$15,600
Lateral Piping Inspections	40	$5	$200
Company Labor FTEs	5.5	N/A	$812
Well Inspection Costs Reassigned to Capital	N/A	N/A	($10,936)
Total O&M	-	-	$5,676

4. Cost Drivers

The most significant cost drivers for this uniquely specialized work performed on high pressure wells is the availability of workover rigs, the skilled field and technical workforce required to produce and analyze data, and the specialized equipment to be employed.

III. CAPITAL COSTS

A. Introduction

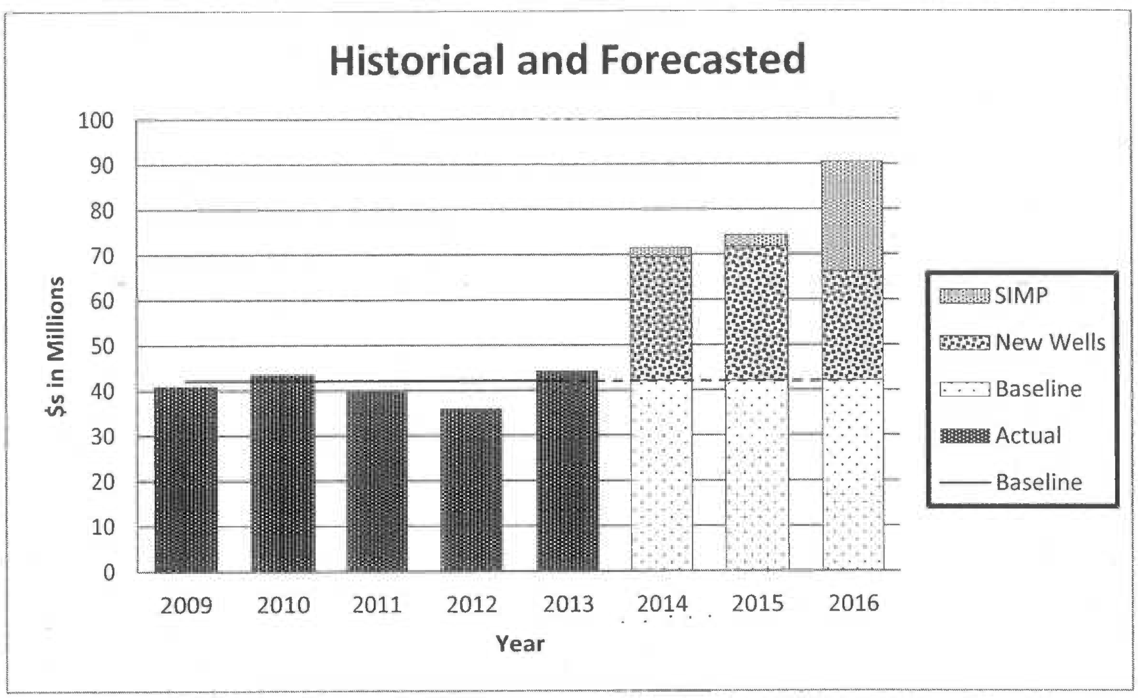
The costs described in this section cover the capital expenditures estimated for Storage operations. The intent behind the capital expenditure plan is to provide safe, reliable delivery of natural gas to customers at the lowest reasonable cost. These investments also enhance the integrity, efficiency, and responsiveness of operations while maintaining compliance with applicable regulatory and environmental regulations. Table PEB-10 below summarizes the total capital forecasts for Gas Storage for 2014, 2015, and 2016.

Table PEB-10
Southern California Gas Company
Capital Expenditures Summary of Costs
(Thousands of $2013)

Category Description	2013 Recorded	2014 Estimated	2015 Estimated	2016 Estimated
Storage Compressors	$8,991	$7,790	$7,790	$7,790
Storage Wells	$10,976	$31,890	$34,360	$36,977
Storage Integrity Management Program	$0	$2,008	$2,510	$24,272
Storage Pipelines	$4,005	$6,546	$10,083	$4,931
Storage Purification Systems	$9,284	$8,796	$7,605	$7,605
Storage Auxiliary Systems	$11,058	$14,398	$11,922	$8,948
Total Capital:	**$44,313**	**$71,429**	**$74,270**	**$90,523**

Figure PEB-6 below presents the Total Capital summary of Table PEB-10 in a graphical format.

Figure PEB-6
Southern California Gas Company
Historical and Forecasted Total Capital by Year



The 2016 capital request of $90.523 million was derived using the following methodology:

- Summation of five-year averages to create a baseline estimate for routine functions.
- Plus, incremental costs to drill new wells at a level that began in 2014 to address natural deliverability declines.
- Plus SIMP.

As noted previously, SoCalGas seeks two-way balancing treatment of the SIMP capital cost estimates. Additional detail on the categories and costs that comprise the total capital forecast is presented in the sections below.

B. Storage Compressors

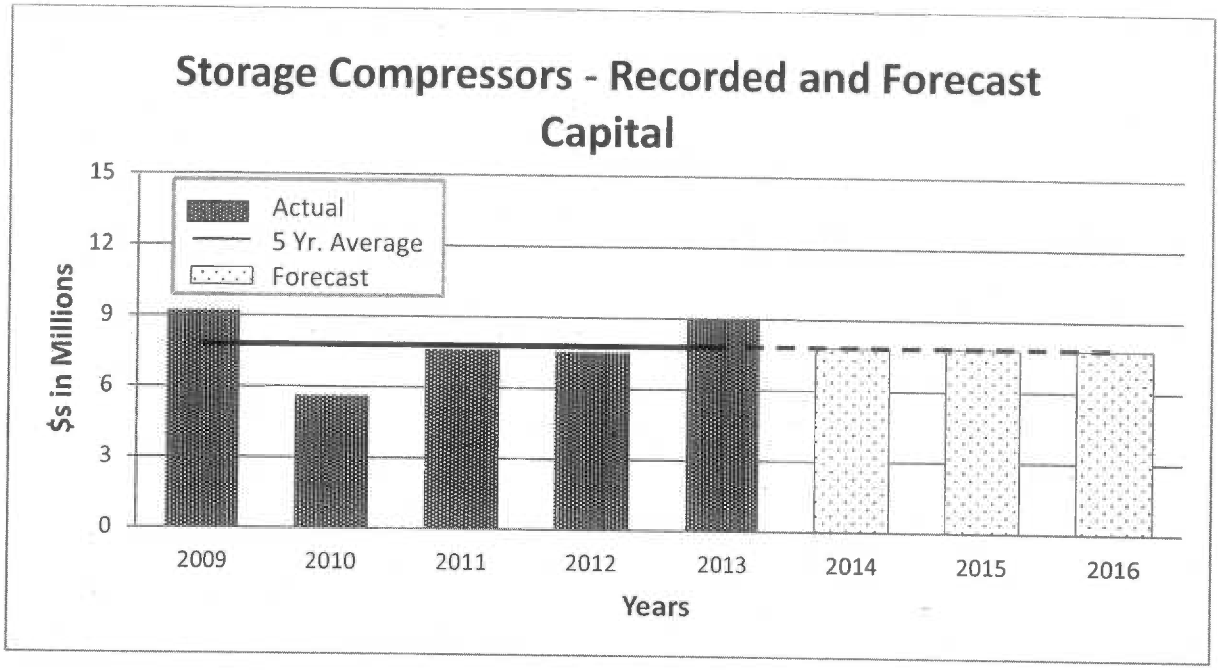
This Budget Category includes costs associated with natural gas compressors. These storage compressor units increase the pressure of natural gas so it can be injected into the underground reservoirs. Examples of equipment within this area include turbines, engines, high-pressure gas compressors, compressed air system equipment, fire suppression systems, gas scrubbers, and related control instruments. This budget category includes the necessary capital for maintenance, replacements, and upgrades of the various storage field compressors to uphold safety, maintain or improve reliability, extend equipment life, achieve environmental compliance, and to meet the required injection capacities. Table PEB-11 below summarizes the cost forecast for storage compressors.

Table PEB-11
Southern California Gas Company
Capital Expenditures for Storage Compressors

STORAGE COMPRESSORS	Thousands of 2013 Dollars		
	Estimated 2014	Estimated 2015	Estimated 2016
B1- Goleta Units #2 and #3 Overhauls	$253	$2,272	$0
B2- Blanket Projects	$7,538	$5,518	$7.790
Total	**$7,791**	**$7,790**	**$7,790**

Due to the annual variability of this category, a five year average was used to develop the 2016 estimate, as presented in Figure PEB-7 below. Projects expected to cost over $1 million are supported by individual capital workpapers that accompany this testimony, Exhibit SCG-CWP.

Figure PEB-7
Southern California Gas Company
Historical and Forecasted Storage Compressor Capital



1. B1-Goleta Units #2 and #3 Overhauls

a. Description

When compressors reach the end of their service lives, they must be overhauled in order to avoid replacing them in-kind. Overhauls are necessary for safety, to restore and/or maintain their efficiency, deliver capacity, maintain compliance with environmental regulations and provide reliable service. While parts and compressor service contractors are still available, an overhaul is typically the most cost-effective solution. Goleta Units #2 and #3 have reached their maximum in-service time and require overhauls in order to maintain safety, efficiency, reliability, and environmental compliance. The overhaul of units #2 and #3 at Goleta is expected to cost $253K, $2.272 million, and $0 in 2014, 2015, and 2016, respectively. Specific details regarding the overhauls may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Costs are based on the knowledge of experienced personnel who have handled similar overhauls in the recent past. Such experience is based on recent costs of component parts and quotes by qualified contractors.

c. **Cost Drivers**

The cost drivers for these capital projects relate to the very specific skill sets, tooling, parts, and specialized knowledge for gas engines, equipment, and the high pressure natural gas compressors they power.

2. **B2-Blanket Projects**

a. **Description**

Compressor Station equipment must have continuing capital maintenance as items continue to age and to wear out. SoCalGas plans to replace and upgrade aging and obsolete compressor equipment via smaller projects with individual costs estimates that do not justify the preparation of individual workpapers. These projects are addressed as "Blanket" projects and cost estimates vary from tens of thousands to several hundred thousands of dollars. Projected work includes, but is not limited to overhauls, rebuilds, major equipment replacements and upgrades to critical assets such as power turbines, gear boxes, compressors, and engines. Deferral of these smaller compressor maintenance projects could jeopardize safety or cause equipment to shut down, which can threaten supply continuity. Forecast capital costs for Blanket projects in $ millions for 2014, 2015, and 2016 are $7.538, $5.518, and $7.790, respectively.

b. **Forecast Method**

This estimate is based on the local knowledge and judgment of the managers at the storage fields, and the historical conditions at each field that routinely need correcting through blanket capital projects.

c. **Cost Drivers**

The underlying cost drivers for Blanket projects relate to equipment type and complexity, operating location, availability of qualified contractors, and workload. There are a limited number of qualified contractors available for compressor work in Southern California, and they perform work for customers other than SoCalGas. Thus, prices for these specialized services vary based on contractor workload and associated equipment lead times. Parts and equipment costs are driven by the limited number of competing suppliers and the very specialized nature of the hardware.

C. **Storage Wells**

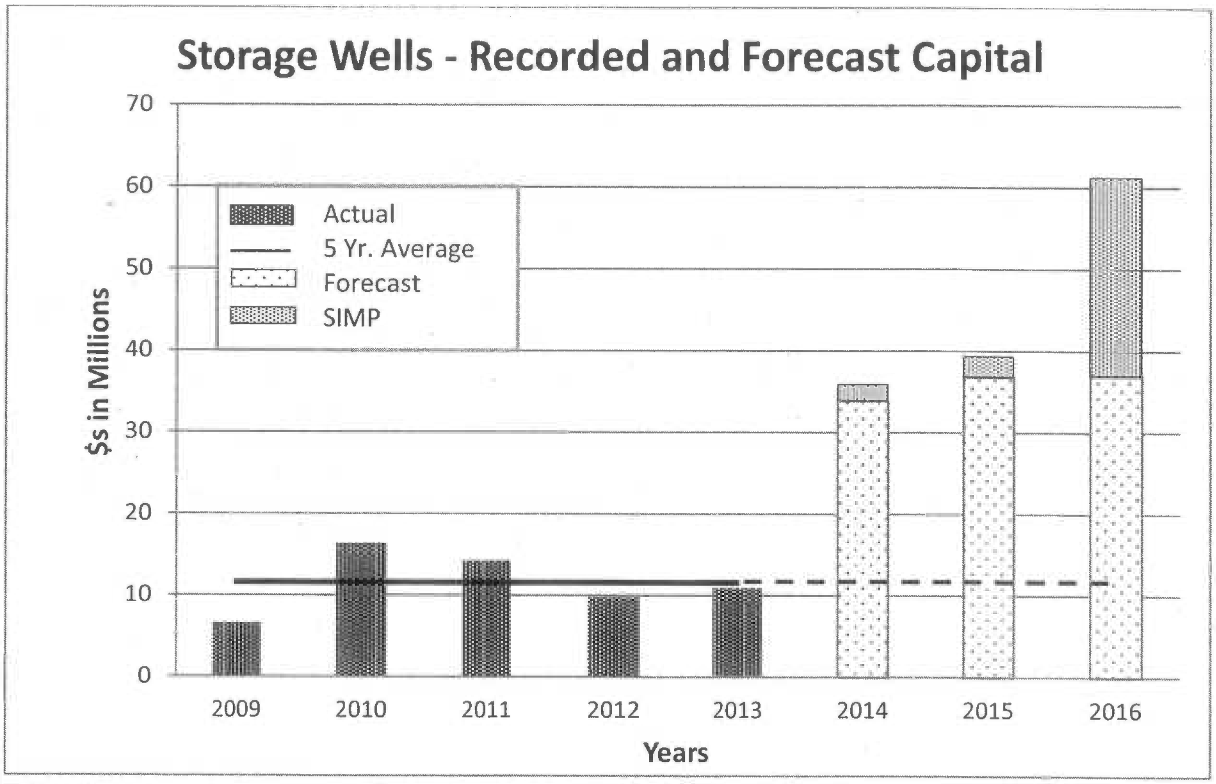
This Budget Category includes costs associated with replacing failed components on existing wells, and the design, drilling and completion of replacement wells for the injection and withdrawal of natural gas and reservoir observation purposes. This includes well workover contractors (major well work), drilling contractors, and component materials such as tubing, casing, valves, pumps, and other down-hole equipment. Table PEB-12 below summarizes the capital cost forecast for this Budget Category.

Table PEB-12
Southern California Gas Company
Capital Expenditures for Storage Wells

STORAGE WELLS	Thousands of 2013 Dollars		
	Estimated 2014	**Estimated 2015**	**Estimated 2016**
C1- Wellhead Valve Replacements	$1,194	$1,194	$1,194
C2- Well Tubing Replacements	$4,041	$4,041	$4,041
C3- Wellhead Leak Repairs	$1,807	$1,807	$1,807
C4- Well Inner-string Installations	$1,707	$1,707	$1,707
C5- Submersible Pump Installations	$552	$552	$552
C6- Well Stimulations	$176	$176	$176
C7- Well Gravel Packs	$3,715	$3,715	$3,715
C8- Well Re-drills	$2,209	$2,008	$0
C9- Replacement Wells	$10,241	$10,442	$18,273
C10- Plug and Abandon Wells	$3,876	$6,195	$4,688
C11- Blanket Projects	$974	$1,125	$824
C12- Cushion Gas Purchase	$1,398	$1,398	$0
C13- SIMP	$2,008	$2,510	$24,272
Total	**$33,898**	**$36,870**	**$61,249**

Figure PEB-8 below illustrates the combined Wells and SIMP capital forecasts from Table PEB-12 in a graphical format.

Figure PEB-8
Southern California Gas Company
Historical and Forecasted Wells Capital



The Storage Wells category in this testimony is further described using the following sub-sections:

- C1-Wellhead Valve Replacements
- C2-Well Tubing Replacements
- C3-Wellhead Leak Repairs
- C4-Well Inner-string Installations
- C5-Submersible Pump Replacements
- C6-Well stimulations
- C7-Well Gravel Packs
- C8-Well Re-drills
- C9-Well Replacements

- C10-Well Plug and Abandonments
- C11-Storage Blanket Projects
- C12-Cushion Gas Purchase
- C13-Storage Integrity Management Program (SIMP)

1. C1-Wellhead Valve Replacements

a. Description

SoCalGas plans to replace and upgrade gas-passing, aging, and obsolete wellhead valves located throughout the four storage fields. This work is necessary due to obsolete and gas-passing wellhead valves, some of which have been in service more than fifty years. Gas-passing wellhead valves can create a safety, operating or environmental hazard if not replaced in a timely manner. Costs in $ millions for 2014, 2015, and 2016 are forecast to be $1.194, $1.194, and $1.194, respectively. The specific details regarding wellhead valve replacements identified as part of routine operations are found in my capital workpapers, Exhibit PEB-06-CWP. An illustrative diagram of a wellhead is provided as Appendix C, Wellhead Diagram and Downhole Schematic.

b. Forecast Method

Historically, there have been twelve to fifteen wellhead valve replacement projects per year at an approximate cost of $85k each. Fourteen projects are planned in 2016. Costs include the material and services required to secure the well, replace the wellhead valves, and return the well to service.

c. Cost Drivers

The cost drivers for wellhead valves are the purchase price of the valves and the installation contracting services. Wellheads must be isolated from reservoir pressure and depressurized in order to replace the principal valve. This is a complex operation that requires controlling well pressures that can reach 3,600 psig.

2. C2-Well Tubing Replacements

a. Description

Continuous tubing replacements are required among the existing 229 aging wells throughout the storage fields. Tubing replacements are necessary to maintain aging well equipment when they have reached the end of their useful life. Leaking tubing strings can become a safety or environmental hazards if not replaced in a timely manner. Costs in $ millions for such work are estimated to be $4.041, $4.041, and $4.041, for 2014, 2015, and 2016 respectively. The estimated costs of the replacement projects include the tubing commodity purchase, all of the activities involved to secure the wells, the equipment and well services required for tubing removal, and the reinstallation operations. Specific details regarding tubing replacements identified as part of routine operations are found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

There are seven workover rig tubing replacement projects estimated per year at an approximate cost of $575k each. Costs include the material and services required to secure the well, replace the tubing, valve work, and returning the well to service.

c. Cost Drivers

Cost of these replacements is driven by the very specific nature and characteristics of high pressure injection wells. This is a complex operation that requires controlling well pressures which can reach 3,600 psig.

3. C3-Wellhead Leak Repairs

a. Description

Wellhead leak repairs are required among the existing 229 wells throughout the storage fields. Wellhead leaks pose safety and environmental risks and must be removed from service while leak repairs are in progress. The costs for these wellhead leak repairs in $ millions are forecast to be $1.807, $1.807, and $1.807, for 2014, 2015, and 2016, respectively. Specific details regarding cost estimates for wellhead leak repairs identified as part of routine operations may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Four wellhead leak repairs requiring workover rig support are planned at an approximate cost of $450k each. Individual project costs typically vary due to the specific equipment required and configuration of the well being repaired.

c. Cost Drivers

The cost driver for this activity relates to the highly specialized nature of work performed on leaking high pressure wells and the skilled workforce and equipment employed. These repairs can be complex operations that require controlling underground well pressures, which can reach 3,600 psig.

4. C4-Well Inner-String Installations

a. Description

When the production casing in a well reaches the end of its useful life, an inner-string may be installed to extend the life of the well, depending on its mechanical condition. This methodology requires the installation of smaller-sized casing due to a loss of production casing integrity observed within the storage wells. Inner-string installations are used as a temporary or interim mitigation strategy in response to aging or damaged storage wells. The well must be removed from service and secured pending the installation process. The well will be unavailable for withdrawal or injection until the work is completed. The costs for inner-string installations in $ millions are projected to be $1.707, $1.707, and $1.707, for 2014, 2015, and 2016, respectively. Specific details regarding inner-string installations identified as part of routine operations are found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

SoCalGas plans to complete two inner-string installations per year, at an approximate cost of $850k each.

c. Cost Drivers

The underlying cost drivers for this activity relate to the highly specialized nature of work performed on high pressure wells and the skilled workforce and equipment employed. These can be complex operations.

5. C5-Submersible Pump Replacements

a. Description

SoCalGas plans to replace existing electric submersible pumps in various storage wells. These pumped wells, required to control liquids and storage reservoir management, typically require replacement on a one to four year cycle. If pumps are not installed in a timely manner, there is the likely risk of reduced reservoir storage capacity. The forecast for 2014, 2015, and 2016 are $552K, $552K, and $552K, respectively. Specific details regarding these capital projects are found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

SoCalGas typically replaces two electric submersible pumps per year, at an approximate cost of $275k each.

c. **Cost Drivers**

The cost drivers for these projects relate to equipment type and complexity, location, and availability of qualified contractors. Individual project costs can also vary due to the depth of the electric submersible pump being replaced. There are a limited number of qualified contractors who specialize in downhole pumps and controls. Thus, the prices for this very specialized work varies according to contractor workload and associated lead times. Parts and equipment costs are driven by the limited number of competing suppliers and the very specialized nature of these pumps.

6. **C6-Well Stimulations/Re-Perforations**

a. **Description**

SoCalGas plans to perform required "stimulation" or "re-perforation" of existing storage wells to improve poor deliverability rates. Storage wells that experience minor productivity damage can be restored via this method. These capital expenditures therefore support the company's goals of maintaining the integrity, efficiency, reliability and continuity of supply. The forecast for well stimulations and re-perforations work in 2014, 2015, and 2016 is $176K, $176K, and $176K, respectively. Specific details regarding these capital projects are found in my capital workpapers, Exhibit PEB-06-CWP.

b. **Forecast Method**

The forecast is based on local knowledge of expected upgrades and capital project estimates prepared on experience.

c. **Cost Drivers**

The underlying cost drivers for these projects relate to the complexity of the operations and availability of qualified contractors. Parts and equipment costs are driven by the limited number of competing suppliers and the very specialized nature of the hardware they produce.

7. **C7-Well Gravel Packs**

a. **Description**

Gas flows will be restricted if a well has a failed gravel pack. Typically, a well will remain out of service until the well is repaired and re-gravel packed. SoCalGas plans to replace failed gravel packs from existing wells at historical rates. The costs in $ millions for well gravel pack replacements are forecasted to be $3.715, $3.715, and $3.715, for 2014, 2015, and 2016, respectively. Costs include the materials and services required to remove existing equipment, sidetrack the well, install a new gravel pack, complete the well, and return the well to service. Specific details regarding gravel pack replacements are found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Typically there are two gravel pack replacements performed per year at an approximate cost of $1.85 million each. Individual project costs may vary from well to well and field to field, depending on the actual depth and mechanical condition of the subject well.

c. Cost Drivers

The underlying cost drivers for this activity relate to the highly specialized nature of work performed on high pressure wells and the skilled workforce and equipment employed.

8. C8-Well Re-Drills

a. Description

It is not uncommon for a well to experience declining or poor deliverability with age. If a storage well has poor deliverability and the well is not re-drilled, the well will likely become a high operating cost, low productivity asset, with negative impacts to service reliability. SoCalGas expects to relocate bottom-hole locations for some wells due to poor or low deliverability. The costs in $ millions for well re-drills are projected to be $2.209, $2.008, and $0, for 2014, 2015, and 2016, respectively. Specific details regarding re-drill projects are found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Re-drill costs are based upon historical projects of similar complexity. However, no storage well re-drills are planned for 2016.

c. Cost Drivers

The cost drivers for this activity relate to the highly specialized nature of work performed on high pressure wells and the skilled workforce and equipment employed.

9. C9-Well Replacements

a. Description

SoCalGas plans to replace mechanically constrained wells with curtailed deliverability, along with high operating cost aging injection/withdrawal wells and their associated production, with new wells that provide higher deliverability rates. These new wells are necessary replacements due to lost deliverability from failed gravel packs or poor deliverability rates from other causes. It also includes the replacement of lost withdrawal capacity from the required abandonments of aging storage wells. The costs for replacement storage wells in $ millions are forecast to be $10.241, $10.442, and $18.273 for 2014, 2015, and 2016, respectively.

At the end of the 2013/2014 winter withdrawal season, during a period of high demand and low field inventory not seen in recent years, Aliso Canyon was not able to meet the deliverability levels expected from existing wells. Declining performance of older wellbores, along with the necessary plugging of problem wells, resulted in the field falling short of delivery expectations by more than 350 MMCFD. Having operated at higher inventories in recent years, this 20% downgrading of well performance was not readily apparent until early 2014.

With modern well design and completion techniques, opportunities exist to reduce the number of storage wells by drilling new replacement wells in a manner that may allow for better than a one-for-one replacement. Depending on the storage field and its geology, a newly drilled and completed replacement well is likely to provide the replacement deliverability of two or more existing older wells. This scenario would be repeated as each new replacement storage well is drilled, thus potentially reducing the overall storage well count and operating expenses.

These projects will locate and prepare drill sites, drill and complete new replacement storage injection/withdrawal wells to be strategically located throughout the Storage Fields. Included are all services and materials to complete each well. The anticipated numbers and locations of the replacement wells are as follows:

- 2014 - Two Aliso Canyon Storage Wells. This work is required to replace naturally declining deliverability from existing wells, and wells that were abandoned due to integrity concerns;
- 2015 - Two Goleta Storage Wells. This work is necessary to improve lost deliverability as well as decrease the footprint of the facility by bringing remotely located wells in a high consequence area closer to the main station and removing injection/withdrawal lines from environmentally-sensitive areas; and
- 2016 - Three Aliso Canyon Storage Wells. This work is needed to continue the replacement of lost deliverability due to the natural productivity declines from aging wells described above.

Specific details regarding storage well replacements are found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Planned replacement wells located among the storage fields will vary in cost, but average approximately $5-6 million each. Costs are based on historical well drilling costs combined with recent vendor cost estimates.

c. Cost Drivers

The underlying cost drivers for these capital projects relate to the highly specialized nature of work performed on high pressure wells and the necessarily skilled workforce and equipment employed. These older storage wells typically require high cost casing repairs ($700K or more) per occurrence and/or repeated re-gravel packing of the wells due to highly erosive sand production. Costs of replacing the gravel packs of these aging wells are typically in the range of $2 million each. Phasing in these new higher-deliverability replacement wells and eliminating the high cost aging wells over time, may reduce the Company's long term operating costs by reducing the need for frequent, high cost, casing repairs and gravel pack capital projects.

10. C10-Well Plug and Abandonments

a. Description

SoCalGas plans to abandon aging, mechanically unsound wells that are beyond their useful lives. Required abandonments are becoming more frequent as various storage wells reach or exceed their useful lives. These subject wells become high risk, high operating cost assets due to poor or declining mechanical integrity, or complete lack of productivity due to age. A number of the abandonments are required for the removal of wells and their operations from environmentally sensitive areas or higher public risk areas and relocating the new replacement storage wells within storage field boundaries.

Currently there are 26 existing mechanically-unsound, unproductive, or aging storage wells located in environmentally-sensitive areas. SoCalGas will focus on the abandonment of aging storage wells located in environmentally-sensitive or high consequence areas. Projected costs include the material and services required to plug and abandon the wells in a manner that meets or exceeds California DOGGR requirements. The cost in $ millions for well plug and abandonments are forecasted to be $3.876, $6.195, and $4.688, for 2014, 2015, and 2016, respectively. Specific details regarding well abandonment projects are found in the capital workpapers, Exhibit PEB-06-CWP.

b. **Forecast Method**

Eight wells per year are planned for abandonment among the existing storage fields, at an approximate cost of $600K each. The individual well abandonment costs will vary depending on the condition of the well at the time of the abandonment, surface location of the well, in addition to the depth of the well to be abandoned.

c. **Cost Drivers**

The underlying cost drivers for these capital projects relate to the highly specialized nature of work performed on high pressure gas wells and the necessarily skilled workforce and equipment employed.

11. **C11-Storage Blanket Projects**

a. **Description**

SoCalGas plans to build and place in service multiple smaller projects with individual costs that do not warrant the preparation of individual workpapers. These forecasted capital expenditures support the goals of maintaining the safety of the public and employees, as well as operating efficiency, reliability and continuity of supply. The costs of individual projects in this category will vary from as low as ten thousand to as high as several hundreds of thousands of dollars. They include shallow zone work in the Aliso Canyon field, projects related to geology and storage engineering, and smaller technology upgrades. The forecast in $ million for 2014, 2015, and 2016 is $0.974, $1.125, and $0.824, respectively. Specific details regarding these projects are found in my capital workpapers, Exhibit PEB-06-CWP.

b. **Forecast Method**

The forecasts of these smaller projects are based on local knowledge of required upgrades and capital maintenance projects prepared by experienced professionals who have worked in the Storage fields for years. This method is appropriate because these professionals are responsible for preparing a list of upgrades and projects, which is updated and prioritized regularly, based on equipment age, wear and tear, failure history, and technical obsolescence.

c. **Cost Drivers**

The underlying cost drivers for these kinds of projects relate to equipment type and complexity, operating location, availability of qualified contractors, and workload. There are a limited number of qualified contractors available for Storage field work. Thus, the prices for this very specialized work varies according to the contractor's workload and associated lead times.

Parts and equipment costs are driven by the limited number of competing suppliers and the very specialized nature of the hardware.

12. C12-Cushion Gas Purchases (Honor Rancho Expansion)

a. Description

SoCalGas plans to purchase cushion gas to support the final phase of the Honor Rancho expansion project. Cushion gas is the volume of gas intended to serve as the permanent inventory within a storage reservoir that is required to maintain adequate pressure for deliverability rates throughout the withdrawal season. The need for storage capacity expansion and its relationship to Gas System supply reliability was established by the CPUC in decision (D) 10-04-034. That discussion is incorporated herein by reference. The cost for cushion gas purchases in $ million is forecast to be $1.398, $1.398, and $0, for 2014, 2015, and 2016, respectively. Specific details regarding this estimate of cushion gas costs may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Costs are estimated for the purchase of 300 MMCF, at a price of $4.55 per decatherm.

c. Cost Drivers

The unit cost of the gas is driven by conditions in the natural gas market.

13. C13-Storage Integrity Management Program

a. Description

Reactive-type well repair work performed by Storage related to safety situations observed as part of routine operations has increased in recent years. In fact, a negative well integrity trend seems to have developed since 2008. The increasing number of well integrity conditions summarized in Table PEB-8 above are attributed primarily to the frequency of use, operating environment, age, and length of time the wells have been in service. In contrast to the reactive capital work discussed above, the SIMP is intended to proactively identify, diagnose, and mitigate potential safety and/or integrity problems associated with gas storage wells. It is important to distinguish that SIMP is incremental work above and beyond the levels traditionally performed. As such, it consists of accelerated mitigation work performed over a condensed period of time in response to the thorough well integrity inspections described above in section II D-2 of my testimony. Early identification and mitigation of well integrity issues will improve safety and increase reliable gas deliveries. The capital costs in $ million for the SIMP are forecasted to be $2.008, $2.510, and $24.272 for 2014, 2015, and 2016, respectively.

Safety and/or integrity conditions that are presently unknown may exist within the high pressure (up to 3,600 psig) above ground pipe laterals and below ground facilities that comprise of 229 aging gas storage field wells that can exceed 13,000 feet in depth. Some SoCalGas wells are more than 80 years old while the average age of all Storage wells is 52 years. A proactive, methodical, and structured approach, using advanced inspection technologies, such as ultra-sonic and neutron type casing logs, along with risk management disciplines to address well integrity issues before they result in unsafe conditions for employees or the public, or become major incidents, is a prudent operating practice. In addition, some SoCalGas wells are located within close proximity to residential dwellings, as depicted in Figure PEB-2.

The primary threats to the SoCalGas well facilities that SIMP will address are internal and external corrosion, and erosion.[12] Immediate repairs may be necessary to minimize safety risks. Lesser risk integrity work will be prioritized to plan and efficiently execute mitigation actions.

SoCalGas proposes that these capital costs receive two-way balancing account treatment due to the highly unpredictable nature of estimating well mitigation costs. Factors contributing to the uncertainty include the unknown number of at-risk wells and their integrity status, the highly variable nature of well mitigation strategies, the uncertainty surrounding the volume and degree of repair work to be performed, the variable cost of consulting experts, when required, specialty equipment and skillful operators to be procured, and erratic field conditions typically encountered once repair work is initiated. All well work to be performed will be dependent on the site-specific conditions found at the time work is initiated. While average costs were utilized to prepare initial forecasts for SIMP, actual conditions and the scale of work to be performed can only be determined after the well is actually entered with inspection devices and/or repair tools. Given the fact that many of the wells have not been worked on in recent years, and the mature age of some wells, major problems and fixes of unknown costs are anticipated.

Past work on well Frew 3 at Aliso Canyon in 2013 is a good example of the wide variability in mitigation costs. Frew 3 was originally targeted for a tubing leak repair scheme,

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12 The gas withdrawn from storage formations typically contains water, sand, and reactive gas constituents such as carbon dioxide that can corrode or erode storage well components especially during periods of high demand.

estimated to cost approximately $600,000. Once the well was entered and repairs began, the wellbore was found to be compromised due to shifting geological formations requiring extensive work. The net result was a decision to abandon the well at a cost of $1.39 million, more than double the original repair estimate.

In addition, costs for the well rigs required for SIMP are dependent on activity throughout the oil and gas industry. The ability to secure equipment and associated prices are dependent on energy demand and rig availability worldwide. Financial outlays to secure rigs and oil/gas field services can vary greatly over time due to domestic and foreign developments related to energy.

b. Forecast Method

The forecast method used for the SIMP capital work is zero-based. This approach is most appropriate because it is an incremental program. The costs per units of work are based on historical averages, and internal labor support was established based on practical considerations and experience. Actual well repair methods will be based upon assessment findings, however, and optimized among the options described in the Capital Costs Section III C-Wells of my testimony. Unit costs based on historical prices of similar type work for the mitigation work would most likely consist of:

- Wellhead Valve Replacements ($85k)
- Well Tubing Replacements ($575k)
- Wellhead Leak Repairs ($450k)
- Well Inner-string Replacements ($850k)

Mitigation work could also consist of well abandonments, well redrills or well replacements typically cost approximately $0.6 million, $2.0 million, and $6 million, respectively.

The decision whether to re-drill an existing well or drill a replacement well as a risk mitigation strategy depends upon localized conditions encountered during the downhole inspections. If data indicate poor conditions of casing in the upper part of the wellbore, a re-drill solution is generally not an option. Other site-specific conditions that could justify a replacement well over a re-drill are wells with a small casing, existing condition of the well/casing cement bond, proximity of integrity issues relative to the surface, and the geographic location of the well within the reservoir. Re-drill versus replacement decisions will be made by experienced storage reservoir engineering personnel using knowledge, professional judgment and site specific information.

Labor totaling 6.5 FTEs to support the capital program consists of two Contract Administrators for Aliso Canyon, and one each for the remaining three fields, one Well Mitigation Project Manager, and 0.5 FTE clerical support. Company labor estimates are presented in Table PEB-13 below.

Table PEB-13
Southern California Gas Company
SIMP Capital Cost Detail

Description	Annual Number	Unit Cost	Estimated Total
		(Thousands of $2013)	
Wells Requiring Capital Mitigation Work	28	$429	$12,014
Lateral Piping Replacements	5	$75	$375
Company Labor FTEs	6.5	N/A	$945
Well Inspection Costs Reassigned to Capital	28	N/A	$10,936
Total Capital	-	-	$24,272

c. Cost Drivers

The most significant cost driver for this uniquely specialized work performed on high pressure wells is the availability of workover rigs, material costs, the skilled field and technical workforce required to produce and analyze data, and the equipment to be employed. Other cost drivers include the unique solutions required to address the conditions discovered during exploratory examinations of the wells, equipment, well design, and permitting requirements.

D. Storage Pipelines

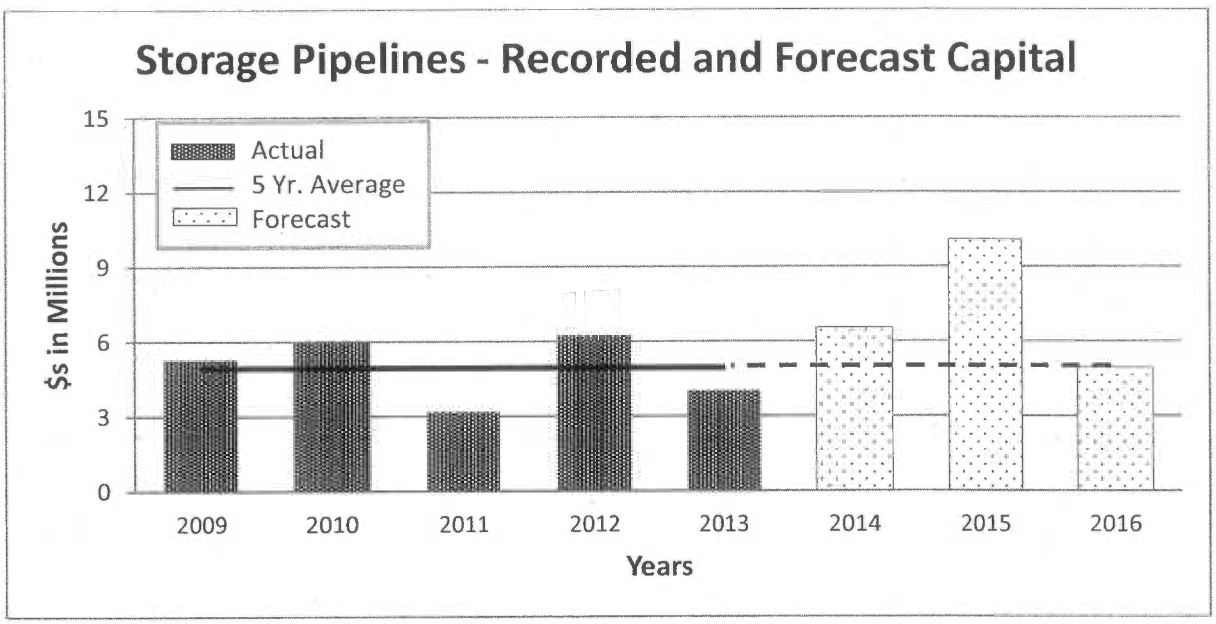
This Budget Category includes costs associated with upgrading or replacing failed field piping and related components. The cost forecast for this work is summarized in Table PEB-14 below.

Table PEB-14
Southern California Gas Company
Capital Expenditures for Storage Pipelines

STORAGE PIPELINES	Thousands of 2013 Dollars		
	Estimated 2014	Estimated 2015	Estimated 2016
D1- Valve Replacements	$889	$889	$688
D2- Aliso Pipe Bridge Replacement	$505	$3,526	$0
D3- Aliso Injection System Debottlenecking	$0	$505	$505
D4- Aliso Canyon Piping Improvements	$1,313	$152	$505
D5- Playa del Rey Withdrawal Debottlenecking	$505	$2,526	$0
D6- Pipeline Blanket Projects	$3,334	$2,485	$3,233
Total	**$6,546**	**$10,083**	**$4,931**

Figure PEB-9 below depicts the Storage Pipeline costs from Table PEB-14.

Figure PEB-9
Southern California Gas Company
Historical and Forecasted Storage Pipelines Capital



The Storage Pipelines category in this testimony is further described using the following sub-sections:

- D1-Valve Replacements
- D2-Aliso Pipe Bridge Replacement
- D3-Aliso Injection System Debottlenecking

- D4-Aliso Canyon Withdrawal System Debottlenecking
- D5-Playa del Rey Withdrawal Debottlenecking
- D6-Blanket Projects

1. D1-Valve Replacements

a. Description

Valves within the storage fields can leak or allow gas to pass as they wear and age. SoCalGas plans to replace various valves of differing sizes and pressure ratings throughout the year, depending on line shut-in capability and valve conditions. The costs for valve replacements are estimated to be $889k, $889k, and $688k for 2014, 2015, and 2016, respectively. Specific details regarding this valve work may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Historical average costs are approximately $20K per valve. The estimated number of replacements, approximately 5% of the larger field valves every year, is based on recent operational experience.

c. Cost Drivers

The underlying cost drivers for this capital category relate to the purchase price of the valves and their installation costs. This includes specialized work performed on high pressure gas lines and the skilled workforce and equipment employed for replacements.

2. D2-Aliso Pipe Bridge Replacement

a. Description

SoCalGas plans to relocate an existing pipe rack in Aliso Canyon out of a ravine area with an active landslide and soil erosion condition that is threatening several existing pipe supports. Failure of pipe and supports in this ravine could result in the potential loss of gas injection/withdrawal capabilities of 21 wells in Aliso Canyon's east field. The combined withdrawal capacity of these wells is approximately 600 MMCFD. A Rupture of these pipes could result in the release of crude oil and brine water into the stream at the bottom of the ravine. The costs in $ million for the Aliso Pipe Bridge Replacement are projected to be $0.505, $3.526, and $0 for 2014, 2015, and 2016, respectively. Specific details regarding this project may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. **Forecast Method**

The project costs were derived by estimates from structural steel fabricators and installation contractors.

c. **Cost Drivers**

The underlying cost driver for this capital project relates to the soil types, customized design, permits, steel fabrication, and the highly specialized nature of work performed on high pressure gas piping, and the skilled workforce and equipment employed.

3. **D3-Aliso Injection System Debottlenecking**

a. **Description**

Through the evolution of the Aliso Canyon storage field, piping restrictions have developed. SoCalGas plans to improve the injection capacities at Aliso Canyon through the installation of larger diameter pipe and associated pipe supports. With new projects such as Aliso Canyon Turbine Replacement, and planned well replacements, the system piping will be studied to eliminate sections that restrict the flow of gas to the storage wells. Pipe will be sized to meet the specific injection criteria. This project will allow for a more efficient gas injection process. If bottlenecks are not removed, adequate pipe capacity at the intended rate of injection at maximum capacity will not be achieved. The costs for the injection system debottlenecking are forecast to be $0, $505k, and $505k for 2014, 2015, and 2016, respectively. Specific details regarding this project are found in my capital workpapers. See 06-CWP.

b. **Forecast Method**

Estimated costs are based on recent projects of similar pipe size, scope and complexity.

c. **Cost Drivers**

The underlying cost drivers for this capital project relate to material costs and the highly specialized nature of work performed on high pressure gas injection piping and the skilled workforce and equipment employed.

4. **D4-Aliso Canyon Piping Improvements**

a. **Description**

SoCalGas plans to perform necessary work to minimize piping restrictions in the Aliso Canyon withdrawal system. In addition, work is also planned for a remote well-kill safety system, installation of field utility gas system (Master Lease Gas), and replacement of high pressure liquid handling pipelines. The improvement of these systems will allow for remote killing of the wells, a cleaner source of motive gas in the field for equipment, and the continued reliability of liquid-carrying piping. The liquid handling pipelines are critical to liquid removal operations from the high pressure gas system that transports, cleans, dehydrates, and meters gas from the facility. If the liquid handling pipelines were to fail, gas deliveries may be significantly impacted or sent through metering without complying with standards for water content in pipeline-quality natural gas. Safety equipment in the field also requires clean motive gas for proper operations. Each of these projects will require new piping, pipe supports and possibly pipe trenches. The costs for these piping improvements are forecast to be $1,313k, $152k, and $505k for 2014, 2015, and 2016, respectively. Specific details regarding these projects may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Estimated costs are based on recent projects of similar equipment size, scope and complexity.

c. Cost Drivers

The underlying cost drivers for this capital project relate to the highly specialized nature of work performed on high pressure pipelines and the skilled workforce and equipment employed.

5. D5-Playa del Rey Withdrawal Debottlenecking

a. Description

SoCalGas plans to perform necessary work to alleviate system bottlenecking in the Playa del Rey withdrawal system. Upgrade of the lower field equipment and piping would help maintain deliverability capacity while achieving the desired standards for water content in pipeline-quality natural gas. The work will include replacement of withdrawal equipment and installation of newly resized piping. The costs in $ million are estimated to be $0.505, $2.526, and $0, for 2014, 2015, and 2016, respectively. Specific details regarding this project may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

This cost estimate is based on previously-completed work, vendor quotes for similar equipment, and current contractor rates.

c. **Cost Drivers**

The underlying cost drivers for this capital project relate to the highly specialized nature of work performed and the skilled workforce and equipment employed.

6. **D6-Pipeline Blanket Projects**

a. **Description**

SoCalGas plans to perform necessary work to alleviate various pipeline issues. This can include various projects including pipe replacements, expansions, upsizing, supports, corrosion protection, and other elements related to piping systems. The upgrade of station piping will help maintain injection and deliverability capacity. The costs in $ million are estimated to be $3.334, $2.485, and $3.233, for 2014, 2015, and 2016, respectively. Specific details regarding these projects may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. **Forecast Method**

This cost estimate is based on the assumption that future costs and projects will be similar in scope and pricing to historical levels.

c. **Cost Drivers**

The underlying cost drivers for this capital project relate to the highly specialized nature of work performed and the skilled workforce and equipment employed.

E. **Storage Purification Systems**

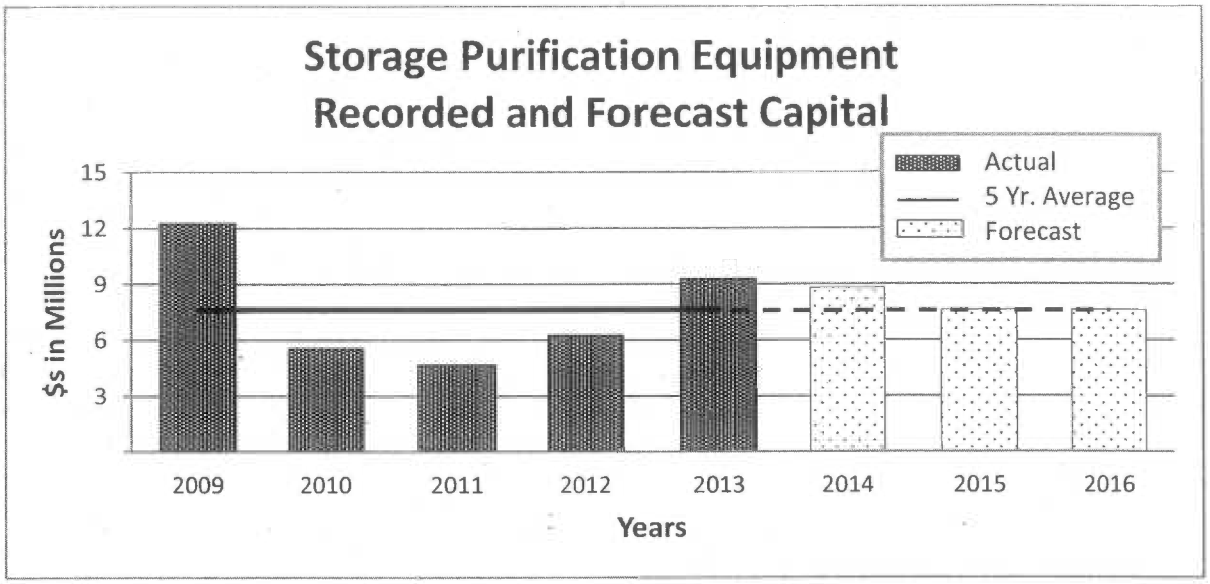
This budget category forecasts costs associated with equipment used primarily for the removal of impurities from, or the conditioning of, natural gas withdrawn from storage. Examples of equipment included in this area are dehydrators, coolers, scrubbers, boilers, pumps, valves, piping, power supply, controls, and instrumentation. Table PEB-15 below summarizes the forecast of capital expenditures for Storage Purification Systems.

Table PEB-15
Southern California Gas Company
Capital Expenditures Purification Systems

STORAGE PURIFICATION SYSTEMS	Thousands of 2013 Dollars		
	Estimated 2014	Estimated 2015	Estimated 2016
E1- Aliso Canyon Dehydration Upgrades	$1,018	$1,018	$1,018
E2- Honor Rancho Dehydration Upgrades	$3,094	$992	$0
E3- Goleta Dehydration Upgrades	$3,055	$1,018	$0
E4- Purification Blanket Projects	$1,629	$4,577	$6,587
Total	**$8,796**	**$7,605**	**$7,605**

Figure PEB-10 below illustrates the Purification Systems forecast from Table PEB-15.

Figure PEB-10
Southern California Gas Company
Historical and Forecasted Purification Systems Capital



The Storage Purification Systems category in this testimony is further described using the following sub-sections:

- E1-Aliso Canyon Dehydration Upgrades
- E2-Honor Rancho Dehydration Upgrades
- E3-Goleta Dehydration Upgrades
- E4-Purification Blanket Projects

1. E1-Aliso Canyon Dehydration Upgrades

a. Description

This project will include the installation of new gas and glycol filters for improved gas conditioning. Instrumentation upgrades will also improve the ability to remotely monitor the plant during operation. In addition, the site Motor Control Center will be replaced to better support existing and new equipment. The Dehydration 2 plant at Aliso Canyon has withdrawal capacity of approximately 750 MMCFD. SoCalGas has plans to upgrade the Dehydration 2 plant to increase its withdrawal capacity. Without this project, the station may not be able to adequately comply with standards for water content in pipeline-quality natural gas and achieve future planned increases in withdrawal capacity. The estimated forecasts in $ million for this project are $1.018, $1.018, and $1.018, for 2014, 2015, and 2016 respectively. Specific details regarding this project may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Costs are based on quotes provided by vessel fabricators, equipment manufacturers, contractor estimates, and similar work completed on previous projects.

c. Cost Drivers

The underlying cost drivers for this capital project relate to the highly specialized nature of work performed, the necessarily skilled workforce, equipment employed, and the cost of materials.

2. E2-Honor Rancho Dehydration Upgrades

a. Description

SoCalGas plans to separate dehydration trains and install filters to allow for more flexibility of operations, less downtime during routine maintenance, improved gas conditioning, and a reduction in glycol degradation. The Programmable Logic Controller system will be upgraded to meet the new operating requirements and instrumentation needs. Without this project, the station may require extended and more frequent shutdowns as part of routine maintenance activities. In addition, this project will also allow the station to better achieve water content standards in pipeline-quality natural gas. The costs for improvements in $ million are $3.094, $0.992, and $0, for 2014, 2015, and 2016, respectively. Specific details regarding this capital project are found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Costs are based on quotes provided by vessel fabricators, equipment manufacturers, contractor estimates, and similar work completed on previous projects.

c. Cost Drivers

The underlying cost drivers for this capital project relate to the highly specialized nature of work performed, the necessarily skilled workforce and equipment employed and the cost of materials.

3. E3-Goleta Dehydration Upgrades

a. Description

SoCalGas plans to install new gas and glycol filters, heat exchangers, glycol regeneration equipment upgrades and instrumentation for remote monitoring in order to improve dehydration efficiency. This project will also allow the station to better achieve water content standards in pipeline-quality natural gas. Costs for the Goleta dehydration project in $ million are projected to be $3.055, $1.018, and $0 for 2014, 2015, and 2016, respectively. Specific details regarding this capital project may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Costs are based on quotes provided by vessel fabricators, equipment manufacturers, contractor estimates, and similar work completed on previous projects.

c. Cost Drivers

The underlying cost drivers for this capital project relate to the highly specialized nature of work performed, the necessarily skilled workforce and equipment employed, and the cost of materials.

4. E4-Purification Blanket Projects

a. Description

SoCalGas plans to perform necessary work to alleviate gas processing and purification issues. This can include work on various equipment including dehydrators, coolers, scrubbers, boilers, pumps, valves, piping, power supply, controls, and instrumentation. Upgrade of purification equipment will help maintain deliverability capacity and allow the station to better achieve water content standards in pipeline-quality natural gas. The costs in $ million are estimated to be $1.629, $4.577, and $6.587, for 2014, 2015, and 2016, respectively. Specific details regarding this project may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

This cost estimate is based on historical and expected levels of work.

c. Cost Driver(s)

The underlying cost drivers for this capital project relate to the highly specialized nature of work performed and the skilled workforce and equipment employed.

F. Storage Auxiliary Systems

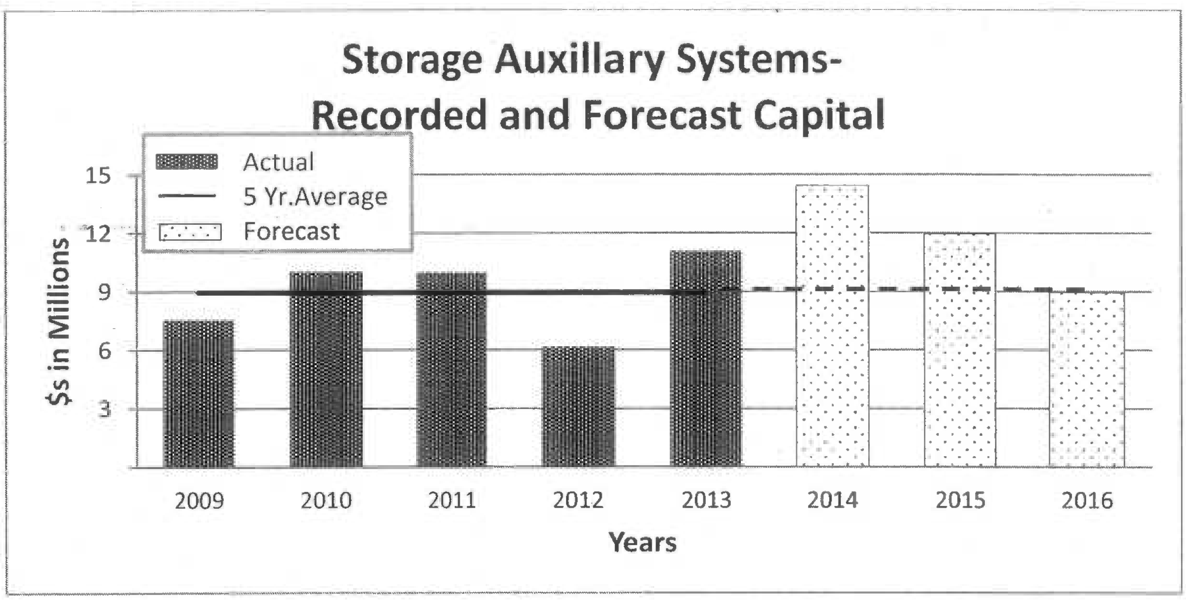
This budget code includes work on various types of field equipment not included in other budget codes such as instrumentation, measurement, controls, electrical, drainage, infrastructure, safety, security, and communications systems. The costs associated with this work are summarized in Table PEB-16 below.

Table PEB-16
Southern California Gas Company
Capital Expenditures for Storage Auxiliary Systems

STORAGE AUXILIARY SYSTEMS	Thousands of 2013 Dollars		
	Estimated 2014	**Estimated 2015**	**Estimated 2016**
F1-Aliso Central Control Room Modernization	$2,021	$1,010	$0
F2-Aliso Main Plant Power Line Upgrade	$1,010	$0	$0
F3-Aliso Sesnon Gathering Plant Project	$1,111	$303	$1,010
F4-Auxiliary Systems Blanket Projects	$10,256	$10,609	$7,938
Total	**$14,398**	**$11,922**	**$8,948**

Figure PEB-11 below depicts the Auxiliary Systems cost forecast from Table PEB-16.

Figure PEB-11
Southern California Gas Company
Historical and Forecasted Auxiliary Systems Capital



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The Auxiliary Systems category in this testimony is further described under the following sub-sections:

- F1-Aliso Canyon Central Control Room Modernization
- F2-Aliso Canyon Main Plant Power Line Upgrade
- F3-Aliso Canyon Sesnon Gathering Plant Project
- F4-Auxiliary Equipment Blanket Projects

1. F1-Aliso Central Control Room Modernization

a. Description

SoCalGas plans to update, modernize and reconfigure the control room at the Aliso Canyon storage facility. This project includes modernization of control room displays, communication equipment, and building renovation. Without this upgrade of the control room, the station operators would be unable to efficiently monitor and operate the new equipment. The costs for the Aliso Central Control Room Modernization project in $ million are forecast to be $2.021, $1.010, and $0, for 2014, 2015, and 2016 respectively. Specific details regarding this project may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Estimated costs are based on recent projects of similar scope and complexity in addition to recently-received vendor quotes.

c. Cost Drivers

The underlying cost drivers for this capital project relate to the highly specialized nature of work performed, the skilled workforce and equipment employed, and the cost of materials.

2. F2-Aliso Main Plant Power Line Upgrade

a. Description

SoCalGas plans to improve the overhead power system with new poles and wire to withstand 120 mile per hour wind load requirements. The new system will continue to allow the main plant, dehydration units and gathering plant to be energized by Southern California Edison, onsite generators, or alternate powers sources. Portions of the system will be installed underground. The project will eliminate wood poles, reduce fire danger and strengthen the electrical lines for high wind conditions. This project will provide Aliso Canyon with increased electrical reliability by upgrading the electrical system infrastructure at the main plant, dehydrators, and gathering plants to remain electrified with utility power during "Red Flag" events. South Coast Air Quality Management District variance requests are required for operation of the onsite generators used during red flag events. This project will also decrease the need for air quality permit variances. The costs forecast in $ million are $1.010, $0.500, and $0, for 2014, 2015, and 2016, respectively. Specific details regarding this capital project may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Costs are based on previously-completed work of similar content and scope. Similar work that increased the wind load capability of the local electrical system was completed at the Porter water injection site in 2012.

c. Cost Drivers

The underlying cost drivers for this capital project relate to the design, the specialized nature of work performed, the availability of qualified workers and equipment purchases.

3. F3-Aliso Sesnon Gathering Plant Project

a. Description

Safety items of concern identified during a process hazard analysis of the pressure relief system at the Aliso Sesnon Gathering Plant will be addressed with a redesign. The current pressure relief system has several critical low points that could interfere with the gathering plant pressure relieving equipment during a full system blow down. The liquid buildup could potentially overwhelm the liquid removing equipment, causing gas withdrawal rates to be reduced. The relief vessel will be relocated, system piping will be modified to eliminate low points, and relief valves will be replaced to better satisfy process conditions. The costs for this project in $ million are forecast to be $1.111, $0.303, and $1.010, for 2014, 2015, and 2016, respectively. Specific details regarding this work may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

Estimated costs are based on vendor quotes and previously completed work.

c. Cost Drivers

The underlying cost drivers for these capital projects relate to the highly-specialized nature of work performed, the availability of necessarily-skilled workforce and equipment employed and the cost of materials.

4. F4-Auxiliary Systems Blanket Projects

a. Description

SoCalGas plans to perform necessary work to alleviate instrumentation, Supervisory, Control and Data Acquisition, measurement, controls, electrical, cyber security, and other auxiliary systems support issues. This can include work on various equipment including, coolers, scrubbers, boilers, pumps, valves, piping, and power supplies. The upgrade of auxiliary systems will help maintain safety, security, deliverability, and reliability in the delivery of pipeline-quality natural gas. The costs of this project in $ million are estimated to be $10.256, $10.609, and $7.938, for 2014, 2015, and 2016, respectively. Specific details regarding this project may be found in my capital workpapers, Exhibit PEB-06-CWP.

b. Forecast Method

This cost estimate is based on historical and expected levels of work.

c. Cost Drivers

The underlying cost drivers for this capital project relate to the highly specialized nature of work performed and the skilled workforce and equipment employed.

IV. CONCLUSION

In this testimony, I describe activities and projects necessary for SoCalGas to achieve its goals of maintaining the safety and reliability of critical gas underground storage infrastructure. The expenditures discussed in this testimony are required to maintain public and employee safety while cost-effectively meeting customer needs, in compliance with mandated regulatory requirements. My O&M and capital forecasts represent a reasonable level of funding for the critical activities and capital projects planned during this forecast period. The forecasts of the planned O&M and capital expenditures represented in this testimony are appropriate and prudently derived, and should be adopted by the Commission. Implementation of the proposed SIMP is justified and prudent and the request for balancing account treatment for SIMP costs is reasonable and should be adopted.

This concludes my prepared direct testimony.

V. WITNESS QUALIFICATIONS

My name is Phillip E. Baker. I am employed by Southern California Gas Company. My business address is 9400 Oakdale Ave., Chatsworth, California 91313-6511.

I am the Director of Storage. In this capacity, I am responsible for maintaining the integrity of the storage system to ensure a safe, reliable supply of natural gas for customers throughout the SoCalGas and SDG&E service territory.

I have a Bachelor of Science degree in Civil Engineering from California State University at Los Angeles. I have worked for SoCalGas for thirty-five years, with a broad background in engineering and gas operations. Throughout my career I have held various staff and operations positions in Gas Distribution, Engineering, Gas Transmission, Fleet, Facilities and Logistics, and Customer Services. In recent years, I have held the positions of Director-Customer Services, Director-Distribution Services, Director-Commercial and Industrial Services. I was named to my present position, Director-Storage, in 2013.

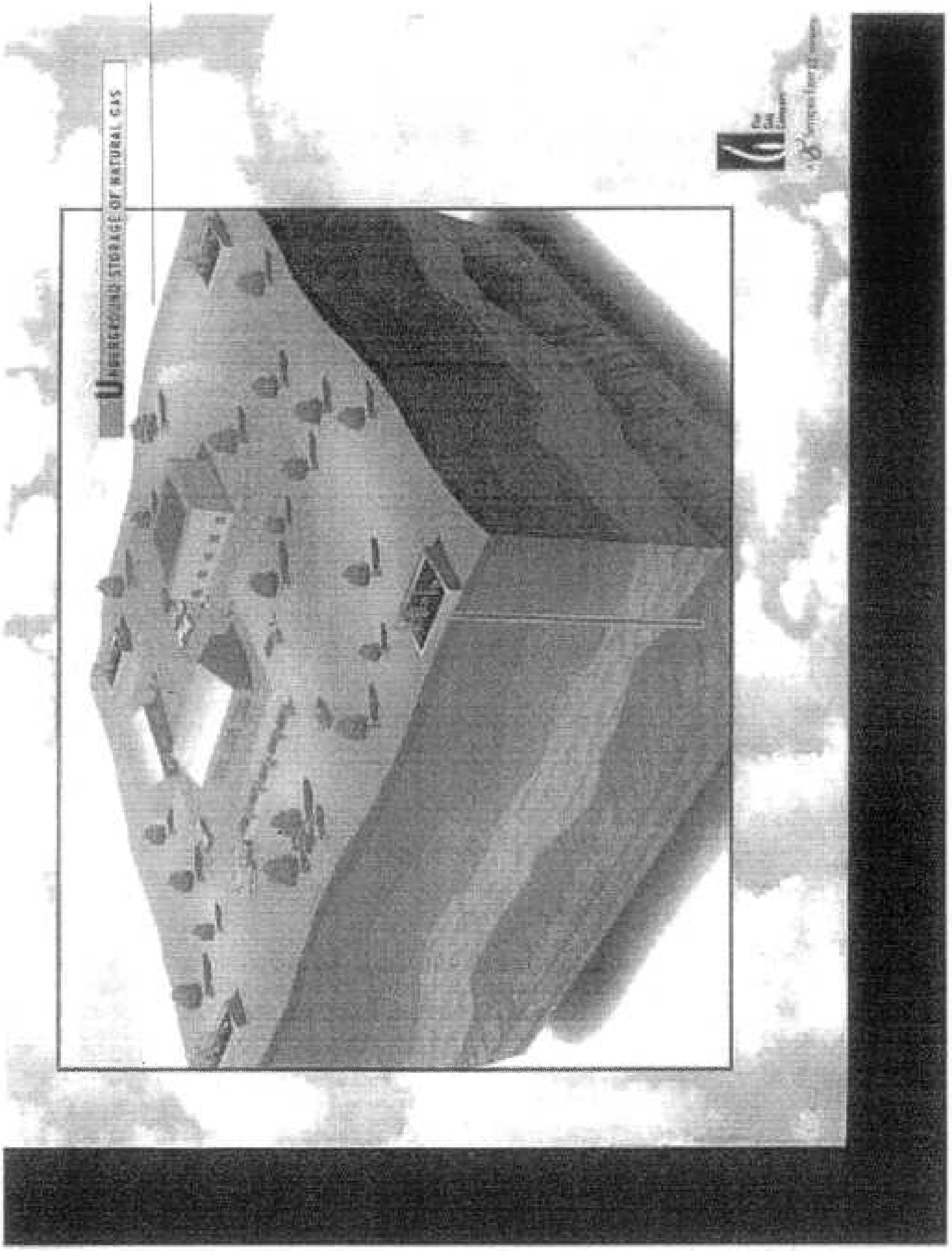
I have previously testified before the Commission.

Appendix A
Glossary of Acronyms

BCF	Billion Cubic Feet
BCFD	Billion Cubic Feet per Day
CPUC	California Public Utilities Commission
DIMP	Distribution Integrity Management Program
DOGGR	California Department of Oil, Gas and Geothermal Resources
DOT	United States Department of Transportation
FTE	Full Time Equivalents
MMCF	Million Cubic Feet
MMCFD	Million Cubic Feet per Day
NERBA	New Environmental Regulatory Balancing Account
O&M	Operations and Maintenance
PSIG	Pounds per Square Inch Gauge
SoCalGas	Southern California Gas Company
SIMP	Storage Integrity Management Program
TCAP	Triennial Cost Allocation Proceeding
TIMP	Transmission Integrity Management Program

Appendix B

Underground Storage of Natural Gas


UNDERGROUND STORAGE OF NATURAL GAS

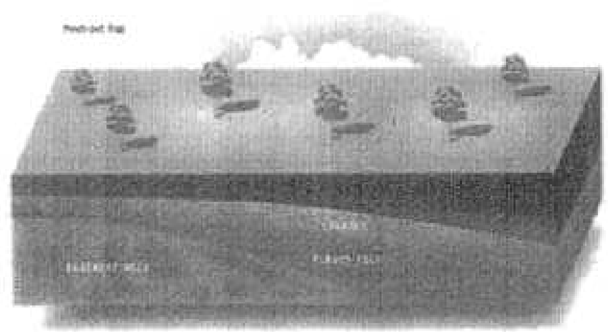
STORING NATURAL GAS THE SAME WAY NATURE ALWAYS HAS...DEEP UNDERGROUND

Underground storage is based on the simple premise that if an underground rock formation held oil and gas securely for millions of years, it could continue to do so under controlled conditions.

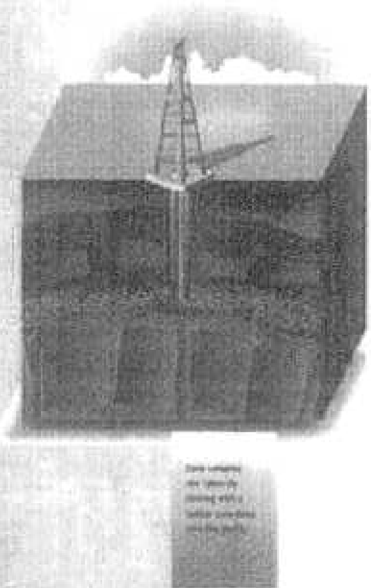
[illegible]

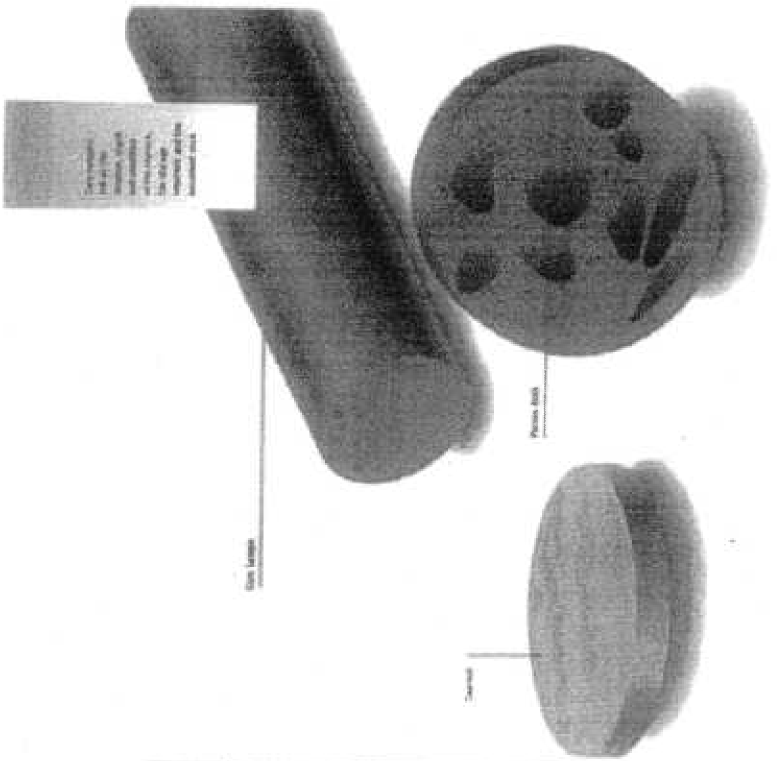
[illegible]

WHERE IS THE GAS STORED?

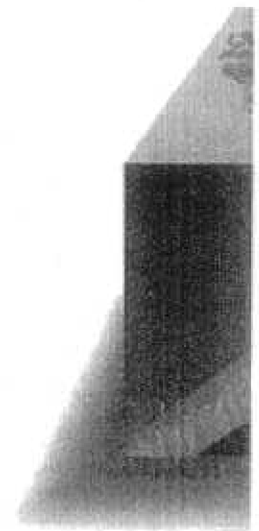


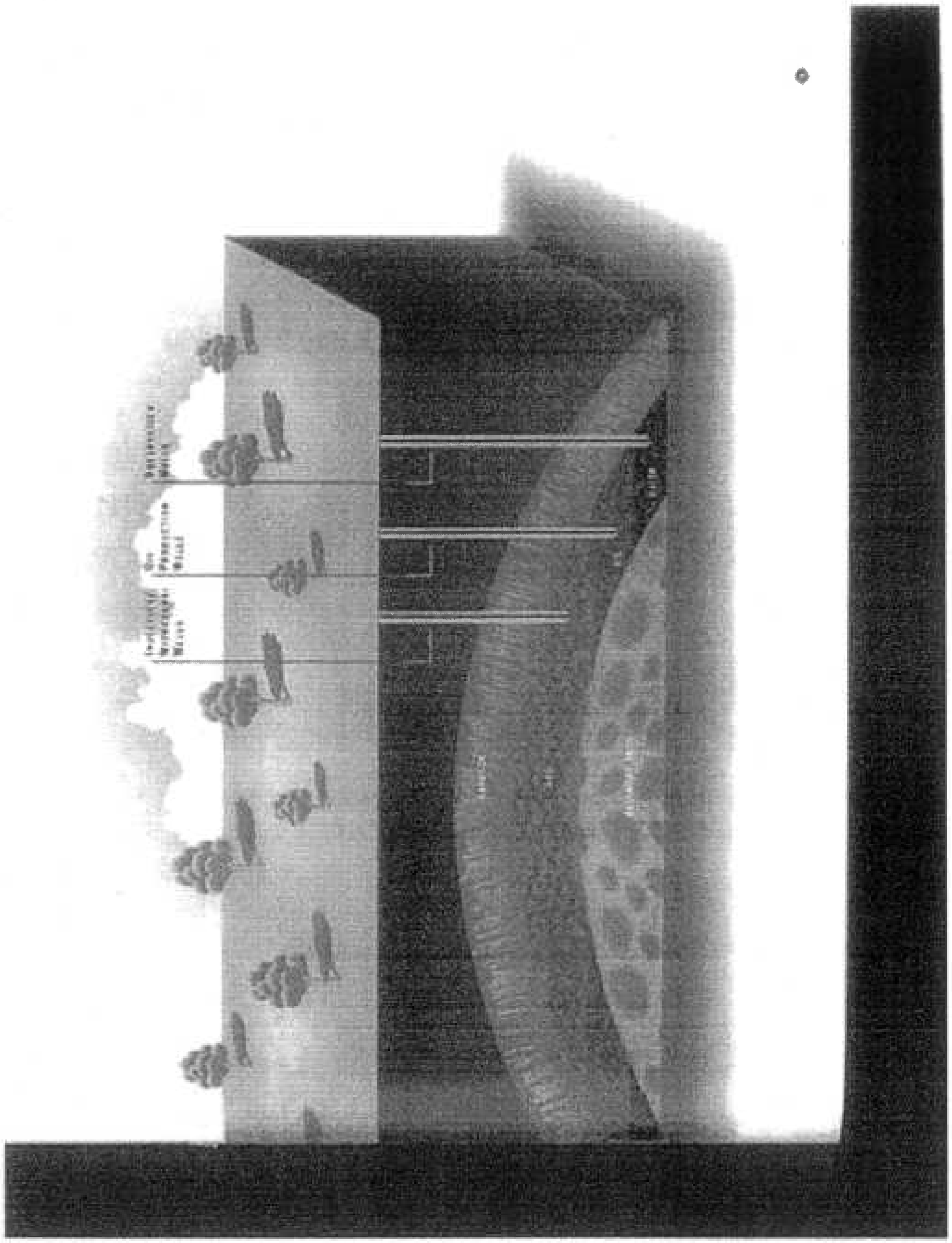
WHAT DETERMINES A GOOD STORAGE FIELD





A TYPICAL UNDERGROUND GAS STORAGE FIELD



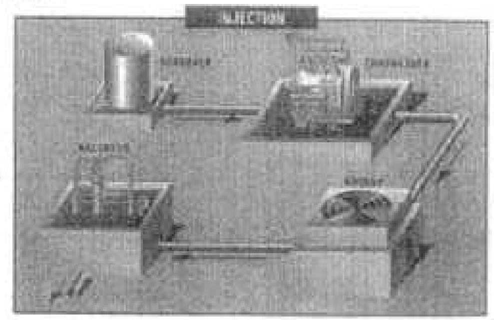


Storage operations are activated on orders from our gas control center to specific storage fields. Customarily, storage is required for seasonal load balancing: injecting summer supplies of gas underground to be held in reserve for winter withdrawal.

INJECTION

[illegible]

INJECTION



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STORAGE FACILITY

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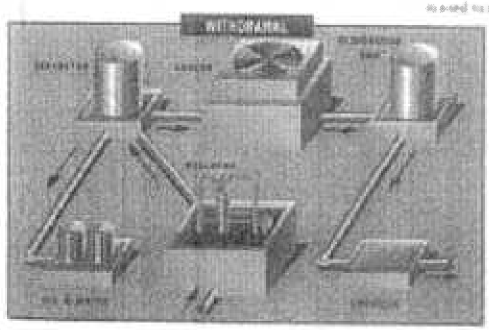


[illegible]

Just as in storage injection, the signal to commence withdrawal of gas from storage is relayed to the field from our main gas control center. Withdrawal is usually ordered to meet heavy customer demand 1 throughout the cold, rainy winter season; 2 on air pollution episode days; or 3 during peak-load conditions when gas from storage augments the volumes constantly flowing in from out-of-state suppliers.

SOUTHERN CALIFORNIA GAS COMPANY'S UNDERGROUND STORAGE SITES

Southern California Gas Company, a subsidiary of Sempra Energy, operates four underground storage fields. Each facility has been developed due to unique geologic characteristics which make it ideal for gas storage. The work done at these sites performs an essential function for all our gas customers in the Southern California area. We work to continue to meet our customers' needs in a safe and environmentally sound manner, thereby assuring the continuance of good neighbor relations with surrounding residents.

[illegible]

[illegible]

[illegible] located in the northern part of Los Angeles County about [illegible] miles ([illegible] kilometers) northwest of downtown Los Angeles.

[illegible]

[illegible] the La Goleta site is located just southeast of the University of California at Santa Barbara campus in Goleta. The subsurface storage structure is a former natural gas reservoir [illegible]

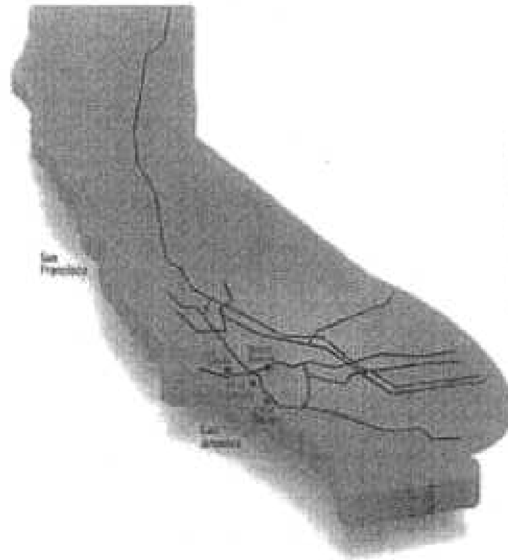
[illegible]

[illegible]

A TRADITION OF SERVICE

Southern California Gas Company has a long tradition of providing dependable service to homes, businesses and industries in [illegible] communities in a twelve-county area.

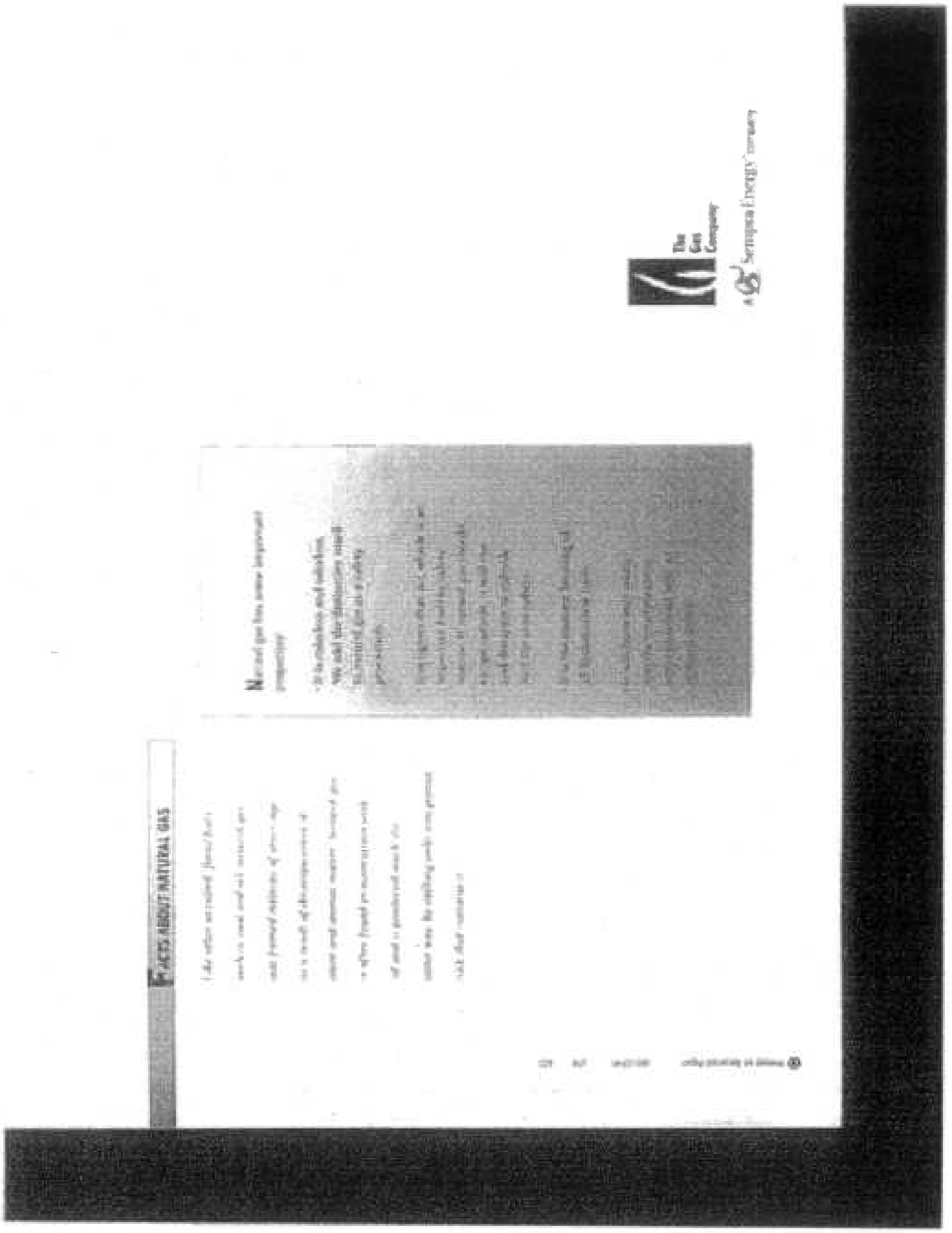
As the largest natural gas distribution company in the nation, we serve most of Central and Southern California. Providing reliable, safe and efficient natural gas service to meet this vast and fluctuating energy demand requires a highly responsive distribution system of more than [illegible] miles ([illegible] kilometers) of gas main. The underground storage of natural gas plays a vital role in balancing the region's energy supply and demand.



This map shows the major pipelines which supply the Gas Company's service territory as well as their strategic location relative to the storage fields.

[illegible]

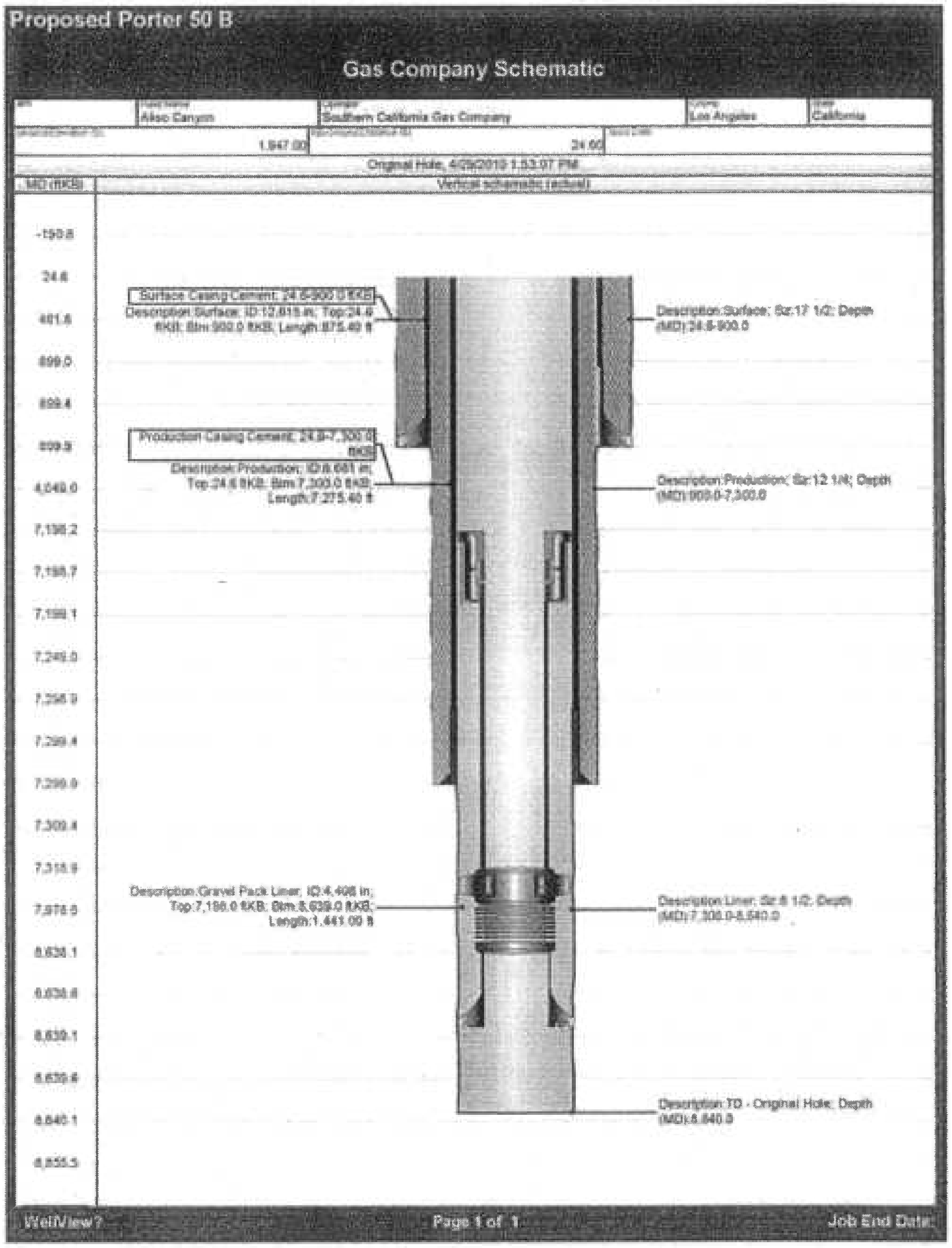
Safety has always been a top priority with us. The technology to [illegible] underground gas storage field has developed steadily through the years, and our facilities are in the forefront of safety controls and procedures. In addition, all of our operations are closely monitored for compliance with the safety standards of the California Public Utilities Commission, the Division of Oil and Gas, the Occupational Safety and Health Administration, and local fire departments.


FACTS ABOUT NATURAL GAS
Natural gas has some important properties
The Gas Company
A Sempra Energy company

Doc #292223

Appendix C

Downhole Schematic and Wellhead Diagram



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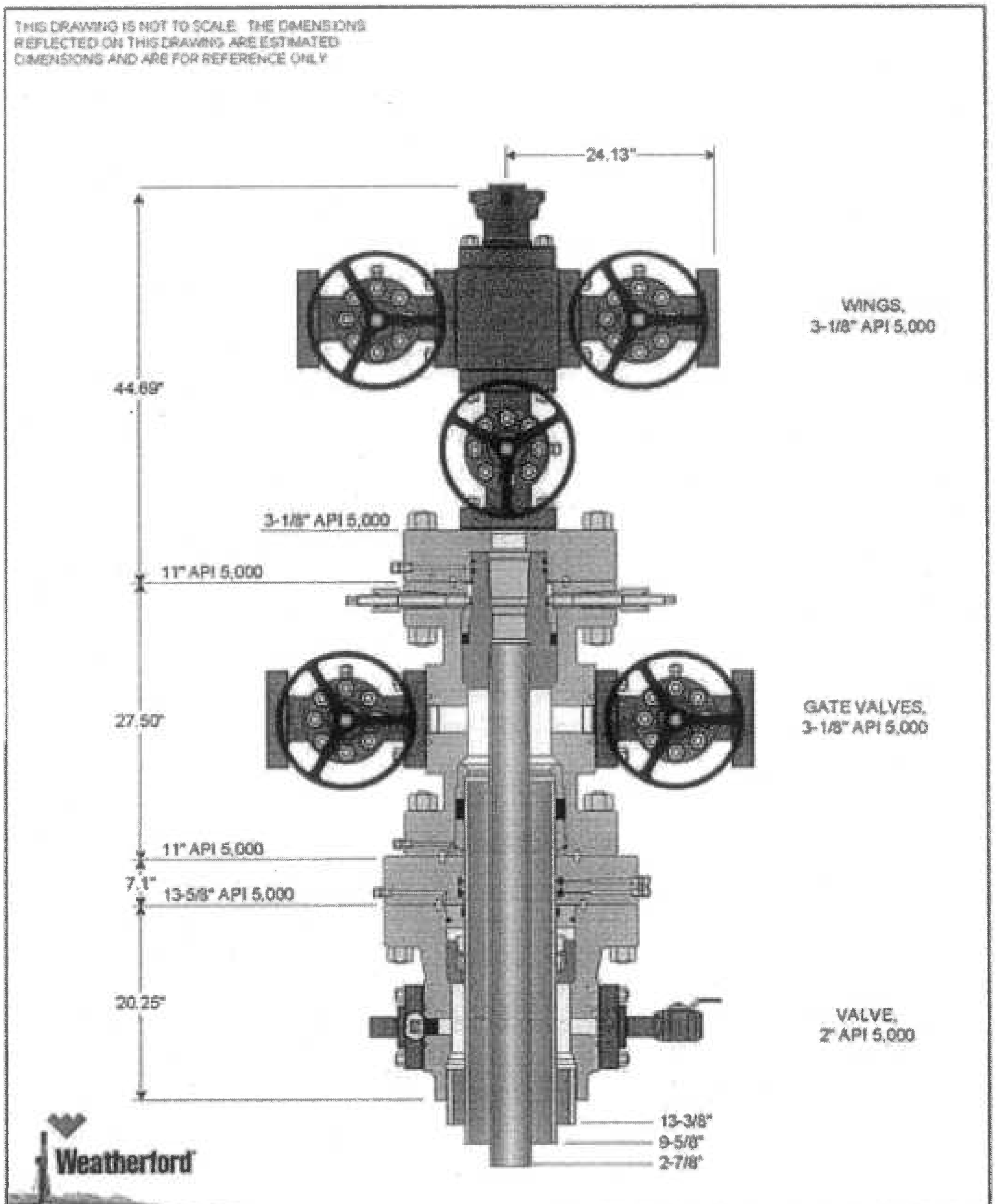

Customer SOUTHERN CALIFORNIA GAS CO.	Project TBD	Quote TBD
Tender, Project or Well ALISO CANYON – PORTER 50B	Date 04-27-2010	Drawn By JJ

Doc #292223

EXHIBIT C

State of California • Natural Resources Agency
Department of Conservation
Director's Office
801 K Street • MS 24-01
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Edmund G. Brown Jr., *Governor*
David Bunn, *Director*

October 8, 2015

The Honorable Mark Leno
Chair, Committee on Budget & Fiscal Review
California State Senate
State Capitol, Room 5019
Sacramento, CA 95814

The Honorable Shirley N. Weber
Chair, Committee on Budget
California State Assembly
State Capitol, Room 6026
Sacramento, CA 95814

The Honorable Fran Pavley
Chair, Committee on Natural Resources & Water
California State Senate
State Capitol, Room 5046
Sacramento, CA 95814

The Honorable Das Williams
Chair, Committee on Natural Resources
California State Assembly
1020 N Street, Room 164
Sacramento, CA 95814

The Honorable Bob Wieckowski
Chair, Committee on Environmental Quality
California State Senate
State Capitol, Room 2205
Sacramento, CA 95814

The Honorable Luis Alejo
Chair, Committee on Environmental
Safety & Toxic Materials
California State Assembly
1020 N Street, Room 171
Sacramento, CA 95814

The Honorable Ricardo Lara
Chair, Committee on Appropriations
California State Senate
State Capitol, Room 2206
Sacramento, CA 95814

The Honorable Jimmy Gomez
Chair, Committee on Appropriations
California State Assembly
State Capitol, Room 2114
Sacramento, CA 95814

DEPARTMENT OF CONSERVATION, DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES REPORT TO THE LEGISLATURE ON THE UNDERGROUND INJECTION CONTROL PROGRAM PURSUANT TO SB 855, 2011 THROUGH 2014

Dear Senators and Assembly Members:

Senate Bill 855 (Chapter 718, Statutes of 2010) directed the Department of Conservation's Division of Oil, Gas, and Geothermal Resources (Division) to give the Legislature an annual report each January until 2015 on various features of the Division's Class II Underground Injection Control (UIC) Program. The Division last submitted required information in 2011, and now submits its 2015 report.

This report will include past due data broken out in annual figures on permits, violations, enforcement, staffing and vacancies, and new legislation and rulemaking, as required by SB 855. It also includes a quite thorough assessment of the state's UIC program in one of the two busiest regulatory regions: District 1 in Cypress, which is responsible for the regulation of some of the state's most productive fields in the Los Angeles Basin.

Though not called for under SB 855, this report also includes a summary of work to date by the Division, United States Environmental Protection Agency (U.S. EPA), and State Water Resources Control Board surrounding these issues, with copies of key correspondence memorializing the work of these three agencies. As you are aware, since mid-2014, the three agencies have been collaborating to improve the state's regulation of Class II injection in general under the Safe Drinking Water Act and, in particular, to remedy the Division's permitting of a number of injection wells in some aquifers that are not currently exempted from the Safe Drinking Water Act, but in most cases have characteristics that would make them eligible for exemption.

Finally, the report concludes with a summary, in table form, of the significant Division problems identified throughout this report, and corresponding steps being taken to address them. During the past year, State Oil and Gas Supervisor Steven Bohlen, working with his senior staff, has conducted a root-cause analysis of many of the systemic problems that have caused the Division's regulatory performance to be suboptimal. Dr. Bohlen has discussed many of these issues with you in numerous meetings and hearings conducted earlier this year. At a high level, these problems include: insufficient staffing to address increasing regulatory workload in addition to significant remedial programmatic work, poor recordkeeping on mostly paper forms and the lack of modern data tools and systems, outdated regulations that in some cases do not address the modern oil and gas extraction environment, inconsistent and undersized program leadership, insufficient breadth and depth of technical talent, insufficient coordination among field districts and Sacramento, and lack of consistent, regular, high quality technical training.

The Supervisor and his staff have enacted strategies and activities to address these long-term systemic problems as laid out in the renewal plan being released by the Department today. The Division will soon be reorganized to improve cooperation and consistency among the districts and Sacramento and to improve technical and programmatic leadership with attention focused on specific regulatory programs, heretofore never done. Teams will be organized under the following programs: UIC; Well Stimulation; Idle and Abandoned Wells and Facilities; Emerging Technologies and Regulations; Well and Data Management; Environmental Review; and Technical Training. Regular training programs are being launched. A robust rulemaking effort is under way that will update the Division's regulations to address current oil-field realities. With the passage of the 2015-2016 budget, the Division has sufficient resources needed to bring a well data management system and modern tools to the Division. Furthermore, the Division is undertaking high-visibility recruiting efforts to hire additional talented technical staff to improve all of the Division's programs, including geographical information systems and data management capabilities, monitoring and compliance of Division activities, environmental review, improvement of the UIC program, and carrying out the compliance schedule agreed to with the U.S. EPA.

As always, we are available to discuss the enclosed report and its attachments as well as the aggressive activities now under way to greatly improve the Division's regulatory performance.

Sincerely,

David Bunn
Director

Enclosures

Underground Injection Control Program Report on Permitting and Program Assessment
Reporting Period of Calendar Years 2011-2014
Prepared pursuant to Senate Bill 855
(Ch. 715, Stats. of 2010)

CALIFORNIA CONSERVATION

Prepared
By
Department of Conservation
Division of Oil, Gas, and Geothermal Resources

October 2015

SUMMARY

Section 35 of Senate Bill 855 (Chapter 718, Statutes of 2010), requires the Department of Conservation's (Department) Division of Oil, Gas, and Geothermal Resources (Division) to report annually on the following seven areas of the Division's Underground Injection Control (UIC) Program:

1) The number of underground injection permits issued by the Department
2) The average length of time to obtain a permit from date of application to the date of issuance
3) The number and description of permit violations identified
4) The number of enforcement actions taken
5) The number of staff and vacancies in the program
6) Any state or federal legislation, administrative, or rulemaking changes to the program
7) The program's assessment findings

With respect to item 7, SB 855 called for a "...report on the Underground Injection Control Program's action plan developed to address the program's assessment findings and its existing efforts to implement the plan..." This information was to be provided annually by January 30 of each year from 2011 until 2015 and cover the prior calendar year's activities. Though the first year report was submitted on February 18, 2011, subsequent reports were not undertaken. Now, with this report, we offer a detailed program assessment (item (7)) focused upon issues with the program in District 1 (the Los Angeles Basin area), one of the Division's busiest regulatory regions.

This report also summarizes progress made by the Division, the State Water Resources Control Board, and the United States Environmental Protection Agency (U.S. EPA). The three agencies have been working together since mid-2014 to systematically address a number of important deficiencies in the UIC program, including, but not limited to, the permitting of a number of injection wells in locations not exempted from the Safe Drinking Water Act, even though many meet the criteria for exemption. Their correspondence covers many important facts about, and objectives for, the Division's Class II UIC program.

This report addresses the following:

A. An overview of the UIC Program as mandated by state and federal statutes and regulations;
B. A summary of the data requested in items (1) through (5), above, broken out by calendar year for 2011 through 2014
C. A description of legislative and regulatory developments per item (6)
D. A summary of the detailed program assessment (item (7)) focused upon issues with the program in District 1 (the Los Angeles Basin area), one of the Division's busiest regulatory regions, with full report enclosed as Appendix 1
E. A summary of the results of discussions between the Division, State Water Resources Control Board, and the United States Environmental Protection Agency (U.S. EPA) designed to rectify certain UIC program shortfalls, with key correspondence included as Appendix 2 to this report
F. A concluding summary table rounding up significant known issues and the fixes being pursued for each

A. Overview of the Requirements of California's Class II UIC Program

The Division's mission requires it to prevent damage to life, health, property, and natural resources, while also encouraging the wise development of oil, gas, and geothermal resources to increase the ultimate recovery of underground hydrocarbons and geothermal resources. The Division is charged with enforcing existing statutes and regulations as defined by State mandates, and exercising primary authority over Class II injection wells for enhanced oil recovery as delegated to it by the U.S. EPA. The Division does this through the issuance of permits covering all forms of drilling, reworks, and abandonment for wells, including orphan and idle wells throughout California.

Injection wells have been an integral part of California's oil and gas operations for nearly 60 years. There are approximately 55,000 oilfield injection wells operating in the State. These include enhanced oil recovery (EOR) wells used to increase oil recovery through sustained injection or reinjection of large volumes of fluids, and wells devoted to the disposal of the "produced water" that emerges from hydrocarbon deposit areas simultaneously with, and commingled with, the production of oil and natural gas. About 75 percent of California's oil production of 600,000 barrels of oil per day (35 percent of California's daily petroleum use) results from deployment of EOR methods such as steam flood, water flood, and natural gas injection.

As a result of the maturity of California's oil fields, for every barrel of oil extracted, over 15 barrels of water are produced along with the oil. Of this amount, roughly two-thirds is returned to oil-bearing reservoirs for enhanced production and reservoir pressure balance. Of the remaining water, over 25,000 acre-feet (nearly 9 billion gallons of water) is cleaned sufficiently that when blended with other water it is safe and usable for agriculture. Some of the produced water is cleaned and released for the benefit of critical habitats. Some is retained and employed for productive uses within the oil fields (for example, cementing, well maintenance, and well stimulation). That water for which other uses cannot be found is disposed of in the State's approximately 1,800 Class II injection wells.

Produced water may only be injected into areas underground that (1) contain no water at all, (2) have water containing more than 10,000 mg/L of total dissolved solids (TDS), or (3) have been exempted from the federal Safe Drinking Water Act (SWDA) because they are too contaminated and/or too deep for economical beneficial use. The premise is that some water underground is associated with chemicals – including hydrocarbon deposits – that make the native water unsuitable for domestic consumption. Thus, a key part of the UIC Program involves reviewing permit proposals asserting that certain locations and depths are appropriate for injection because they target exempt aquifers, zones without any native water, or zones excluded from the SDWA owing to their high salt content or other contaminants.

In 1983, the U.S. EPA, under the federal Safe Drinking Water Act, delegated to the Division primary authority – primacy – to regulate wells injecting of fluids resulting from oil and gas extraction, or "Class II" wells. The Division's Class II UIC program is monitored by the U.S. EPA. In other states lacking the primacy delegation, the U.S. EPA regulates Class II injection directly.

The main features of the Division's Class II UIC program include permitting, inspection, enforcement, mechanical integrity testing, plugging and abandonment oversight, data management, and, increasingly, public outreach. In accordance with the 1983 primacy agreement between the Division and the U.S. EPA, the Division's Class II program is compensated annually based on the number of Class II wells. Although the Division has received close to $500,000 from the U.S. EPA in each of the past five years for managing the UIC program, this is only a small fraction of the funding required to manage the program on behalf of the U.S. EPA. The full cost of managing this program exceeds approximately $25 M annually.

Operators and owners of Class II injection wells must file for a permit with the Division before any drilling, well re-work, or plugging and abandonment can take place. Permits to drill are sought from the Division by submitting a Notice of Intent. When approval for a new project is sought, the project must be approved before individual permits can be issued. The proposed injection project is evaluated by Division engineers and reviewed by the appropriate Regional Water Quality Control Board.

The UIC Program strives to achieve "zonal isolation" of proposed injection. "Zonal isolation" is the concept that fluids injected into a geologic zone or strata will remain in that zone and not migrate into a different zone. In part to ensure zonal isolation, State regulations beginning with California Code of Regulations Section 1724.6 et seq., require that plugged and abandoned wells in the area will not have an adverse effect on the project or cause damage to life, health, property, or natural resources, and that formation pressures are not exceeded to the extent that damage occurs. Meeting these regulations requires extensive reviews of formation geology and of existing wells nearby that are drilled into the injection zone, to determine if they are compromised or could otherwise become a conduit for injection fluid into a different zone.

Well integrity is required for all injection wells. All wells must meet casing requirements aimed at achieving zonal isolation. Metal casing is placed in the drilled hole (wellbore), and cement is added in the space between the casing and the hole (annulus) to bond the metal casing to the surrounding rock and/or aquifer through which the well has been drilled. This annular cement creates a seal or barrier that prevents fluids from moving up or down the wellbore. Casing must be of specified strength, competence, and length and extend through all oil and natural gas formations that contain not just hydrocarbons, but also water. In the case of UIC wells, there are high standards for mechanical integrity testing, owing to the importance of well construction and well integrity in achieving zonal isolation.

When an operator seeks to operate an injection well, there are two approvals that must be received prior to injection. The first is a "project" approval. A "project" under UIC consists of many wells, sometimes as many as 200 wells, in an injection-production system. Some of the wells are injection wells, others will be production wells, and some wells are often converted from one use to another as a field matures. The "project" proposal includes evaluation of the geology of the area to be subject to injection and production operations. It also must include review of the construction of neighboring wells and the ability of the geologic structures to contain injection fluid within the intended injection zone.

Approval of a "project" under the UIC program, however, is not the same as the approval of a well. An operator must also submit a permit request for each well. These permits may be submitted simultaneously with the "project" or may be submitted later as the operator continues to develop the production from the project area. The well permit addresses the well's construction and how that construction meets the well construction standards.

In 2011, the Department requested, and U.S. EPA contracted for, an audit of the UIC Program. That audit was the first comprehensive evaluation of the federally-delegated UIC Program in its nearly 30-year history. The Department has been engaging in ongoing review with the U.S. EPA and the State Water Resources Control Board since then. To date, the review has found inconsistent practices among district offices, unclear and inconsistent histories about aquifer exemptions, inconsistent application of area reviews under project permitting, and aging regulatory constructs that need to be updated to match current oil production methods.

These shortcomings of the UIC Program have resulted in a relatively small number of wells being permitted where they should not have been in the context of over 55,000 injection wells permitted in the State. The Department and the State Water Board are reviewing the siting, as permitted, of hundreds of existing injection wells. Out of more than 500 injection wells identified as posing a potential risk of contamination to potential sources of drinking water, 23 have been shut-in (11 in the summer 2014, and 12 more in March 2015).

Limited testing of nearby water supply wells has shown no contamination of adjacent water supplies. However, this review is continuing, and will be followed up with a finely-detailed project-by-project review of each UIC project, regardless of location, encompassing the more than 55,000 UIC wells in California under the terms of the UIC action plan developed jointly with U.S. EPA, the Department, and the State Water Board. If and when additional high-risk wells are located, they will be shut in quickly as has been current practice.

B. DATA SPECIFICALLY REQUESTED UNDER SB 855

1. PERMITTING: NUMBERS AND TIMING

SB 855 requests data on the annual number of underground injection permits issued by the department and the average length of time to obtain a permit from date of application to the date of issuance. (SB 855, § 35, subd. (a)(1)-(2).) That information is as follows:

- For 2011, the Department received 11 applications for UIC Projects. Six projects were approved in that year, and 4 were disapproved or cancelled. Three hundred individual injection well applications were received. The average time to permit a well during that year was 22 days, with a median permit processing time of 14 days.

- For 2012, the Department received 30 applications for UIC Projects. Twenty projects were approved in that year, and 2 were disapproved or cancelled. Three hundred thirteen individual injection well applications were received. The average time to permit a well during that year was 19 days, with a median permit processing time of 14 days.

- For 2013, the Department received 62 applications for UIC Projects. Thirty-one projects were approved in that year, and 1 was disapproved or cancelled.

Three hundred ninety-one individual injection well applications were received. The average time to permit a well during that year was 14 days, with a median permit processing time of 11 days.

- For 2014, the Department received 41 applications for UIC Projects. Thirty-six projects were approved in that year, and 1 was disapproved or cancelled. Three hundred twenty-three individual injection well applications were received. The average time to permit a well during that year was 11 days, with a median permit processing time of 11 days.

The table below summarizes the above data and includes for reference the permitting time for all wells, not just for UIC wells.

	UIC Projects			Well Permits			
				All Wells		UIC	
Year	Received	Approved	Disapproved / Cancelled	Ave. Time to Issue Permit	Median	Ave. Time to Issue Permit	Median
2011	11	6	4	16	13	22	14
2012	30	20	2	15	14	19	14
2013	62	31	1	12	10	14	11
2014	41	36	1	12	11	11	11

The number of permitted projects appears to show a significant increase in 2012. In part, this is an artifact of the specific interval in time – a longer time series shows ups and downs in the annual number of permitted projects. In addition, the increase represents increased Division capacity with the hiring and training of staff following approval of additional positions for UIC in the FY 2011-2012 budget. Furthermore, it is worth noting only 5 projects were approved in the latter half of 2014, when UIC staff were focused on wells reviews and activities related to the engagement with U.S. EPA for UIC compliance.

2. *Compliance*

SB 855 requests reporting the number and description of permit violations identified and the number of enforcement actions taken. (SB 855, § 35, subd. (a)(3)-(4).) For this report, permit violations are aggregated into these six categories:

1) Injection without a completed project approval
2) Failure to address mechanical integrity issues identified by the Division
3) Failure to operate under permitted conditions, such as rate or pressure, as identified by the Division
4) Ineffective/insufficient plugging identified during witnessing or inspection
5) Monitoring and Reporting Violations – failure to properly and/or timely report information
6) Other violations

Enforcement actions are aggregated into the following categories:

1) Notices of Violation (NOV) – advises operator of failure to comply with Division regulations and requires operator to remedy
2) Administrative Orders – issued if/when operator fails to remedy NOV issues and can include shut-in of well
3) Well shut-ins – operator shuts-in well under agreement with Division as an expedited version of NOV – Administrative Order process
4) Pipeline severances – direction to disconnect injection piping to a shut-in well to ensure compliance with order to cease injection; may be issued when plugging and abandonment is not required or advisable
5) Other enforcement actions

The numbers of violations and enforcement actions for calendar years 2011 through 2014 are as follows:

	Year			
	2011	2012	2013	2014
Permit Violations Identified				
Unauthorized Injection	9	323	12	17
Mechanical Integrity	227	29	85	110
Operations and Maintenance	15	106	763	822
Plugging and Abandonment	0	10	1	2
Monitoring and Reporting Violations	672	72	69	122
Other Violations	2	2	24	0
Enforcement Actions Taken				
Notices of Violations	235	133	938	764
Administrative Orders	0	0	11	11
Well Shut-ins	662	6	3	11
Pipeline Severances	13	3	0	0
Other Enforcement Actions	22	16	43	120

As with the number of projects permitted, interpretation of these numbers reflects a variety of actions taken by the Division and must be viewed in context. Owing to insufficient staffing, the Division has focused staff time on specific issues that change from year to year. In some cases, the numbers reflect enhanced efforts by the Division to educate and ensure compliance by the industry about revised regulatory frameworks. In some cases, the numbers reflect an increase or decrease in the number of new wells drilled versus reworking and recompleting wells in new zones, etc. as well as ups and downs in the price of oil that affect specific industry activities and result in a varying set of violations.

3. *Staffing*

SB 855 further requests a report on staffing changes in the UIC Program during the reporting period. (SB 855, § 35, subd. (a)(5).) When the Department provided the January 2011 report on 2010 activities, the hiring for positions authorized in the FY2010-2011 Budget was not complete. Therefore, this report includes reference to changes in staffing since those positions were authorized.

We defined "staff changes" to mean the number of positions authorized at the beginning of a fiscal year that were filled by the end of that fiscal year. In some cases, newly-authorized positions became opportunities for advancement of internal candidates. When an internal candidate fills a newly-created position, the Department must engage in a secondary process to fill the vacant position created by the promotion/transfer of the internal candidate into the new position. In this manner, some vacancies consistently exist within the Department across all program areas.

The Fiscal Year 2010-2011 Budget authorized 17 positions for enhancement of UIC Program implementation. Those positions were all filled by late June 2011.

For the Fiscal Year 2011-2012 Budget, the Department proposed 36 new positions in the Division of Oil, Gas, and Geothermal Resources, 11 of which were to be dedicated to UIC and related enhanced oil recovery (EOR) permitting. The proposal was made late in the budget process during the May budget revision. The Legislature approved half of the 36 positions requested, directing the Department to resubmit any of the other 18 positions for consideration through the routine annual budget process that starts with the release of the Governor's proposed budget on January 10 of each year. Of these 18 approved positions, many were filled in the FY2011-2012 period, but 5 were not filled until the next FY. These were Associate Oil and Gas Engineers, for which recruitment had been very difficult given competition for their expertise in the private sector.

For the Fiscal Year 2012-2013 Budget, the Department requested the 18 positions that remained from the original Fiscal Year 2011-2012 request. These were approved by the Legislature. All 36 positions – including the 11 positions identified specifically for UIC and EOR – authorized in this fiscal year and the prior fiscal year were filled prior to the end of the Fiscal Year 2012-2013 Budget.

The Fiscal Year 2014-2015 Budget included 65 positions across the Department for implementation of Senate Bill 4 (Pavley), a bill related to well stimulation practices such as hydraulic fracturing that required the development, now nearing completion, of a new, comprehensive regulatory program. As a consequence, none of these positions are dedicated to UIC program work.

Over the arc of this reporting period, the number of positions requested show two consistent features – (1) recognition by Division leadership that additional resources were needed to manage the UIC regulatory program, and (2) the number of staff needed was uncertain and therefore consistently underestimated. Both result from the growing realization of the number and complexity of problems being addressed as identified in the Horsley-Witten audit, and the growing magnitude of the challenge of managing these problems.

C. New Legislation and Regulations

SB 855 requests a description of any state or federal legislation, administrative, or rulemaking changes to the program. (SB 855, § 35, subd. (a)(6).)

1. *Legislation*

Senate Bill 83 (Committee on Budget and Fiscal Review, Chapter 24 Statutes of 2015) establishes an aquifer exemption proposal process in which the Division coordinates with the State Water Resources Control Board on a state level to conduct a public evaluation of aquifers prior to submitting exemption proposals to the United States Environmental Protection Agency for consideration. The bill also establishes biannual reporting requirements for the Division and Water Board. Beginning January 30, 2016, the Division and the Water Board must provide the following information to the Legislature:

1. The number and location of underground injection well and permits and project approvals issued by the Department, including permits and projects that were approved but subsequently lapsed without having commenced injection.
2. The average length of time to obtain an underground injection permit and project approval from date of application to the date of issuance.
3. The number and description of underground injection permit violations identified;
4. The number of enforcement actions taken by the department.
5. The number of shut-in orders or requests to relinquish permits and the status of those orders or requests.
6. The number, classification, and location of underground injection program staff and vacancies.
7. Any state or federal legislation, administrative, or rulemaking changes to the program.
8. The status of the review of the underground injection control projects and summary of the program's assessment findings completed during the reporting period, including any steps taken to address identified deficiencies.
9. A summary of significant milestones in the compliance schedule agreed to with the USEPA, as indicated in the March 9, 2015, letter to the Division and SWRCB from the USEPA, including, but not limited to, regulatory updates, evaluations of injection wells, and aquifer exemption applications.
10. Progress addressing the program's assessment findings and delivery of that report to the fiscal and relevant policy committees of each house of the Legislature.

Finally, SB 83 requires the Secretary for the California Environmental Protection Agency and the Secretary of the Natural Resources Agency to appoint an independent review panel, on or before January 1, 2018, to evaluate the regulatory performance of the Division's administration of the UIC Program, and to make recommendations on how to improve the effectiveness of the UIC Program, including resource needs and statutory or regulatory changes, as well as UIC Program reorganization, including consideration of transferring administration of the program to the State Water Board.

2. *Regulations*

The chief development in this area has been the Division's adoption of injection compliance regulations. These emergency regulations and proposed permanent regulations provide that if operators injecting in identified aquifers fail to obtain an aquifer exemption duly issued by the U.S. EPA under the Safe Drinking Water Act by specified dates, the injection activity must cease. The key deadlines in both the emergency and proposed permanent regulations are as follows:

- October 15, 2015: injection must cease in all non-exempt, non-hydrocarbon-bearing aquifers with water less than 3,000 mg/L TDS unless an aquifer exemption duly issued by the U.S. EPA has been obtained (Cal. Code Regs. Title 14, § 1779.1, subd. (a)(1)).

- December 31, 2016: injection must cease in eleven aquifers historically treated as exempt unless the aquifer has been duly exempted by the U.S. EPA (Cal. Code Regs. Title 14, § 1779.1, subd. (b)).

- February 15, 2017: Injection must cease into aquifers between 3,000 mg/L and 10,000 mg/L TDS unless a duly-issued exemption is obtained. (Cal. Code Regs. Title 14, § 1779.1, subd. (a)(2), (3)).

The Division is currently conducting public workshops regarding the permanent regulations.

Additionally, the Division will begin work this fall on a series of other regulation packages described more fully in the joint letter of the Division and State Water Board on July 15, 2015.[1] (See also summary, below.)

[1] See Appendix 2, July 15, 2015 letter, Attachment 2, *Plan for Class II Program Improvements*, pp. 11-13.

D. Program Assessment: The Monitoring and Compliance Unit Report on District 1.

SB 855 requests a description of the findings of a program assessment (SB 855, § 35, subd. (a)(7)), and a report on the action plan developed to address the program assessment findings and its efforts to implement the plan. (SB 855, § 35, subd. (b).)

In early 2011, the Division established a Monitoring and Compliance (MC) Unit to assess the Division's management of its UIC program, adherence to state and federal requirements, internal record-keeping, and to generally evaluate program performance. The Unit is comprised of one Senior Oil & Gas Engineer and three Associate Oil & Gas Engineers. The new Senior Oil & Gas Engineer overseeing this unit began February 1, 2011, with the Associate Oil and Gas Engineers being hired over the next several months.

The MC Unit has two functions: to monitor Division programs, and to act as a team to provide resource assistance. The MC Unit has now looked in-depth at the UIC program in District 1 (Cypress, California – Los Angeles Basin). Its report, *Underground Injection Control Program Assessment Report, District 1: Determinations and Recommendations* is now complete, and is included with this report as Appendix 1.

The evaluation methodology used in the Program Assessment Report for District 1 was based on the selection and analysis of sample populations representing UIC application completeness, project files management, project approval letters, area of review (AOR), UIC well monitoring program practices, and annual project reviews. To the extent possible, program reviewers selected sample data from different historical intervals for evaluation against current program standards.

The Program Assessment Report for District 1 identifies problems whose root cause can be traced to the issues noted in the transmittal letter, including a shortage of Division staff, inadequate data management systems, and a lack of uniform staff training with regard to file handling and data entry. Lack of organization was noted in the handling and storage of paper files, and project approval letters were confusing, information-deficient, overly generic, or simply absent.

Deficient or Absent AORs. In 2012, owing to an insufficient number of properly trained staff, a decision was made that AORs could be deferred until after the commencement of injection. This policy was instituted based on two assumptions: (1) that AOR evaluations would be performed during the annual project review process, and (2) that the subject fields had previously undergone an appropriate AOR process. However, given the number of uncompleted AOR evaluations, and issues with annual reviews (discussed below), these conditions were not met in all cases.

Well Monitoring to Ensure Zonal Isolation. The goal of the well monitoring program is to ensure that injected fluid does not migrate out of the approved zone(s) of injection. To ensure this isolation, the Division employs a well monitoring program that includes establishing a maximum allowable surface injection pressure (MASP), and requires mechanical integrity tests (MITs), including standard annular pressure tests (SAPTs) and radioactive tracer (RA) surveys, of injection wells.

Evaluation of the adequacy of the District's well monitoring program revealed that although step-rate-tests (SRTs), used to derive the MASP, generally met current industry standards, few SRTs met U.S. EPA standards. However, as a result of minor changes in the Division's procedural practices and data capture, these deficiencies were corrected.

MIT Tests. Evaluation of MIT surveys was generally thorough in District 1. In cases of a failed test, operators were required to remediate and retest the well to obtain a passing MIT. However, data entry fields for these tests were frequently left blank, or incorrectly entered in the Division's California Well Information Management System database. This indicates that the Division's data quality control and quality assurance need to be improved and that more robust staff training is necessary.

Annual Reviews. The Primacy Agreement requires that all existing Class II projects in California be reviewed annually. Our reviews found the state has not met this obligation in District 1. Moreover, a review of the District's active project list revealed that the majority of projects have not been reviewed since 2007.

These and other findings are set forth in detail in the MC Unit's full report, enclosed herewith as Appendix 1.

E. JOINT EFFORTS OF THE DIVISION, STATE WATER RESOURCES CONTROL BOARD, AND U.S. EPA TO IMPROVE THE DIVISION'S REGULATION OF CLASS II INJECTION

The Division, State Water Resources Control Board, and U.S. EPA have been meeting regularly to put in place a plan that addresses some of the concerns with the program as a whole that the Legislature had when it passed SB 855. The Division and U.S. EPA had been corresponding occasionally since the 2011 U.S. EPA's Horsley-Whitten report – an audit of the Division's overall performance of its Class II UIC responsibilities. In mid-2014, following revelations of injection wells being permitted with unclear or absent exemption status, the Division and U.S. EPA meetings took on a new urgency. The State Water Resources Control Board, as the agency with statutory review authority for injection well permits, joined the effort.

In letters and meetings between the State (the Division and State Water Resources Control Board) and U.S. EPA, the three-agency group developed a plan for the Division to close down wells and improve and modernize its UIC practices. Though the plan has not as yet been reduced to a single document, its various components appear in five key letters between the State agencies and U.S. EPA. This correspondence, and a current summary table of all of the deadlines agreed to by the agencies, appears as Appendix 2 to this report, *Interagency UIC Program Improvement Planning: Major Correspondence and Deadlines.*

The plan consists of four major efforts to be conducted concurrently. First, and of highest priority, has been the ongoing review of permits for hundreds of individual injection wells in potentially unsuitable areas, with closures of wells as necessary. Second, the Division has committed to conduct a project-by-project review of each UIC project. Third, this fall, the Division will embark on a series of rulemakings to modernize and enhance the State's regulatory framework. And fourth, the Division and the administration are developing a modern well and data management system to handle all of the Division's records and data.

The four components of the plan and its current status are summarized below.

1. *Well Review and Aquifer Exemptions.*

The Division and State Water Board have been systematically reviewing injection wells that may have been sited inappropriately. From the beginning of the effort last year, the Division has placed first priority on the review of disposal wells that may pose an immediate risk to waters of beneficial use, and has agreed to order the closure of, or obtain operator permit relinquishments for, wells appearing to pose such a risk.[2] As of today, the Division has secured the closure of 23 such disposal wells.[3]

The remaining wells have been placed into three priority categories for review and action:

Category 1 Wells: Class II water disposal wells injecting into non-exempt, non-hydrocarbon-bearing aquifers or the 11 aquifers historically treated as exempt

Category 2 Wells: Class II enhanced oil recovery (EOR) wells injecting into non-exempt, hydrocarbon-bearing aquifers

Category 3 Wells: Class II water disposal and EOR wells that are inside the surface boundaries of exempted aquifers, but that may nevertheless be injecting into a zone not exempted in the primacy agreement[4]

The Division has also agreed to set deadlines for operators to either shut in or obtain exemptions for these wells as required. These regulations may be found on the Department's web site at:

http://www.conservation.ca.gov/dog/general_information/Pages/UndergroundInjectionControl(UIC).aspx

Emergency regulations, and follow-up permanent regulations require the shut-in of the following wells, or the securing of an exemption from U.S. EPA, by the following dates:

October 15, 2015: Wells injecting into non-hydrocarbon-producing zones of less than 3,000 mg/L total dissolved solids (TDS) (Cal.Code Regs., tit. 14, § 1779.1(a)(1))

December 31, 2016: Wells injecting into 11 specified aquifers historically treated as exempt (Cal.Code Regs., tit. 14, § 1779.1(b))

February 15, 2017: Wells injecting into non-hydrocarbon-producing zones of between 3,000 and 10,000 TDS (Cal.Code Regs., tit. 14, § 1779.1(a)(2))

February 15, 2017: Wells injecting into hydrocarbon-producing zones of less than 10,000 TDS (Cal.Code Regs., tit. 14, § 1779.1(a)(3))

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[2] See Appendix 2, February 6, 2015, letter, Enclosure D: More Detailed Look at Administrative Concepts, at p. 1.

[3] See Appendix 2, May 15, 2015, letter, Attachment H: Orders and Relinquishments.

[4] See Appendix 2, February 6, 2015, letter, pp. 3-4.

Again, it should be stressed that this prioritized set of deadlines, now committed to regulation, guides the ordering of the Division's well review process but does not supplant or otherwise delay the Division's ability to take action on wells of immediate risk. The Division remains empowered to close wells of greatest risk throughout this process, either by securing the operator's voluntary relinquishment of the permit, or by administrative order.

With respect to aquifer exemptions, which are determined by the U.S. EPA, the Division is collecting information from operators interested in pursuing exemptions, and will take each operator data package through a process that will culminate either in a determination by the State (both the Division and State Water Board) to inform the U.S. EPA of the State's opinion that exemption criteria appear to be presently met, or that there is insufficient information for such a conclusion to be drawn. The U.S. EPA has final authority to declare an aquifer exempt going forward.[5]

2. *Project-by-Project Review of Injection Project Approvals.*

The Division has also committed to begin conducting individual project reviews designed to find missing data, identify UIC compliance issues, and to compare existing project approvals with current conditions in the field.

During this process, operators will be required to provide missing data, and the Division will reevaluate the project based on all relevant regulations, mandates, and policies, including demonstration of zonal isolation of injected fluids. Projects will be reapproved, modified, or cancelled as appropriate.[6]

3. *New Regulations and Program Revisions.*

In addition to the regulations described above calling for the shut-in of wells in the absence of a determination by the U.S. EPA that a portion of a geologic formation is not covered by the SDWA (either because it does not contain water or does not contain water of quality suitable for use), the Division has also committed to doing other new rulemaking. Many state regulations governing underground injection control are obsolete, deficient, or simply unable to address current industry practice. Therefore, beginning this fall, the Division will undertake a series of rulemakings to improve the State's regulatory framework so as to address these issues.

New regulations will address a myriad of issues, such as zonal isolation, the quality of water to be protected, well construction practices, cyclic steam operations, maximum allowable surface pressure, ongoing project review, and idle well standards and testing.[7]

New business practices, apart from those expressed in regulation, will include new staffing, compliance monitoring, and business process reviews.[8]

4. *Development of A Modern Well and Data Management System.*

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[5] See Appendix 2, July 15, 2015, letter, Attachment 2, Plan for Class II Program Improvements, p. 9.

[6] See Appendix 2, July 15, 2015, letter, Attachment 2, Plan for Class II Program Improvements, pp. 6-9.

[7] See Appendix 2, July 15, 2015, letter, Attachment 2, Plan for Class II Program Improvements, pp. 11-12.

[8] See Appendix 2, July 15, 2015, letter, Attachment 2, Plan for Class II Program Improvements, pp. 10-11.

The Division has committed to U.S. EPA that it will pursue a vastly improved data management system.[9] The improvement of the Division's data management system is now under way as a result of funding forthcoming in the FY 15-16 Budget. The development and implementation of this system is central to the improved performance of every aspect of the Division's work – regulatory compliance and effectiveness, transparency, and support of all stakeholders.

Finishing every piece of the UIC improvement plan submitted to the U.S. EPA will consume 3-4 years. However, as each component piece is completed, tangible improvements in the Division's performance of its mission will follow. Such changes will be supported by the development of sustained, comprehensive training programs to support the process of constant internal review and adjustments for continuous improvement of the execution of the Division's responsibilities.

CONCLUSION: PROBLEMS AND SOLUTIONS: POINT-BY-POINT DESCRIPTION OF SIGNIFICANT TROUBLE SPOTS AND EFFORTS BEING MADE TO ADDRESS EACH

Monitoring and Compliance UIC Review

Findings	Corrective Actions	Status
There has not been a consistent standard of practice for collecting and maintaining information about projects. - Record-keeping has been poor. Many project files – mostly from previous decades – are missing information that is required by regulations and is also necessary to fully monitor, inspect and evaluate a project. - Project files are not centralized. Data and records are poorly organized and often located in multiple places. - Project files are not digitized.	1. As part of the Division's statewide project-by-project review beginning in September 2015, field inspectors and staff will collect all missing required data plus any additional data necessary to confirm the confinement of injected fluid. 2. Project-by-project review guidance document creates a standard of practice for record-keeping to achieve consistency at the district and statewide levels. All project files will have a checklist to ensure all data has been received and evaluated. 3. As the Division restructures and acquires new staff, it will institute systematic training among new and existing staff on the new standards of practice. 4. Build a publicly accessible and fully searchable online database that integrates paper files from multiple past decades with modern data collection practices going forward, and also identify data gaps.	Prior to 2011, 56% of the "pre-primacy" projects had incomplete data. After the letter of expectations in 2011, and the Division obtained missing data, the percentage of projects missing data has dropped to 17% in District 1. Project applications are now returned to operators with a request to provide all missing information before they will be considered. Meetings with operators have been conducted to convey expectations to operators. The Legislature allocated $10 million in the 2015-16 budget for the Division to expedite construction of a data system by 2017-2018; Stage-Gate process under way.

[9] See Appendix 2, February 6, 2015 letter, p. 10.

Project Approval Letters (PALs) are incomplete, unclear and inconsistently modified. - Essential elements are often missing or difficult to discern, such as type of project or the injection zone. - Many projects have multiple injection zones and permit times, all under the same PAL. - Some PALs lack clarity as what operations were approved and under what conditions the project is required to operate.	1) With the Project-by-Project review, new PALs will be written to clearly identify the paramenters of the project. 2) If necessary, projects may be split into multiple projects to address the specifics in the field. 3) New PALs will be written to address specific project conditions, including a list of wells in the project. 4) A guidance document is being prepared to provide clear direction regarding the permitting of a UIC project and will accompany additional technical training.	Project-by-project review will commence in September; schedule for completion in each District is given in the document submitted to U.S. EPA, "Plan for Class II Program Improvements," attachment 2 of submittal to US EPA on July 15, 2015.
Problem wells located within the Area of Review could potentially provide a conduit for injected fluid to migrate.	1) The Project-by-Project review is designed to ensure all required data is obtained and evaluated. This includes the many issues identified in the review concerning well construction and associated casing diagrams. 2) Problem wells will be remediated or the project modified accordingly. 3) An assessment of the zone of endangering influence will be performed to determine the extent of impacts caused by injection. 4) New regulations addressing well construction are being developed. 5) The Monitoring and Compliance team is gaining additional staff to increase the oversight of the work being completed in the District offices.	Publicorkshops initiating phase 1 of two phases of rulemaking were held in September 2015. Phase 1 included: standards for zonal isolation, well construction standards, regulatory requirements for cyclic steam, regulatory requirements for cyclic steam extraction from diatomite, standards for establishing maximum allowable surface pressure for injection operations.

Inadequate number of step rate testing performed. Mechanical Integrity Tests (MIT) not being performed or being performed but past due. Poor tracking system does not provide for alerts when tests are due.	1) As part of the Project-by-Project review additional testing will be required where either tests were not conducted in the past or there is concern about the validity of the data. 2) A new data management system is being developed to better track test results and to aid in the field monitoring of actual injection pressure being utilized in the wells. 3) The guidance document being prepared for UIC approvals will include strict guidelines for step rate testing in compliance with U.S. EPA standards.	Guidance document requires current, accurate test results before a PAL can be issued or reissued.
Lack of consistency of annual project reviews. In addition, over time the Division substituted a questionnaire instead of a face-to-face meeting with operators to discuss projects.	1) Annual project reviews will be addressed in the Project-by-Project review. Once the missing data are collected and the project files are organized, project reviews will be performed annually and more efficiently. 2) New regulations will outline the requirements for an annual project review.	Hiring of UIC staff positions funded in the 2015-2016 budget to bolster the resources needed to conduct the annual reviews and other UIC related duties is under way. Guidance document for project-by-project review specifies documents and their order in a project file. The review will also require extensive interactions, now under way, with operators to collect missing data, remediate past-due tests, and reevaluate the project.

Department of Conservation,
Division of Oil, Gas, and Geothermal Resources

Underground Injection Control Program Assessment Report, District 1: Determinations and Recommendations

Appendix 1 to Report to the California Legislature under SB 855 (2010)

Monitoring and Compliance Unit
May 2015

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VII. Tables

LIST OF ACRONYMS AND ABBREVIATIONS

AOR	Area of Review
APR	Annual Project Review
BCP	Budget Change Proposal
BFW	Base of Fresh Water
CalWIMS	California Well Information Management System
CBL	Cement Bond Log
CCR	California Code of Regulations
CFR	Code of Federal Regulations
Department	Department of Conservation
Division	Division of Oil, Gas, and Geothermal Resources
GS	Gas Storage
ISIP	Instantaneous Shut-in Pressure
MASP	Maximum Allowable Surface Pressure
MC	Monitoring and Compliance
Mg/l	milligrams per liter
MIT	Mechanical Integrity Test
N/A	Non-applicable
NEA	No engineer available
NEI	Not Enough Information
P&A	Plugged & Abandoned
PAL	Project Approval Letter
PC no.	Project Code Number
PPM	Parts per million
Psi/ft	Pounds per square inch per foot
RA	Radioactive tracer
SAPT	Standard Annular Pressure Test
SB4	Senate Bill 4
SB858	Senate Bill 858
SDWA	Safe Drinking Water Act
SRT	Step-Rate Test

TDS	Total Dissolved Solids
TIZ	Top of Injection Zone
TVD	True Vertical Depth
UIC	Underground Injection Control
U.S. EPA	United States Environmental Protection Agency
USDW	Underground Source of Drinking Water
WD	Water Disposal
WF	Water Flood
ZEI	Zone of Endangering Influence

I. EXECUTIVE SUMMARY

The Division of Oil, Gas and Geothermal Resources (Division) has conducted an in depth review and evaluation of the Underground Injection Control (UIC) Program of the District 1 office in Cypress, California (Los Angeles Basin). The objective of the review was to evaluate the implementation of the UIC program in the Division's District 1 (Cypress) in accordance with Division mandates, regulations and policies. As a result of this review, performance issues have been identified that can be mitigated through programmatic improvements designed to move the District and the Division towards full compliance with UIC Program standards.

Program evaluation methodology involved analyzing sample populations of UIC applications, project files management, project approval letters, area of review (AOR) evaluations, UIC well monitoring program practices, and annual project reviews (APR). To the extent possible, program reviewers selected sample data from different historical intervals for evaluation against current program standards.

In 1983, the United States Environmental Protection Agency (U.S. EPA) granted the Division "primacy" -- primary authority for the management and enforcement of the UIC Class II Program in California. This authority gave the Division primary responsibility for protecting underground sources of drinking water (USDWs). In general, we found a significant increase in completed injection applications consistent with a pattern of improved Division practices following primacy.

The UIC program evaluation found deficiencies in the District 1 UIC program related to the shortage of Division staff, inadequate well and data management systems, and a lack of uniform staff training with regard to file handling and data entry. Lack of organization was noted in the handling and storage of paper files, and project approval letters (PALs) were confusing, information-deficient, overly generic, or incomplete.

AOR evaluations need to be conducted more consistently. While the performance of required AOR evaluations increased significantly following the granting of primacy in 1983, a large number of evaluations remain to be performed.

In 2012, District 1 initiated a Division wide deferral policy to allow for an AOR evaluation to occur along with the annual project review. This policy was based on two assumptions: 1) that AOR evaluations would be performed during the APR process, and 2) that the subject oil fields had previously undergone an appropriate AOR process. However, analysis showed that the AOR evaluations were not up to date and there were deficiencies in the annual reviews.

The Division employs a well monitoring program to ensure "zonal isolation to migrate against the potential for injected fluids to migrate out of the intended zone or formation. To ensure zonal isolation, the Division requires establishing a maximum allowable surface injection pressure. Maximum Allowable Surface Pressure (MASP) is determined by a step-rate test

(SRT), and requires mechanical integrity tests (MITs), including standard annular pressure tests (SAPTs) and radioactive tracer (RA) surveys, of injection wells.

Our review of the District's well monitoring program revealed that while SRTs used to derive the MASP generally met current industry standards, some SRTs were not completely consistent with EPA regulations. However, these problems have since been corrected through modification of procedures and improved data capture. In addition, as a result of a backlog of regulatory actions, about 1/3 of the most recent required SAPT and RA surveys were past their current scheduled performance date.

District oversight of MIT surveys was generally thorough. In cases of a failed test, operators were required to remediate and retest the well to obtain a passing MIT, though the results were often not correctly entered in the Division's California Well Information Management System (CalWIMS) database.

The Primacy Agreement requires that all existing Class II projects in California be reviewed annually. The Division has generally not met this obligation because the magnitude of the effort requires additional staff, improved training, and better and more easily accessible records. In District 1, in depth review of the active project list revealed that a majority of projects have not been reviewed since 2007.

II. INTRODUCTION

General

Since 1983, the Division, part of the Department of Conservation (Department), has had primary authority to regulate Class II injection wells in California under the federal Safe Drinking Water Act (SDWA). That authority is carried out within the Division's UIC program.

In 2010, the Department and Division prepared a Budget Change Proposal (BCP) to augment the UIC permitting program. That effort coincidentally revealed some significant issues with program performance statewide. Subsequently, the Division created the Monitoring and Compliance (MC) Unit to evaluate regulatory compliance issues generally, and particularly with the UIC Program.

The MC Unit was tasked with evaluating and reporting on the strengths and challenges of the UIC Program in meeting the statutory and regulatory standards on which the program is based. These underlying standards consist of state statutes and regulations, the Primacy Agreement and Memorandum of Agreement with the U.S. EPA, and the Division's 2010 Letter of Expectations delivered to UIC staff. This report is focused upon the Division's Cypress field office, District 1, and identifies the manner in which key UIC Program components have been implemented there.

Understanding this report requires delineation of four major periods of significant regulatory changes to UIC program requirements. These are listed in Appendix A of this report and may be summarized as follows:

1. *Pre-Regulation to 1978.* Statutes and regulations prior to 1978 relied on requirements to prevent movement of fluid, chiefly water, into neighboring operators' hydrocarbon reservoirs.

2. *Regulations from 1978 to 1982.* In 1978, regulation section 1724 was added to require specific data be submitted with an application for injection project approval.

3. *The Initiation of Primacy,* 1983 to 2010. In 1983, the Division was granted primary authority ("primacy") from the U.S. EPA for the management and enforcement of the UIC Class II Program in California. This authority gave the Division, instead of the U.S. EPA, primary responsibility for protecting USDWs, meaning waters containing 10,000 milligrams per liter (mg/L) or less of total dissolved solids (TDS). This authority to protect USDWs required some program changes, including adding a two-part MIT procedure, a specific AOR evaluation prior to the project approval process, and clarification of how to protect waters with 3,000 mg/L TDS or less.

4. *From 2010 to 2013.* In 2010, the Division prepared a Letter of Expectations to staff, clarifying certain aspects of the UIC program implementation. During this time, Division district offices were instructed to implement the Letter of Expectations during permitting and annual reviews of existing projects.

To the extent possible, program reviewers selected representative sample data from each of these historical time periods for evaluation against current program standards.

Purpose

The purpose of this review is to determine whether the Division UIC practices, including permitting, inspection, monitoring, well MIT, plugging and abandonment, enforcement, and data management practices, conform with UIC program standards as mandated.

Practical benefits of this report are expected to include improved APRs in accordance with State Senate Bill 855 (SB 855 [2010]), better compliance with mandated report requirements, and ultimately the adjustment of UIC projects going forward to meet current standards so the state is in full compliance with the Safe Drinking Water Act.

Scope of Work & Audit Report Process

The scope of this analysis was patterned upon the Assessment portion, in Section II, of the Work Plan submitted with the 2010 Budget Change Proposal, which called for the following activities to be undertaken:

1. Evaluate a representative sampling of old projects that are in fields that were discovered in the 1930s and 1940s to determine if appropriate AORs were completed and to determine if potential conduits for the injection fluid were identified.

2. Evaluate a representative sampling of recent projects to determine if appropriate AORs were completed and to determine if potential conduits for injection fluid are present.

3. Evaluate a representative sampling of the records for annual project reviews to determine if they were performed and documented adequately to determine if the project was in compliance with the project approval.

4. Evaluate a representative sample of the Division's UIC well monitoring program to determine if adequate MIT surveys were conducted, evaluated, and documented to ensure mechanical integrity of the injection wells.

5. Evaluate a representative sampling of the Division's UIC monitoring program to determine if the MASPs were determined correctly and monitored to ensure compliance with the PAL.[10]

This analysis focused primarily on items 1 through 5, of the work scope items above. Additional findings related to program compliance were also included. Additionally, while SB 855 and the 2010 Work Plan describe the need for a Division-wide evaluation, this analysis is limited to findings of UIC program issues for District 1 as a first step towards a Division-wide program review. District 1 was chosen as the first district office for review because of its high population density and urban setting, with corresponding higher risk to life, health and public resources. As of December 2013, District 1 had a total number of 268 injection projects, of which a total of 154 were active.

A team approach was used to conduct the assessment. Engineers were assigned to review specific program technical areas corresponding with their area of expertise. The MC Unit Review Team received training in advance of this analysis by assisting the Cypress, Bakersfield, and Orcutt offices with performance of AORs for proposed UIC projects for a year prior to initiating this review.

Report Organization

This report is divided into the following sections: (A) UIC Project Applications, which looks at UIC application completeness, project files management, and PALs; (B) AOR Evaluations; (C) Maximum Allowable Surface Injection Pressure Calculations; (D) MIT; and (E) APRs.

Tabulated data summaries are presented at the end of the document in the Tables section. **Appendix B** provides a simplified review of technical concepts and definitions related to oil and gas drilling and the UIC program useful for an understanding of concepts and terms used frequently in this report.

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[10] The BCP also specified a sixth and seventh activity, namely to evaluate whether the Division's UIC staff are appropriately educated, trained and have the necessary tools to enforce the SDWA in regards to Class II wells, and whether the Division has enough staff and resources to adequately enforce the SDWA in regards to Class II wells. These important areas of inquiry are not addressed in this report.

III. DETERMINATIONS AND RECOMMENDATIONS

A. UIC Project Applications

1. Application Completeness

Before an injection project can be approved, operators must submit an application package with data demonstrating that no damage will occur as a consequence of injection operations. Current UIC program standards require that every application received by the Division, whether for a new project or expansion of an existing injection project, must undergo an AOR evaluation to ensure zonal isolation in the area surrounding each injector, so that no injected fluids will migrate out of the approved injection zones. Zonal isolation determination requires an evaluation of the well construction of every well within an area surrounding the injector and a geologic demonstration that no conduits exist for fluid movement out of the intended injection zone. The list of data required with an injection project application under current program standards is detailed in the California Code of Regulations (CCR) section 1724.7, and includes, but is not limited to:

1. A description of the purpose of the project.

2. An engineering study that includes reservoir characteristics such as porosity and permeability of the formation, areal extent, average thickness, fracture gradient, original and present formation temperature and pressure, and original and residual oil, gas and water saturations.

3. A geologic study that includes structural contour maps drawn on a geologic marker at or near the top of each injection zone in the project area, an isopach map, a geologic cross section through at least one injection well, a representative electric log to a depth below the deepest producing zone that identifies all geologic units, formations, freshwater aquifers, and oil and gas zones.

4. Casing diagrams of all wells located in the area affected by the project. The casing diagrams must include cement plugs, and actual or calculated cement fill behind casing, and evidence that all plugged and abandoned wells will not have an adverse effect or cause damage.

5. An injection plan and map showing injection facilities, maximum anticipated surface injection pressure and daily rate of injection by well, a monitoring system to ensure that no damage is occurring and that fluid is confined to the zone.

6. The source and fluid analysis of the proposed injection fluid and the formation fluid, and the treatment of water to be injected.

7. Other data necessary for a complete review of the proposed injection operation. These data may include the results of injectivity tests and other formation tests to determine the ability of the formation to take fluids without fracturing.

The MC Unit Review Team conducted an evaluation of the UIC applications for each period against current standards. A sample of 52 injection project applications were reviewed for this evaluation; 25 applications were reviewed from pre-Primacy periods, and 27 from post-Primacy periods. **Table 1** and **Appendix B** of this report present, respectively, a brief summary and expanded discussion of these historical regulatory periods introduced in the preceding section.

Determinations

An analysis of UIC injection project applications in District 1 indicated that:

1. Early period UIC project applications were generally compliant with standards corresponding to the periods' application completion standards. Results of this evaluation are summarized in **Table 1** of this report.

2. Retaining incomplete project applications in a queue while requesting additional and/or missing data from the operator is inefficient and increases the amount of work and time required by District staff.

3. As shown in **Table 1**, 56% of the pre-Primacy injection projects were incomplete and 41% of approved post-Primacy injection projects were incomplete. Within the post-Primacy sample population, only 1 of the 6 (17%) post-Letter of Expectations UIC injection projects were incomplete.

4. While indicating a need for considerable improvement, these data suggest an improving trend in UIC application completeness over time.

Recommendations

The following program recommendations are based on general observations of application review practices in District 1.

1. To expedite the application process, operators should assume responsibility for ensuring that their injection project application contains sufficient and accurate engineering and geological information necessary to demonstrate to the Division's satisfaction that their project will operate in compliance with the UIC program requirements.

2. Incomplete applications received by the District should be promptly returned to the operator for completion, and not kept in a queue in the office as is the current practice.

3. As part of a project application package provided to operators, the application checklist should be updated to include the requirements of the CCR Division 2, Chapter 4, Subchapter 1 Sections 1724.7, 1724.8 and 1724.9 (Project Data Requirements), as well as updates resulting from the implementation of Senate Bill 4 (SB4 [2014] Well Stimulation and Treatment Regulations).

4. Applicants must provide the source of information and/or data contained in their project application.

5. Staff should crosscheck all the regulatory references, geological information, well construction, field and reservoir characteristics, plugging and abandonment plans, information about fracture gradient, proposed operating conditions, USDW definition, proposed construction and formation testing etc.

2. Project Files Management

The content of project applications should include: an engineering study; reservoir characteristics for each injection zone (porosity, permeability, average thickness, areal extent, fracture gradient, etc.); reservoir fluid quality data for each injection zone (oil gravity and viscosity, water quality and specific gravity of gas); casing diagrams, including cement plugs, actual or calculated cement fill behind casing of all idle, plugged and abandoned, or deeper-zone producing wells within the area affected by the project; a geologic study including structural contour maps drawn on a geologic marker at or near the top of each injection zone; an isopach map of each injection zone or subzone; geologic cross section through injection well; representative electric log; and an injection plan showing injection facilities and method of injection.

Determinations

1. Project file reviews revealed that important file documents are frequently not kept together in a single location, but are found in different locations throughout the District office.

2. Projects not recently reviewed are often missing critical data, possibly because the data were not originally submitted, or because they were not organized in a manner that was easily manageable or accessible. This makes it difficult to determine whether the project files have all the necessary data needed to evaluate the project. It also makes it difficult to cross-reference and/or check information for accuracy. This issue was not limited to any particular time period or operator, rather seems to be an ongoing filing and data management problem.

Recommendations

1. The District is currently making an effort to address the issue of files management with the implementation of electronic filing, with the goal of storing all project file documents in a single electronic database. The majority of recent project applications are submitted electronically, making it easier to assemble all the components of the project file into the appropriate electronic folder. For older projects, the District is completing a files scanning project wherein paper project files are electronically scanned and stored within an electronic database. This practice should be continued, and ways to enhance this practice (e.g. – better data management systems) should be evaluated.

2. For projects already approved, missing data should be requested from the operator to complete data gaps in project files.

3. Project Approval Letters

Once the proposed project has been reviewed, the District determines if the project can operate in compliance with all the applicable statues, regulations and the Primacy agreement. If so, a PAL is issued to the operator. At a minimum, this PAL should contain the requirements specified in CCR Section 1714 – Approval of Well Operations, Section 1724.6, Approval of Underground Injection and Disposal Projects, and Section 1724.10 – Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects. These sections of the regulations specify the conditions for approval and requirements for operating an underground injection project. Other conditions, such as safety, operational, and environmental requirements, are typically added to the PAL.

Determinations

1. PAL records were confusing. Many projects had more than one PAL in effect at the same time. Several letters rescinded prior letters by date; others had more recent approval letters referencing older approval letters.

2. Many projects have multiple injection zones, permitted at different times throughout the life of the project, all under the same unmodified PAL. Projects originally permitted for deep zones were later permitted, under the same PAL, for shallower zones, and vice versa. Such project injection wells may not be appropriately cased or cemented for injection into the proposed injection zone(s), thereby posing a threat to USDWs.

3. Many PALs were issued without clear identification of the approved zone(s) of injection.

4. Many PALs written in the 1990s and 2000s, do not include the *type* of project, whether water flood, steam flood, water disposal, or pressure maintenance.

5. Some projects have no PAL. Project #849-18-013, approved in 1977, is one example of a project that has no PAL.

6. The PALs are often generic with many having the same assumed project formation fracture gradient of 0.8 pounds per square inch per foot (psi/ft). There is no evidence on file on when or how such a fracture gradient was determined, and why all the PALs are assigned the same fracture gradient.

Recommendations

1. In addition to the current standard conditions for new PALs, new PALs should have unique identifying conditions in addition to the project identification number, field, fault block and pool. Additionally, each PAL should have an expiration date, after which it is renewed upon comprehensive review for compliance with its operating conditions, applicable statutes, rules and regulations. Each PAL must specify the date for its APR.

2. Any change in the project, including a change in operator, injection zone etc., should require the issuance of a new PAL. Injection zone changes should require a new evaluation, and a new, and unique, PAL.

3. According to the Primacy Agreement, if an operator wishes to change or modify the work plan or conditions of a project, the operator must submit a new application to the division for evaluation. If circumstances warrant, the division will issue a new permit reflecting the changes and resulting condition.

4. Each PAL must contain a list of all the wells (injectors, producers, idle and plugged wells etc.) associated with the project.

5. Every project formation fracture gradient must be based on a SRT conducted on the project's injection zone(s). Also, the date of the test must be specified on the PAL. A PAL for multiple injection zones, must identify the fracture gradient for each zone.

B. Area of Review Evaluations

As of December 2013, there were 268 injection projects listed in District 1, of which 154 were active projects. A review of a sample of District 1 injection projects was conducted to confirm whether appropriate and complete AORs had been submitted by the operator and reviewed by the Division. The MC Unit Review Team selected 45 injection projects for evaluation. UIC project files and well files were reviewed to gather data for this evaluation. This sample group comprised various project statuses (40 active, 4 terminated, and 1 rescinded project), from fields discovered in the 1930s and 1940s. The selected projects included a variety of project approval dates and project types, including water flood (WF), water disposal (WD), and gas storage (GS).

Of the 45 projects used as a sample population for this review of AOR use, 24 projects were permitted pre-Primacy (pre-March 1983), and 21 projects were permitted post-Primacy. Of the 24 pre-Primacy projects, 20 projects were permitted before, and four after, the 1978 regulations (CCR Title 14, section 1724, February 17, 1978). Of the 21 post-Primacy projects, 16 projects were permitted before, and five after, the 2010 UIC Letter of Expectations.

Tables 2 and 3 respectively, present the pre- and post-Primacy injection project findings summaries for the sample group reviewed. Tabulated data includes: project status, initial project approval date, whether an AOR was completed, number of "bad" wells identified, and comments regarding how identified potential zonal conduits were addressed.

An overview of the criteria required for evaluation of the appropriateness and completeness of an AOR is presented within **Appendix B** of this report. As detailed in the appendix, the presence, or lack of supporting AOR-essential criteria within a project or well file was used to determine whether the required project review *could have been* completed. For example, it is highly unlikely that an AOR could have been completed without casing diagrams. Casing diagrams submitted with injection project applications are critical in determining zonal isolation within the AOR. Casing diagrams are therefore a crucial application component that, when missing, suggests that an AOR could not have been conducted.

When an AOR is delineated, the casing diagrams of the wells (including open-hole wellbores) within the AOR are closely evaluated as potential conduits for fluid migration outside the intended zone of injection. For the purposes of this review, wells evaluated are classified as "good," "bad," or "gray." Wells are classified as "good" when they meet current standards of zonal isolation. Those wells identified as direct or partial conduits due to poor, inadequate or lack of cement, or mechanical problems, are classified as "bad" wells subject to remediation prior to commencement of any injection. A third category of wells referred to as "gray" wells do not fit into either of the first two categories. Gray wells were either completed and/or abandoned to the standard existing at the time of their drilling, but are not now cemented to the current standard as required by CCR section 1722.4 (Cementing casing); or do not meet the specific plugging and abandonment or annular cement lengths required by CCR, Chapter 4, Article 3, Sections 1723.1 (a) (Plugging of Oil or Gas Zones) and 1723.2 (Plugging for Freshwater Protection), Section 1723.1(b); 1723.1 (c) (4) (open hole plugging and abandonment).

Determinations

Tables 2 and **3** present findings summaries of the 45 projects evaluated. **Figures 1** through **4**, present illustrated analyses of the AOR evaluation findings discussed below.

District 1 - Pre-Primacy Projects Review

Only 1 of the 24 approved pre-Primacy injection project files evaluated contained sufficient AOR-essential criteria to support a complete AOR. Although these projects were approved (including the 2 terminated and 1 rescinded projects-see **Table 2**) pre-Primacy, all of the projects remained active post-Primacy and in conformance with Primacy requirements, should have been reviewed, updated, and issued a modified PAL.

Figure 1 on the following page provides an illustration of the number and percentages of AORs, completed (blue) and not completed (red) for projects sampled from the pre-Primacy and post-Primacy time periods.

Common deficiencies in pre-Primacy AOR project file evaluations include: missing well lists, missing well casing diagrams, casing diagrams with insufficient data such as the location of the top of the injection zone(s) (TIZ), cement information, specific USDW depths, or reference to a USDW, and well histories with inconsistent information.

Appropriate AOR'S Completed Pre- and Post-Primacy

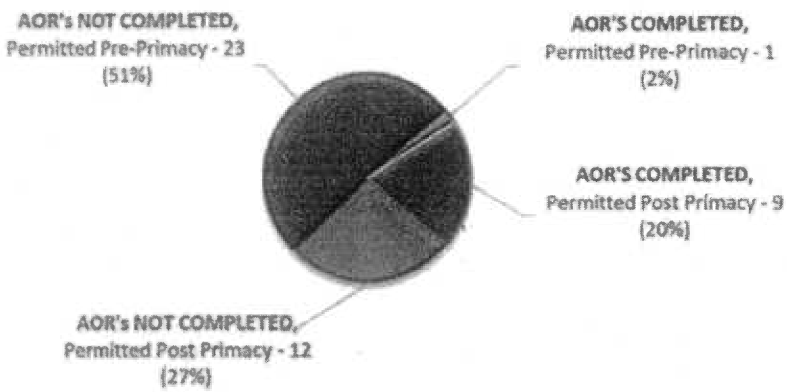


Figure 1: Appropriate AOR's completed Pre- and Post-Primacy (total 45 selected projects). AOR's not completed (78%) are shaded red and AOR's completed (22%) are shaded blue. All but one of the completed AORs was completed during the post-Primacy period.

District 1 – Post-Primacy Projects Review

A representative sample of 21 approved post-Primacy projects were reviewed for the presence of appropriately delineated and complete AOR evaluations, and to determine if potential conduits for injection fluid were present. Nine of the 21 projects were appropriately delineated and had complete AOR evaluations; 12 projects did not. A total of 154 bad wells were identified by District 1 post-Primacy AOR evaluations. These results are presented in **Table 3**, which gives a project code number (PC no.) for each project evaluated.

Highlights of the **Table 3** results were as follows:

1. Two approved injection project reviews indicated that no bad wells were identified by District AOR evaluations. (PC nos. 78206011 and 84903013.)
2. Two AOR evaluations identified a significant number of bad wells still under additional review by the Division as of December 2014. (PC nos. 32400015 and 32400016.)
3. Two AOR evaluations identified bad wells that were remediated as a condition of a letter or PAL. (PC nos. 84939009 and 32018003.)
4. Three AOR evaluations identified bad wells to be addressed by implementing a monitoring program. (PC nos. 66600007, 84918008 and 47806002.)
5. Graphical data for two of the projects with monitoring programs was not submitted to the

Division in accordance with a stated condition of the PAL. (PC nos. 66600007 and 47806002.)

6. Applicant operator submitted incomplete AOR data to the Division. In one instance, out of 57 wells in the one-quarter mile AOR, only 7 casing diagrams were submitted for review. A review of the casing diagrams shows inadequate casing information; moreover, there was no information on the diagrams locating the top of injection zone. (PC no. 66600008.)

7. For the 12 post-Primacy projects identified in this review as having incomplete AOR evaluations, the data suggest that the District did not identify or address them. For each of these 12 projects, AORs should have been completed during the initial project application evaluation before the issuance of a PAL especially considering these projects were permitted under the post-Primacy agreement. Annually thereafter, these projects could have been brought up to standard during the APR but were not.

8. Nine of the 21 project applications approved post-Primacy had appropriate AOR evaluations completed. Eight of the nine applications were approved between 2005 - 2013. This demonstrates an improvement in AOR completions for new applications.

9. Many project files failed to contain maps of the directional path of the wells within the AOR completely, or at all. Prior to 2010, AORs did not include the directional path of wells in the area surrounding the proposed injection wells to determine the AOR boundary. Consequently, a complete or accurate list of wells within the AOR was not available.

10. Records were frequently insufficient to determine if problem wells found in the AOR evaluation were remediated prior to commencing injection.

Other Determinations Concerning Post-Primacy Projects:

11. Following direction from upper Division management in 2012, District 1 no longer required use of the term "remediation" in permit language regarding "bad" wells (potential injection fluid conduits) identified during AOR evaluations. The approved PAL terminology was changed from "remediate" to "address." It is unclear whether this terminology change was intended to mean remediation, or merely monitoring. From 2009 to 2012 there was an increase in the number of applications for new or extension of existing injection projects. This surge of applications, together with the number of incomplete applications in the queue awaiting required data, resulted in delays of project approvals. In 2012, to expedite the injection project evaluation and approval process, a new Division policy was established that allowed operators to add injection wells (new wells or well conversions) within existing injection project boundaries, without comprehensive AOR reviews. This "deferral" policy was initiated based on the premise that AOR evaluations would be performed later, during the APR process, and that the subject fields had previously been through the AOR evaluation process.

12. A review of 159 projects for APR compliance found that 5 projects had APR within the last 5 years, 135 had no evidence of an APR conducted within the last 5 years (some as long as 20 years), and 19 had no APR conducted. Evidence suggests reliance on a questionnaire submitted by operators was used as an APR. For a more in-depth analysis, refer to **Table 10**, in the annual project review section of this report.

Figures 2 and 3 below illustrate the results of the reviewed injection project evaluations and breakdown of well status percentages within the 10 completed injection projects identified both pre-Primacy (1 project) and post-Primacy (9 projects).

Overview of Pre-Primacy and Post-Primacy Injection Projects Evaluated for AOR Completion

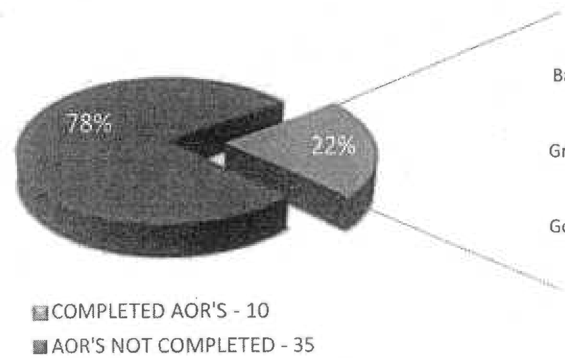
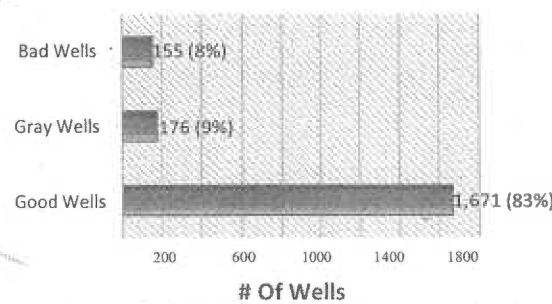


Figure 2: Overview of Pre-Primacy and Post-Primacy Injection Projects Evaluated for AOR Completion. An AOR evaluation should have been completed for each of the 45 selected projects.

Breakdown of Wells Reviewed



Note: A total of 2,002 wells from 10 AORs were evaluated

Figure 3: Breakdown of Wells Reviewed (from the 10 completed AORs) showing the numbers and sample population percentages of the good, gray, and bad wells identified from the District 1 review of the 10 completed AORs.

Seven In-Depth AOR Evaluations Conducted During This Review:

Based on the finding that 35 out of the 45 pre- and post-Primacy projects reviewed had no AOR evaluations, the MC Unit selected a subset of 7 project files from this group to perform its own in-depth AOR evaluations. The MC Unit Review Team identified and listed the wells in each AOR, reviewing individual well histories and evaluating casing diagrams.

Determinations

These focused evaluations led to the following determinations:

1. A total of 230 well casing diagrams from the 7 injection projects were reviewed for zonal isolation. The review indicated that 37 wells (16%) were "bad", 69 wells

(30%) were "good," 16 wells (7%) were "gray," and 108 wells (47%) were "NEI" (Not Enough Information) (see **Figure 4** below).

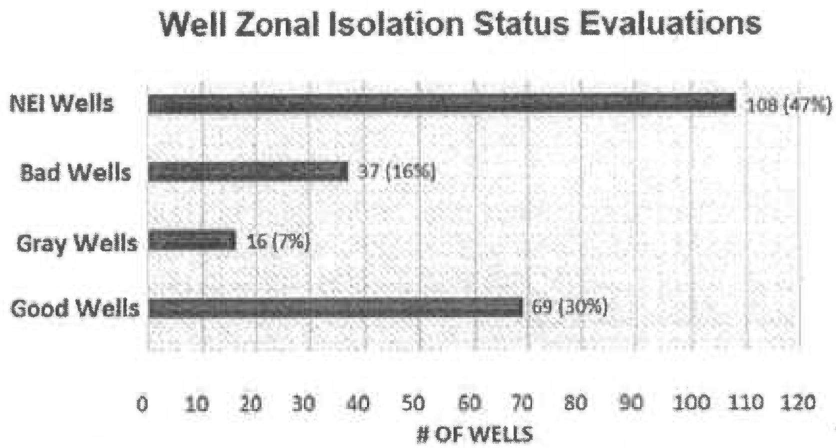


Figure 4: Well Zonal Isolation Status Evaluations (of 7 Projects Reviewed)
"Good" wells, meet the required zonal confinement; "gray" wells were either completed and/or abandoned to the standard applicable at the time of their drilling, but not to the current standard; or do not meet the specific plugging and abandonment or annular cement lengths required by current regulations; "bad" wells evidence a direct or partial conduit from the injection zone. A total of 37 wells were identified via the detailed review as potential conduits. A large number of well files reviewed did not have enough information to make a determination whether the well has a direct, or partial conduit from the injection zone.

2. 108 well casing diagrams, or 47 percent of the 230 well casing diagrams, reviewed for this focused evaluation, lacked sufficient information. These casing diagrams did not set forth enough information to determine whether the well had complete integrity or could be a potential conduit for fluid to migrate from the injection zone. Information missing typically included casing sizes and setting depths, detailed cement information, (type, additives, amount in cubic feet, and yield if available, placement depths, perforations), depths to TIZ, to USDW, to the base of fresh water (BFW), and to geologic markers true vertical depth (TVD). Also missing, in typical samples, was an indication of whether the well is directional or vertical (straight hole), sidetracked or redrilled, and the depth to theoretical or calculated tops of annular cement, and cement plugs. Finally, these casing diagrams had not been brought up to date, and thus did not reflect the current status of the well.

3. The "bad" wells identified by the MC Unit had direct conduits or partial conduits from the injection zone. Of the 37 identified "bad" wells, 16 are currently plugged and abandoned (P&A); 17 are active, two are idle, and two are designated "unknown status" in the CalWIMS database.

4. Under certain conditions, an operating production well can become a conduit for fluid migration outside the intended injection zone if its operational status changes, or there is a change in the production well, or a change in the depth of fluid injection within the AOR of the production well. Many currently active producing wells located within the area of influence of an injection project are not cemented across the top of the injection zone. Consequently, if the well stops producing (becomes idle/shut-in), the absence of draw-down from pumping activity, which previously created a cone of fluid depression below the top of the injection zone, can allow the well to become a vertical conduit for injection fluid as production pumping subsides.

   A second potential scenario wherein a previously adequate production well can become an injection fluid conduit occurs when the operator begins injection to a shallower zone within the radius of influence of the producing well. If the production well is not cemented across the top of this previously unanticipated injection zone, the production well can become a conduit for injection fluid outside the intended injection zone.

   Despite these scenarios, there was no evidence that any of the 37 wells identified as "bad" in the project files were addressed as potential conduits.

   Eight of the 37 bad wells also failed to meet the cement standard at the base of freshwater (BFW) (3,000 parts per million TDS), which requires that, unless the BFW is located behind the surface casing which is cemented to surface, a 100 foot barrier of cement should be placed in the annular space between the casing and the wellbore across the BFW (Title 14 CCR section 1722.4). For plugged and abandoned wells a 100 foot cement plug shall be placed inside the casing across the BFW interface (Title 14 CCR section 1723.2).

Recommendations

1. The District should base all project evaluations on the requirements of Title 14 of the CCR; and applicable requirements of Title 40 of the Code of Federal Regulations (CFR) parts 144 through 146 which, as amended in July 1, 1983, set the minimum requirements for individual UIC projects.

2. All active projects should have an appropriate and complete AOR conducted for each project. If an AOR was not completed or if a project file is missing any geologic or engineering data (i.e., maps, logs, casing diagrams, etc.) required for a completed project, then this data should be submitted by the operator, reviewed by the District, and the project file updated during the APR. The District should also ensure that each project file contains a list of all the wells in the project and that the casing diagrams have complete casing, cement, and formation information, in addition to data on TDS in

formation water.

3. When a project application is submitted, either for expansion of a project, addition of one or more wells, or conversion of a producer/observation well to an injection well, the districts should use the opportunity to verify whether a proper AOR evaluation has been conducted for that project. If no AOR evaluation has been conducted, a full AOR should be conducted prior to project approval.

4. The AOR delineation should be based on the zone of endangering influence (ZEI) vs. use of the quarter-mile fixed radius review. Unless a field study has been conducted to justify exclusive use of a fixed-quarter mile radius AOR, in a given field, analytical methods should be used in conjunction with the fixed-radius method, especially when adequate reservoir data is available. The Division must determine which method is most appropriate for each geographic area by either using the ZEI calculated value or the standard quarter-mile fixed radius. The ZEI is defined as the lateral distance surrounding the injection well in which the pressure in the injection zone is sufficient to cause the migration of fluids out of the zone. To determine the ZEI, both the Primacy application and 40 CFR 146.6 (b) require that a radial flow equation, such as the Modified Theis or Bernard's equation, be used when appropriate data are available. Radial flow equations predict the behavior or movement of fluid in a confined porous media, such a subsurface formation.

5. Unless a field study has been conducted to justify exclusive use of a fixed-quarter mile radius AOR in a given field, analytical methods should be used in conjunction with the fixed-radius method, especially when adequate reservoir data is available.

6. The definition of zonal isolation should be more carefully defined based on the operations proposed. When mud inside the casing is used to support an argument for zonal isolation, the adequacy of the mud as an effective barrier to fluid migration should be demonstrated.

7. Production wells considered "good" for AOR purposes, based on the assumption that continued operation should prevent their becoming a fluid conduit, should be flagged during AOR evaluation as a potential concern, and listed on the PAL. The operator should be required to notify the Division if the well is shut-in for more than 30 days as a condition of the PAL.

8. In most cases, a change in injection depth should trigger a requirement for a new AOR evaluation to determine whether wells within the AOR are adequately cemented across the new TIZ, and the remediation of wells that are not adequately cemented across the top of the new zone. The practice of changing injection zones within a well could present problems with zonal isolation resulting in potential conduits for fluid migration

since these wells were not originally constructed to isolate the new zones. Special attention should be paid to projects when the injection zones proposed are shallower than the original production/injection zones.

9. The District should confirm whether wells placed in a monitoring program are being monitored according to PAL testing requirements.

10. AOR reviewers should document all the steps taken to complete a review. All calculations and methods the engineer uses to conclude whether potential conduits exist should be documented on each casing diagram, and in the well and project files.

11. Locating the USDW in each project area should be a priority since the Primacy Agreement specifies that the USDW and base of fresh water shall be protected.

12. The District should continue the current practice of aquifer protection based on both the state BFW and the U.S. EPA USDW definitions, and zonal isolation. Also, the District should, at a minimum, spot-check the depth of BFW and/or USDW during AOR evaluations using current electric log and reservoir information.

13. The District should ensure that the depths of BFW and USDW, TIZ(s) and formation markers are identified on all the casing diagrams.

14. Casing diagrams for all well bores within an AOR should be reviewed to ensure fluid confinement to the intended injection zone.

15. The Division should acquire software for 3-D plotting of the subsurface bottom location of all wells within an AOR. The Division currently depends on the operator to submit directional survey data to prove whether or not a well penetrates the AOR anywhere along the length of the well path. Also, 3-D software should be utilized to keep track of project wells and injection formation tops.

16. Records should be tracked and made easily available to expedite AOR evaluations. Project records should be placed in one location for project review. Currently, in order to review a project, an engineer needs to review multiple paper and electronic files to find all the data for a project review. District 1 is currently scanning all project and well files, with new data submitted and filed electronically. This practice should be continued and expanded upon. This will mitigate some of the file organization issues, and reduce the time needed for AOR evaluation.

17. The District should use well histories to verify the accuracy of casing diagrams in the project files (e.g. cement volumes used, cement injection point depths and intervals, casing and hole size) to provide quality assurance for the UIC project well data. .

18. All injection wells given "deferrals" of AOR evaluations should have a project review completed as soon as possible. At a minimum, these wells should be evaluated to determine whether proper project evaluations were in fact previously conducted for those projects.

Additional Considerations:

19. The "gray" category of wells (see Figure 4, above) has no defined criteria, resulting in inconsistencies in well classification among staff. Also, lack of defined criteria for classifying a well as gray makes it difficult for staff to decide on the appropriate form of remediation to require.

20. Among the minimum requirements of 40 CFR Parts 144 through 146 as amended in July 1, 1983, is the delineation of the AOR based on 1) Theis equation or an equivalent analytical method; or 2) a fixed-radius of not less than one-quarter mile. Each method is supposed to be chosen based on its ability to predict with confidence the ZEI and therefore the area that is to be examined for potential pathways. The District uses the fixed-radius method in exclusion of any analytical method in determining the ZEI or AOR boundary. With reliable field data and a good understanding of the basic underlying assumptions, an analytical method should be used to delineate the boundary of an AOR based on the ZEI or to confirm the use of the fixed-quarter mile radius.

21. In the majority of evaluations, the location and depth of BFW or USDW were determined from old drilling records, spontaneous potential logs (used to detect permeable beds and formation water salinity) and resistivity logs. Our spot-checks of formation depths against electric logs found that some depths were inconsistent. With improvement in technology and the interpretative methods for determining both BFW and USDW, a more accurate result and/or confirmation of the existing data could be made.

C. Maximum Allowable Surface Injection Pressure Calculations

General

The MC Unit evaluated a representative sample of Division 1 UIC monitoring program projects to determine whether the MASPs are determined correctly and monitored to ensure compliance with project approval requirements. MASPs were reviewed for their adherence to State and Federal regulations (2010 Letter of Expectations, and 1999 U.S. EPA SRT Procedures) by analyzing SRT results --the approved test method for determining MASP—provided in UIC project folders and on the District's shared SRT data drive. The unit also queried the CalWIMS database to review the District's monitoring of active UIC well MASPs.

Of the initial 46 historical UIC project files reviewed, only four contained SRT data. This sample size was determined to be too small to evaluate whether: 1) SRT data was consistently used in establishing formation fracture gradients, and 2) SRT were conducted accurately. Determining the formation fracture gradient, i.e., the factor, in psi/ft, used to determine the pressure the formation will fracture, is necessary to set to the limit for the maximum injection pressure allowed for the project. Therefore an additional 29 SRTs, from the District's step rate test analysis conducted post-Primacy and post-Letter of Expectations, were added to the 4 historical step rate test found in the project files for a total 33 SRT. These were evaluated under the District's current SRT procedures and U.S. EPA standards.

The formation fracture gradients obtained from the SRTs were compared against the permitted injection gradients to examine the accuracy of the District's fracture/injection gradient permitting process. According to the Letter of Expectations, the permitted injection pressure should be 95% (or less) of the fracture gradient (Letter of Expectations, 2010). The review also looked at the number of SRTs witnessed in the field by District staff.

Determinations

1. None of the SRT data in the four "historical" UIC project files met the U.S. EPA standards for an acceptable SRT, and only 16 of the 33 SRTs evaluated met U.S. EPA standards. Additionally, 5 of the wells evaluated were permitted at an injection gradient above the fracture gradient, as determined by a SRT. **Table 4** provides a summary of these results.

   The most common reasons observed for the failure of SRTs relative to the U.S. EPA standards are: insufficient step-rate duration and lack of notation of the instantaneous shut-in pressure (ISIP).

2. The permitted injection pressures for each UIC injection well corresponded closely with the fracture gradients determined by the SRTs.

3. As shown on **Table 5** of this report, of the 33 SRTs evaluated, 13 were witnessed by Division staff and five were waived, leaving 15 SRTs with no indication of whether test notification or witness by the Division was provided.

4. Data management for SRTs was deficient. File reviews showed that while more recent data was entered into the Division's CalWIMS database, it was often sporadic and incomplete. Historical data, only available in hard copy, was usually not clearly marked or identified in well files, or UIC project files. This lack of clear data management procedures or systematic storage of STR reports, makes it difficult to locate test results thereby impairing decision making. MASP are established from

fracture gradients calculated from SRT.

5. There are two permitted injection gradients. One is set for the UIC Project as a whole, and is the more general, conservative, gradient found on the PAL. The second injection gradient is set specifically for each component injection well, based on SRT result obtained for each well. The more specific injection gradient, and not the general PAL injection gradient, should therefore be used for the well-specific permit for each component well. District 1 follows this correct practice.

6. Many historical MASPs approved on original PALs have not been verified by field tests. The District has been reviewing many MASPs, and is developing a more robust testing procedure to accurately determine the MASP as per State laws and regulations.

Recommendations

1. SRT data should be included in both the UIC project file as well as the specific well file for which the SRT was conducted. It is important to document how the initial MASP and fracture gradients were determined for a UIC project, and it is also important that each injection well be assigned its own fracture gradient (as determined by a SRT), and calculated MASP. No formation is completely homogeneous, and fracture gradients can vary greatly within a single project area.

2. To properly determine fracture gradients and MASPs, a proper SRT is needed.

3. Where a permit specifies an injection gradient greater than the fracture gradient determined by an SRT, corrections to the permit should be made promptly with notification and acknowledgement by the operator.

4. The Division's CalWIMS database should be modified to include data fields for SRTs witnessed, test results, and observations, making it easier for Division staff to permit and monitor injection wells.

D. Mechanical Integrity Testing

General

Zonal isolation is required to meet the dictates of the federal SDWA. To help ensure zonal isolation, the Division requires MITs to verify injection well casing integrity, and to ensure that there is no fluid migration out of the approved zones of injection. Pursuant to title 40 of the CFR, section 46.8(a), an injection well has mechanical integrity if: (1) there is no significant leak in the casing, tubing, or packer; and (2) there is no significant fluid movement into an USDW through vertical channels adjacent to the injection well bore. This two-part criteria is verified through the **SAPTs** for internal mechanical integrity, and **RAs** to detect fluid movement.

MIT Numerical Performance Adequacy

To determine if a sufficient number of MITs were conducted in conformance with applicable testing schedules, a review of recent MITs was performed for all of the UIC wells in District 1. Due to the large number of UIC wells, the detailed review of the MIT schedule was only conducted for District 1 WD wells. All active WD wells in District 1 were reviewed, with 20 selected for further numerical MIT evaluation. MIT data for these 20 wells were compiled from the year 2000 forward.

The MC Unit reviewers noted the number of MITs conducted for each well, then compared this number to the number of tests required by the schedule. **Table 6** presents a data evaluation summary showing SAPT surveys performed versus SAPTs required. **Table 7** presents a similar data evaluation summary showing RA surveys performed versus RA surveys required.

Test Schedule

State and federal regulations require specific testing schedules for MITs. SAPTs for wells are required prior to initial injection and every five years after, while RA surveys for fluid migration are scheduled on the basis of well type, as follows:

1. Water Disposal Wells: Once every year
2. Waterflood Wells: Once every two years
3. Steamflood Wells: Once every five years
4. Cyclic Steam Wells: Once every five years (added in Letter of Expectations)

The District Deputy also has the option to modify the testing schedules on the basis of geologic and reservoir information documented and submitted by the operator.

MIT Tests Witnessed

Determining the percentage of tests witnessed by district field engineers is an important aspect of the UIC program. A U.S. EPA audit of the State UIC program set a witnessing requirement of 25% for MITs, and the district staff has made increased MIT witnessing a priority.

CalWIMS Data Entries

There are 11 possible test result selections used by District 1 in the CalWIMS database for both

RA surveys and SAPT tests. These are:

1. Cancelled
2. Deferred
3. Inconclusive
4. N/A (Non-applicable)
5. No Test
6. Not Good
7. OK/Pass
8. See Report
9. Waived
10. Waived-NEA (No Engineer Available)
11. (Blank)

Of the possible test result selections, the majority of tests generally fall under one of the following:

1. N/A – A seldom used status in the past, N/A has been redefined by District 1 staff in 2013 to be used as a means of tracking MITs that the operator did not report to District 1 staff. The ability to determine how many MITs were conducted but not reported is important when calculating the percentage of all MITs witnessed. If the test was never called in, Division staff never had the opportunity to witness the test, and these tests are subtracted from the overall number of MITs conducted when determining the percentage of MITs witnessed.

2. Not Good – MITs that fail for any reason are labeled as "Not Good". It provides a list of wells to follow up on to determine if the proper actions were taken by the operator to remediate the well. Common failures are injection above MASP, leaking packers or tubing, and holes in casing allowing injection fluid to migrate above the approved zone of injection.

3. Waived/Waived-NEA – Due to operator scheduling, and District staffing levels, there are many more MITs conducted than there are field staff available to witness. Frequently a test cannot be witnessed because the only available field engineers are witnessing other tests, or participating in other activities including higher-prioritized field work, staff meetings, or training sessions. A primary goal of District 1 is to maintain the total number of MITs witnessed to at least 25%, as per agreement with the U.S. EPA.

4. (Blank) Not an official status. "Blank" simply refers to an empty data field in the CalWIMS database. There are different reasons why some MIT status fields may be left blank, the most common being the engineer entering the data forgot to fill out one or more input boxes on the MIT form. Other causes of blank data fields are associated with older MITs for which data may not be available, or missing field data from the engineer witnessing the MIT who did not record the data properly during the test.

Data Schedule & Witness Review Methodology

The Division considered a large number of UIC wells for the MIT test portion of this review, looking at such information as: the number of wells with overdue MITs, the number of wells which currently do not pass the MIT requirements, and an estimate of the percentage of MITs witnessed in the field by Division staff. Emphasis was placed on determining if testing schedules were maintained, and if a method was in place for identifying overdue tests and bringing well testing schedules back into compliance. There may be many reasons a MIT becomes overdue, and it is critical to be able to identify and update overdue MITs.

Figures 5 & 6 illustrate the relative proportion of MIT-related data entries including operator notifications, witnessed and waived tests, and results of witnessed test results for District 1 WD wells' SAPT and RA surveys, respectively. **Tables 8 and 9** provide summaries of the percentages of MITs witnessed prior to 2013, and in 2013, respectively.

To evaluate these data in CalWIMS, specific data fields including "Last Test Date," "Next Test Due Date," "Test Interval," and the most recently entered test were reviewed. The "Last Test Date" data field was compared with the most recently entered test, and to check if a test was currently up to date, the most recently entered test date was compared to the current date of the query (11/13/13) to see if the test interval had been exceeded.

The accuracy of this "Last Test Date" data field is important because this is the method by which CalWIMS tracks overdue MITs. If the "Last Test Date" field is blank, or overdue, it appears in the report as an overdue MIT test. However, wells that are actually current on all MITs, but did not have the "Last Test Date" entered or updated, will also appear on this overdue list. It then becomes critical that the "Last Test Date" data be as up-to-date and accurate as possible to capture all overdue MITs and is something the district offices should be updating routinely when evaluating their overdue MITs.

Figures 7 through 11 illustrate the breakdown of the "Last Test Date" data. These data were determined to be correct about 50% of the time.

Findings

1. Since 2013, the District has made significant strides in improving the quality of data entries into the CalWIMS database and in eliminating the backlog of MIT data.
2. RA surveys were conducted on all of the 20-well sample groups used in this review (**Table 7**), however SAPTs were conducted on only 12 wells during this same time

interval (**Table 6**).

3. The majority of MITs were recorded in the CalWIMS database, and the data were mostly accurate. Wells not passing their SAPT or RA survey were flagged and a notice containing the reason for the test failure was sent to the operator directing them to remediate and retest the well to obtain a passing MIT.

4. CalWIMS offers an MIT module to track overdue MITs, however it is cumbersome to use and relies on the "Last RA Date" and "Last SAPT Date" data fields. These fields are separate data boxes which an engineer must fill out when entering MIT data into CalWIMS , and are often forgotten, not updated, or left blank, especially when older data is transferred manually, separate from the MIT test data entry section in CalWIMS.

5. Four out of the 12 SAPTs were not conducted according to schedule. Only 5 RA surveys were conducted on schedule, and 7 wells had 3 or fewer missing RA surveys.

6. Field engineers do not consistently enter data in the same way, or even in the same database field, sometimes leaving database entries empty (blank data fields). This suggests that field engineers may not receive sufficient, or specific and consistent, instructional emphasis on details of field testing data collection and data entry.

7. The District has improved its performance in witnessing MITs in the field. The number of witnessed tests rose from 20% (prior to 2013) to 30% by 2013. This is more than the EPA requirement of 25%. Review of test schedule data shows that approximately 32% of RA survey and SAPTs were overdue at the time of the review team's program evaluation in 2013.

8. The Division's recent stress on the subjects of witnessing and data tracking has likely prompted more complete and accurate information entries into CalWIMS. **Tables 8** and **9** provide summaries of the percentages of MITs witnessed prior to 2013, and in 2013, respectively.

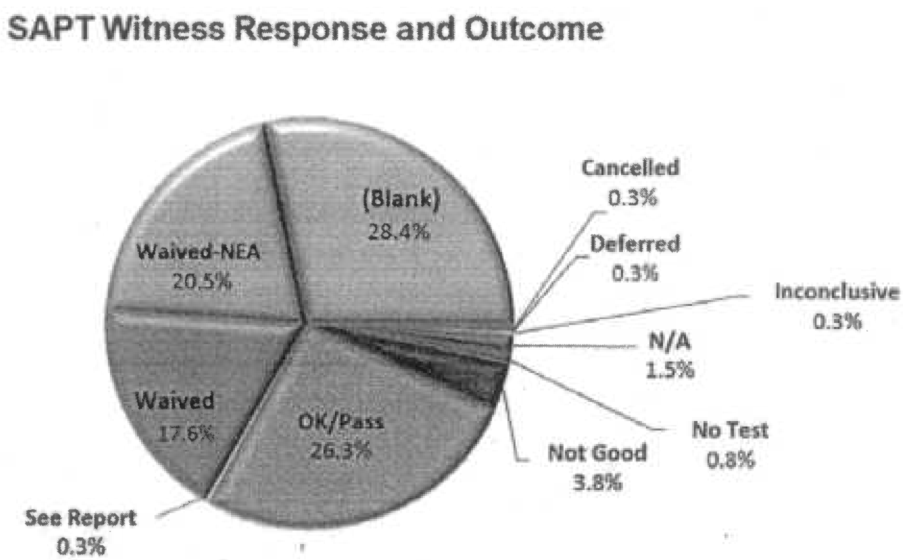


Figure 5: SAPT Witness Response and Outcome (1144 total District 1 SAPTs reviewed)

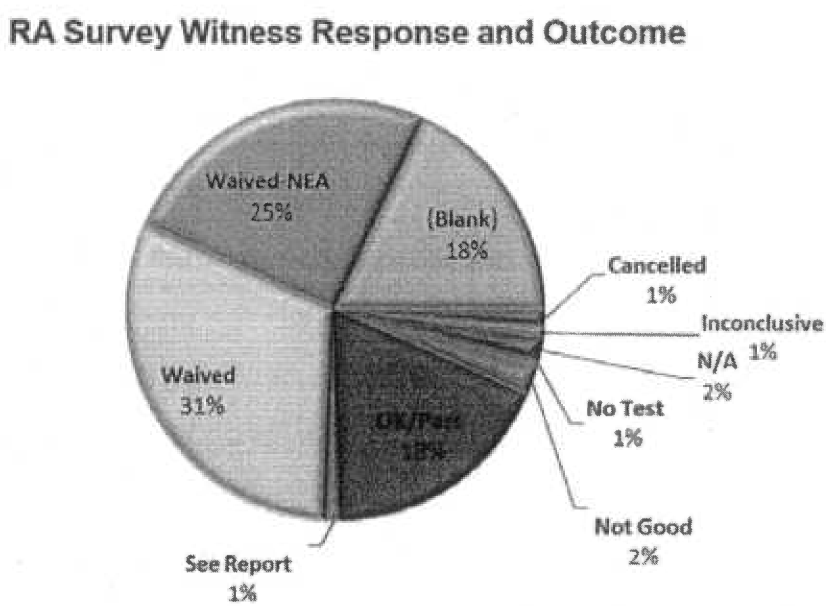


Figure 6: RA Survey Witness Response and Outcome (1,857 total District 1 RA surveys reviewed)

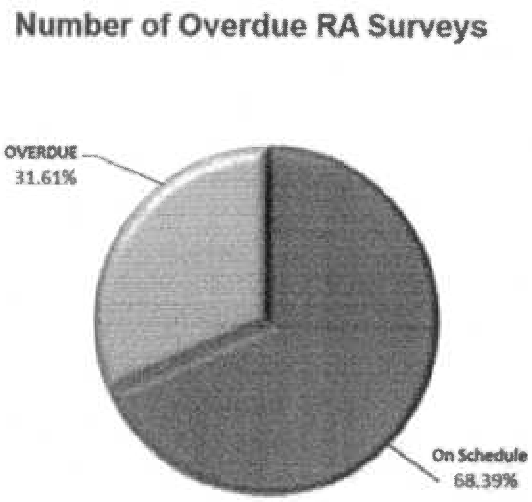


Figure 7: Number of Overdue RA Surveys

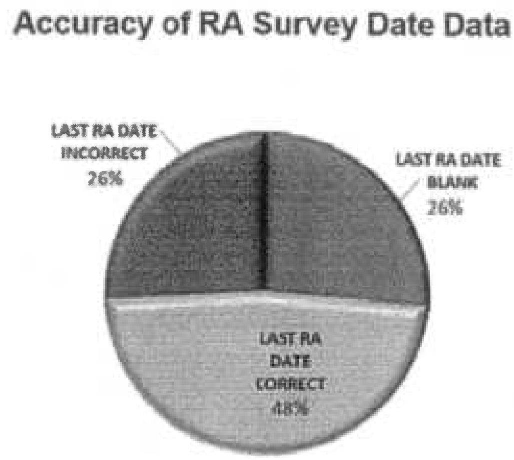


Figure 8: Accuracy of RA Survey Date Data

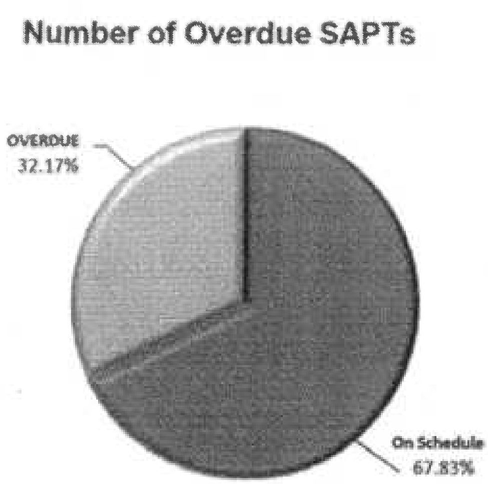


Figure 9: Number of Overdue SAPTs

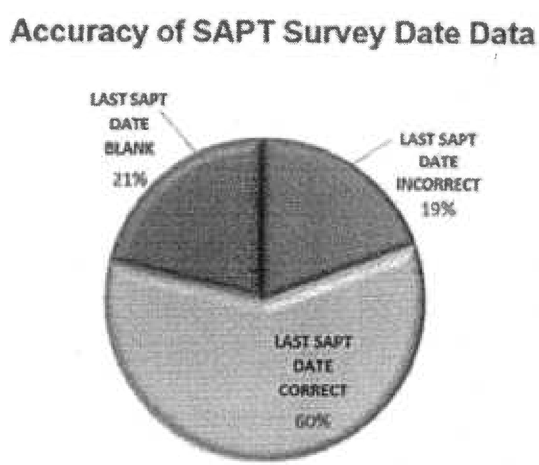


Figure 10: Accuracy of SAPT Survey Date Data

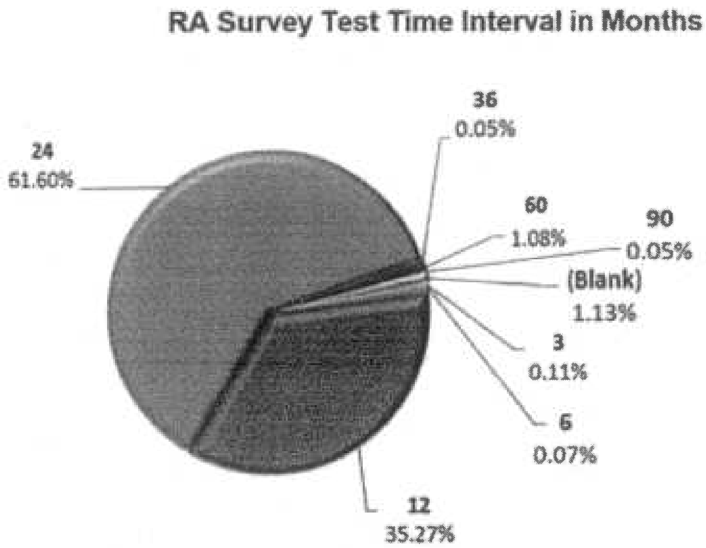


Figure 11: RA Survey Test Time Interval in Months

Recommendations

1. For a failed MIT on any injection well, the operator should be required to shut in the well, remediate the problem, and retest the well, repeating until it passes, or to plug and abandon the well and disconnect all injection lines to the well.

2. Field engineers should receive adequate instruction and emphasis on methods and importance of test data collection.

3. The District needs to catch up with the out of date MIT surveys and bring those wells back into compliance.

4. A better, automated method of populating the SAPT and RA survey date fields would eliminate the data errors and provide more accurate information which can be utilized to easily find wells with out of date MITs.

5. The District should continue improving the witness percentage of all SAPT, RA survey tests in order to keep up with the U.S. EPA requirements and provide accurate data in CalWIMS.

E. Annual Project Reviews

To verify that a UIC project is in compliance with applicable statutes, regulations and the Primacy Agreement, an annual review of the project is required. Annual project reviews (APR) are also required to determine if the PAL conditions are sufficient to ensure that the project does not pose a danger to an USDW and BFW. The MC Unit conducted an evaluation of 70 UIC projects, sampled from projects approved between 1959 through 2013 (pre-regulatory through the Letter of Expectation periods), to determine if projects were reviewed annually. In addition to the project files, other District records, such as the active project database, were reviewed to determine the frequency and the extent of the APRs.

Under the file review component, the District staff reviews the project file to ensure that: (1) all appropriate data and test results are on file; (2) they are properly analyzed; and (3) any missing data and/or information is identified. Information for annual reviews is developed by sending a questionnaire to the operators requesting information about the project. This is followed by a face-to-face office meeting with the operator to discuss the project. The third and final phase is the onsite field inspection to verify that operating conditions conform to conditions of the PAL.

From the 1930s through the 1990s the District conducted regular APRs, including office meetings with operators, to discuss projects. The frequency of those meetings increased after the adoption of the 1959 Repressuring Act. The frequency and scope of the meetings began to decrease, and were replaced in the 1990s with a reliance on written questionnaires sent to the operators to be completed and returned to the District. These questionnaires were based on project review, production and injection data.

As discussed in Section B of this document, from 2009 to 2012 there was an increase in the number of applications for injection projects. With improved data and information submittals resulting from more thorough District reviews and project data requests, coupled with a shortage of staff, a surge in applications caused delays in project evaluation and approval. To expedite injection project evaluation and approval, a new policy was established in 2012 that allowed operators to expand injection projects for currently active fields without having to go through comprehensive AOR review, on the assumption that AOR review could be accomplished at the next annual project review. However, in most instances, there was no such follow-up annual review.

Table 10 presents a summary of overdue annual project reviews from the District's 154 active, and 5 proposed projects. **Figure 12** illustrates the number of annual project reviews overdue by years overdue.

Findings

1. For many injection projects, there is insufficient documentation to verify whether the APR questionnaires were reviewed after they were received by the District, or if there was a follow-up information request, or onsite field inspection. There is, however, evidence indicating that notices were sent to operators regarding overdue tests. This indicates that some level of review was conducted.

2. There is a lack of consistency in the comprehensiveness of APRs. Several versions of APR questionnaires were found, each with varied information requirements.

3. The active project list shows that 76 projects were last reviewed in 2006. Forty-five of the 76 projects have the same review date of June 4, 2006. It is not known whether the date was the actual review date or the date the review was recorded in the database.

4. The practice of AOR project deferrals involved deferring AOR evaluations for new or converted injection wells located within existing injection project boundaries, with the understanding that these new injectors would be evaluated during the projects' APR. Out of the total 209 project applications in the queue for 2013 review, 176 AORs were deferred.

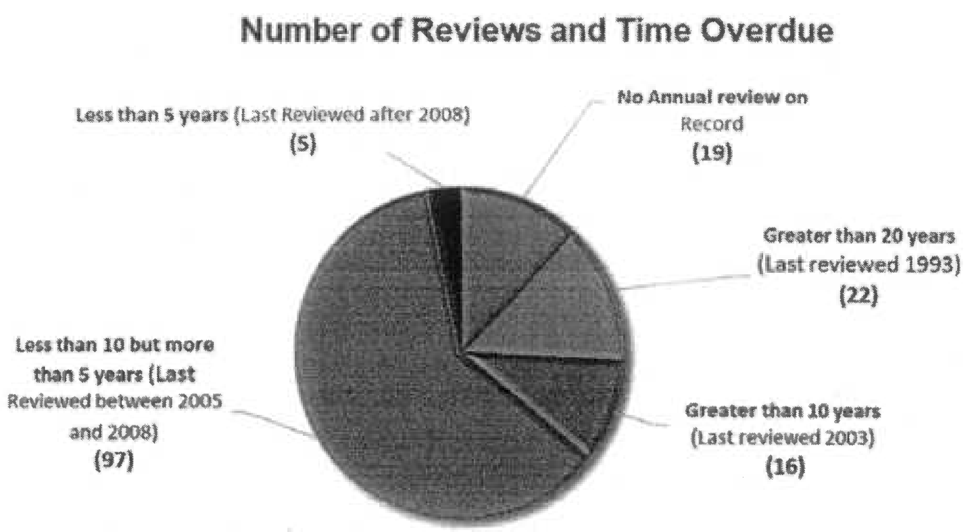


Figure 12: Number of Reviews and Time Overdue

Recommendations

1. To ensure compliance with the requirements of Title 14 of the CCR, section 1724.10(h), the District should review all active projects annually. Projects not operating in compliance should not be renewed until the operator can demonstrate

compliance.

2. APRs should be consistent and comprehensive, and should include verification of the project's engineering analysis, review of required tests and their respective analyses, and review of special conditions of the PAL. Reviews should include field verification of PAL conditions and special requirements.

3. With anticipated increases in staffing, the District should use the APR as an opportunity to conduct comprehensive AOR evaluations of projects that have not previously had an evaluation conducted.

4. Several versions of the APR questionnaire displayed varied and inconsistent information requirements. APR questionnaires should be comprehensive and standardized for use for all operators.

5. The questionnaire used for APR should be revised to include the provisions of the Division's Well Stimulation Treatment Program (SB 4).

IV CONCLUSIONS

The Division of Oil, Gas and Geothermal Resources (Division) has conducted an in-depth review and evaluation of the Underground Injection Control (UIC) Program of the District 1 office in Cypress, California (Los Angeles Basin). The UIC program evaluation found systemic problems in the execution of the UIC program in District 1. Some of the problems relate to local issues such as the lack of organization in the handling and storage of paper files, and project approval letters (PALs) that were confusing, overly generic, or missing. At a higher level, these problems reveal some systematic problems that have existed within the Division for many years and are the focus of active remedial activities currently. These include: insufficient staffing to address increasing regulatory workload in addition to significant remedial programmatic work, poor recordkeeping on mostly paper forms and the lack of modern data tools and systems, outdated regulations that in some cases do not address the modern oil and gas extraction environment, inconsistent and undersized program leadership, insufficient breadth and depth of technical talent, insufficient coordination among fields districts and Sacramento, and lack of consistent, regular, high-quality technical training.

The Department of Conservation and the Oil and Gas Supervisor and his staff have enacted strategies and activities to address these long-term systemic problems. The Division will soon be reorganized to improve cooperation and consistency among districts and Sacramento and improve technical and programmatic leadership with attention focused on specific regulatory programs. These include UIC, Well Stimulation, Idle and Abandoned Wells and Facilities, Emerging Technologies and Regulations, Well and Data Management, Environmental Review, and Technical Training. Regular training programs are being put in place. A robust rulemaking effort is underway that will refresh the Division's regulations to address current oil field realities. With the passage of the 2015-2016 budget, the Division has begun working through the state process to bring a well data management system and modern tools to the Division. Furthermore, the Division is undertaking high-visibility recruiting efforts to bring talent to improve the Division's geographical information systems and data management capabilities, monitoring and compliance of Division activities, environmental review, and additional staff to meet the challenges of constant improvement of the UIC program and the obligations of the compliance schedule with the US EPA.

In addition, the Division, by virtue of its compliance agreement with the US EPA, has committed to a project by project review that will commence this fall and be undertaken concurrently in all districts. The Monitoring and Compliance Unit will be deployed to both assist with the review and conduct internal oversight of the review process. Via this review, each project will be reviewed, reevaluated, and any deficiencies resolved, which in some cases may require termination of the project. The schedule for this review is contained in the plan (attached) for UIC improvements submitted to the US EPA on July 15, 2015.

Appendix A

History of Injection Regulations in California

& Development of UIC Standards

The Division of Oil and Gas (later renamed the Division of Oil, Gas, and Geothermal Resources) was created in 1915 to address the needs of the State, local governments, and industry by establishing statewide uniform laws and regulations to supervise the drilling, operation, maintenance, and plugging and abandonment of onshore and offshore oil, gas, and geothermal wells. Division mandates include preventing damage to: life, health, property, and natural resources, including underground and surface waters suitable for irrigation or domestic use, and oil, gas, and geothermal deposits.

Many of the statutes and regulations in effect today began with a focus on maximizing oil and gas production and protection of correlative rights. Although the California oil and gas industry began in the 1860s, prior to 1915 there were few formal regulations for drilling and production activities in the state. By 1915 laws were passed, under the jurisdiction of the State Mining Bureau, in response to a widespread demand from oil operators to regulate the drilling of wells. Of primary concern was the loss of oil and gas production from the infiltration of subsurface waters into producing reservoirs. In June of 1915, laws requiring operators to use metal well casings were enacted in an effort to prevent water from migrating into oil or gas-bearing strata; again, not to protect ground and surface water, but to protect oil and gas zones by keeping water out.

Table 1 of this report presents the development of regulatory standards in California as occurring within 4 major periods of significant regulatory changes divided within the principal division of pre- and post-Primacy. These periods are outlined below:

1. **1930 to 1978 - Pre-Regulation:** In the early years, the level of data and information submitted as part of a project application varied in scope and quality. The data and information were sometimes based on the standard and criteria contained in an order and/or lease agreement in effect at the time. Prior to 1958, there were no specific data and/or information requirements for project applications. Application for most projects were basically discussions of the projects followed by a written request for project approval. The discussions focused on protection of oil and gas strata, and reduction of waste or conservation of oil and gas reserves.

In 1958 the California Subsidence Act was passed in response to the issue of land subsidence due to oil and gas production from Wilmington Oil Field. With the passage of this act, came the 1959 S-59-1 repressuring plan that established specifications for operations in the Wilmington Oil Field. The plan established criteria for injection project applications. Although this Plan was specific to the Wilmington Oil Field, it became the template for injection project applications and later the forerunner of injection project approvals found in current sections 1724.7 and 1724.10 of the CCR passed in 1978.

Prior to the adoption of the plan, there was no formal application or uniform operating standard. After the adoption of the Plan (S-59-1), most project proposals included basic information such as contour maps on or near the top of the producing zone; a cross-section through the proposed injection well; an analysis of the zone water salinity and proposed water to be injected; electric logs, a well list; a letter outlining the project; and depth of BFW. Information submittals served both as project application, project proposals, and analysis. However, information quality and quantity in these vintage applications varies widely, with some project applications having no casing diagrams, cement and plug information, reservoir data.

After the passage of the Well Spacing and Unitization act in 1971, some operators used digital computer simulations to determine the best well spacing and configurations for a flood pattern. This increased the sophistication of project evaluation.

In 1974, congress passed the SDWA. This act authorized the U.S. EPA to promulgate regulations for injection fluids through wells into subsurface formations either for enhanced oil recovery or to dispose of excess produced water. The purpose of this regulation was to protect USDWs. The UIC Program of the SDWA classified injection wells according to type of injection fluid. The injection of fluids generated by the exploration and production of oil and gas through wells into subsurface formations either for enhanced oil recovery or to dispose of excess produced water was classified as Class II. This led to expansion of project data and information requirements. Of projects reviewed from this period, (1930 to 1978) that had data on file, the data included was significant and of technical value. The discussions regarding the proposed injection projects were well explained and detailed, even when there was no specific regulatory requirement. The technical discussions and engineering evaluations by some operators of the period especially after the introduction of digital computer, sometimes rival that of current project evaluations in quality and completeness. Examples of projects reviewed in this pre-regulations period are located in Appendix A of this report.

2. **1978 to 1982 - Regulation to Pre-Primacy:** In 1978 the Division adopted CCR Division 2, Chapter 4, Subchapter 1 Sections 1724.6 (Approval of Underground Injection and Disposal Projects), 1724.7 (Project Data Requirements), 1724.8 (Data Required for Cyclic Steam Injection Project Approval), 1724.9 (Gas Storage Projects) and 1724.10 (Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects. This led to uniform data and information requirements and to a subsequent improvement in quality and quantity of data and project evaluations across the board. Also, most of the proposed projects had well penetration charts, production graphs, and geochemical information, including the formation fluid TDS. The BFW was identified and provisions for protecting it were included as well as the geologic cross-sections and contour maps through the proposed injection zone(s). The application/project description included information on reservoir characteristics, proposed source and quality of injection fluid, and the proposed injection zone. Some projects include casing diagrams of all the wells on the lease associated with the project, or a list and diagrams of all the wells thought to be affected by the project based on the proposed project flood pattern or unit agreement.

3. <u>1982 to 2010 – Primacy to Letter of Expectations</u>: In 1982, the Division entered into an agreement with the U.S. EPA effectively giving the state primary responsibility to implement the requirements of the federal UIC Program for Class II wells (Primacy). This authority required some program changes that included: two-part mechanical integrity testing, a specified area of review evaluation prior to project approval, protection of USDW (10,000 mg/L TDS or less), and clarification of protection of waters with 3,000 mg/L TDS or less. Only the mechanical integrity testing requirement was codified in regulation.

The Primacy Agreement requires Division compliance with, among other requirements, the following procedures:

- the review of <u>all</u> wells in area of review prior to project approval;
- identification of wells needing remedial work and the filing of notices of intent to
- perform remedial well work to assure such wells will not serve as conduits to freshwater aquifers;
- maintain data to show performance of the project to establish that no damage is occurring;
- conduct SRTs to determine the fracture gradient of the formation before sustained injection;
- comply with a testing program to confirm that fluid is confined to the intended zone of injection;,
- the termination of an injection project if there is evidence that damage is occurring; and other requirements.

Furthermore, the Division agreed, within the first 5 years of Primacy, to review every active existing injection project, bringing all projects into compliance with the new requirements. (The review of the project files and discussion of the Division's success rate with this agreement is presented in the APR section of this report).

AOR boundaries were established as a fixed radius distance of a quarter- mile, or radial flow equation, if appropriate data was available, to determine the ZEI. With these new requirements, most proposed underground injection projects submitted included a list of wells with casing diagrams based on a defined AOR. In addition, geochemical information (including TDS in formation water), BFW, geologic cross sections, contour maps through the proposed injection zone(s), reservoir characteristics, and the source and quality of the proposed injection fluid were required.

4. <u>2010 to Present - Letter of Expectation</u>: In May of 2010, Division management developed the Letter of Expectations to: "...help ensure that UIC Program requirements are being applied in a manner consistent with the laws, regulations, primacy application, and agreements the Division is mandated to enforce." There was emphasis on ensuring that project application packages included all required data and that the submission include good quality data and accurate supporting documentation.

In 2011, the U.S. EPA conducted an audit of the Division's UIC Program to determine compliance with requirements of the Primacy Agreement and the Memorandum of Agreement. The audit found the Division lacking in the implementation of a number of requirements, including among other items: the use of appropriate AOR particularly for disposal wells, enforcement of maximum allowable surface injection pressure, and accurate determination of fracture gradient.

As a result of this audit, the Division revised the Letter of Expectations to include recommendations from the U.S. EPA audit in future UIC evaluations. It also, outlined procedures and clarified UIC Program standards for staff to apply during injection project review, permitting, monitoring, enforcement, and maintenance of project and well records. This period has seen the greatest improvement in data submission and analysis. There has also been a greater emphasis and use of the ZEI in determining the AOR (versus fixed-radius review).

APPENDIX B

UIC Program Concepts Review
Area of Review
Zonal Isolation
Base of Fresh Water
Underground Sources of Drinking Water

Area of Review

The AOR, also known as the ZEI, is defined as the area surrounding an injection well or wells in which the pressure change in the injection zone is sufficient to cause the migration of fluid out of the zone during the life of the project. The intent of the AOR is to identify the area around injection wells that will be evaluated to locate potential conduits for fluid movement out of the zone. The **process** of identifying this surrounding area is the AOR, and the **review** of the condition of the wells in this area is the AOR evaluation.

Determining the AOR accurately requires an evaluation of data that includes, but is not limited to the zone: depth and thickness, porosity and permeability, fluid characteristics, formation pressures, geologic structure, lithology, and changes to these parameters with distance from the well. Furthermore, consideration must be given to the proposed rate of injection, the dynamics in the reservoir resulting from the activity of surrounding wells, and the planned duration of injection.

The injection of fluids into a formation requires the formation to have effective qualities of porosity and permeability. Depending on the properties of the reservoir, injection fluids can move quickly or slowly through a formation potentially increasing the pressure in the reservoir. It is this mechanism that helps to drive, or push, hydrocarbons to producing wells to increase the recovery of oil and gas. This driving force, or pressure front, may affect wells within the vicinity. Fluids will flow from areas of higher pressure to lower pressure if there is a pathway through which flow can occur. This "path of least resistance" will determine the path fluids will take. If wells within the area of influence are not properly sealed, reservoir fluids and/or injection fluids can migrate out of the confining reservoir through improperly sealed wells, and into other zones and aquifers above or below the injection zone.

Possible conduits can be found in:

- Active, inactive, P&A wells located within a distance influenced by injection operations
- Formations with non-barrier faults and/or fractures
- Porous formation boundaries in natural conductivity with each other

Wells located within the area of influence of an injection well where the effects of injection can be felt are evaluated to identify wells not properly cased and cemented, and identify possible conduits for fluid migration out of the zone. These wells must be remediated. In cases where this is not possible because access to the well is blocked, injection operations are not allowed. In a few cases, if appropriate, a buffer zone is created around the injection well, and a well monitoring program is designed to detect fluid movement.

Some of the factors that are taken into consideration when determining the radius of the AOR include:

- Local and regional geology
- Local and regional stratigraphy
- Geologic structure
- Properties of the proposed injection reservoir
- Location of useable surface and ground waters
- Flow properties of the injection zone
- Determination of the vertical hydraulic gradient
- Propose operating conditions

An appropriate AOR should be determined on a case-by-case basis. Where there is data on past injection activity, the use of a "fixed-radius review" may be appropriate.

For Division purposes, as outlined in the Primacy Agreement, the Division can use the one-quarter mile area surrounding each injection well for a "fixed-radius review." This surrounding area can be larger or smaller depending on reservoir conditions and structural geology; larger if the injection zone is very permeable, or smaller if the existence of bounding faults and formation pinch outs limit fluid migration. The district office may request the operator provide data for a larger AOR. A radial flow equation, such as the Modified Theis or Bernard's, may be used to determine the lateral distance in which the pressures in the injection zone may cause migration of the injection or formation fluid out of the permitted zone. The actual distance calculated by the radial flow equation is only as accurate as the data used in the determination. The calculated AOR may or may not reflect the actual distance injected fluid may travel because formations are not homogenous nor equally extensive in all directions. Where gas migration is an issue (gas is more mobile than fluid), care is needed to determine an appropriate AOR.

Neither the analytical method, nor the fixed-radius should be used exclusive of each other because the ZEI can vary from one injector to another even within the same reservoir or field. It is therefore necessary to choose any method only if it is technically justified and based on the particular reservoir, well hydraulics, hydro-geology and other information specific to the project.

Whatever method chosen must be able to satisfy the basic requirement of the AOR; which is to be able to predict with confidence, the ZEI, so that review of migration conduits and potential for contamination can be identified and remediated prior to initiating injection.

Directionally drilled wells in the AOR must be identified. The delineation of the area must take into consideration the subsurface location of straight hole and directionally drilled wells in the project area. The accurate surface and subsurface location of every well in this area must be determined and the current condition of the casing and cement seals evaluated. Wellbore trajectories through the subsurface must be accurately plotted to determine the location where the wellbore intersects the top of the formation.

For multiple directionally drilled wells, such as exist in the Los Angeles area, the determination of the AOR can be very complex and requires the operator to provide proof that wells are or are not located within the area of influence.

In this complex environment, identifying the exact location of wellbores and the location of wells with respect to each other at every depth is difficult to determine without 3-D spatial analysis. To identify wells that fall in the AOR, the Division is dependent on industry to provide detailed maps, and supporting X, Y, Z plots detailing distances between where the wells intersect the injection zone and the one-quarter mile radius. The complexity of these AORs make a review difficult and time consuming as meticulous attention to details is required to accurately assess the absence of migration pathways and fluid conduits.

The diagram on the following page illustrates the difference between the use of a straight hole and a directional well in determining the AOR. Notice how the directional well plot in the subsurface can significantly extend the AOR.

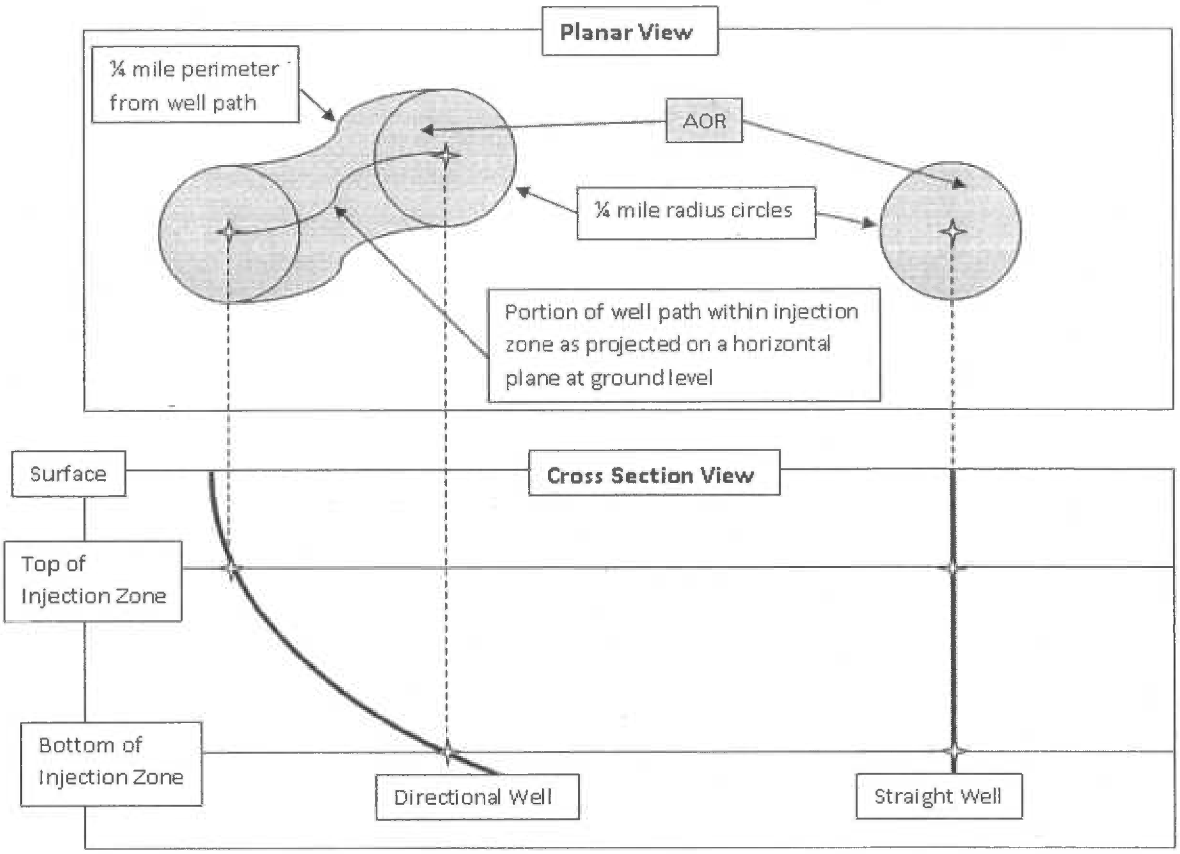


Figure A1: Area of Review outline of directionally drilled and straight hole wells.

Once the AOR has been accurately identified, casing diagrams of all wells located within this area must be analyzed and evaluated to ensure there are no pathways for fluid migration. Operators are required to submit casing diagrams that detail casing construction, including the location of annular and internal cement and casing perforations. Casing construction review is the next step in determining zonal isolation.

Criteria for Determination of Appropriate Use and Completion of the AOR:

Evaluation criteria for the appropriate use of the AOR included determination of whether an AOR had been completed in the following instances:

- During original injection project application
- After Primacy (1983) (all existing injection projects should have been brought into compliance with current standards)
- During APRs if an AOR had not been completed
- On change of injection zone within an existing project

For the AOR: Evidence that an AOR evaluation can be completed for a project has to include the following within the project file:

- a list of all wells within the AOR, including the proposed injectors and wells within the one-quarter mile area,
- casing diagrams for all wells within the AOR,
- for wells within the AOR not penetrating the proposed injection zone: Evidence that wells were not drilled through the top of the injection formation,
- for directionally drilled wells: Evidence showing the subsurface location with respect to other wells in the AOR where the well penetrates the injection zone, and the location of the well with respect to other neighboring wells,
- geologic information with the TIZ clearly marked on casing diagram for each well,
- BFW depth marked on the casing diagram,
- top and bottom location of cement plugs inside casing, and whether the cement was witnessed and/or verified by a tag, with depth noted,
- top and base of cement present in the well annulus, and information on the quantity and cement mixture used for each cement section,
- whether cement location and quality was verified with a cement bond log (CBL), and
- date the casing diagram was prepared for comparison with application submittal date to verify that it is up-to-date.

For Casing Diagrams: When an AOR is delineated, the casing diagrams of the wells within the AOR are closely evaluated as potential conduits for fluid migration. Wells are classified as "good" when they meet current standards of zonal isolation. Those wells identified as potential conduits due to poor or inadequate cementing, or mechanical problems, are classified as "bad" wells subject to remediation prior to commencement of any injection. A third category of wells referred to as "Gray" wells do not fit into either of the first two categories. Gray wells were either completed and/or abandoned to the standard existing at the time of their drilling, but are not now sealed to the current standard; or do not meet the specific plugging and abandonment or annular cement lengths required by CCR, Chapter 4, Article 3, Sections 1723.1 (a) (Plugging of Oil or Gas Zones) and 1723.2 (Plugging for Freshwater Protection), Section 1723.1 (b); 1723.1(c) (4) (open hole plugging and abandonment)

Evidence that a casing diagram review has been conducted to determine zonal isolation requires the inclusion of the following minimal critical information within the project file:

- casing sizes and setting depths for all well casing
- detailed cement information, i.e., cement type, additives, quantity in sacks of cubic feet, and yield if available, placement depths, perforations
- depth to TIZ and geologic markers
- TVD of hole
- whether the well is directional or a straight hole

- size of drilled wellbore, reamed intervals, and depth of wellbore sizes
- whether well bore is the original hole, sidetracked hole, or redrilled hole
- theoretical or calculated tops of annular cement, and
- cement plugs, depth to bottom and top, tagged depth

Zonal Isolation

The fundamental objective of injection operation oversight is to ensure the containment and confinement of the injected fluid to the formation or zone approved by the Division. This standard is reflected in Division statutory language that requires the isolation of oil and gas producing zones and protection of underground and surface waters from the infiltration of detrimental substances. Simply stated, "zonal isolation," as it is commonly referred, requires that fluid injected into an approved zone must stay in that zone. Migration of fluids out of the approved zone is not allowed since fluid movement can threaten fresh waters and migrate into oil and gas producing zones causing the watering out of hydrocarbon zones and loss of production.

Zonal isolation can be maintained through a variety of methods. The most protective method is by creating physical barriers between the injection zone and the zones above and below. (For this report, zonal isolation is limited to the evaluation of formations above the approved zone of injection and the protection of freshwaters.)

The drilling of a well removes existing natural physical barriers between formations and the zones within a formation. It is important to note that not all formation or zone boundaries are barriers to fluid movement. Some formations composed of sands and silts by their nature are porous and permeable, to a degree, and allow for fluid movement between them. Zonal isolation is dependent on the quality of the cap rock above the injection zone and its ability to resist fluid movement into it. Such qualities as low permeability, low porosity, and lack of faults and fractures are necessary to prevent fluid movement. Shale makes a good cap rock because of its typical low permeability; i.e., the ability of fluid to move through pore spaces.

The placement of mechanical barriers in wellbores for the purpose of fluid containment, in essence an attempt to replace the natural barriers removed during drilling, can be an effective means of zonal isolation. Such methods as the placement of good quality casing and cement during well construction and maintenance activities can prevent fluid movement out of the injection zone (for further discussion, see the well plugging and abandonment section). Non-mechanical methods can also be implemented, such as control of formation or zone pressure. This method can be effective, but requires continuous monitoring to provide assurances. In some areas of California, such as highly urbanized locations, the pressure monitoring system may be the only means of ensuring zonal isolation because wells are located underneath structures where they cannot be readily accessed. Monitoring programs, however, are limited in effectiveness and where conduits exist for fluid migration, injection should not be allowed.

Base of Freshwater and Underground Sources of Drinking Water

Historically the Division has protected groundwater suitable for irrigation and domestic purposes. The demarcation of this freshwater limit became 3,000 mg/L TDS. The reference for this limit is unknown but has been used by many regulatory agencies and industry for decades. When the SDWA was passed by the federal government, a new well defined standard was implemented. This standard identifies protected aquifers as, an aquifer, or its portion, that contains a sufficient quantity of ground water to supply a public water system; and currently supplies drinking water for human consumption; or contains fewer than 10,000 mg/L TDS; and which is not an exempted aquifer. This 10,000 mg/L limit was included in the Primacy agreement between the Division and the U.S. EPA and since 1983 required protection when permitting Class II injection wells. The Division continued to protect the BFW at 3,000 mg/L TDS and was responsible for the protection of 10,000 mg/L TDS ground waters.

Federal regulations allow for the exemption of aquifers less than 10,000 mg/L TDS after a lengthy application process that requires concurrence from the state water quality agencies. However, it is important to note that aquifer exemptions are divided into two categories, i.e., major and minor exemptions. Minor exemptions are those exemptions for aquifers with fluids between 3,000 and 10,000 mg/L TDS and major aquifer exemptions are for those fluids less than 3,000 mg/L TDS. Major aquifer exemptions must be submitted to the Washington D.C. office of Drinking Water for approval and are difficult to get approval for. Aquifer exemptions requested through the Division to the federal office must have concurrence from the California State Water Quality Control Board.

Table 1: Project Applications Sample Distribution by Period and Percent Incomplete

Historical Regulatory Periods		Number of Sample Injection Projects	Number of Incomplete Project Applications	Percent Incomplete Project Applications
Year Intervals	Significant Change of Program Standard			
Pre-Primacy				
Pre-Regulation - 1978	Pre-Regulation	19	11	58%
1978 - 1982	First Regulations- to Pre-Primacy	6	3	50%
	Pre-Primacy Totals	**25**	**14**	**56%**
Post-Primacy				
1982 - 2010	Primacy to Letter of Expectations	21	10	48%
2010 - 2013	Letter of Expectations	6	1	17%
	Post-Primacy Totals	**27**	**11**	**41%**
	Grand Totals	**52**	**25**	**48%**

Notes: A brief description of each period interval is provided below. More detailed discussion of program standards development is included in Appendix A of this report.

1930 - 1978 Pre-Regulation – Statutes and regulations prior to 1978 relied primarily on requirements to prevent fluid movement from watering out (diluting) an off-set operator's hydrocarbon reservoirs.

1978 - 1982 First Regulations- to Pre-Primacy – In 1978, CCR section 1724 was promulgated to require specific data be submitted with an application for injection project approval.

1982 - 2010 Primacy to Letter of Expectations – In 1982, the Division entered into an agreement with the U.S. EPA effectively giving the state primary responsibility to implement the requirements of the federal UIC Program for Class II wells (Primacy). This authority required some program changes that included: two-part mechanical integrity testing, a specified area of review evaluation prior to project approval, protection of underground sources of drinking water (USDW - waters 10,000mg/L TDS or less), and clarification of protection of waters with 3,000 mg/L TDS or less. Only the mechanical integrity testing requirement was codified in regulation.

2010 - 2013 In 2010, in 2010 the Division prepared the policy Letter of Expectations for the clarification of portions of the UIC program implementation. During this time, Division district offices were instructed to implement the Letter of Expectations during permitting and annual reviews of existing projects.

Table 2: AOR Reviews - Pre-Primacy

Project Code	Project Status	Initial Date of PAL	Appropriate AOR(s) Completed?		Bad Wells Identified	How Were Potential Conduits Addressed?
			Yes	No		
84915001	Active	8/13/1954	--	X	No AOR	No AOR
84918002	Active	3/14/1958	--	X	No AOR	No AOR
84915002	Active	3/17/1958	--	X	No AOR	No AOR
50406001	Terminated	7/1/1959	--	X	No AOR	No AOR
84903001	Active	10/15/1959	--	X	No AOR	No AOR
38203001	Active	1/4/1965	--	X	No AOR	No AOR
38212001	Active	1/4/1965	--	X	No AOR	No AOR
38215001	Active	5/4/1965	--	X	No AOR	No AOR
84918006	Active	1/4/1967	--	X	No AOR	No AOR
78206002	Active	1/24/1969	--	X	No AOR	No AOR
61803001	Active	4/7/1970	--	X	No AOR	No AOR
61803002	Active	4/7/1970	--	X	No AOR	No AOR
78206003	Active	5/6/1971	--	X	No AOR	No AOR
84903003	Active	12/6/1971	--	X	No AOR	No AOR
78206004	Active	12/15/1972	--	X	No AOR	No AOR
66600002	Active	1/31/1973	--	X	No AOR	No AOR
66600003	Active	1/31/1973	--	X	No AOR	No AOR
68812001	Active	2/28/1974	--	X	No AOR	No AOR
84903005	Active	4/23/1975	--	X	No AOR	No AOR
68806004	Active	8/8/1977	--	X	No AOR	No AOR
38212002	Active	1/12/1979	--	X	No AOR	No AOR
38215002	Terminated	8/30/1979	--	X	No AOR	No AOR
84906013	Active	8/19/1981	X	--	1	Remediated - under condition of PAL
78206006	Rescinded	12/15/1982	--	X	No AOR	No AOR
Totals	**24**		1	23	1	

Notes: Projects reviewed were from fields discovered in the 1930's and 1940's
PAL - Project Approval Letter
AOR - Area of Review

Table 3: AOR Reviews – Post-Primacy

Project Code	Project Status	Initial Date of PAL	Appropriate AOR(s) Completed?		Bad Wells Identified	How Were Potential Conduits Addressed?
			Yes	No		
84918010	Active	10/18/1985	--	X	No AOR	No AOR
84939012	Active	10/18/1985	--	X	No AOR	No AOR
66600005	Active	4/29/1988	--	X	No AOR	No AOR
32021001	Active	5/20/1988	--	X	No AOR	No AOR
50406003	Active	11/21/1989	--	X	No AOR	No AOR
32003001	Active	7/10/1991	--	X	No AOR	No AOR
84903011	Active	2/25/1992	--	X	No AOR	No AOR
66600007	Terminated	11/10/1992	X	--	Unknown	Monitoring Program - Under condition of the PAL
7000010	Active	11/9/1995	--	X	No AOR	No AOR
66600008	Terminated	6/3/1996	--	X	Unknown	Monitoring Program - Under condition of the PAL
7000011	Active	8/11/1998	--	X	No AOR	No AOR
68806005	Active	1/7/2000	--	X	No AOR	No AOR
50403001	Active	4/25/2001	--	X	No AOR	No AOR
84918008	Active	9/13/2005	X	--	Unknown	Monitoring Program - Under condition of the PAL
32400015	Active	8/2/2007	X	--	46	AOR Under review
32400016	Active	8/2/2007	X	--	98	AOR Under review
84939009	Active	10/7/2010	X	--	2	Remediated - By District mandate
32018003	Active	11/22/2011	X	--	2	Remediated - Condition of a Permit
47806002	Proposed	4/25/2013	X	--	6	Monitoring Program - Under condition of the PAL
78206011	Proposed	4/25/2013	X	--	0	No Bad Wells Identified
84903013	Active	7/29/2013	X	--	0	No Bad Wells Identified
Totals	21		9	12	154	

Notes: PAL - Project Approval Letter
AOR - Area of Review
Projects reviewed were from fields discovered in the 1930's and 1940's

Table 4: Step-Rate Test Review Summary

Results from a Total of 33 Division 1 Step-Rate Tests Reviewed			
SRTs Meeting EPA Standards (Acceptable)	SRTs Not Meeting EPA Standards (Not Acceptable)	Permitted Injection Gradients < SRT Fracture Gradients (Acceptable)	Permitted Injection Gradients > SRT Fracture Gradients (Not Acceptable)
16	17	28	5

Notes: SRT - Step Rate Test
< - Less than
> - Greater than

Table 5: Division Witnessed Step-Rate Tests

Division Witnessed SRTs	
Witnessed	13
Waived	5
Unknown	15
Total	**33**

Notes: SRT – Step-Rate Test
Waived - Indicates that the operator provided advance notice of the impending SRT, and was given permission to proceed with the test without witness by the Division.
Unknown - Indicates that there is no record of the operator's advance SRT notice to the Division.

Table 6: SAPTs Performed Versus SAPTs Required

Well API Number	Date of First Test (Post 2000)	Inj. Start Date	Idle Well Time	Test Schedule, Months	SAPT Tests Required Since 2000	SAPT Tests Performed
03701055	7/22/2014	4/1/2007	11/11 - 10/12, 1/13 - 3/13, 7/13 - 3/14	60	1	1
03701813	3/21/2014	4/1/2006	1/08 - 9/10, 6/11 - Present	60	1	2
03707204	3/7/2012	1/1/1977	2/12 - 4/12, 9/13 - 11/13	60	3	2
03712459	6/21/2013	7/1/2000	4/03 - 8/04	60	2	3
03717304	3/12/2014	7/1/1977	None	60	3	2
03718605	9/5/2006	2/1/1979	None	60	3	1
05904675	7/16/2014	8/1/1994	1/00 - 8/00, 12/02 - 5/05*	60	3	1
05907666	7/22/2009	2/1/2002	5/06 - 10/07, 2/08 - 8/08	60	2	6
05920082	6/23/2008	7/1/1977	1/00 - 3/08	60	2	2
05921169	3/31/2006	6/1/2006	1/13 - Present	60	2	3
23722797	6/28/2009	7/1/2003	9/11 - Present	60	2	2
23722902	3/21/2012	8/1/2012	None	60	1	2
	Totals				25	27

Notes: SAPT - Standard Annular Pressure Test
* During this time period the injection well only injected every other month

Table 7: RA Surveys Performed Versus RA Surveys Required

Well API Number	Date of First Test (Post 2000)	Inj. Start Date	Idle Well Time	Test Schedule, Months	RA Surveys Required Since 2000	RA Surveys Performed
03701055	5/16/2008	4/1/2007	11/11 - 10/12, 1/13 - 3/13, 7/13 - 3/14	12	6	3
03701813	2/9/2007	4/1/2006	1/08 - 9/10, 6/11 - Present	12	3	3
03707204	10/16/2001	1/1/1977	2/12 - 4/12, 9/13 - 11/13	24^	7	6
03712459	9/24/2004	7/1/2000	4/03 - 8/04	12	11	3
03717304*	5/29/2001	7/1/1977	None	24^	7	7
03717592	1/14/2004	11/1/1984	11/11 - 5/12	12	14	5
03718805	4/17/2001	2/1/1979	None	12	14	5
03718809**	4/17/2001	2/1/1979	2/00 - 8/00	12	13	6
05904675**	4/25/2001	8/1/1994	1/00 - 8/00, 12/02 - 5/05*	12	13	8
05906986	2/9/2000	9/1/1982	2/04 - Present	12	4	2
05906987	2/4/2004	7/1/1977	1/00 - 2/04	6	19	4
05907002	4/25/2001	5/1/1987	2/02 - 6/05*	12	14	7
05907619	1/20/2000	8/1/1999	11/01 - Present	12	1	1
05907666	3/13/2002	2/1/2002	5/06 - 10/07, 2/08 - 8/08	12	10	5
05920082	4/11/2008	7/1/1977	1/00 - 3/08	12	6	5
05921169	7/12/2006	6/1/2006	1/13 - Present	12	7	5
07100227	6/12/2006	5/1/1987	1/00 - 8/01, 1/03 - 6/03, 9/03 - 12/03, 2/04 - 6/04, 2/09 - Present	24^	3	1
23722797	9/23/2003	7/1/2003	9/11 - Present	6	15	18
23722902	6/8/2001	8/1/2012	None	3	5	7
23726553*	9/20/2011	8/1/2008	None	6	11	9
Totals					183	110

Notes: RA - Radioactive Tracer

* During this time period the injection well only injected every other month

** Well with failed test(s) - not retested

^ Wells with testing schedules greater than the 12 month schedule defined in the regulations

Table 8: MITs Witnessed Prior to 2013

SAPTs Prior to 2013		RA Surveys Prior to 2013		Collective SAPT & RA Surveys conducted Prior to 2013	
Total SAPTs	**921**	**Total RAs**	**1052**	**Total MITs (SAPTs plus RAs)**	**1973**
Cancelled	3	Cancelled	5	Cancelled	8
No Notice (N/A)**	9	No Notice (N/A)**	0	No Notice (N/A)**	9
No Notice (NG, Blank)^	47	No Notice (NG, Blank)^	68	No Notice (NG, Blank)^	115
Subtotal SAPT	**862**	**Subtotal RA**	**979**	**Subtotal MIT**	**1841**
Witnessed SAPT	213	Witnessed RA	159	Witnessed MIT	372
% Witnessed*	**25%**	**% Witnessed***	**16%**	**% Witnessed***	**20%**

Notes: MIT - Mechanical Integrity Test (comprising both SAPTs and RAs Surveys)

SAPT - Standard Annular Pressure Test

RA - Radioactive Tracer Survey

N/A - no advance notice of test/survey was provided to the Division

NG - Not Good; test failed

* The witnessed MIT ratios are based on the number of the witnessed MITs (comprising SAPTs and RAs) over their respective subtotals, which eliminate the tests for which no advance test notice was provided to the Division (N/A), tests/surveys that were cancelled by the operator (cancelled), or test/surveys for which insufficient data is available in Division records to determine whether the test was witnessed (Blank).

** These tests were labeled as "N/A" to indicate that the operator failed to notify the District office to witness the test

^ These tests were labeled as "Not Good" or left blank, however the notes written by the field engineer stated that the operator failed to notify the District office to witness the test.

Table 9: MITs Witnessed in 2013

SAPTs 2013		RA Surveys 2013		Collective SAPT & RA MITs 2013	
Total SAPTs	**223**	**Total RAs**	**805**	**Total MITs**	**1028**
Cancelled	1	Cancelled	19	Cancelled	20
No Notice (N/A)	8	No Notice (N/A)	30	No Notice (N/A)	38
No Notice (NG, Blank)	3	No Notice (NG, Blank)	14	No Notice (NG, Blank)	17
Subtotal SAPT	**211**	**Subtotal RA**	**742**	**Subtotal MIT**	**953**
Witnessed SAPT	77	Witnessed RA	207	Witnessed MIT	284
% Witnessed*	**36%**	**% Witnessed***	**28%**	**% Witnessed***	**30%**

Notes: SAPT - Standard Annular Pressure Test
RA - Radioactive Tracer
MIT - Mechanical Integrity Test (comprising both SAPTs and RAs)
N/A - no advance notice of test/survey was provided to the Division
NG - Not Good; test failed
* The witnessed MIT ratios are based on the number of the witnessed MITs (comprising SAPTs and RAs) over their respective subtotals, which eliminate the number of tests for which no advance test notice was provided to the Division (N/A), tests/surveys that were cancelled by the operator, or test/surveys for which insufficient data is available in Division records to determine whether the test was witnessed (Blank).

Table 10: Overdue Annual Project Reviews

Years Overdue*	Number of Reviews Overdue	Percentage of Overdue Reviews Over 159** Total Projects
No annual review on record	19	11.95
> 20 years (last reviewed 1993)	22	13.84
> 10 years (last reviewed 2003)	16	10.1
< 10 years > 5 years	97	61
< 5 years (last reviewed after 2008)	5	3.1

Notes: * From the end of the 2013 files review
** Including 5 proposed project

Department of Conservation,
Division of Oil, Gas, and Geothermal Resources

Interagency UIC Program Improvement Planning: Major Correspondence and Deadlines

Appendix 2 to Report to the California Legislature under SB 855 (2010)

Attachments comprising Appendix 2:

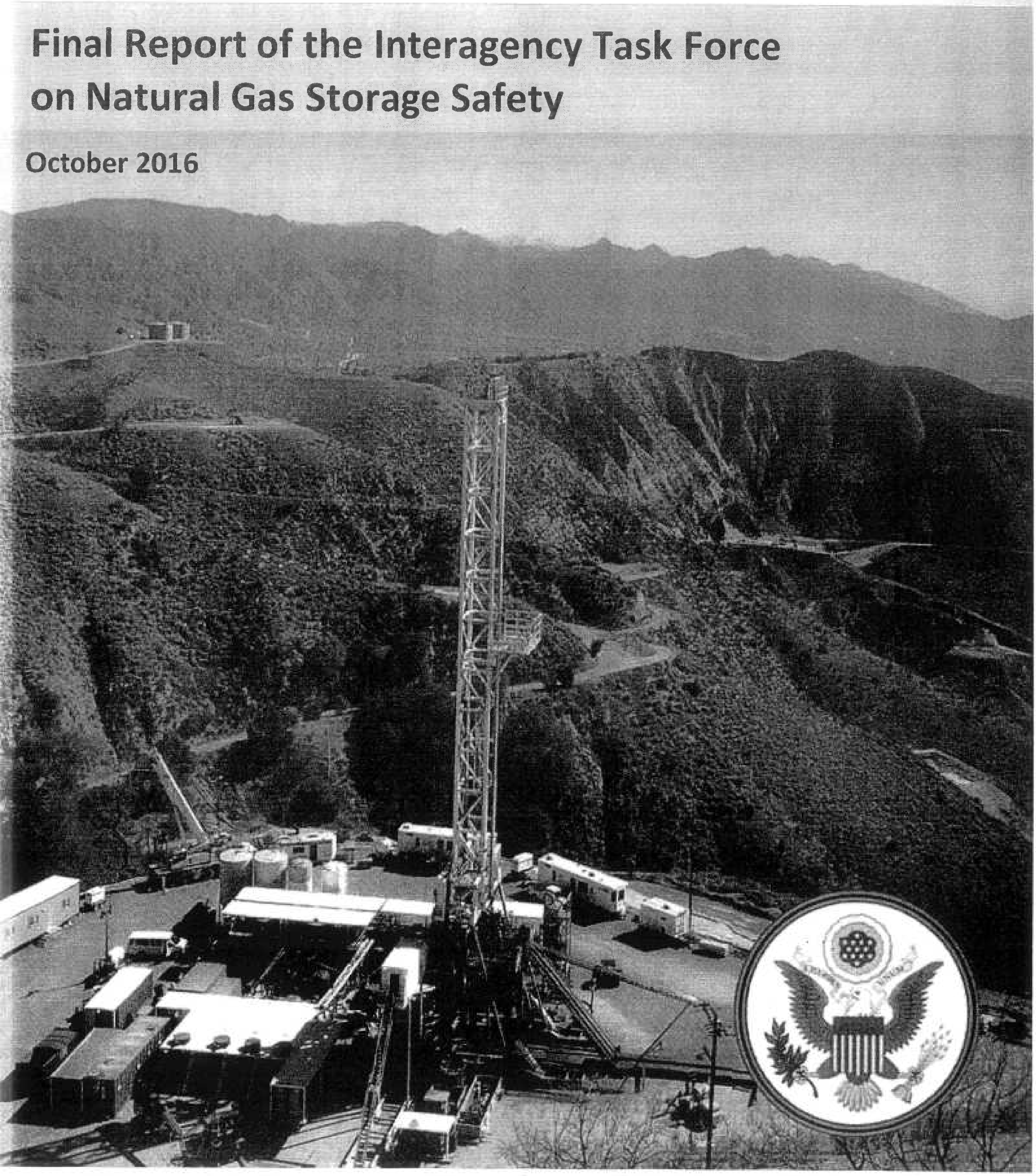
1. Division and State Water Board February 6, 2015 Letter to US EPA;
2. USEPA's March 9, 2015 Response
3. Division and State Water Board May 15, 2015 letter to U.S. EPA;
4. USEPA's May 28, 2015 response letter; and
5. Agreed Joint Submittal to US EPA, July 15, 2015]

EXHIBIT D

Ensuring Safe and Reliable Underground Natural Gas Storage

Final Report of the Interagency Task Force on Natural Gas Storage Safety

October 2016



About the Cover:

Relief well at the SoCalGas Aliso Canyon Gas Storage Facility well Standard Sesnon 25 (SS-25) (February 2016)

Message from the Secretary of Energy

Earlier this year, Congress and the Administration worked together to establish a Federal Task Force to analyze California's Aliso Canyon natural gas leak and make recommendations on how to reduce the likelihood of future leaks from underground natural gas storage facilities across the country. While these incidents are rare, the leak at Aliso Canyon is a reminder that failures at aging natural gas storage facilities can have damaging effects on communities, the environment, and the reliability of our energy supplies.

At the same time, the Nation's 400+ natural gas storage facilities provide essential services. They deliver gas at times of high demand to heat our homes and businesses, to power American industry, and increasingly, to provide fuel for electricity generation.

The Task Force identified three principal research areas associated with natural gas storage facilities: minimizing the risk of well failures; reducing health and environmental impacts of major leak incidents; and understanding energy reliability implications. Across these areas, the Task Force has made more than 40 recommendations that identify the need for additional actions at our Nation's natural gas storage facilities to ensure their long-term safety and reliable operation.

Key recommendations of the Task Force include:

- Gas storage operators should begin a rigorous evaluation program to baseline the status of their wells, establish risk management planning and, in most cases, phase-out old wells with single-point-of-failure designs.
- Advance preparation for possible natural gas leaks and coordinated emergency response in the case of a leak can help manage and mitigate potential health and environmental impacts of leaks when they do occur.
- Power system planners and operators need to better understand the risks that potential gas storage disruptions create for the electric system.

No community should have to go through something like the Aliso Canyon leak again. The recommendations in this report outline the steps we can take to prevent such an incident in the future. Now, it is up to industry to implement these recommendations in a timely fashion, while State and Federal officials develop regulations that enhance the safety of underground storage facilities in the United States.

Ernest J. Moniz
Secretary of Energy

Message from Task Force Co-Chairs

In April, as a part of the Administration's ongoing commitment to support State and industry efforts to ensure the safe storage of natural gas, and with the support of Congress, the Department of Energy (DOE) and the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) announced the formation of an Interagency Task Force on Underground Natural Gas Storage Safety.

Two months earlier, along with the Secretary of Energy, we visited the Aliso Canyon site to review efforts to control the leak and to learn from experts and local officials about the impacts of the leak on the environment and community.

The Task Force includes premier scientists, engineers and technical experts from across the DOE complex, including five National Labs, DOT, the Environmental Protection Agency (EPA), the Department of Health and Human Services (HHS), the Department of Commerce (DOC), the Department of the Interior (DOI), the Federal Energy Regulatory Commission (FERC), and the Executive Office of the President. As a Task Force, we have held three national-level workshops and met with community members, industry representatives, environmental organizations, and State officials.

The Task Force established three working groups for research and analysis: (1) the physical integrity of wells at gas storage facilities, (2) the reliability of natural gas supplies from gas storage facilities, and (3) the public health and environmental impacts associated with the Aliso Canyon leak.

The "Well Integrity" working group was led by DOE's Office of Fossil Energy, with important contributions from four DOE National Labs—the National Energy Technology Laboratory, Lawrence Berkeley National Laboratory, Lawrence Livermore National Laboratory, Sandia National Laboratories, and PHMSA.

The "Reliability" working group was led by the Department of Energy's Office of Electricity Delivery and Energy Reliability with important contributions by DOE's Argonne National Laboratory, DOE's Energy Information Administration, and FERC.

The "Health and Environment" working group was led by the EPA and HHS's Centers for Disease Control and Prevention. DOC's National Oceanographic and Atmospheric Administration and PHMSA also contributed.

This final report is a synthesis of the three working group reports, which will be made available as separate technical appendices to the report.

PHMSA plans to initiate regulatory actions to help ensure the safety of natural gas storage facilities across the country, beginning with an Interim Final Rule due out by the end of this year. Moving forward, PHMSA will consider the recommendations of this Task Force in developing future regulation and safety standards as required by the PIPES Act of 2016 (P.L. 114-183).

Natural gas provides heat to millions of American homes and is expected to provide a third of our Nation's total electric power generation this year. As co-chairs of this Task Force, we have made it a priority to support States, industry and the American public to ensure that our infrastructure is safe. The Task Force's efforts are an important step forward as we continue to work toward protecting public health and safety and making progress in reducing greenhouse gas emissions. We offer our recognition and gratitude to all those whose hard work and thoughtful analysis are assembled here.

Franklin Orr
Under Secretary for Science and Energy

Marie Therese Dominguez
Administrator, Pipeline and Hazardous Materials Safety Administration

Contents

Errata: This document was originally published on October 18, 2016. An update to the document was published on October 24, 2016, incorporating changes to recommendations that were accidentally omitted and correcting minor typographical errors.

Executive Summary

On October 23, 2015, the largest methane leak from a natural gas storage facility in United States history was discovered by the Southern California Gas Company (SoCalGas) at well SS-25 in its Aliso Canyon Storage Field in Los Angeles County. The leak continued for nearly four months until it was permanently sealed on February 17, 2016. In the interim, residents of nearby neighborhoods experienced health symptoms consistent with exposures to odorants added to the natural gas; thousands of households were displaced; and the Governor of California declared a state of emergency for the area. Approximately 90,000 metric tons of methane was released from the well, although estimates vary and the State of California is continuing its analysis. The incident also created serious energy supply challenges for the region and prompted broader public concerns about the safety of natural gas storage facilities.

Motivated by the events at Aliso Canyon, Federal officials, including many concerned members of Congress, sought to better understand and identify opportunities to improve the overall safety and environmental impacts of our Nation's natural gas storage infrastructure. To support these efforts, the Federal Government in April 2016 formed an Interagency Task Force on Natural Gas Storage Safety. Congress codified the Task Force through the Securing America's Future Energy: Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (PIPES Act). Congress directed the Task Force to perform an analysis of the Aliso Canyon events and make recommendations to reduce the occurrence of similar incidents in the future. To do so, the Task Force examined three key areas: integrity of natural gas wells at storage facilities; public health and environmental effects from natural gas leaks; and vulnerability to reduced energy reliability in the case of future leaks.

Natural gas currently meets nearly 30% of U.S. energy needs, and natural gas storage facilities are essential to the functioning of a highly seasonal natural gas market. They provide quick access to large volumes of natural gas for end users during periods of high demand, such as during a cold spell in the winter or during periods of high electricity demand in the summer. The Aliso Canyon leak illustrated how the loss of a large gas storage facility can disrupt enough gas delivery service to cause major energy reliability concerns, including potential electricity blackouts. Gas storage facilities are key components of a large and complex natural gas delivery infrastructure that serve homes, offices, power plants, and industrial facilities. Smooth functioning of that infrastructure is vital to our economy, our quality of life, and our national security. Major leaks or functional disruptions elsewhere in the gas infrastructure (i.e., at pipelines, compressor stations, gas processing plants, and liquefied natural gas terminals) could have impacts similar to those of the Aliso Canyon incident, and perhaps on an even larger scale. Further, the electric power and natural gas industries have become much more interdependent in recent years, and their interdependence is expected to grow over the next decade as the U.S. becomes more reliant on gas-fired electric generation capacity.

Approximately 80% of wells in the Nation's natural gas storage fields were completed in the 1970s or earlier. They have been exposed to decades of physical and mechanical stresses and pre-date many current materials and technology standards. In addition, many of these wells were converted to gas storage from oil production and may not have piping designed for the higher overall operating pressures of natural gas. Although rare, large natural gas storage leakage events can have negative impacts on human health and communities.

In June 2016, as part of the PIPES Act, Congress mandated that the Pipeline and Hazardous Materials Safety Administration (PHMSA) issue minimum Federal standards for all underground gas storage facilities. In response, PHMSA has stated that it plans to issue interim regulations in 2016.

This final report is organized into three chapters. Chapter 1 provides an overview of underground natural gas storage uses, locations, and regulations. Chapter 2 describes the Aliso Canyon incident, the responses by SoCalGas and various State, local, and Federal agencies to the leak, and an analysis of the impacts of the incident on gas and electric system prices and reliability. Chapter 3 records the Task Force's observations and recommendations to improve the safety and reliability of underground natural gas storage across the Nation. Those recommendations are summarized below. The appendix to the report contains a glossary of terms.

Preventing incidents like the one at Aliso Canyon in the future will require improving how operators manage the integrity of wells at storage facilities. Except under limited circumstances, natural gas storage operators should phase out single-point-of-failure well designs. In addition, they should develop risk management plans (RMP) that include several key components: analysis of risks associated with factors such as the condition of wells and their proximity to population centers; well records relevant to mechanical integrity; risk management plans that include testing programs and plans for remediating substandard wells; continuous monitoring plans; and emergency operation plans in the event of a significant integrity breach. Operators should create plans that lay out timelines to remediate substandard wells and determine how risks can be adequately monitored during periods of transition. Regulators should consider the impacts of such measures on ratepayers and reliability. Once the RMPs have been developed, operators should periodically review and update them. Along with RMPs, operators should improve and publish data on the integrity of wells within a gas storage field. This information and additional research in safety technologies will progressively improve the safety of natural gas storage fields.

Advance preparation and early coordination by the appropriate Federal, State, and local agencies would help manage and mitigate potential health and environmental impacts should another leak at a natural gas storage facility occur. A "unified command" should be formed early in response to a natural gas release when human health and environmental threats are present and multiple jurisdictions are involved in the response effort. State and local air monitoring agencies in jurisdictions where natural gas storage facilities are present should have the capacity to establish robust air quality monitoring in order to adequately characterize the public health impacts of a release. State and local air monitoring agencies should also consider developing emergency air monitoring plans to expeditiously deploy ambient air monitoring networks to assess possible health risks if a leak should occur. A quickly deployed monitoring framework and improved measurement techniques and technologies will assist State and local agencies to better measure greenhouse gas emissions in the event of a similar leak. States with underground natural gas storage should review their legal authorities to require greenhouse gas measurement and mitigation of fugitive emissions from underground natural gas storage facilities. Future decisionmaking would also benefit from further research to determine the short- and long-term effects of exposures to natural gas odorants.

Industry and government officials need to better understand the implications and risks associated with the growing interdependence of electricity and gas markets. The Task Force analysis has identified a small number of underground gas storage facilities other than Aliso Canyon that have the potential to affect energy reliability. More detailed analysis is required to better delineate whether disruptions at these underground storage (UGS) facilities could result in energy reliability concerns. Power system planners and operators, working with their natural gas counterparts, should study and understand the electric reliability impacts of prolonged disruptions of large-scale natural gas infrastructure (e.g., storage facilities, processing plants, key pipeline segments and compressor stations, and liquefied natural gas (LNG) terminals). They should share their analyses with State and Federal officials to ensure that policymakers fully understand the risks to electric reliability and can develop appropriate mitigation policies and strategies. Finally, greater availability of backup options, such as dual-fuel capabilities, energy storage options, and maintaining alternative sources of natural gas, may help electricity operators handle uncertain gas availability during extreme events while maintaining a reliable source of operable capacity available to meet seasonal peak demands.

In summary, the Task Force concludes that while incidents at U.S. underground natural gas storage facilities are rare, the potential consequences of those incidents can be significant and require additional actions to ensure safe and reliable operation over the long term.

Legislative Requirement

This report responds to legislative language set forth in Section 31 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (P.L. 114-183) which was signed by President Obama on June 22, 2016. Section 31 states that no later than 180 days after the day of enactment, a Task Force established by the Secretary of Energy shall submit a final report to Congress that contains analysis and conclusions regarding the cause and contributing factors of the Aliso Canyon natural gas leak; an analysis of measures taken to stop the natural gas leak, with an immediate focus on other, more effective measures that could have been taken; an assessment of the impacts of the natural gas leak on health, safety, and the environment, wholesale and retail electricity prices, and the reliability of the bulk-power system; and an analysis of how Federal, State, and local agencies responded to the natural gas leak; recommendations on how to improve the response to future leaks in order to lessen the negative impacts of leaks from underground natural gas storage facilities; recommendations on how to improve coordination among all appropriate Federal, State, and local agencies in the response to the Aliso Canyon natural gas leak and future natural gas leaks; an analysis of the potential for similar occurrences of natural gas leaks at other underground natural storage facilities in the United States; recommendations on how to prevent any future natural gas leaks; recommendations regarding Aliso Canyon and other underground natural gas storage facilities located in close proximity to residential populations; any recommendations on information that is not currently collected but that would be in the public interest to collect and distribute to agencies and institutions for the continued study and monitoring of natural gas storage infrastructure in the United States; and other recommendations as appropriate.

Chapter 1. Gas Storage Primer

Natural Gas Storage Basics

Why is natural gas stored underground?

Natural gas is an important commodity in the United States and the world, particularly for heating and for power generation. Underground natural gas storage is used in the transportation and delivery of gas by pipeline to end users. For example, the facilities can provide quick access to large volumes of gas for end users during periods of high demand, such as during a cold spell in the winter or a period of high electricity demand in the summer.[1]

How is natural gas stored?

Natural gas is injected down the wellbore and into a subsurface geological formation. As gas is injected, pressure builds within the formation. Higher reservoir pressures allow higher gas flow volume during the extraction (withdrawal) part of the storage cycle to help ensure suitable production gas flow rates.[2] Typically, vertical wells are used to inject and withdraw the gas, although horizontal wells are becoming more common.

A significant portion of the gas that is injected initially will remain in the subsurface and will not be extracted during a typical withdrawal cycle. This gas is commonly known as "base gas" or "cushion gas." It is a permanent inventory in a storage reservoir that is needed to maintain adequate pressure, minimize water being produced with the gas, and maintain delivery rates throughout the withdrawal season.

More about how natural gas storage fields work can be found in the Niska Gas Storage Industry Primer (2010) and from the Energy Information Administration's (EIA) *Basics of Underground Natural Gas Storage.*

Where is natural gas being stored?

Underground natural gas storage is found in three main types of storage formations: depleted oil and gas fields, aquifers, and salt caverns. These storage facilities can be found across the United States in 415 facilities, including approximately 400 active facilities, in more than 30 States (as shown in Figure 1). Most (~80%) of the existing natural gas storage in the United States is in depleted natural gas or oil fields that are located close to consumption centers.

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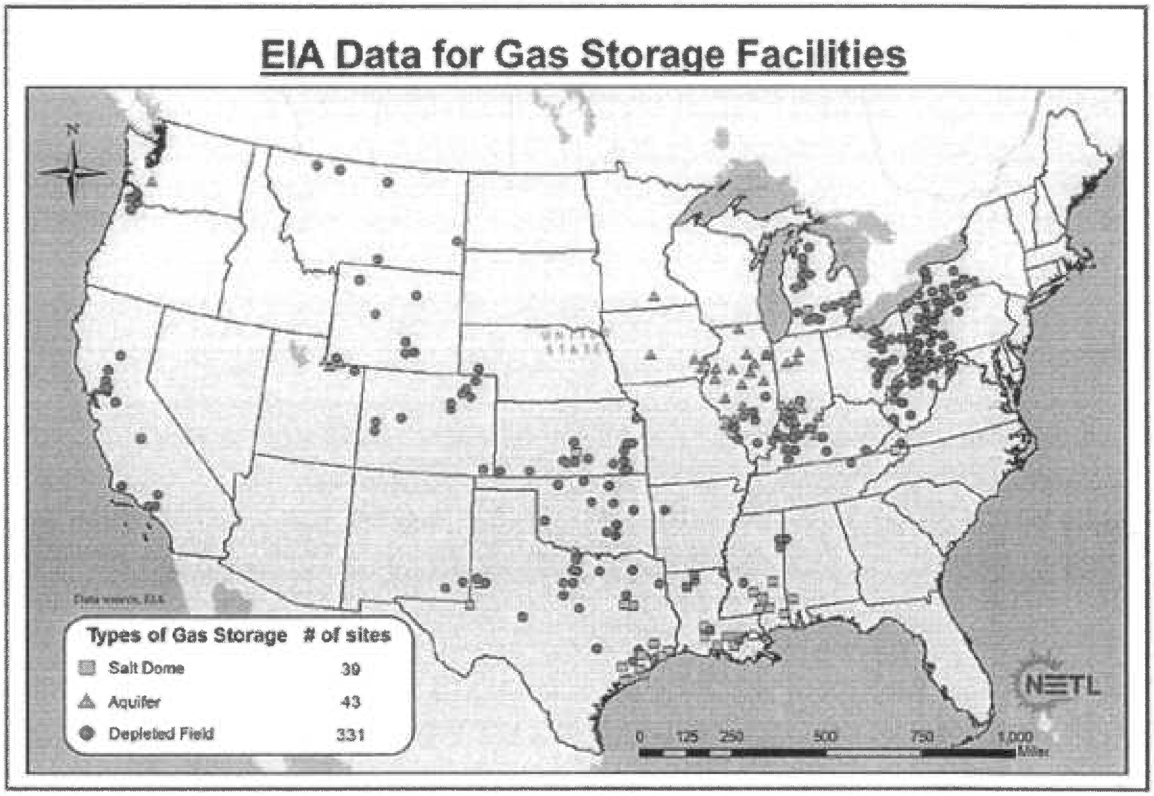
[1]U.S. EIA [Online], *The Basics of Underground Natural Gas Storage*, released November 16, 2015, September 2016, www.eia.gov/naturalgas/storage/basics/.

[2]Niska Gas Storage [Online], 2010, *Gas Storage Industry Primer*, September 2016, www.niskapartners.com/wp-content/uploads/2010/04/GasStorageIndustryPrimer.pdf.

Figure 1. Types and count of underground gas storage facilities in the United States



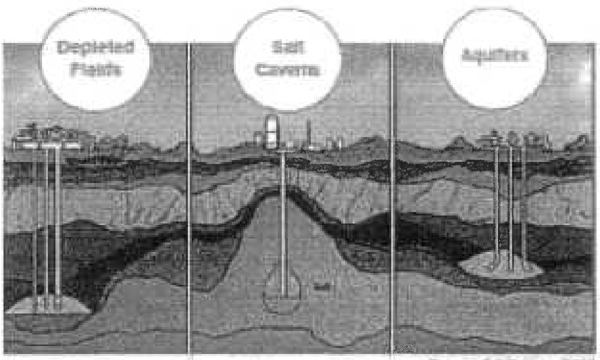
Why do we care about natural gas leaks from UGS facilities?

A gas storage field experiencing failures can be a health and safety hazard. Natural gas is flammable and can cause considerable damage if leaks are ignited. Natural gas may contain hydrogen sulfide (H_2S), other sulfur compounds, benzene, and natural gas odorants, which cause health concerns. Methane (the main constituent of natural gas) is a potent greenhouse gas. Releases of methane, such as the recent Aliso Canyon incident in California, contribute to climate change. A gas leak also causes the loss of a valuable commodity. In addition, a large UGS failure may disrupt enough gas delivery service to cause energy reliability concerns, including potential electricity blackouts.

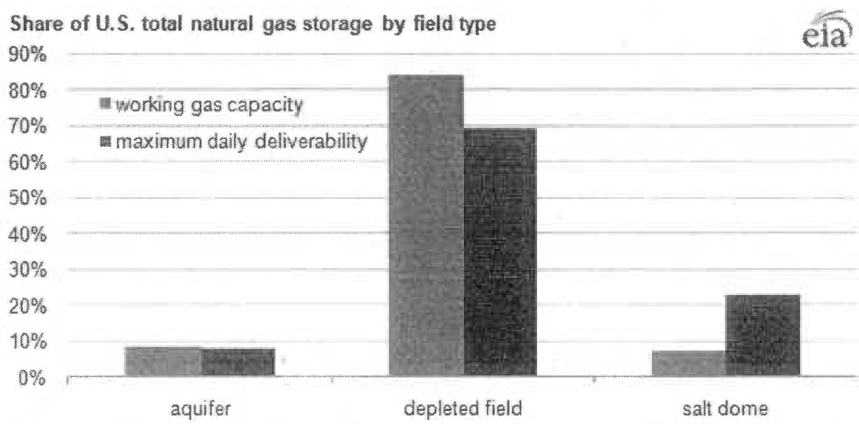
Gas storage facilities are key components of a large and complex natural gas delivery infrastructure that serve homes, offices, power plants, and industrial facilities. Smooth functioning of that infrastructure is vital to our economy, our quality of life, and our national security.

Underground Storage Types

Natural gas is stored in three principal types of underground geologic formations, including two types of naturally occurring structures: (1) aquifers, (2) depleted oil and gas reservoirs, and (3) man-made salt caverns.



Source: API Energy 2016



Depleted oil and gas fields are the most common type of underground natural gas storage field. These fields typically have been relatively well characterized (measured and mapped) during oil and gas activities and have demonstrated an ability to contain hydrocarbons over geologic time. They also typically already contain some "cushion gas" from the production phase.

Aquifers account for about 10% of the UGS fields. They are similar to the oil and gas fields in the way they function, as porous permeable formations capable of holding and releasing fluids. Although aquifers are often more expensive to develop than depleted oil and gas fields, they are more widely distributed across the United States than are oil and gas fields, and they can be found in locations that are useful for underground gas storage (e.g., near population centers with high demand).

Salt caverns differ significantly from the two other types of storage formations. They are formed in salt domes or salt beds, and they are usually mined by injecting fresh water, dissolving the salt, and producing the saturated brine in order to enlarge the cavern.

Salt caverns provide very high withdrawal and injection rates relative to their working gas capacity. Cushion gas requirements are relatively low. Most salt cavern storage facilities have been developed in salt dome formations located in the Gulf Coast States. Cavern construction is more costly than depleted field conversions when measured on the basis of dollars per thousand cubic feet of working gas capacity, but the ability to perform several withdrawal and injection cycles each year reduces the per-unit cost of gas injected and withdrawn.

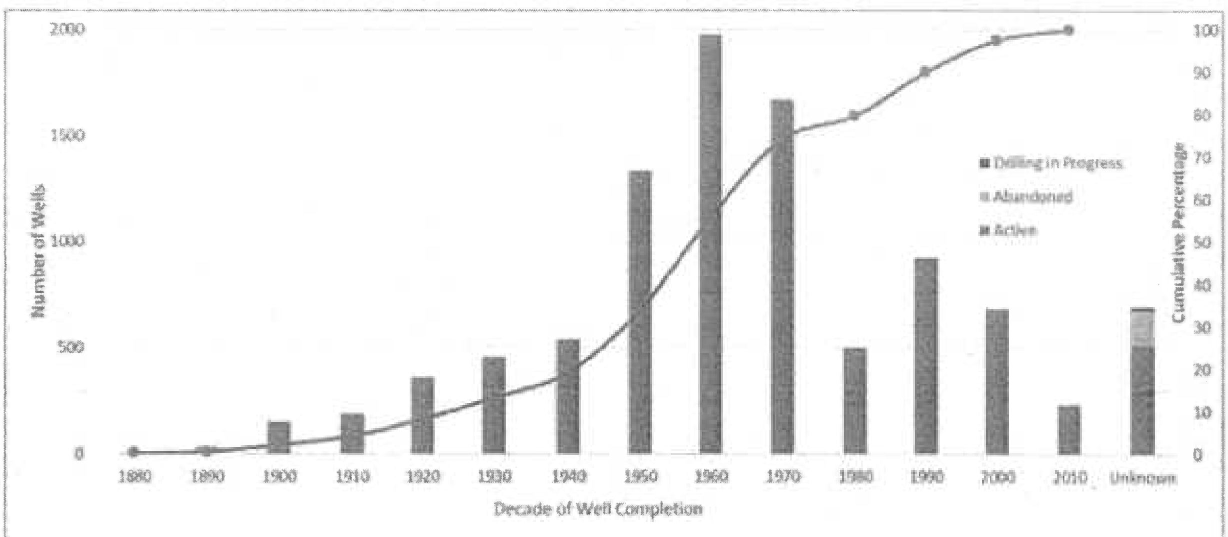
Gas Storage Wells in the United States: Data and Analysis

Analysis of Gas Storage Well Completions

Many wellbores presently in use for natural gas storage were initially designed and installed for other uses. Permitting and registration of such wellbores vary, depending on the years in which they were drilled and the States in which they are located.[3] The structural integrity of a wellbore is at least partially related to its age and past production type. Older wells are less likely to have been constructed with redundant barriers, and they are more likely to have degradation related to age (such as internal or external corrosion) or pressure cycle.[4] Nevertheless, a first-order analysis of wellbore records either drilled as—or converted to—natural gas storage wells, can assist with risk management planning and can inform the need for more detailed investigation of specific regions or wells. Wells that were originally designed for oil production and have subsequently been converted to natural gas storage may not have piping designed for the higher overall operating pressures of natural gas.

Figure 2 displays temporal trends in gas storage well records. About 80% of wellbores characterized as natural gas storage wells with known completion years were drilled before 1980. Although no firm cutoff can be stated for what constitutes an "old" well based on its completion year, wellbore construction materials and practices for all wells will be vestigial to the years in which they were drilled. Hence, the vast majority of the natural gas storage wells presently in use predate current materials and technology standards and have experienced physical and mechanical stresses from injection and withdrawal of natural gas across multiple decades.

Figure 2. Natural gas storage wells by completion date



The geographic distribution of natural gas storage wells is shown in Figure 3 and Figure 4. Ohio has the largest number of wells classified as gas storage wells (1,772), followed by Pennsylvania (1,327) and New York (964).

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[3]D. Glosser, K. Rose, and J.R. Bauer, "Spatio-Temporal Analysis to Constrain Uncertainty in Wellbore Datasets : An Adaptable Analytical Approach in Support of Science-Based Decision Making," pp. 1-19, 2016.

[4]R.M. Dilmore, J.I. Sams, D. Glosser, K.M. Carter, and D.J. Bain, "Spatial and Temporal Characteristics of Historical Oil and Gas Wells in Pennsylvania: Implications for New Shale Gas Resources," *Environ. Sci. Technol.*, vol. 49, no. 20, pp. 12015–23, 2015.

Figure 3. Number and drilling status of natural gas storage wells in each State

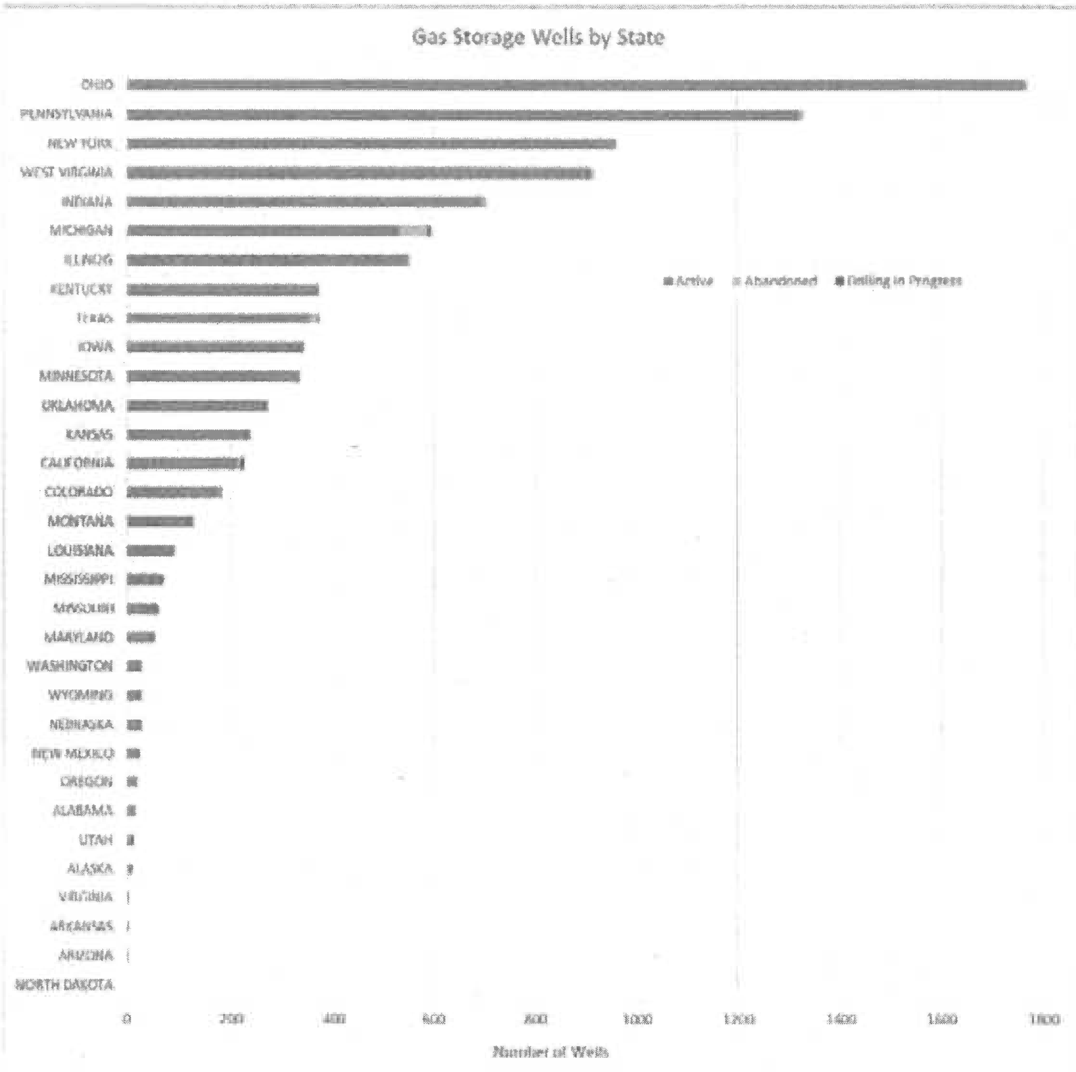
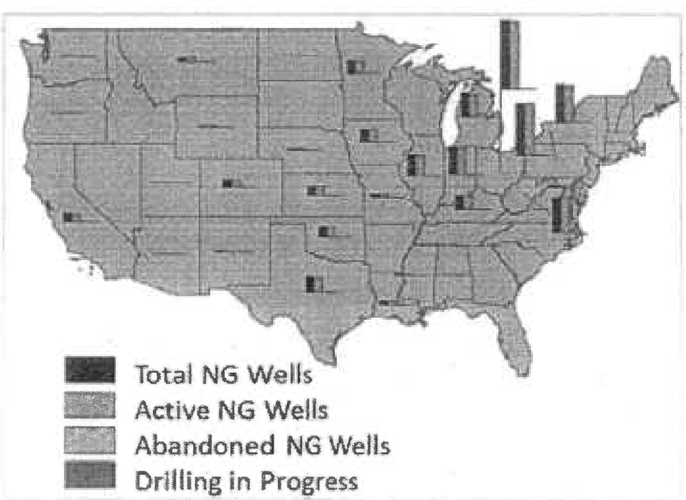


Figure 4. Geographic distribution of natural gas storage wells



Adapting legacy energy infrastructures (such as those constructed with older oil and gas exploration and engineering practices) to contemporary use requires careful consideration of the original designs and construction practices and the operational risks that flow from those practices. Construction, inspection and monitoring, and management practices can then be put in place to mitigate those risks. Legacy uses of natural energy resources cross jurisdictional and geographic boundaries in the United States.

Natural Gas Storage and Population Centers

Although they are rare, large natural gas storage leakage events can have negative impacts on human health and communities. The proximity of human population centers to natural gas storage infrastructure clearly influences the extent and severity of the risk to human health consequent to such events. Natural gas moves relatively slowly through pipeline networks (at about 10 to 25 miles per hour), and hence storage facilities are often most valuable when they are located relatively close to the power plants and residential and commercial users that depend on the gas. Use of any gas storage facility must balance the need for storage to support reliability of heating, electric power generation, and industrial uses with safety, health, and potential environmental impacts.

Currently, 370 population centers identified as "Census Designated Places" in the 2010 U.S. census are within 5 kilometers of an active natural gas storage well (Figure 5).[5] In other regions, separation distances are much larger. Given this distribution, a graded approach to gas storage regulations may be warranted.

Figure 5. Population centers within 5 kilometers of an active natural gas storage well

[5]"United States Census." [Online]. Available: http://www.census.gov/geo/reference/gtc/gtc_place.html.

Regulation of Natural Gas Storage Facilities

Overview of Jurisdiction to Regulate Natural Gas Storage Facilities

Just as natural gas storage and transmission are essential for ensuring reliability of domestic energy supplies, appropriate regulations are essential for ensuring the safety of such systems. Regulation of natural gas pipelines bringing gas in and out of UGS facilities falls under Federal jurisdiction under the Natural Gas Pipeline Safety Act (NGPSA), codified at 49 U.S.C. § 60101, et seq., and the Natural Gas Act (NGA), 15 U.S.C. § 717f(c), et seq.

The Pipeline Hazardous Materials Safety Administration (PHMSA) has been regulating gas pipelines for decades in partnership with the States, including the surface piping at UGS facilities up to the wellhead. Until recently, PHMSA has not chosen to exercise its regulatory authority over the underground gas storage facilities, which include wells and related "downhole" infrastructure. PHMSA has recently notified the public of its intent to exercise its Federal rulemaking authority in the domain of UGS facilities from the wellhead and extending downhole, to include wellbore tubing and casing, later this year. Several States have issued and enforced rules related to their intrastate facilities.[6, 7]

Interstate versus Intrastate Regulation

Regulatory responsibility for permitting and inspection of wells and facilities receiving or storing gas currently differs for interstate and intrastate gas storage infrastructure. UGS facilities that link multiple States are considered to be "interstate" facilities and are subject to the permitting authority of the Federal Energy Regulatory Commission (FERC). Intrastate UGS facilities are facilities that exist solely within the boundaries of a State and receive natural gas from an intrastate pipeline. State public utility commissions and State oil and gas boards currently establish their own regulatory frameworks for these intrastate facilities. Approximately half of the Nation's 415 UGS facilities are interstate facilities, and half are intrastate facilities.

Past Challenges to State Jurisdiction to Regulate Natural Gas Storage Facilities

Understanding potential jurisdictional limits on State regulatory oversight can inform the development of future regulations aimed at improving natural gas storage safety. A 2010 challenge to State regulation over interstate natural gas storage facilities in Kansas provides insight into potential limitations on State rulemaking and enforcement. In 2001, the Kansas Legislature vested jurisdiction for the safety of underground porosity and salt storage of natural gas in Kansas in the Kansas Corporation Commission and Kansas Department of Health and Environment. This regulatory action occurred following a 2001 natural gas storage leakage incident in Hutchinson, Kansas, that caused two fatalities. A series of Kansas State regulations were adopted and codified in the following years. However, a Federal court blocked Kansas from applying those regulations to a gas storage facility operated by Colorado Interstate Gas, on the ground that Congress had conveyed exclusive power to regulate interstate gas storage facilities to FERC and PHMSA.[8]

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[6] *General Rules and Regulations for the Conservation of Crude Oil and Natural Gas,* State Corporation Commission of the State of Kansas.

[7] *Underground Storage of Gas in Productive or Depleted Reservoirs.* Rule §3.96, Texas Administrative Code.

[8] *Colorado Interstate v. Wright*, 707 F.Supp.2d 1169.

Industry Develops Consensus-Based Recommended Practices with State and Federal Authorities

In August 2011, PHMSA published an Advance Notice of Proposed Rulemaking (ANPRM) in the *Federal Register*, which among other things requested comments as to whether new regulations were needed for UGS facilities.[9] Subsequently, the Interstate Natural Gas Association of America (INGAA) and the American Gas Association (AGA) created a joint task team with participation from PHMSA and State agencies. The American Petroleum Institute (API) acted as the American National Standards Institute (ANSI)-approved Secretariat of the task group's final product: consensus-based standards developed under an ANSI-approved process, published as API Recommended Practices (RPs). The task teams met over the next several years and in September 2015 produced API RP 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage," and API RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs." The development of those national RPs brought together expertise from industry and both State and Federal governments. The U.S. Congress, in addressing the concerns for the integrity of UGS facilities under Section 60141(b) of the 2016 PIPES Act, required PHMSA to consider consensus standards, such as API RPs 1170 and 1171, in adopting minimum standards for the operation, environmental protection, and integrity management of underground natural gas storage facilities.

Congress Mandates Minimum Federal Standards

With passage of the PIPES Act of 2016, the U.S. Congress mandated that the Pipeline Safety Act authority encompassing interstate and intrastate underground gas storage facilities served by pipeline be exercised, and required the issuance of minimum Federal standards. PHMSA anticipates that State requirements for intrastate facilities in turn will be based on adoption of those Federal standards once they are in place. Notably, the PIPES Act provides that the State authorities may adopt additional or more stringent safety regulations for intrastate UGS facilities as long as they are compatible with the Federal minimum standards.

In 2016 PHMSA issued an advisory bulletin regarding safe operations of UGS facilities for natural gas. As of the writing of this report, PHMSA has stated publicly that it intends to issue interim regulations in 2016.

State-Level Regulations by Reservoir Type

Many States have enacted rules covering intrastate natural gas storage facilities within their borders. Nineteen States with natural gas storage fields were selected for an analysis of State-level natural gas storage regulations; 90% of all active natural gas storage wells are located in their jurisdictions. Of the 19 States, 11 have regulations of some type that specifically address surface or subsurface infrastructure within such facilities. Four of the 11 States have regulations addressing underground natural gas storage in all three reservoir types: depleted fields, aquifers, and salt caverns. Details of annual gas storage capacity by reservoir type are shown in Figure 6.[10]

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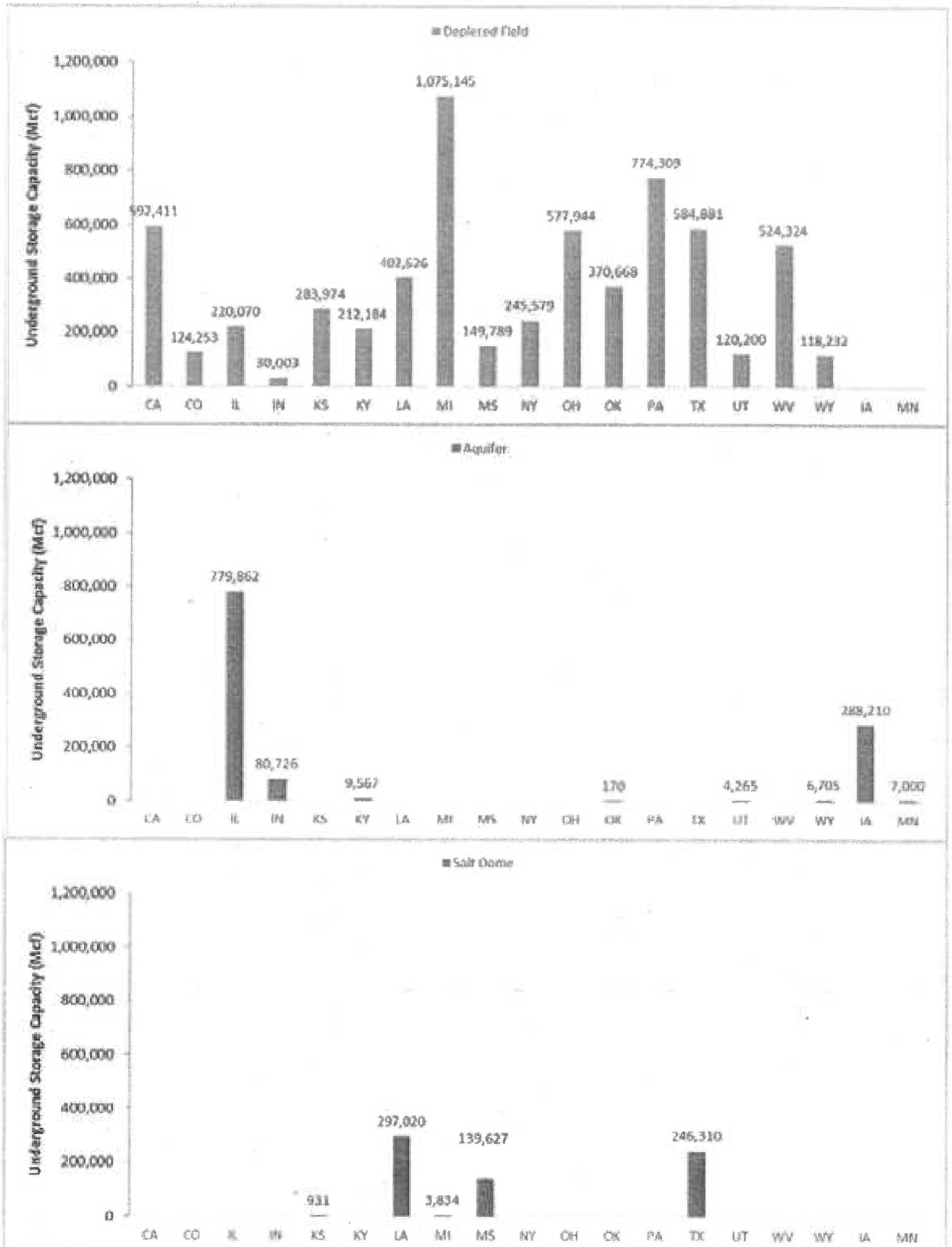
[9] https://www.federalregister.gov/documents/2011/08/25/2011-21753/pipeline-safety-safety-of-gas-transmission-pipelines.
[10] U.S. EIA, "Gas Storage Capacity." [Online]. Available: https://www.eia.gov/dnav/ng/NG_STOR_CAP_A_EPG0_SA6_MMCF_A.htm.

Figure 6. 2012 State-level natural gas storage capacity (Mcf) by reservoir type



State Regulations Related to Natural Gas Storage Wellbore Integrity

Wellbores are the primary engineered pathway linking the subsurface and surface. Maintaining the integrity of the wells across the three stages of their lifespans—initial design and construction, use, and final plugging and abandonment—is of critical importance for mitigating risk of leakage. Several, but not all, States with natural gas storage facilities have implemented regulations that address wellbore integrity at these stages (Table 1).

Table 1. States with regulations regarding natural gas storage well construction, maintenance, and plugging and abandonment as of August 2016[11, 12, 13]

	Well Constructioi	Well Maintenance	Plugging and Abandonment
CA	X	X	X
CO			
IL	X		X
IN			
KS	X	X	X
KY			
LA			
MI	X	X	
MS	X		
NY			
OH	X		X
OK			
PA	X	X	X
TX		X	
UT			
WV			
WY			
IA	X	X	X
MN			

Note: The California regulations are interim emergency regulations.

Only California, Kansas, and Pennsylvania have regulations addressing well integrity at all three stages. At the design and construction phase, Kansas regulation requires a drilling and completion plan to be signed by a professional engineer or geologist. At the operations and maintenance phase, Kansas has requirements for pressure testing, leak detection, and the presence of a safety plan. Finally, Kansas requires specific plugging and completion procedures for all natural gas storage wells.[14] In Pennsylvania, there are several gas storage well design and construction rules: specific casing and cementing procedures,

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[11] G. P. Council, "Summary of Gas Storage Regulations from 17 State Oil and Gas Agencies, Ground Water Protection Council, April, 2016." 2016.

[12] *2015 Minnesota Statutes.*

[13] *Iowa Administrative Code.*

[14] T.S.C. COMMISSION and O.T.S.O. KANSAS, *General Rules And Regulations For the Conservation of Crude Oil and Natural Gas.* 2006.

blowout prevention equipment rules, and storage well construction requirements are all prescribed by the State.[15] At the operation stage, Pennsylvania requires mechanical integrity testing every 5 years, including geophysical logging and pressure testing, and leak and corrosion inspections. Finally, Pennsylvania requires bridge plugs above and below the gas storage reservoir during the plugging and abandonment of natural gas storage wells.

The California proposed rulemaking that is underway for natural gas storage wells at the design and construction phase requires primary and secondary well barrier construction (including production casing to the surface); and tubing and packer. At the operations stage, California's interim emergency regulations and draft rules require mechanical integrity testing (temperature and noise log, and casing thickness inspections), as well as monitoring and inspections for leaks. The interim emergency regulations do not have specific requirements for plugging and abandonment protocols; however, the Division of Oil, Gas and Geothermal Resources ("DOGGR") remains vested with the authority to oversee the plugging and abandonment of the wellbores.[16] In some cases, States have developed regulations particular to ensuring the integrity of injection wells but have specifically excluded gas storage wells from those regulations.

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[15]Pennsylvania, *Oil and Gas Wells*. 2012.

[16]California, *Onshore Well Regulations*. 2016.

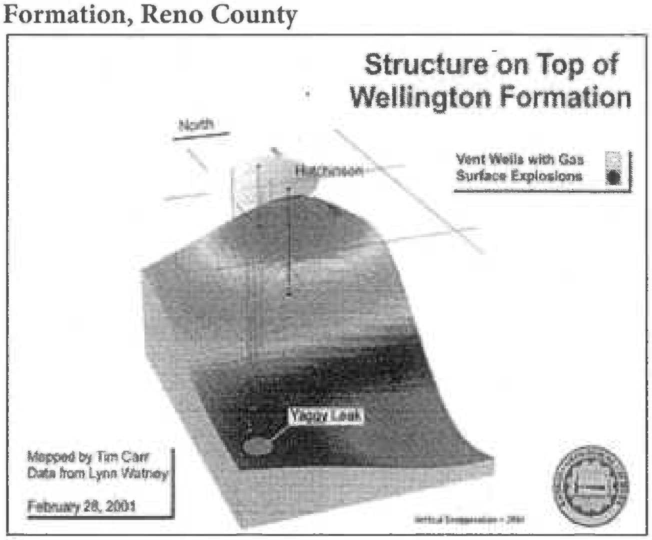
Notable Gas Storage Failures

The Yaggy Incident

On January 17 and 18, 2001, an accident occurred at the Yaggy underground natural gas storage field operated by Kansas Gas Service. Natural gas stored in underground salt caverns escaped and migrated laterally more than 8 kilometers through a porous underground geologic formation, where it came into contact with several abandoned wellbores used long before as brine wells. The gas escaped through the wellbores and caused two separate explosions in Hutchinson, Kansas. Two people were killed, and several businesses were destroyed in the explosions. Approximately 143 million cubic feet of natural gas leaked from the storage field.

Figure 7. Photo of downtown Hutchinson, KS, after explosion from an underground storage field at Yaggy

Figure 8. Structure contours on top of the Wellington Formation, Reno County



The Yaggy incident highlights the critical role of wellbores (particularly older, improperly abandoned, and structurally unsound wellbores) as a conduit for fluid flow, as well as the need to address wellbore integrity to reduce future risks related to natural gas storage. The Kansas Geological Survey investigated the incident and determined that the leak was a result of damaged casing in one of the older wellbores. The casing damage was determined to have occurred from the re-drilling of an old, cemented wellbore when the Yaggy field was reopened and converted from propane storage to natural gas storage.[17]

The Moss Bluff Incident

On August 19, 2004, the Market Hub Partners Moss Bluff storage facility, located in Liberty County, Texas, had an accident in which a wellhead fire and explosion occurred, releasing 6 billion cubic feet of natural gas.

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[17] http://www.kgs.ku.edu/Hydro/Hutch/GasStorage/apr_19_97.pdf.

Prior to the explosion , the storage cavern was operating in "de-brining" mode, wherein brine is extracted as natural gas is injected. The cause of the explosion was determined to be a separation of the production casing (well string) inside the cavern. When the brine reached the separation point in the casing, pressurized gas entered the string, where it was brought to the surface through brine piping at the wellhead. Although the wellhead assembly closed properly when the pressure change was detected, the mechanical force produced by the rapid change in flow rate caused a breach in the pipe, which was already weakened from wall loss due to internal corrosion. The pipe was only 4 years old at the time of the event.

On August 26, 2004, the fire eventually self-extinguished, and installation of a blowout prevention valve was completed, effectively placing the well back under control. Most of the methane released in the leak was combusted in an explosion and subsequent fire and therefore was emitted to the atmosphere as carbon dioxide (not as methane).

Figure 9. Uncontrolled gas release and fire at storage Cavern #1

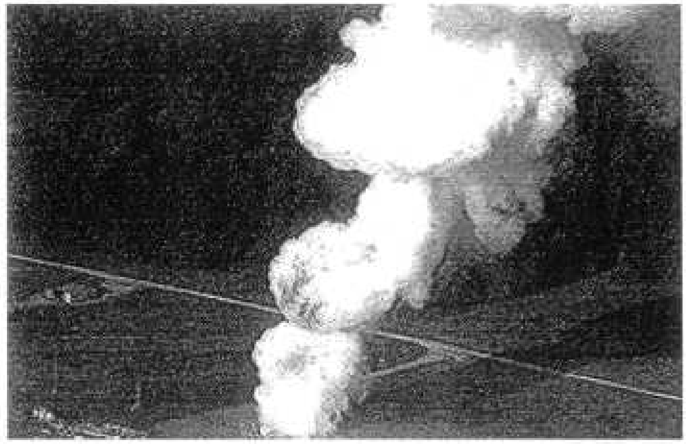


Figure 10. Local fire department response to Moss Bluff

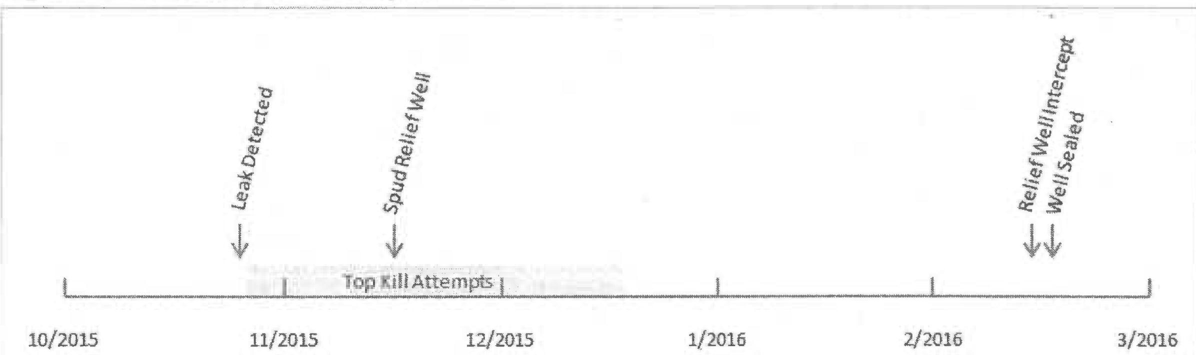
Chapter 2. The Aliso Canyon Incident

Well History and October 2015 Well Failure Analysis

On October 23, 2015, the largest methane leak[18] from a natural gas storage facility in United States history was discovered by the Southern California Gas Company (SoCalGas) at well SS-25 within its Aliso Canyon Storage Field in Los Angeles County. SoCalGas, a subsidiary of Sempra Utilities, is the owner and operator of the Aliso Canyon facility. The leak initially released approximately 53 metric tons of methane per hour, or a total of approximately 1,300 metric tons of methane per day.

The leak was exacerbated by repeated (eight) top kill attempts over the course of the first two months of the event. A relief well, which was drilled beginning in late November, was used eventually to kill the well. Relief well intercept occurred on February 12, 2016, and gas flow was stopped immediately. The well was subsequently cemented and sealed on February 17, 2016. An overview timeline of the events at Aliso Canyon is provided in Figure 11.

Figure 11. Timeline of Aliso Canyon events



SS-25 Well History

The Aliso Canyon Facility consists of 115 storage injection wells with spud ages ranging from 1939 to 2014.[19] The Aliso Canyon facility has a total storage capacity of 86 billion cubic feet (bcf) of natural gas, making it one of the largest natural gas storage facilities in the United States. Natural gas is injected into the old sandstone reservoir formation at approximately 8,500 feet below ground surface for storage and withdrawn for transmission and sale in response to market conditions.

Drilling of the SS-25 started on October 1, 1953, and the well was completed in April 1954. During drilling, the original borehole was abandoned due to an unrecoverable drill string and tool set that were lost in the hole. The main hole was sidetracked at a depth of approximately 3,900 feet, and then drilled to full completion depth of 8,749 feet.

In May 1973, a reworking of SS-25 to convert it to a gas storage well was started. As a gas storage well, it was operated by injection and withdrawal through both tubing and casing; thus, the long casing string functioned as a single barrier to the environment.

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[18]A large release of natural gas occurred from a storage facility in Moss Bluff, TX. in 2004, but most of the methane was combusted due to an explosion and subsequent fire, and therefore emitted as carbon dioxide (not methane) to the atmosphere.
[19]A "spud" is the process of beginning to drill a well. After a surface hole is completed, the main drill bit is inserted, which performs the task of drilling to the total depth; this is referred to as "spudding in."

In general, it appears that downhole safety valves (DHSVs) were installed in many of the original wells, including SS-25, when the field was converted to a gas storage facility in the 1970s. DHSVs, commonly used in the offshore environment, are devices designed to shut off flow to the surface under off-normal conditions, such as during loss of pressure control. These systems differ from the subsurface sliding sleeve valves (SSVs) that provide connections between the tubing and casing. SSVs are used during normal well operations to facilitate maintenance operations, permitting fluid circulation between the tubing and the tubing-casing annulus.

At Aliso Canyon, many DHSVs were then removed and not replaced during later well workover operations. In some cases, SSVs replaced the DHSVs. Wells drilled since approximately 1980 have not had any DHSVs installed at any time. Table 3 shows a summary of the use of DHSVs and packer and tubing well completions for the Aliso Canyon gas storage facility, based on review of the publicly available well history files maintained by the California Division of Oil, Gas, & Geothermal Resources (DOGGR). Both DHSVs and SSVs were used at various times in many of the wells, and there are some inaccuracies noted in the records, which reflect the lack of standardized terms and acronyms used to refer to various types of downhole devices. Wells were considered to be capable of casing production if the tubing was configured for gas flow to the casing using SSVs, or if there was no production tubing.

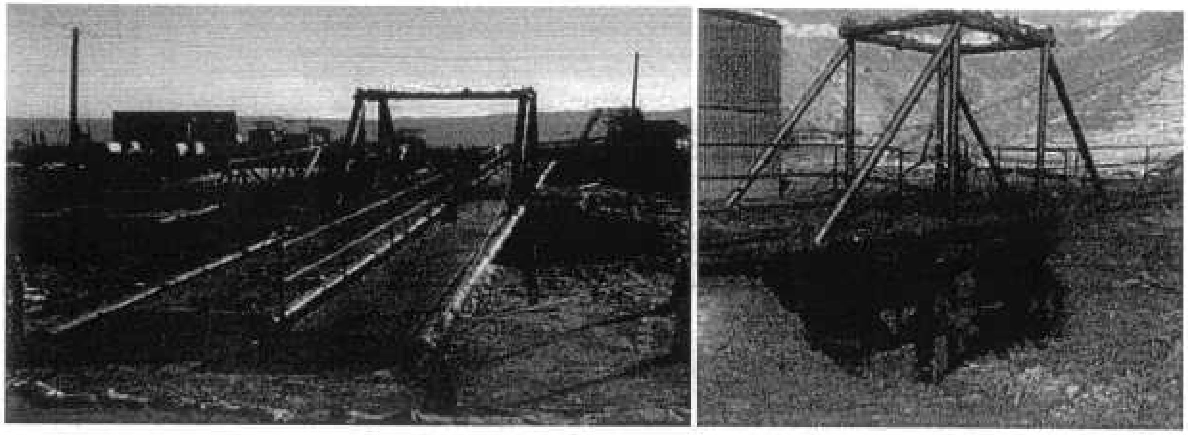
Table 3. Summary of Aliso Canyon Gas Storage Facility Well Configurations

Parameter	Well count
Total number of wells	115
Wells with a DHSV at some point in their history	54
Wells with no indication of a DHSV installation	60
Wells using packer and tubing production	102
Wells configured for casing production (includes wells with SSVs permitting tubing to casing flow)	80

Top Kill Attempts in Response to the 2015/2016 Leak

Starting on October 24, 2015, one day after the leak was discovered, and continuing until December 22, SoCalGas conducted eight separate "top kill" operations to stop the leak. "Top kill" operations involve pumping heavy drilling muds, fluids, and other material (together known as "kill fluids") into the leaking well in an attempt to plug the well from above. After the first well kill attempt failed on October 24, SoCalGas on October 25, 2015, retained the services of Boots & Coots, a wholly owned subsidiary of Halliburton, for assistance. Boots and Coots is a company recognized as expert in well control services. After the leak was recognized at the surface on October 23, 2015, top kill attempts were made on October 24, November 6, 13, 15, 18, 24, and 25, and December 22, 2015. Heavy barite mud and calcium chloride solutions were systematically pumped with lost circulation materials. Over time, as successive top kill attempts caused erosion and expansion of the vent, the vent eroded to include the wellhead (Figure 12). During the later top kill attempts, the wellhead experienced severe vibrations and movement. In an effort to protect the wellhead and the casing couplings, the operator secured it with strapping (which failed during a top kill attempt). The wellhead was eventually secured with a bridge structure as shown in Figure 12. The final vent reached a dimension of approximately 40 feet by 60 feet and a depth of more than 20 feet, with an estimated maximum gas flow rate of 25 to 60 million cubic feet per day (MMcfd). None of the top kill operations was successful.

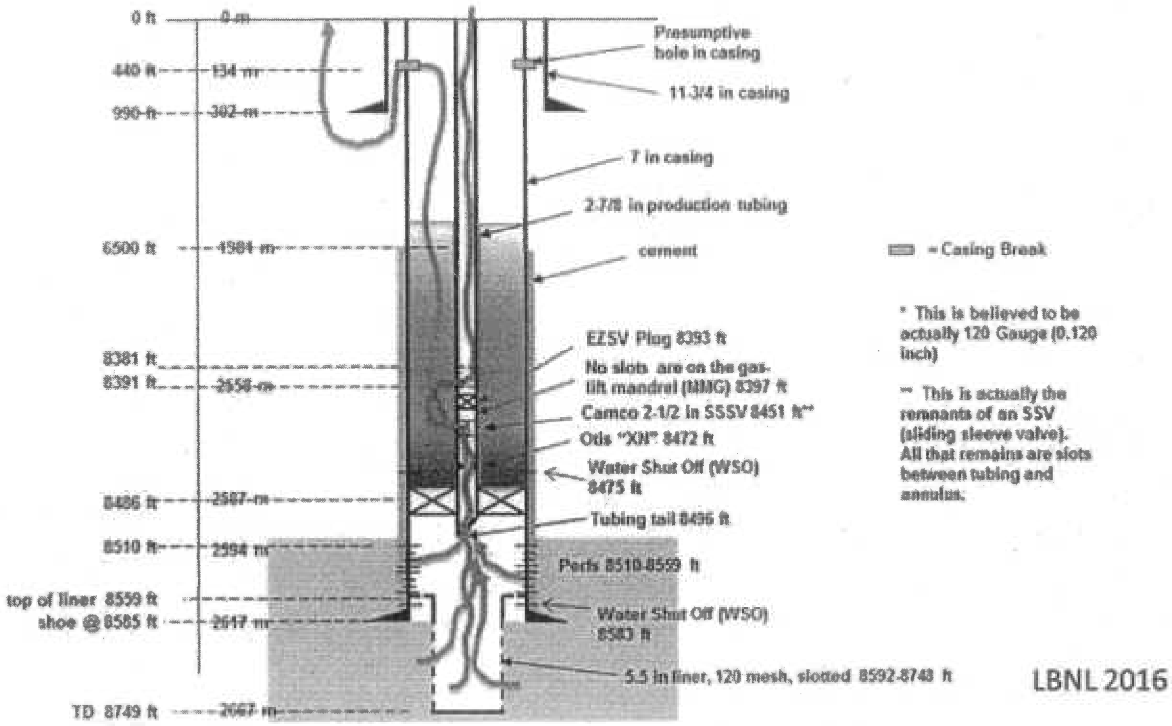
Figure 12. Vent crater caused by expulsion of top kill attempt materials



In at least one top kill attempt, significant volumes of kill fluids were expelled from the borehole by the escaping gas. Because the Aliso Canyon storage facility uses abandoned petroleum-bearing formations, the escaping gas also caused residual petroleum from the formations to be expelled from the well, resulting in the deposition of an oily residue on many Porter Ranch residences, vehicles, and outside areas. It is believed that these unsuccessful top kill attempts partially aerosolized some kill fluid constituents, such as barium, and that the aerosolized products, in the form of an oily mist, were in turn carried in the air and deposited in the interior of some Porter Ranch residences. To mitigate this problem, starting on January 3, 2016, SoCalGas installed a series of metal screens (called "coalescing trays") over SS-25 in an attempt to contain the oily mist.

Lawrence Berkeley National Laboratory (LBNL) simulated the top kills based on information provided by SoCalGas. The modeling showed that the high gas flow rates and the geometry of the lower section of the well severely inhibited the effectiveness of the top kill attempts. During the top kill attempts, fluids pumped down the tubing had to exit the perforations above the plug and then re-enter the tubing through the original valve at 8,451 feet in order to enter the gas-producing area of the well. The gas flowing up the well was able to entrain the kill fluids exiting the tubing, and gas flowing out from the tubing inhibited the kill fluids from re-entering the tubing. Exacerbating this issue were kill operation limitations caused by concerns for the structure of the wellhead, as shown schematically in Figure 13, where the kill fluid (brown) has to build up in the casing and overcome the methane gas (blue) flowing out of the SSV slots. In the lower section of the cased interval gas and liquid were mixed, and the upward velocity of the escaping methane was sufficient to force the liquid/gas mixture up the well and out the leak.

Figure 13. SS-25 top kill failure scenario



Bottom Kill Attempts in Response to the Leak

In early November, SoCalGas also began planning for the drilling of a relief well for a "bottom kill" operation, if needed. "Bottom kill" operations involve drilling a relief well to intercept the leaking well at depth and pumping drilling muds and cement through the relief well into the leaking well to seal the well.

SoCalGas began withdrawing natural gas from the Aliso Canyon facility in early November 2015, in an effort to reduce pressure around SS-25, and on November 25, 2015, began drilling a relief well in order to conduct a bottom kill operation. SoCalGas also started preparing for a second relief well, should it become necessary. The first relief well was ultimately successful in plugging SS-25, and no other relief wells were drilled. Relief well intercept occurred on February 12, 2016, and gas flow was stopped immediately thereafter.

Monitoring and Leak Detection History at Aliso Canyon

The gas storage industry generally has relied on subsurface measurements to detect subsurface leaks. Noise logs, listening for noise irregularities (perhaps indicative of a leak), and temperature logs, looking for thermal anomalies indicative of subsurface flow, are commonly used by the industry. For both of these technologies, historical records are of great value for comparative purposes.

Early logging of wells at Aliso Canyon (in the 1950s) was primarily for formation characterization. In the 1970s, as part of the field's conversion to storage, a small fraction (about one-fourth) of the wells were logged, focusing on cement bond and neutron logs. In recent years there has been much more well logging; however, before the 2015 leak event, the vast majority of the wells remained unevaluated for cement integrity along the production casing.

- Noise and temperature logs have been obtained for all wells in the field in 2016, as required by the California Division of Oil, Gas, and Geothermal Resources (DOGGR).
- In the preceding 5 years (2010-2015), most wells were surveyed annually for temperature.
- In the years 2006-2010, most wells were surveyed every other year.
- In the years 1990-2005, most wells were surveyed at time intervals longer than every other year.
- In the years from the 1970s conversion date to 1990, surveying was sporadic.
- There are infrequent additional geophysical log data for the storage wells, but nothing recent or systematic that could possibly have been used to assess well integrity.

Observations regarding SS-25's Failure

A formal root cause analysis of the leak at SS-25 has been initiated by the California Public Utilities Commission (CPUC) through a third-party contractor. The analysis will include detailed work at the leak site, but it is not yet known when the analysis will be completed. While the Federal Government is not part of this investigation, a review of publicly available information about SS-25[20] allows the following observations:

- SS-25 was constructed under ordinary circumstances consistent with the rest of the Aliso Canyon field. It began as a production well and then was converted to use in natural gas storage.
- The data indicate that SS-25 was operated in natural gas storage pressure cycling through both casing (uncemented in the uppermost critical sections) and tubing, providing only a single barrier. This was common practice at the storage field.
- SS-25 was monitored for gas leaks in a similar manner to other wells at the field, annually in recent years, and ranging from sporadic to biannually in earlier years.
- Logs that could be used to assess the risk of the well system (e.g., metal loss in the casing) were not located.
- Complex subsurface flow paths may have impeded the delivery of kill fluids required to suppress gas flow.

While investigation of the failure remains ongoing, there are preliminary indications that the practices for monitoring and assessing leaks (temperature and noise) and leak potential (cement bond, metal thickness, and pressure testing) at the Aliso Canyon facility were inadequate to maintain safe field operating pressures.

As a result of the Aliso Canyon incident, PHMSA in 2016 issued an advisory bulletin[21] regarding safe operations of UGS facilities for natural gas. Because Aliso Canyon is an intrastate facility, the CPUC and DOGGR have primary regulatory responsibility, and they have issued numerous orders to the operator imposing various operating restrictions and mandating remedial actions. PHMSA and DOE are providing extensive technical support to those agencies. The actions taken PHMSA, DOE, and other Federal and State regulatory agencies are described in greater detail later in this report.

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[20] http://www.conservation.ca.gov/dog/Pages/AlisoCanyon.aspx.

[21] ADB-2016-02.

Health and Environmental Effects and Responses

Ambient Air Pollutant Monitoring and Public Health Risk Assessment

State and local air pollution control agencies have the primary responsibility for conducting ambient air monitoring within their jurisdictions, including monitoring for emergency response. EPA provides funding and oversight to enable these agencies to accomplish these objectives. The two air pollution control agencies that conducted emergency ambient air monitoring in response to the Aliso Canyon natural gas leak were the South Coast Air Quality Management District (SCAQMD) and the California Air Resources Board (CARB). SoCalGas and the Los Angeles Unified School District (LAUSD) also collected ambient air samples on facility property and in the Porter Ranch community. Later during the response, and on its own initiative, the University of California at Los Angeles (UCLA) conducted ambient air monitoring.

Discrete Sampling

A series of discrete sampling efforts was conducted beginning on October 26, 2015. The first samples were taken by SCAQMD in direct response to the first community complaints received on October 24, 2015, the day after the leak was detected. Following this initial sampling, numerous other samples were taken for a wide variety of pollutants. In addition to the discrete sampling, continuous monitoring was established for a small set of pollutants at fixed monitoring sites, which is described in the next section (see Figure 14 for a map of SCAQMD and CARB sampling and monitoring locations).

The monitoring objectives for the ambient air monitoring of pollutants were generally threefold: (1) to assess potential exposure to various pollutants determined to be of concern, (2) to evaluate the extent of the emissions transport into the surrounding area, and (3) to provide information to Porter Ranch community members. One study monitored air quality at twenty schools in the area near the leak to assess students' exposure to pollutants of concern associated with the leak. Most of the sampling was done in and around the Aliso Canyon Facility, but monitoring was also conducted in a separate area in order to re-verify potential pollutants of concern within the community compared to a background location.[22] Finally, indoor air was also sampled for radon to determine whether levels exceeded EPA's action level, due to concerns about the potential presence of radon in the released natural gas.

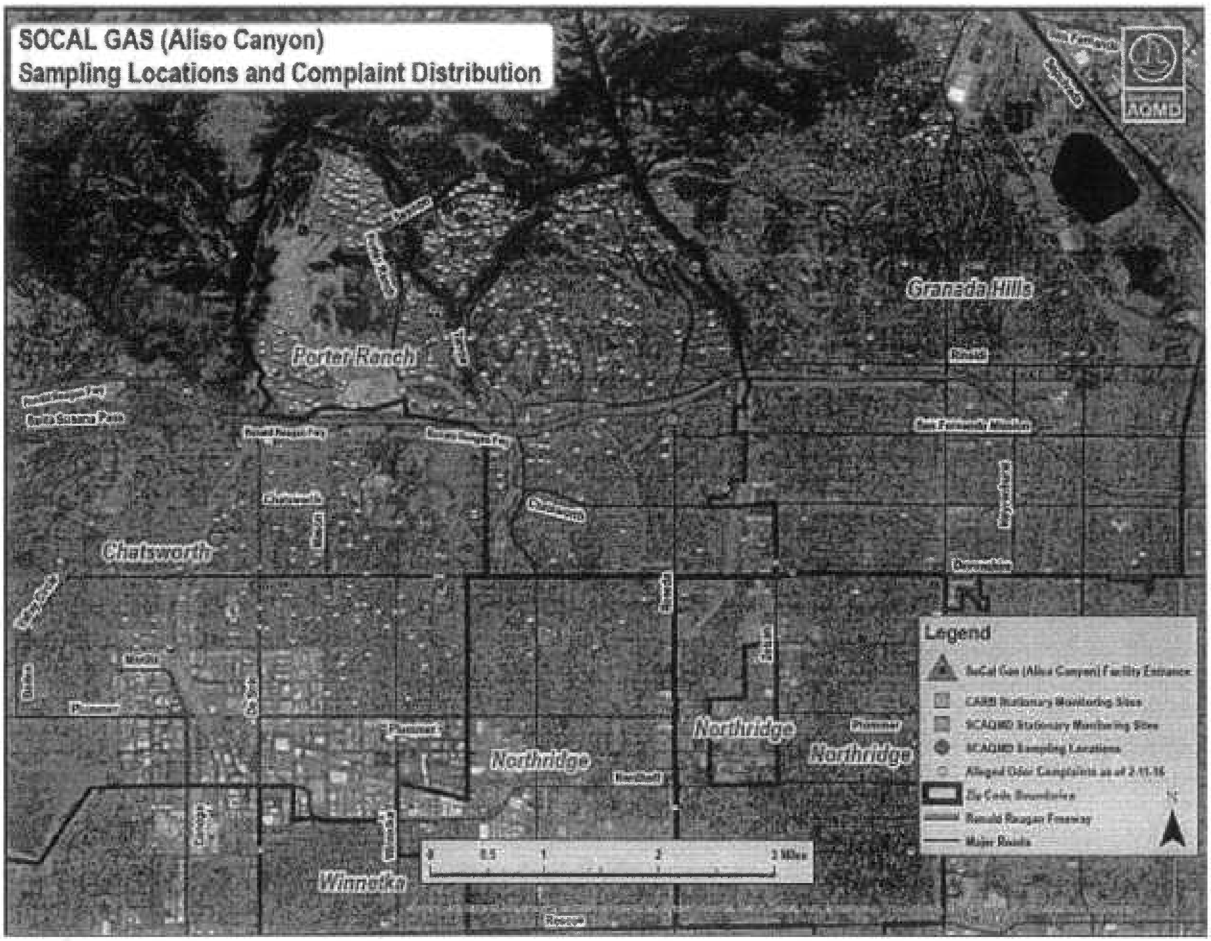
The discrete monitoring methods included:

- Instantaneous grab samples[23] and 12- and 24-hour canister samples that can collect over 50 volatile organic compounds (VOC), semivolatile organic compounds (SVOCs), metals, carbon monoxide, carbon dioxide, methane, ethane, polycyclic aromatic hydrocarbons (PAHs), and non-methane non-ethane organic carbon and sulfur species.
- Liquid scintillation activated charcoal canisters, which can be used to measure radon.

[22]https://www.alisoupdates.com/1443738525764/Facility-Supplemental-Sampling-Summary_02_15.pdf.

[23]Also referred to as short-term air samples, instantaneous grab samples are typically 10-minute samples used to assess air quality at a particular point in time, thus giving a very time resolved understanding of the ambient air, which then can be used to address specific community complaints or concerns.

Figure 14. SCAQMD and CARB sampling/monitoring locations



Each monitoring entity was responsible for reporting its own data. All agencies were committed to providing results to the public quickly and in a transparent and understandable way. Results from the SCAQMD samples were posted on its website as soon as the laboratory analysis was complete, within two to four days after sampling.[24] The results from SoCalGas sampling were summarized on the SoCalGas website under "air sample summary," which included detailed lab reports for each sample. The results for samples collected by LAUSD were posted on the LAUSD website.[25, 26]

Fixed Continuous Monitoring Sites

In December 2015, SCAQMD and CARB began to deploy a network of eight fixed ambient air monitoring sites throughout the Porter Ranch community to continuously measure methane, hydrogen sulfide (H_2S), total sulfur, and benzene (Figure 15)[27] in order to develop a baseline for various measurements and track the trends of pollutants throughout the leak event. The fixed locations allowed the agencies to collect reliable continuous measurements that provided a useful supplement to the discrete

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[24]http://www.aqmd.gov/home/regulations/compliance/aliso-canyon-update/air-sampling/laboratory-results---air-sampling-data.
[25]http://achieve.lausd.net/Page/4244.
[26]http://achieve.lausd.net/cms/lib08/CA01000043/Centricity/Domain/135/LAUSD_Radon_Testing_Report_MD.pdf.
[27]Slide 21, Federal Task Force – Aliso Canyon Presentation – June 9, 2016. Presented by Mohsen Nazemi, P.E., Deputy Executive Officer, Engineering and Compliance, SCAQMD to the Public Health and Environment Workgroup on June 9, 2016.

samples, which occurred at different locations throughout the community and provided only a snapshot of air quality during a particular sampling period. Methane and meteorological measurements were also collected at the SCAQMD's Reseda State and Local Air Monitoring Station (SLAMS)[28] monitoring site, located 3.5 miles to the south. Results from the continuous monitors were posted on the SCAQMD and CARB websites in near-real time.

All the CARB sites were located at residential properties in the community. The SCAQMD sites were located at the Porter Ranch Community School (Site #3), Highlands Community Pool (Site #4), and the Castlebay Lane Charter School (Site #6).

To ensure that the data collected during the SoCalGas natural gas leak were accurate and of robust quality, both CARB and SCAQMD implemented quality assurance and quality control checks throughout the monitoring network on a regular basis and performed on-site visits for routine maintenance of the instruments.

Mobile Methane Monitoring

In addition to the eight fixed monitoring sites, SCAQMD operated a mobile monitoring platform measuring methane concentrations[29] in order to better characterize methane concentrations and track emissions transport within the community and surrounding area. While methane itself is not harmful unless it is present in such high concentrations that it displaces the oxygen needed to breathe (generally only in confined spaces), methane measurements throughout the community served as markers for areas with high emissions that could potentially include other pollutants. Mobile methane measurements beginning on December 21, 2015, were performed during different times of the day under varying meteorological conditions. Methane emissions were also observed qualitatively with a Forward Looking Infrared (FLIR) thermal camera, which allowed SCAQMD and CARB to identify the plume of fugitive emissions in areas near SS-25 and to observe the eventual leak closure.

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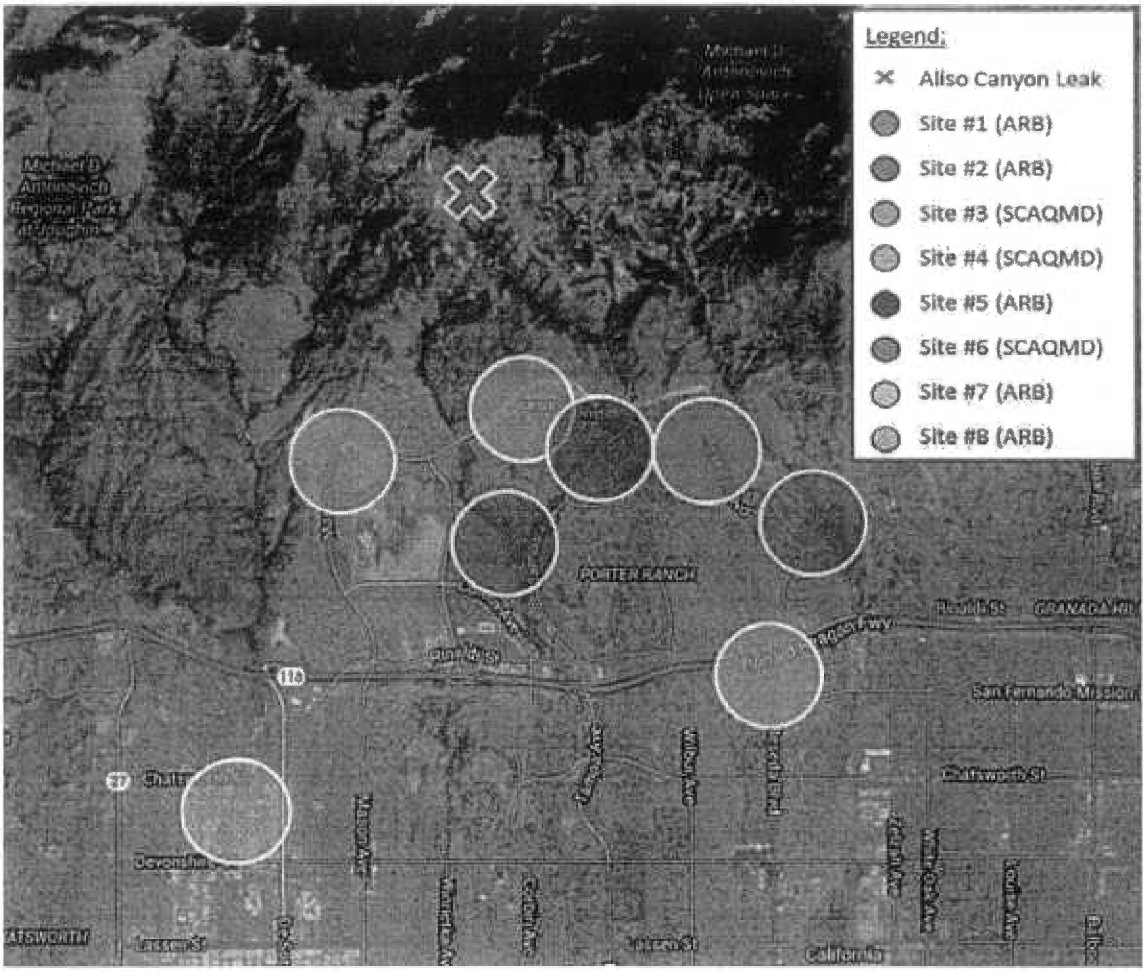
[28]SLAMS monitoring sites are part of the national ambient air monitoring network that typically measure the six criteria pollutant (Particulate matter, lead, ozone, nitrogen oxides, sulfur oxides, and carbon monoxide) in accordance with federal regulations contained in 40 CFR Part 50 and 58.

[29]LI-COR 7700 open path instrument and a Global Positioning System (GPS) mounted on a hybrid vehicle.

Figure 15. Map of fixed monitoring locations



Summary of Results of Ambient Air Pollutant Monitoring

Although final reports from the various ambient air monitoring studies have not yet been released, some preliminary results are available from SCAQMD[30] and the California Office of Environmental Health Hazard Assessment (OEHHA).[31] The collective studies found higher levels of certain air pollutants in some instantaneous samples in the Porter Ranch community. The same air pollutants were identified in a sample taken about 10 feet from SS-25.

The VOC concentrations did not exceed any available acute Reference Exposure Levels (RELs), which are concentrations of chemicals in the air that the general public can be exposed to without experiencing health problems.[32] Of the VOCs, benzene levels tended to be highest and most closely approached the

[30] http://www.aqmd.gov/home/regulations/compliance/aliso-canyon-update/health-impacts-estimates.

[31] http://oehha.ca.gov/air/general-info/aliso-canyon-underground-storage-field-los-angeles-county.

[32] RELs do not include consideration of cancer, which is evaluated using other methods. Exposure to a concentration that is higher than its REL does not necessarily cause health problems, because the RELs are based on several substantial uncertainty factors. A list of OEHHA Acute, 8-hour and Chronic RELs can be found here: http://oehha.ca.gov/air/general-info/oehha-acute-8-hour-and-chronic-reference-exposure-level-rel-summary.

corresponding acute REL. The sample with the highest levels of benzene (3.0 ppb) and other air toxics measured by SCAQMD, out of more than 70 instantaneous community samples, was collected on October 26, 2015, in Porter Ranch. Using the concentrations from that sample, SCAQMD calculated the acute health risk as approximately one-third of the REL. Out of more than 1,000 instantaneous grab samples collected by SoCalGas through February 13, 2016, the highest benzene levels (5.55 ppb) were reported on November 10, 2015. SCAQMD and OEHHA both found the estimate of acute health risk for that sample to be approximately two-thirds of the acute REL—still below the levels at which adverse health effects might begin to be observed.

SoCalGas also measured hydrogen sulfide in instantaneous samples in the Porter Ranch community. The majority of the samples had concentrations that were too low to be measured, but six community samples had detectable levels of hydrogen sulfide.[33] Among those six samples, five had concentrations well below the acute REL of 30 ppb, and only one instantaneous grab sample (collected on November 12, 2015) exceeded the acute REL, at 183 ppb. The only other sulfur-containing compound detected to date in the Porter Ranch neighborhood was a sulfur dioxide level of 54 ppb at the same location on the same day. While detectable, this was still below the sulfur dioxide acute REL of 250 ppb and below the EPA's 75 ppb 1-hour National Ambient Air Quality Standard for sulfur dioxide. These elevated levels of hydrogen sulfide and sulfur dioxide were not detected in other samples.

The majority of hourly methane levels measured at the fixed monitoring sites operated by CARB and SCAQMD were below 30 ppm. The highest hourly methane level measured at one of the sites was 96 ppm, observed on February 11, 2016, just prior to final well kill operations. While the levels are elevated, SCAQMD and CARB do not consider them to be a health concern.[34, 35]

In summary, agencies including LADPH, OEHHA, and SCAQMD reviewed the SCAQMD and SoCalGas data to determine whether there were public health risks associated with exposures to the measured air pollutants. The measured concentrations of air pollutants were below relevant thresholds of concern, except where noted above. More detailed information on the Aliso Canyon health risk assessments are provided in the following section.

Health Risk Assessment and Air Quality Criteria

On October 28, 2015, five days after the leak was discovered, LADPH was asked by the LA County Office of Emergency Management to assess whether the leak could be adversely affecting the health of nearby residents. On November 19, 2015, LADPH issued a Public Health Directive to SoCalGas, along with its first Preliminary Environmental Health Assessment based on its review of available environmental and health data at the time.[36] The directive ordered the gas company to continue the abatement process, eliminate odorous emissions, and provide free temporary relocation to residents who chose to relocate. The preliminary health assessment advised that "methane gas itself poses little direct health threat upon

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[33]The sample detection limit (SDL) is equal to the Detection Limit (1.58 ppbV) x Canister Dilution Factor X Analysis Dilution Factor. For most samples the SDL is approximately 3–4 ppb.

[34]There are no specific exposure limits for methane. Methane is a simple asphyxiant. Its primary health effects relate to its flammability as well as its ability to displace oxygen in certain situations within enclosed structures. The levels found in the community were far below the concentrations that would cause oxygen displacement. Levels of methane found in the community were substantially lower than flammable limits (50,000 ppm).

[35]http://www.aqmd.gov/home/regulations/compliance/aliso-canyon-update/air-quality-criteria.

[36]http://publichealth.lacounty.gov/eh/docs/AlisoCanyon.pdf.

inhalation in an outdoor space. Mercaptans, however, do pose a health threat to the community, including short-term neurological, gastrointestinal, and respiratory symptoms that may result from inhalation." The assessment went on to state that exposures to these pollutants would not constitute an immediate danger to life, and that permanent or long-term health effects were not expected. After the publication of that preliminary health assessment, LADPH went on to publish a number of reports summarizing the results of the SoCalGas monitoring data.[37]

OEHHA also convened an independent panel of scientific and medical experts to review public health concerns stemming from the gas leak, and to evaluate whether additional measures beyond those already put in place were needed to protect public health.

In conducting its assessment, OEHHA compared the measured peak concentrations to acute RELs in order to evaluate potential effects due to short-term exposures.[38] OEHHA also compared longer-term average benzene exposures to chronic RELs, although chronic RELs typically are used to evaluate exposures that last for at least 8 years.

One of OEHHA's earliest health risk assessments, from January 14, 2016,[39] concluded:

- Overall, the available air sample data did not indicate that an acute toxicity health hazard existed in the Porter Ranch neighborhood as a result of the Aliso Canyon natural gas leak.
- This did not mean that the adverse physical symptoms reported by many Porter Ranch neighborhood residents were not real. The natural gas odorants tert-butyl mercaptan and tetrahydrothiophene have strong odors that can be perceived at concentrations below the levels that can be detected in air samples. These odors can evoke physiological responses (e.g., nausea, headaches) without inducing more serious or longer-lasting health effects, such as eye or respiratory system damage.

The SoCalGas air samples measured levels of certain volatile organic compounds (VOCs) and sulfur-containing compounds, including benzene, hydrogen sulfide, and sulfur dioxide, all of which are pollutants that can be harmful to human health if levels are high enough. Key findings from OEHHA's review of the data included:

- Of the sampled VOCs, none was found to be above levels expected to result in adverse health effects.
- Benzene, a VOC, tended to have the highest levels, although they still were below levels expected to result in adverse health effects. (The highest sampled benzene concentration measured by SoCalGas, observed on November 10, 2015, in the Porter Ranch Community, was 5.55 ppb, which is approximately 70% of the acute health benchmark[40]).
- The level of sulfur-containing compounds (hydrogen sulfide and sulfur dioxide) sampled in the area were generally below detection limits and below levels expected to result in adverse health impacts,

[37]http://www.publichealth.lacounty.gov/media/gasleak/reportpress.htm.

[38]The assessment could only be conducted on pollutants for which a Reference Exposure Level (REL) exists. RELs are concentrations of chemicals in the air that the general public can be exposed to without experiencing health problems. RELs do not cover cancer, which is evaluated using other methods. Exposure to a concentration that is higher than its REL does not automatically cause health problems, because the RELs are based on several substantial uncertainty factors. A list of OEHHA Acute, 8-hour and Chronic RELs can be found here: http://oehha.ca.gov/air/general-info/oehha-acute-8-hour-and-chronic-reference-exposure-level-rel-summary.

[39]http://oehha.ca.gov/media/downloads/air/general-info/oehhaalisocanyonbackground01142016.pdf.

[40]Collected with 12-hour canister sample.

with one exception. On November 12, 2015, one instantaneous grab sample of hydrogen sulfide was above the acute health benchmark (183 ppb, which exceeds the acute health benchmark of 30 ppb). This elevated concentration was not repeated in other samples and was considered to be anomalous.

Subsequent updates to OEHHA's health assessments did not fundamentally change as new sampling data were collected. Evaluations of potential health impacts to the Porter Ranch community were also published by SCAQMD and the LADPH, and both agencies reached similar conclusions to those found by OEHHA.[41, 42]

OEHHA also convened an independent panel of scientific and medical experts to review public health concerns stemming from the gas leak and evaluate whether additional measures were needed to protect public health beyond those already put in place.[43], [44]

SCAQMD and CARB jointly developed a document titled "Criteria for Determining when Air Quality in the Porter Ranch and Surrounding Communities Has Returned to Typical (Pre-SS-25 Leak) Levels".[45] The criteria were developed to determine when air quality in Porter Ranch and the surrounding community returned to levels consistent with those that were typical prior to the leaking well at the Aliso Canyon natural gas storage facility.

Since February 11, 2016, when these criteria were first applied to the collected air data (after well closure), all laboratory samples and continuous monitoring data have met their respective criteria for mercaptans, benzene, and hydrogen sulfide. The only samples that have not met their criteria are a number of 12-hour methane samples collected by SoCalGas that were greater than the 3 ppm criterion for methane. According to the SCAQMD website:

> "It is possible that continued off-gassing of residual methane in the soil near SS-25 is causing higher measurements near the facility fence line. However, the reason for the slightly higher than criteria levels of methane at community sites located further south is unclear. ARB and SCAQMD are investigating to determine the cause, including reviewing potential sources and quality assurance between laboratories."

The methane criteria were set primarily to make sure that the SS-25 well had not resumed leaking. SCAQMD and CARB do not consider these levels to be a health concern, because health effects from methane exposure occur at levels far above the criteria level of 3 ppm.[46]

CARB staff also researched filtration technologies for portable indoor air cleaning devices and in-duct filters and identified those that were most likely to be effective in removing sulfur compounds and other chemicals likely to be in the plume. They communicated their recommendations to SoCalGas staff. In December 2015 and January 2016, guidance for selecting and maintaining an air cleaner, and a list of

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[41]http://www.aqmd.gov/home/regulations/compliance/aliso-canyon-update/health-impacts-estimates.

[42]The reports can be found on the LADPH website: http://www.publichealth.lacounty.gov/media/gasleak/reportpress.htm.

[43]http://oehha.ca.gov/media/downloads/air/document/alisocanyonadvisorypanel01152016.pdf.

[44]http://oehha.ca.gov/media/downloads/air/document/alisocynsummaryexpertadvisors02122016n.pdf.

[45] http://www.arb.ca.gov/research/aliso_canyon/aliso-canyon-criteria-description.pdf.

[46]Methane is a simple asphyxiant. Its primary health effects relate to its flammability as well as its ability to displace oxygen in certain situations within enclosed structures. The levels found in the community were far below the concentrations that would cause oxygen displacement. Levels of methane found in the community were substantially lower than flammable limits (50,000 ppm).

available air cleaners that appeared to be most effective for homes in the plume, were posted on a website developed specifically for the Aliso Canyon residents.[47]

Greenhouse Gas Emissions

Significant ambient air monitoring was conducted at and around the vicinity of the Aliso Canyon release, as discussed above. In addition to the methane data collection by CARB, a number of additional measurement resources were deployed by SCAQMD, LAUSD, SoCalGas, and others to quantify the methane emissions from the leak site by a variety of State, local, and Federal agencies in collaboration with several independent research teams. They included measurements near the ground at the well site, at tall monitoring network towers, and from airplanes and satellites. The efforts were intended to calculate the direct emission rates in order to help estimate the total methane emissions associated with the leak.

Aircraft Studies

Based on four airborne samples collected over the first 6 weeks of the release, the average leak rate was estimated to be 53 metric tons of methane per hour. The leak rate showed a decreasing trend after the initial 6 weeks, likely due to a deliberate effort, beginning on November 11, 2015, to withdraw natural gas to reduce the pressure in the subterranean reservoir. The estimates collected between November 7, 2015, and February 4, 2016, were interpolated over time to arrive at a total estimate of methane emitted from the event. In a February 2016 journal article, Conley et al. estimated the total mass of methane released at 97,100 metric tons over the 112-day duration of the leak.[48, 49]

On February 13, 2016, CARB publicly released its preliminary estimate of cumulative methane emissions from the Aliso Canyon natural gas leak, based on flights and updated estimates of hourly methane emissions. The February 2016 CARB preliminary estimate was 94,500 metric tons of methane.[50]

In January and February 2016, several flights funded by the National Aeronautics and Space Administration (NASA) were made for rapid response airborne surveys over Aliso Canyon with two Jet Propulsion Laboratory (JPL) imaging spectrometers. The results are being validated against measurements of methane mixing ratios from other aircraft and surface vehicles, surface observations of wind direction and speed, and up-looking thermal plume imaging. Results will be published in 2016 or early 2017.

Tracer flux from instrumented vans

Under contract with SoCalGas, Aerodyne conducted a study to estimate methane emissions by using nitrous oxide as a "tracer" in the released gas. From December 21, 2015, to March 8, 2016, Aerodyne released a known concentration of nitrous oxide near the well, then measured the nitrous oxide and methane concentrations downwind of the site. Because the concentration of nitrous oxide released at the well is known, and can be compared to the measured nitrous oxide concentration downwind, that information together with co-located measured methane concentrations can be used to estimate the

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[47]http://www.arb.ca.gov/research/indoor/aircleaners/air_cleaners_gas_leak.htm.

[48]While several data sources discussed here provide uncertainty ranges on certain components of their data (e.g. estimate for an individual day or flight), uncertainty ranges were not available from the sources for the estimates of the total methane released by the leak.

[49]Methane emissions from the 2015 Aliso Canyon blowout in Los Angeles, CA; *Science*, 18 March 2016.

[50]Aliso Canyon Natural Gas Leak Preliminary Estimate of Greenhouse Gas Emissions; CARB, as of April 5, 2016.

concentration of methane released from the well. This process is referred to as the "tracer flux ratio" method. Although the study has not yet been published, the Aerodyne estimate of the release is understood to be 86,000 metric tons of methane.[51]

Stored Gas Inventory Analysis

Stored gas inventory analysis is an industry standard method used to determine the quantity of natural gas in an UGS reservoir. The basic data used for inventory analysis are well pressures and measured volumes of gas metered into and out of the field (injection and withdrawal).[52] SoCalGas conducts periodic pressure checks of the reservoir, which require a complete multi-day shutdown of the reservoir field to let the pressure equalize throughout the reservoir. These events are referred to as "shut-ins." SoCalGas used the most recent data from "shut-in" events, which were gathered in the spring and fall of 2014 and again in late February 2016 to estimate emissions. The February 2016 shut-in inventory was done between February 19 and 29, after SS-25 was sealed. These pressure data were used to calculate total natural gas volumes and to calculate the leaked methane by accounting for total injections and withdrawals. This approach yielded a total leak estimate of 4.62 bcf of natural gas, which translates to emissions of approximately 84,200 metric tons of methane. The leak at Aliso Canyon was the largest release of methane to the atmosphere from a UGS facility in U.S. history. The 2004 UGS leak at Moss Bluff, TX, was burned as it was released, converting the methane to carbon dioxide and resulting in a lower climate change impact.

CARB Final Estimates of Methane from Aliso Canyon

CARB will issue a revised estimate of the leak from Aliso Canyon after reviewing data available from numerous monitoring methods. Consideration of multiple measurement methods should provide for a more robust assessment of methane emission rates and result in an improved quantification of emissions compared to the preliminary assessment. The final State calculation of total methane emitted, based on the full set of data, is anticipated to be released by CARB in 2016.

Environmental Impacts

This methane release is likely the largest of its kind ever in the United States, exceeding methane emissions from other known gas release incidents, such as those occurring at storage facilities in Moss Bluff, TX, in 2004 and Hutchinson, KS, in 2001. For context, the radiative forcing of about 90,000 metric tons of methane over the next 100 years is equivalent to the atmospheric release of more than 2 million metric tons of carbon dioxide—using 100-year methane global warming potential (GWP)[53]—or the greenhouse gas emissions of around 500,000 passenger cars driven for 1 year.[54, 55] CARB, in its mitigation

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[51]*Airborne Estimate of surface emissions*, slide presentation by Dr. Stephen Conley and Ian Faloona, presented at CARB's Methane Symposium on June 6, 2016; http://www.arb.ca.gov/cc/oil-gas/Conley_Presentation_ARB%20(1).pdf, accessed August 3, 2016.

[52]Aliso Canyon Underground Gas Storage Facility - Methane Emission Estimates, SoCalGas, June 14, 2016.

[53]Fifth Assessment Report of the United Nations Intergovernmental Panel on Climate Change (AR5), Synthesis Report, Box 3.2. The 100-year GWP of methane is 28 in AR5, and is 25 in AR4. EPA's Inventory of Greenhouse Gas Emissions and Sinks notes that methane emissions from the energy sector totaled 328 million metric tons of CO2 equivalent in 2014.

[54]USEPA Greenhouse Gas Equivalency Calculator, https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator; accessed June 13, 2016.

[55]The concept of the Global Warming Potential (GWP) was developed to allow comparisons of the global warming impacts of different gases. The U.S. primarily uses the 100-year GWP as a measure of the relative impact of different greenhouse gases (GHGs). However, the scientific community has developed a number of other metrics that could be used for comparing one GHG to another. These metrics may differ based on timeframe, the climate endpoint measured, or the method of calculation.

program, uses a 20-year methane GWP resulting in methane emissions equivalent to about 8 million metric tons of carbon dioxide.

Post-Well Closure Indoor Air and Source Sampling/CASPER Health Assessment

Following the closure of SS-25 in mid-February, residents began returning to their homes from temporary housing. From late February into March, LADPH began receiving a large number of health complaints from the Porter Ranch community. The complaints included reports of headache, nasal congestion, sore throat, respiratory problems, nausea, dizziness and skin rash. Symptoms ceased when residents returned to temporary housing located outside of the area affected by the gas leak.

On March 23, 2016, LADPH announced a protocol developed in conjunction with EPA Region 9, UCLA, CARB, SCAQMD, and others for sampling the interior of homes for residual contamination from the release. The protocol was intended to address volatile contaminants that had been measured in ambient air during the release, as well as semi-volatiles and metals that may have been present in the geological formation or in the material used during the top kill attempts and released into the air.

In an effort parallel to the indoor sampling, LADPH, with the help of the California Department of Public Health (DPH), began a Community Assessment for Public Health Emergency Response (CASPER) health assessment on March 10-12, 2016. Initial results of the assessment indicated that there were health issues reported that could be related to the gas leak or other emission sources near the storage facility.[56]

On April 20, 2016, LADPH collected six soil samples in the vicinity of SS-25 to address a data gap in the environmental sampling. Some soils near SS-25 were visibly impacted by non-volatile constituents of the release. While the soil data could have been biased by chemical breakdown, volatilization, and other weathering, it was judged as the best indicator of chemical signatures of the release that might persist in the community. These samples indicated elevated levels of chemicals including hydrocarbons up to C_{40}, barium, and naphthalene.

On May 13, 2016, LADPH released its public health assessment report, titled *Environmental Conditions and Health Concerns in Proximity to Aliso Canyon Following Permanent Closure of Well SS-25.*[57] The report presented the results of both the indoor exposure evaluation and the CASPER health effects evaluation.[58]

Indoor Exposure Evaluation

LADPH relied on testing and analysis protocols used in other environmental incidents. Using a list of 200 chemicals potentially associated with both natural gas leaks and well closure attempts at Aliso Canyon (including drilling material components), LADPH selected for analysis metals, semi-volatile organic compounds (SVOC), volatile organic compounds (VOC), and petroleum hydrocarbons. A subset of this group was identified as priority chemicals of potential concern: sulfur compounds, benzene and other volatile organic compounds, barium, petroleum hydrocarbons, and polycyclic aromatic hydrocarbons. Because reported symptoms occurred after residents returned to their homes, LADPH considered that symptoms could be the result of exposure to indoor air or from surfaces in homes, and tested for chemical

[56]http://publichealth.lacounty.gov/media/docs/assessment.pdf.

[57]http://www.publichealth.lacounty.gov/media/docs/PublicHealthAssessment.pdf.

[58]Results are presented in Appendix A of the following report:
http://www.publichealth.lacounty.gov/media/docs/SummaryFieldSamplingReport.pdf.

contaminants in both indoor air and household surface dust in 114 homes and two schools. Eleven of the homes, located 6 miles from SS-25, were used as a comparison group.

Surface wipe sample analysis showed a pattern of barium plus other metals in Porter Ranch homes not observed in comparison homes. This pattern is consistent with the composition of barium sulfate drilling fluids used in well kill attempts. Indoor air analysis showed that levels of chemicals detected were similar between Porter Ranch homes and comparison homes, and were consistent with expected background levels in home environments.

CASPER Health Effects Evaluation

LADPH developed two survey tools to collect information on health symptoms experienced by residents in the Porter Ranch community. The first survey tool used was a Community Assessment for Public Health Emergency Response, or CASPER, to collect information from a representative sample of 210 homes within a 3-mile radius of SS-25. The CASPER survey was conducted March 10-12, 2016. The second survey tool was a modification of the CASPER survey directed to the approximately 100 households participating in the indoor exposure evaluation to assess the health symptoms experienced by residents.

The majority of households experienced health symptoms in the month following well seal. Households closer to the well were more likely to report health symptoms or oily residue. There was no difference in reports of gas odor in relation to well proximity. The majority of households reported using air cleaners or purifiers.

Home Cleaning Activities

On May 13, 2016, LADPH issued a Directive to SoCalGas to offer comprehensive cleaning to all homes in Porter Ranch, all homes of relocated residents, and all homes within 5 miles where residents experienced symptoms.[59] This directive was followed by a May 20, 2016, ruling from the Los Angeles Superior Court that ordered SoCalGas to pay for cleaning the homes of those households participating in the SoCalGas relocation program. According to SoCalGas, all residents who had been relocated at the time of the ruling have returned home after the completion of interior home cleaning.[60]

Additional Sampling Activities

On June 22, 2016, June 23, 2016, and July 9, 2016, LADPH collected samples from community pools in three Porter Ranch neighborhoods. Samples were analyzed for petroleum hydrocarbons (EPA Method 8015B), metals (EPA Method 6010B), and mercury (EPA Method 7470A). Petroleum hydrocarbons and mercury were not detected in any of the samples. Several metals were detected, including barium ranging from 0.085 to 0.422 milligrams per liter (mg/L), which is below the Federal maximum contaminant level (MCL) for drinking water of 1 mg/L.[61] According to LADPH, the purpose of this sampling was to provide guidance regarding the collection and analysis of water from the selected community swimming pools. The resulting data will be used to assess potential public health impacts of the gas leak event on water quality in pools, though no public health statements have yet been issued.

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[59] http://www.publichealth.lacounty.gov/media/docs/LACHODirectivetoSCG(w%20Atts).pdf.

[60] https://www.alisoupdates.com/our-commitments.

[61] The protocol and report are available at: http://publichealth.lacounty.gov/media/docs/CommunityPoolWaterSamplingProtocol.pdf.

Greenhouse Gas Mitigation Plan

Mitigation of the greenhouse gas impacts from the Aliso Canyon natural gas leak is not required under California regulations, nor are fugitive emissions capped by California's economy-wide greenhouse gas cap and trade program. On December 7, 2015, the City of Los Angeles filed a civil lawsuit in California Superior Court in Los Angeles against SoCalGas in connection with the Aliso Canyon leak. In early 2016, CARB joined the suit. The lawsuit includes claims alleging that methane emissions from the leak have created a nuisance and have impaired and polluted the environment. The complaint seeks relief related to the leak's climate impacts.

On December 18, 2015, SoCalGas sent a letter to Governor Brown confirming the company's commitment to "mitigate environmental impacts from the actual natural gas released from the leak" and "work with State officials to develop a framework that will help us achieve this goal." On March 31, 2016, CARB recommended a program to achieve full mitigation of the climate impacts of the Aliso Canyon natural gas leak. CARB's development process included consultation with other State agencies and two rounds of public comment. CARB recommends that the emission reduction offsetting component should focus on reducing methane emissions from California agriculture (including dairies) and waste (including landfills and wastewater) that would allow for a direct ton-for-ton comparison between leaked emissions and emissions reductions from mitigation projects. CARB notes the pending litigation and its potential effect on any mitigation program.

Southern California Gas and Electric System Reliability Analysis

Role of Aliso Canyon in SoCalGas and Electric Reliability

SoCalGas owns and operates an integrated natural gas pipeline system consisting of intrastate pipeline and four storage facilities. The SoCalGas system has the capacity to accept up to 3.875 billion cubic feet per day (Bcfd) of natural gas supply, primarily from the southwestern United States, the Rocky Mountain region, Canada, and California, but system supplies generally do not exceed 3.0 Bcfd. The SoCalGas system uses natural gas from storage and pipeline supplies to meet customer demand. As a result, storage fields are essential operating assets in the SoCalGas system for delivering natural gas and maintaining pipeline pressure while serving all demand for natural gas and allowing for operating flexibility.

The four SoCalGas storage fields have a combined capacity of 136.1 billion cubic feet (Bcf), with the ability to inject up to 850 MMcfd and withdraw up to 3.68 Bcfd. Aliso Canyon is the largest storage field, with storage capacity of 86.2 Bcf, withdrawal capacity of 1.9 Bcfd, and injection capacity of 0.4 Bcfd. During the leak, California State agencies ordered SoCalGas to withdraw natural gas from Aliso Canyon in order to reduce the rate of the gas leak by reducing the pressure at the field. The field was drawn down to 15 Bcf, all of which remained available as of October 2016 in storage at Aliso Canyon to meet peak day demands and maintain system pressure. SoCalGas will need CPUC approval to begin any injections at Aliso Canyon, although it can withdraw from storage the remaining 15 Bcf if needed.

The absence of Aliso Canyon's full storage capabilities especially affects SoCalGas's Los Angeles local gas pipeline system, the L.A. Loop. The L.A. Loop is a low-pressure local pipeline system that serves a number of customers, including 17 power plants which, in sum, have a total generating capacity of about 9,400 megawatts (MW).[62] Given Aliso Canyon's size, it is important to maintaining pressure on that part of the SoCalGas system. For example, if pipeline pressure on the L.A. Loop drops too low, SoCalGas may be forced to curtail natural gas deliveries to the power plants. The three other SoCalGas storage facilities (Honor Rancho, La Goleta, and Playa del Rey) are smaller and less capable of providing natural gas to the L.A. Loop.

The amount of natural gas-fired generation on the L.A. Loop makes maintaining pipeline pressures more difficult. The power produced by the natural gas-fired generation on the L.A. Loop fluctuates continuously, because it provides ramping supply to accommodate the variability of renewable generation. The most extreme daily ramp occurs during the afternoon, when solar generation declines due to the changing angle of the sun and natural gas-fired generation must increase to meet increased load.

The increase in net electric load (load minus variable renewable generation) from daily minimum to maximum load in the afternoon to evening coincides with the increase in locally located renewable generation. While the significant growth in wind and solar generation over the past few years has reduced the net electric load served by all conventional generation, it has also increased the need to ramp up large amounts of natural gas-fired generation each afternoon to make up for the decline in solar output that occurs during the afternoon peak in electricity demand.

Gas-fired generation is typically used to meet this increase in demand for conventional generation because of its ability to respond to changes in demand quickly and efficiently, as compared with other conventional generation. This results in increased demand for natural gas pipeline deliveries and storage withdrawals. The loss of Aliso Canyon has greatly reduced the ability of storage to help meet the surge in gas demand required to support the daily ramping requirement and evening peak load in Southern California.

In prior summer periods, SoCalGas used Aliso Canyon primarily to maintain pipeline pressure, and also to assist in meeting peak demand. On average, SoCalGas withdrew natural gas from Aliso Canyon approximately 10 days per month during the summer. Between April and October, SoCalGas normally injected gas into Aliso Canyon, refilling it by the end of October so that it could be used to meet winter peak gas demand.

In prior winter periods (November-March), SoCalGas demand peaked at 5.1 Bcfd, of which 1.0 Bcfd (about 20%) was demand from electricity generation facilities. Because SoCalGas pipeline capacity for imports into Southern California is only 3.875 Bcfd, Aliso Canyon has been used to make up the difference on peak days. Toward the end of winter, SoCalGas typically has begun refilling the field to support summer needs. Concerns for winter 2016/2017 are discussed below.

Gas Balancing

In general, the largest potential cause of gas curtailments in the summer occurs when the natural gas nominated for delivery on the SoCalGas system is significantly less than gas demand, or when demand

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[62]The 17 power plants connected to the L.A. Loop, with a combined capacity of 9,388 MW, include: Los Angeles Water and Power (LADWP) Haynes, LADWP Scattergood, LADWP Valley, LADWP Harbor, Southern California Edison (SCE) Alamitos Toll, SCE Huntington Beach, SCE Redondo Beach, SCE Barre Peaker, SCE Center Peaker; El Segundo Energy Center, Long Beach Generation, City of Glendale, City of Burbank, City of Pasadena, City of Anaheim-Canyon Power, City of Vernon-Malburg, and Southern California Public Power Authority-Magnolia.

exceeds the short-term delivery capability of the gas system, creating an imbalance. Large imbalances reduce pipeline operating pressure. If pressure drops enough, reliability of gas service to gas-fired generators and other customers is jeopardized. This is of particular concern during periods of high demand for electricity generation during the summer, when natural gas is used by generators to serve electricity demand. Other challenges occur during periods when predicting demand (and thus generator dispatch) becomes especially difficult, such as periods of monsoon cloud cover.[63] In addition, large changes in electricity generation (which, in practice, translate to large changes in demand for natural gas) within short periods push the limits of the gas system's ability to keep up without the nearby supplies formerly stored in Aliso Canyon. The electricity generators in the SoCalGas L.A. Loop have limited access to additional gas during the day to meet unanticipated shortages in gas supply. Gas that is available at connecting interstate pipelines at the Arizona-California border cannot be delivered in real time to electricity generators in the L.A. Loop, because gas moves through the transmission system at approximately 25 miles per hour.

If demand for natural gas approaches any of the gas system's constraints, SoCalGas can issue an Operational Flow Order (OFO) in order to maintain gas system pressure. During an OFO, customers must keep actual gas demand close to their nominated amounts on the SoCalGas system or face penalties. If an OFO fails to improve the match of flowing gas to use, SoCalGas can order curtailments of gas supply to non-core customers, which include electricity generators. The loss of a curtailed generator can be mitigated by redispatch of the electric system, but the amount of generation available for re-dispatch is limited. In 2016, to mitigate the impacts of the limited operation of Aliso Canyon, SoCalGas issued OFOs identifying the need to keep gas flows and usage within a 5-percent tolerance to maintain pipeline pressures during certain conditions.

Compounding Concurrent Events

Potential curtailments of natural gas supply can occur as a result of concurrent events on the gas or electricity systems. Such events may place additional constraints or exhaust any operating margin on the gas system, which will limit the rate at which gas can flow. Events may include:

- Scheduled maintenance and testing of natural gas pipeline systems that may remove facilities from service or reduce the capacity of those facilities (work on the gas pipeline typically is performed during non-winter months to prepare the natural gas system to meet winter peak demands for heating)
- Forced outages due to equipment failures on the SoCalGas system
- Lack of supply into the SoCalGas system from upstream pipeline interruptions
- Deviation in actual demand from forecasts of both core (residential and commercial) and non-core (electric and industrial) natural gas customers during periods of rapidly changing weather
- Temperatures higher or lower than expected that translate into unexpected demand for electricity.

Implications for Summer Operations

During the summer of 2016, the loss of Aliso Canyon increased the likelihood of curtailments of natural gas deliveries to generators because of a lack of supply or problems maintaining sufficient pipeline pressure, which subsequently increased the likelihood of regional electricity generation shortages. The

[63]Monsoon rain storms typically develop in hot summer afternoons which result in significant cloud cover and rain which block the sun, which lowers solar electric production.

analysis performed in the Joint California Agencies April 2016 Aliso Canyon Risk Assessment Technical Report[64] estimated, in a worst case scenario, that there would be up to 14 days of loss of load and 16 days of gas curtailments during the summer of 2016. The determination of the number of loss of load and gas curtailment events assumed concurrent events, ineffective mitigation measures, and/or no gas withdrawals from Aliso Canyon.[65] As of September 2016, there were no loss of load events from curtailments of natural gas supply.

The California Independent System Operator (CAISO) and the LADWP have the ability to change their electricity generation dispatch to absorb some curtailments, depending on local and system demand. CAISO has said that it can re-dispatch about 1,500 MW out of the area affected by a curtailment; beyond that, it is at risk of being unable to serve all anticipated electric loads.[66] As of September 2016, the entities have been able to avoid electricity curtailments primarily by being attentive to the need to balance natural gas supply and demand more tightly and through the occasional use of "flex alerts," which signal electricity consumers to reduce electricity usage where possible during periods of expected high electricity use (e.g., high temperatures).

Electric Reliability Concerns for Winter 2016–2017

The *Joint California Agencies Winter Technical Analysis Report*[67] indicates that, through a series of significant mitigation measures, the L.A. Basin electric power system is expected to be able to maintain reliability for the winter 2016-2017 without interruption to electric service. This is despite the fact that winter normally brings a significant increase in natural gas demand from the residential and commercial sectors for heating needs. In a typical winter, SoCalGas meets its peak demand with a combination of pipeline gas and storage withdrawals from facilities like Aliso Canyon. Without Aliso Canyon for winter 2016-2017, the likelihood of natural gas supply curtailments, and reductions in electric power generation, increases. In addition, unforeseen events during the upcoming winter period—such as upstream supply interruptions into the SoCalGas system, gas well "freeze offs," and other equipment failures that can occur during very cold weather—may present energy reliability challenges.

However, because electricity demand throughout the U.S. Southwest is lower in the winter than in the summer, there is an ability to use spare capacity on electric transmission lines and at power plants outside the L.A. Basin to import power if SoCalGas needs to curtail gas deliveries to power plants inside the L.A. Basin. That extra capacity can be used to reduce electric reliability concerns.

Mitigation of Reliability Concerns

To mitigate the reliability risks associated with the loss of Aliso Canyon, FERC, CEC, CPUC, and SCAQMD have taken regulatory and other actions, including the following:

- FERC expedited approval of additional authority, processes, and cost recovery that CAISO claimed it needed to operate reliably.

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[64]http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf.

[65]http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf.

[66]Re-dispatching the system involves reducing generation at one or more generation plants and increasing generation at other generation plants while maintaining load-generation balance.

[67]http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN212913_20160823T090035_Aliso_Canyon_Winter_Risk_Assessment_Technical_Report.pdf.

- The SCAQMD approved temporary variances to allow fuel switching of some of LADWP's electric generation plants in the L.A. Basin.
- The Joint California Agencies—CEC, CPUC, LADWP, and CAISO—analyzed the risks of operating without Aliso Canyon, suggested mitigation measures, and raised awareness of the issues through workshops, technical conferences and presentations at regulatory meetings to disseminate information on how each of the entities (both gas and electric) are preparing to address electric reliability issues.
- The CPUC approved a settlement addressing SoCalGas's operational issues.

The implementation of OFO and CAISO stakeholder processes has helped to raise awareness of the operational problems created by the Aliso Canyon outage. The market changes implemented in response to the Aliso Canyon have motivated generators and other gas shippers to better balance their gas supplies with their usage. Previously, SoCalGas balanced its system on a monthly basis, which allowed customers great flexibility in either under-taking or over-taking nominated gas volumes each day, provided that the amounts evened out over each month. The outage at Aliso Canyon has all but eliminated the ability to operate with that level of flexibility. SoCalGas has frequently used OFOs to require shippers to balance natural gas supply and demand by keeping their daily natural gas demand close to their daily pipeline nominations.

Peak Reliability, the WECC reliability Coordinator, has also been involved in local and regional procedures and activities to ready regional operators for possible system issues, ranging from local calls for conservation to the delivery of capacity and energy from resources across the Western Interconnection to the L.A. Basin. Peak Reliability has also reviewed firm load shed plans and procedures in preparation for shortages.

Gas/Electric System Reliability Conclusions for Southern California

Aliso Canyon has historically been a significant storage facility on the SoCalGas system used to meet peak day demand and maintain system pressure. Preparing the gas and electric systems for the absence of Aliso Canyon, by defining new gas balancing parameters, training personnel, and addressing barriers to sharing information on gas and electric deliveries into the southern California region has played and will continue to play a key role in avoiding electric load curtailments since the Aliso Canyon leak.

During 2016 summer operations planning, day-ahead scheduling, and real-time operations, the information flow between gas and electric operation planners enhanced existing processes. This led to the adjustment and coordination of gas and electric maintenance schedules in order to avoid overlapping outages that could lead to gas curtailments of electricity generation, which in turn could lead to blackouts. The information flow to both gas and electric operations and market personnel in the day-ahead gas and electric scheduling processes permitted the adjustment of gas and electric energy schedules to help balance both systems to minimize OFOs and avoid gas curtailments.

This winter, additional preparation and coordination are required in order to avoid gas and electric curtailments.

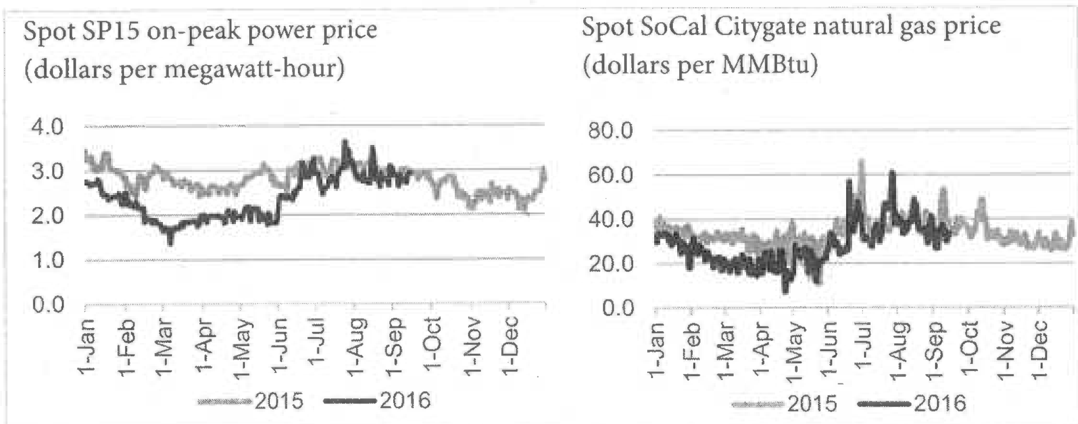
Gas/Electric Price Analysis

Summary

Through mid-September 2016, Southern California natural gas and electric prices have continued to trade within ranges set during 2015, despite restrictions on the use of the Southern California Gas Company's

(SoCalGas) Aliso Canyon natural gas storage field at Porter Ranch in Los Angeles County (Figure 16). However, the spread between the price of forward contracts for natural gas delivery in winter 2016-17 in Southern California and those for delivery at Louisiana's Henry Hub, the most important trading center for natural gas in the United States, have widened substantially from year-ago levels (Figure 17). The wider current spread is consistent with an anticipated lower level of natural gas storage deliverability from the SoCalGas system compared to expectations prior to the leak at the Aliso Canyon facility that began in October 2015 and was plugged in February 2016.

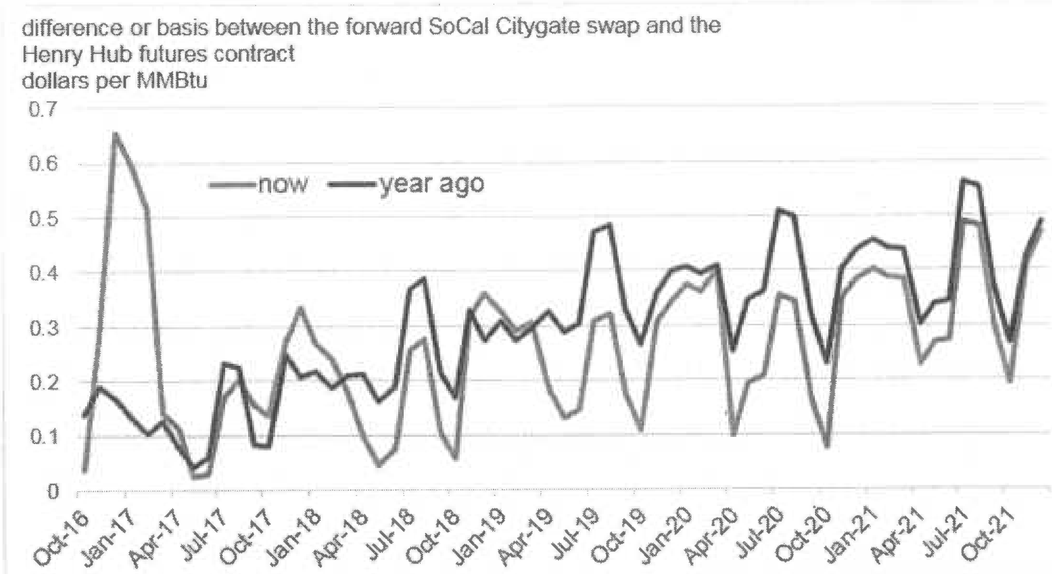
Figure 16. Southern California spot electricity prices and spot natural gas prices down slightly in 2016 compared to 2015



Note: Covers January 1, 2015-September 15, 2016.
Source: SNL Energy.

Retail energy prices are different from wholesale prices. Retail prices are determined through regulatory processes that incorporate average wholesale prices with other energy delivery expenses. Because of regulatory decisionmaking, retail prices can vary significantly by customer class and energy usage. Recent changes in retail natural gas costs are most directly linked to changes in wholesale natural gas prices.

Figure 17. Forward basis swaps for natural gas are much higher during winter 2016-17 due to lower Southern California natural gas inventories, but this effect moderates over time



Source: Bloomberg, L.P. Data reported as of September 9, 2016.

Additional Discussion

The Aliso Canyon facility plays a key role in helping to balance natural gas supply with the needs of natural gas customers, including electricity generators, in the Los Angeles basin. During the summer months, natural gas withdrawn from Aliso Canyon supports electricity generation at in-region gas-fired plants when peak or near-peak levels of in-region electricity generation are required to meet electricity demand. The electricity produced by gas-fired plants in the Los Angeles basin augments other electricity supplies. These additional supplies include:

- electricity generated from gas-fired power plants in Southern California but outside of the L.A. basin
- electricity generated by fuels other than natural gas
- electricity imported from outside Southern California.

Understanding the effects of Aliso Canyon's operating status on regional wholesale and retail electricity and natural gas prices is difficult, because the power and natural gas markets in Southern California have many moving parts. However, key findings on the effects of Aliso Canyon's status on energy prices in Southern California since last October show that:

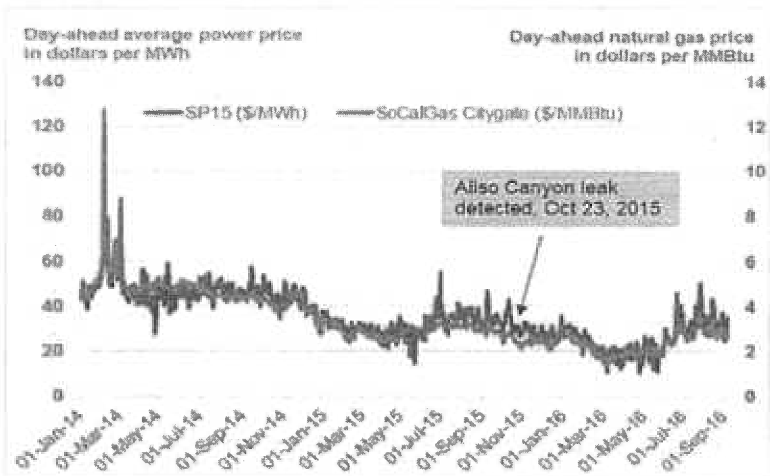
- A combination of factors have influenced trends in spot natural gas and electricity prices since the detection of the leak at the Aliso Canyon storage facility: SoCalGas storage use limitations; the fall and rise in Henry Hub natural gas prices; higher levels of electricity imports, in-State hydroelectric availability, and solar generation; and moderate load conditions.
- Wholesale, next-day, or spot natural gas prices have been generally lower but more variable during the summer of 2016 compared to the summer of 2015. For example, during several heat waves this summer the differential in the spot prices of natural gas between Southern California trading points and the Henry Hub reached winter levels; operating restrictions at Aliso Canyon likely contributed to these higher basis differentials.

- Despite changes in the regional capacity generating mix, natural gas is often the fuel that helps determine the price of electricity in Southern California.
- Wholesale electricity prices at the SP15 trading hub in Southern California in mid-September 2016 were about 8% lower than SP15 prices a year ago, despite the restrictions on Aliso Canyon.
- Higher retail prices for natural gas in Southern California starting in April 2016 probably coincided with the general rise in natural gas prices at the Henry Hub.
- The retail price of electricity in Los Angeles, Riverside, and Orange counties in July 2016 (latest data available) was about 21 cents per kilowatthour, or about the same as the retail electricity price in September 2015, according to the Bureau of Labor Statistics.

Southern California electricity fundamentals. Overall, Southern California electricity load is up by about 2% this summer (April 1 – September 12) compared with the same period in 2015, which reflects little change in cooling degree days (CDDs) in Los Angeles through summer 2016. Because of the high level of precipitation in California last winter, in-State hydroelectric generation has nearly doubled so far in 2016 compared to the same period in 2015, up by almost 1,200 megawatts (MW). Generation from renewables, including solar and wind, is up by 18%, and overall electricity imports are up by 2%. As a result, thermal generation reported by the CAISO, which covers a majority of electricity sales in California, mostly from natural gas, is down by 20% year-to-date.

Thermal generation, nearly all gas-fired in California, is often the marginal source of electricity in the power market in California. Consequently, Southern California power prices tend to move in fairly close coordination with natural gas prices; however, other factors occasionally drive them apart (Figure 18).

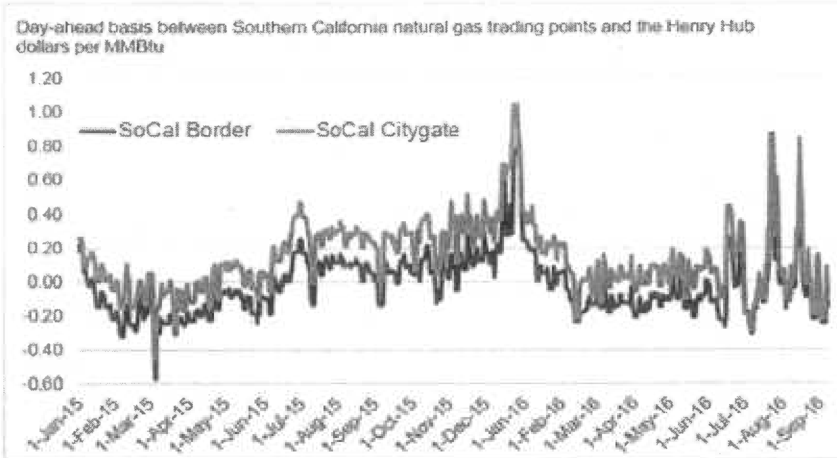
Figure 18. Southern California power prices continue to move with natural gas prices after Aliso Canyon use restrictions



Source: SNL Energy. Data provided for January 1, 2014–September 8, 2016.

Southern California natural gas fundamentals. On average, the natural gas load met by SoCalGas to date in 2016 is similar to the load in the same period for 2015. The increase in the price of natural gas in Southern California since April is attributable, in part, to rising prices across the United States. Before more volatile summer electric generation demands began to affect regional natural gas prices, 2016 Southern California natural gas prices were actually slightly closer to prices at the Henry Hub, the key benchmark for pricing natural gas throughout the United States (Figure 19).

Figure 19. Price differences or basis between Southern California natural gas trading hubs and the benchmark price of natural gas at the Henry Hub have been more volatile during summer 2016



Note: "Basis" is the difference between natural gas priced at the Henry Hub and natural gas priced at another geographic location such as the Southern California Border or the SoCal Citygate.
Source: Bloomberg, L.P. Data provided for Jan 1, 2015-Sept 8, 2016.

The pace of net national natural gas storage injections slowed this summer. Record natural gas inventories at the end of winter—due to a warm winter, slowing production, and rising demand—contributed to lower net average storage injections this summer and boosted expectations for natural gas prices.

Despite the slower-than-normal pace of injections during the 2016 refill season so far, U.S. working gas stocks were 7% above the 5-year average (2011-15) as of September 30, 2016. However, working gas stocks in the Pacific region were down by 25 Bcf, or 7% below the 5-year average for this time of year, mostly because of the injection limitations at the Aliso Canyon storage facility.

The October bidweek prices (or the price established during the last 3-5 business days of each month when buyers and sellers may transact for natural gas for the upcoming month) for wholesale natural gas at key trading points in Southern California settled between $2.80 and $2.95 per million British thermal units (MMBtu). As of October 11, 2016, the price of spot natural gas at the Southern California border was about $3.00/MMBtu. By contrast, Southern California spot natural gas prices were about $2.35/MMBtu when the Aliso Canyon leak was detected on October 23, 2015.

Prospects for wholesale Southern California energy prices this winter. Forward basis values in Southern California are expected to be higher this winter. The forward basis markets for natural gas in Southern California indicate higher price expectations for the 2016-17 winter, at least in part because of an anticipated lower level of natural gas storage deliverability from the SoCalGas system. Basis, in this context, indicates the future value of relative price differences between two market locations—in this case natural gas delivered to the SoCal Citygate and the price of natural gas established at the Henry Hub based on the Nymex futures contract. Significant changes in basis can indicate constraints in the natural gas system. Figure 19 shows higher expected basis values for the winter of 2016-17 (the light blue line) compared with what was expected a year ago at this time (the dark blue line). Before the leak at Aliso Canyon, the basis value expectations for the winter of 2016-17 were less than $0.20/MMBtu and only modestly higher until late 2018. Recent winter 2016-17 expectations for this difference recently traded as high as about $0.65/MMBtu for December 2016, suggesting concerns about meeting peak winter demands with given pipeline supplies, the level of natural gas inventories, and the restrictions on the use of the Aliso Canyon storage facility. Lower basis values are likely a key driver of the significant change in pricing, which does not persist beyond the upcoming winter.

In addition, the forward price for natural gas priced at the SoCal Citygate is considerably higher than the forward price of natural gas priced at the SoCal Border. The higher price premium at SoCal Citygate indicates that natural gas deliveries into the Los Angeles Basin will likely be influenced more by the reductions in gas inventories and deliverability than the market at the California border, at least through the 2016-17 winter.

Retail Southern California energy prices. Retail energy prices are different from wholesale prices. Retail prices are determined through regulatory processes that incorporate average wholesale prices with other energy delivery expenses.

Because of regulatory decisionmaking, the resulting prices can vary by customer class and energy usage. Recent changes in retail energy costs relate most directly to rising wholesale natural gas prices. For example, the SoCalGas residential retail natural gas rates were between $10 and $12/MMBtu in August 2016, up by about $2/MMBtu since October 2015.

Nationwide Gas/Electric System Reliability Analysis

The Task Force commissioned DOE's Argonne National Laboratory (ANL) to analyze the potential impacts of an abrupt and protracted loss of natural gas deliverability due to some disabling event at each of the Nation's other UGS facilities. The method ANL used in this analysis[68] required the estimation of two major variables for each of the Nation's 400+ UGS facilities: the probability of a major failure, and the consequences of such a failure. ("Failure" was defined as the total loss of function from the facility for a period of at least a month's duration, at the time of peak gas demand upon the facility.) Because the 400+ facilities are owned by three types of owners (local distribution companies, interstate natural gas pipelines, and third-party independent operators), and because these three types of owners use UGS facilities in somewhat different ways to serve downstream customers, three separate models were devised to estimate the impacts of the loss of a given UGS facility.

Estimated Likelihood of UGS Failure

The availability of systematic data concerning the histories of the wells at individual UGS sites, the failure rates for different categories of wells, and major incidents at UGS facilities (i.e., incidents resulting in injury, fatality, property damage, site evacuation, or uncontrolled leaks) is limited.

Consequently, a simplified approach was used to estimate the likelihood of failure. Based on available data concerning 137 incidents, the frequency of an incident at a UGS facility was estimated to range between 8.4×10^{-4} and 6.0×10^{-3} per site-year, or once every 167 to 1,190 years of UGS site operation. Assuming that there are 400 UGS facilities currently in the United States, this equates to a major incident every 4 months to 3 years in the United States, for an average of 1.4 incidents per year. Note, however, that many of the reported incidents did not result in a "failure" of the UGS facility as defined above (i.e., total outage of the affected UGS site for a month or more at time of peak demand).

[68]See *U.S. Natural Gas Storage Risk-based Ranking Methodology and Results*, Steve Folga et al., Argonne National Laboratory, forthcoming (2016).

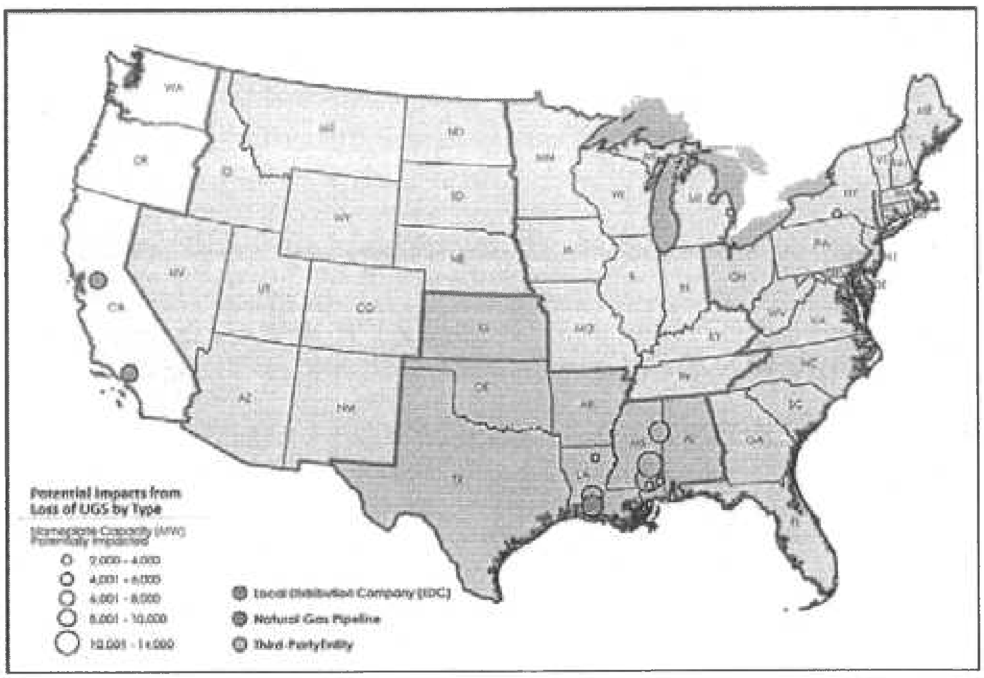
Estimated Consequences of UGS Failure

The consequence of a UGS failure was expressed in terms of the number of customers affected per sector and the amount of gas flow lost. For the purposes of this study, customers in the electric sector are of particular interest because of the interdependency that exists between the electric and gas systems, and the principal impacts in the electric sector are expressed in terms of megawatts (MW) assumed to have been forced out of service by lack of fuel.

Potential Electric Sector Impacts

Aliso Canyon is not unique as a UGS facility providing generation fuel that is, or may be, essential to maintaining electric reliability in "downstream" communities. An unexpected loss of generation capacity usually does not affect electric reliability unless the loss is relatively large (2 GW or more). ANL's screening analysis found that a total of 12 UGS facilities appear to have the potential to affect 2 GW or more available generation capacity. Note, however, that these figures are preliminary, because the operators of the affected power plants may or may not have dual-fuel capability (i.e., diesel or equivalent liquid fuels, with access at short notice to sufficient inventories of alternative sources of natural gas) or access to alternative generation via transmission. The general locations of these UGS facilities are shown in Figure 20. Two are located in California (one of which is Aliso Canyon). Five are in Mississippi, three are in Louisiana, one is in Michigan, and one is in New York.

Figure 20. Locations of 12 UGS Facilities, Disruption of Which Could Potentially Affect 2 GW or More of Generation Capacity



This analysis indicates that the greatest impact on natural gas-fired electricity-generating plants could occur from the hypothetical loss of a high-deliverability UGS facility owned by a third-party independent storage service provider. This finding is consistent with the current evolution of the natural gas sector, in which the deregulation of underground storage combined with other factors such as the growth in the number of natural gas-fired electricity generating plants has placed a premium on high-deliverability storage facilities. Nine of the top twelve UGS facilities (in terms of potential impacts on natural gas-fired electricity generating plants) are owned by independent storage service providers.

Further, the impacts of the Aliso Canyon outage tell us that we need to estimate the likelihood and consequences of a long outage of all of the important components of our natural gas infrastructure, whether singly or in combination, and devise appropriate plans to address unacceptable risks. Given the increasing reliance on gas-fired generation in meeting our electricity requirements, maintaining electric reliability during such outages is particularly important.

The Aliso Canyon experience has also highlighted the need to address more fully the operational challenges associated with the timely provision of fuel to gas-fired generation capacity needed to ensure electric reliability. When a large gas-fired generator is dispatched to serve electricity needs, the abrupt incremental draw on the gas delivery system can be large enough to reduce pipeline pressures and the system's ability to meet other customers' needs. While some gas-fired generators have contracted for firm pipeline capacity and gas supplies, others, especially peaking generators, have relied on interruptible capacity and spot market purchases. During periods of peak gas demand, there may be little or no interruptible pipeline capacity available to serve generators that have not contracted for firm supplies, threatening electric reliability.[69] There is continuing debate among the affected companies and regulators over whether electricity generation companies should be relying to a greater extent on firm supply contracts, and if so, how best to distribute the additional costs associated with such contracts.

The Aliso Canyon experience has also led to efforts to ease some of the strains associated with abrupt reductions in gas deliverability by making changes to gas tariffs.[70] On June 11, 2015, the California Public Utilities Commission authorized SoCalGas to revise its tariff to implement new low Operational Flow Order (OFO) and Emergency Flow Order (EFO) requirements. On June 23, 2016, the Commission reaffirmed and augmented those requirements. The low OFO and EFO requirements, which will be in effect year-round, replace winter balancing rules that were in place since the early 1990s with a unified, State-wide approach.

On the electricity side, the CAISO formed a group to look at potential reliability risks to both gas and electricity markets in Southern California due to the limited operation of the Aliso Canyon gas storage facility. Through an expedited stakeholder process, the group created a proposal for tariff changes that address gas balancing, electricity and gas scheduling misalignment, and market-based mitigation measures. CAISO's proposal identifies ways to mitigate risks that impact the electric system when rapid ramping could exceed the dynamic capability of the gas system.[71]

These changes imply that the current tariff structure used in other States and regions for wholesale gas purchases by utilities may need to be examined to promote generator bids that reflect gas system limitations, to reduce the chance that Independent System Operators (ISOs) or Regional Transmission Operators (RTOs) will dispatch generators in a way that harms gas system reliability, and to permit

[69]American Gas Association (AGA), 2016. "Gas-Electric Coordination," available at https://www.aga.org/federal-regulatory-issues-and-advocacy/gas-electric-coordination, accessed September 20, 2016.

[70]Marelli, G., 2016. Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for Authority to Revise their Curtailment Procedures, available at https://www.socalgas.com/regulatory/documents/a-15-06-020/Ch%201%20Curtailment%20Testimony%20-%20Marelli.pdf, accessed September 20, 2016.

[71]California ISO, 2016. *Aliso Canyon Gas-Electric Coordination Straw Proposal*, available at http://www.caiso.com/Documents/StrawProposal_AlisoCanyonGas_ElectricCoordination.pdf, accessed September 20, 2016.

ISOs/RTOs to reserve sufficient internal electric transmission transfer capability to react to changes in the gas system.

The challenges that have arisen in California over the past year have highlighted concerns that have become more acute over the past decade, including gas system dependency on storage to maintain operating pressure, and insufficient appreciation of the operational characteristics of natural gas systems and their potential implications for the operations of bulk power systems. Improved coordination between electric and gas industry entities will be critical to mitigating risks and minimizing their impact. For example, the timeframe for nominating natural gas transportation service is generally not synchronized with the timeframe during which electric generators receive confirmation of their bids in the ISO/RTO day-ahead market. The North American Electric Reliability Corporation (NERC) has suggested two potentially constructive measures that merit consideration: tightening the gas balancing rules; and giving generators dispatch information as early as practicable, so that they can procure gas more accurately.[72]

Potential Impacts on All Sectors

The loss of an underground gas storage facility would in most cases affect many kinds of customers, not just electricity generators. Figure 21 provides the estimated impacts per UGS facility across all customer classes (including the electric sector), converted to an expected equivalent number of residential customer outages (loss of gas service) per year. The largest estimated impact is approximately 32,000 customer outages per year, with most UGS facilities having a predicted impact of less than 1,000 expected equivalent residential customer outages per year.[73]

The results in Figure 21 agree with indications that the loss of gas service to a large number of customers is a relatively rare occurrence. For example, in the past 35 years in the Chicago Metropolitan Area, the largest number of customers losing gas service at any one time has been on the order of 4,500.[74] Similarly, the Southwest cold weather event of February 1–5, 2011, led to extensive curtailments of gas service to more than 50,000 customers in New Mexico, Arizona, and Texas.[75] When compared with customers affected by electric power outages (which can be in excess of 100,000 at any one time), the estimated number of annual customer outages in Figure 21 appears relatively small.

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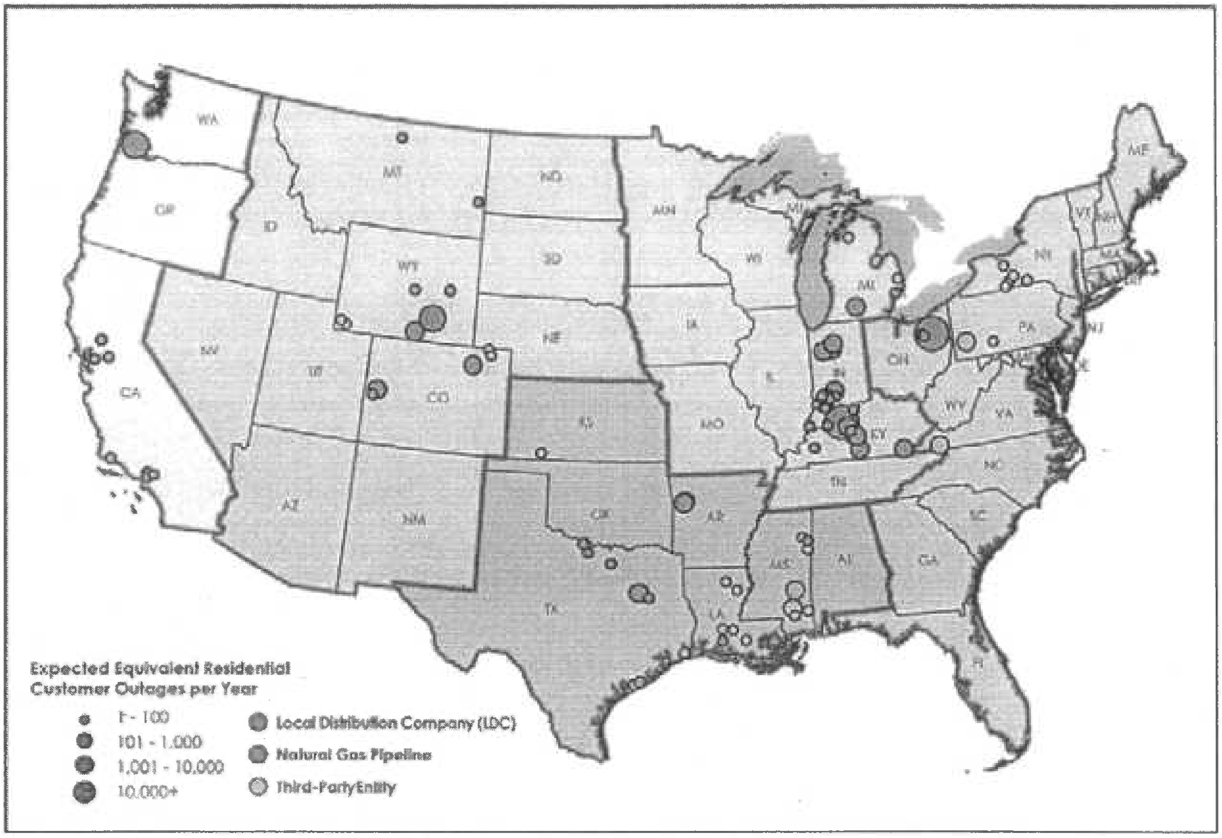
[72] North American Electric Reliability Corporation (NERC), *Short-Term Special Assessment - Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*, available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf, accessed September 20, 2016.

[73] See *U.S. Natural Gas Storage Risk-based Ranking Methodology and Results*, Steve Folga et al., Argonne National Laboratory (forthcoming 2016) for details on these calculations.

[74] http://www.ipd.anl.gov/anlpubs/2003/02/45798.pdf.

[75] http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf.

Figure 21. Locations of underground gas storage facilities with non-zero potential impact values



Government Agency Responses to the Aliso Canyon Incident

Multiple actions were taken by SoCalGas and Federal, State, and local agencies to address the leak and associated health concerns before the leak was fully controlled on February 17, 2016.

Porter Ranch, a residential community of approximately 30,000 people, is located near the Aliso Canyon facility. The Porter Ranch properties nearest to SS-25 are located approximately 1 mile away and 1,200 feet below the leaking wellhead. Immediately after discovery of the leak, many residents began reporting odor complaints (related to mercaptans, the familiar sulfur-smelling odorant added to natural gas for safety) to various local and State agencies, including 911. The Los Angeles County Fire Department responded to the complaints and sent personnel to the scene. However, the responding personnel were informed of non-emergency circumstances of the incident at the gate of the facility by SoCalGas and departed. SoCalGas placed a call to the Los Angeles County Fire Department on October 24, 2015, and reported that the incident should be resolved by 6:00 PM PST.

Many Porter Ranch community members experienced adverse health impacts in the days following the leak. On November 19, 2015, the Los Angeles County Department of Public Health (LADPH) determined that emissions from SS-25 had caused health symptoms in some Porter Ranch residents and ordered SoCalGas to provide temporary relocation to residents who desired to move.[76]

[76]http://publichealth.lacounty.gov/eh/docs/AlisoCanyon.pdf.

Initial Monitoring and Regulatory Actions

The SCAQMD started receiving odor complaints from Porter Ranch residents on October 24, 2015, and began ambient air quality monitoring soon thereafter. SoCalGas began its own air sampling effort on October 30, 2015. On November 5, 2015, SCAQMD issued a "Notice to Comply" that required SoCalGas to take specific steps to abate the natural gas leak, monitor the leaking gas, and reduce the impacts of nuisance odors on the local community.[77]

On November 7, 2015, CEC sponsored the first airborne methane sampling collection. Flights continued through February 2016. The National Aeronautics and Space Administration/Jet Propulsion Laboratory (NASA/JPL) conducted an onsite field survey of the Aliso Canyon facility on November 10, 2015, and began satellite imaging of methane plumes on November 13, 2015.

The California Natural Resources Agency/Department of Conservation/DOGGR and CPUC had the most direct operational oversight at the Aliso Canyon facility. In early November, DOGGR convened a panel of technical experts from the Lawrence Berkeley National Laboratory, Lawrence Livermore National Laboratory, and Sandia National Laboratory to provide independent expertise to assist the Division in monitoring and evaluating SoCalGas actions.

DOGGR issued two orders to SoCalGas, one on November 18, 2015, and a second one on December 10, 2015.[78] The November 18 order required SoCalGas to provide information on SS-25; the December 10 order required SoCalGas to develop plans to expeditiously capture the escaping gas, stop the leak, and communicate with State and local regulators. The December 10 order also required SoCalGas to provide access to the SS-25 site and information to a group of experts from the DOE National Laboratories who were assisting DOGGR in evaluating the SoCalGas plans for stopping the leak. In addition, the order required SoCalGas not to inject any additional gas into the Aliso Canyon reservoir without approval from DOGGR. Furthermore, it required SoCalGas to maximize the rate of withdrawal from the reservoir to reduce reservoir pressure. Gas was withdrawn from the reservoir at 0.75 to 1.5 BCF a day.

The CPUC also provided directives to SoCalGas regarding its response to the incident via a series of letters issued between December 2015 and February 2016. The information collected by CPUC from SoCalGas informed the steps that were taken by State regulatory agencies to address the gas leak, investigate its root causes, and model how an interruption in the operation of the Aliso Canyon facility might impact the availability and reliability of power generation in the Los Angeles Basin in 2016 and 2017.

The Los Angeles County Fire Department had an active operational presence with SoCalGas starting in November. They deployed a "short Incident Management Team" to work with the SoCalGas Operation and Planning Sections, preparing Incident Action Plans and other documents, and reviewing operations. The State Office of Emergency Services was also present from the first weeks of the incident.

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[77]South Coast Air Quality Management District Notice to Comply E-26893, http://www.aqmd.gov/docs/default-source/compliance/aliso-cyn/so-cal-gas-aliso-canyon---notice-to-comply-e26893.pdf?sfvrsn=2.

[78]Emergency Order No. 1104; November 18, 2015, Provide Data Re: Aliso Canyon Storage Facility; Emergency Order No. 1106; December 10, 2015, Provide Data and Take Specified Actions Re: Aliso Canyon Storage Facility.

Initial Federal Actions

On December 4, 2015, PHMSA's Office of Pipeline Safety began to provide technical assistance to the California Public Utilities Commission on the leaking well at Aliso Canyon. On December 20, 2015, PHMSA and other Federal agencies began to participate in daily Incident Command calls led by SoCalGas. PHMSA conducted a site visit at Aliso Canyon on December 22, 2015.

The U.S. EPA became actively involved in the Aliso Canyon incident in early December at the request of the California Office of Emergency Services and entered into an informal Federal multi-agency coordinating group with PHMSA and DOE. On December 16, 2015, two EPA Federal On-Scene Coordinators (FOSCs) conducted a site visit at the Aliso Canyon facility with LA County Fire/HazMat. The EPA FOSCs' assessment concluded that SoCalGas appeared to have well-control experts with the appropriate knowledge in charge of the site operations. From early December 2015 to the cessation of on-site activities in February 2016, the EPA participated in multiple daily calls, briefings, and updates with Federal, State, and local partners. Federal agencies included DOE, PHMSA, Department of Interior/Bureau of Safety and Environmental Enforcement (DOI/BSEE), and NOAA.

In early December the FAA issued a Notice to Airmen (NOTAM) restricting pilots from flying aircraft within a half-mile radius of the Aliso Canyon storage facility. The restriction extended up to 2,000 feet above the surface. The flight restriction expired on March 8, 2016.

Operations to Plug SS-25

Starting on October 24, 2015, and continuing until December 22, 2015, SoCalGas conducted eight separate "top kill" operations to stop the leak. SoCalGas also began planning for the drilling of a relief well for a "bottom kill" operation, if needed. In response to the December 10, 2015, order from DOGGR to develop plans for capturing the methane at the surface, SoCalGas submitted a permit application to the SCAQMD on January 4, 2016, to obtain approval for construction and operation of temporary equipment to capture and control natural gas from the leaking well. SoCalGas ultimately abandoned this effort, after several weeks of investigation and design work, due to significant safety concerns raised by LA County Fire and by the company's well-control experts regarding the feasibility of constructing, installing, and operating a gas capture system in a methane-rich environment.

On January 6, 2016, California Governor Jerry Brown issued a proclamation declaring a State of Emergency in Los Angeles County as a result of the natural gas leak at the Aliso Canyon facility. The Governor's emergency proclamation provided for "all State agencies to use personnel, equipment and facilities to ensure a thorough and continuous response to the incident, as directed by the Governor's Office of Emergency Services and the State Emergency Plan."[79] The emergency proclamation contained requirements for a number of State agencies, including the CPUC, CEC, CARB, Office of Environmental Health Hazard Assessment (OEHHA), CAISO, and DOGGR regarding stopping the leak, protecting public safety, ensuring accountability, and strengthening oversight of gas storage facilities.

Further Federal Action

On January 4, 2016, PHMSA and EPA met to discuss the convening of a National Response Team (NRT) to coordinate the Federal agency response to the incident. The NRT is a component of the National

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[79]Proclamation of a State of Emergency, January 6, 2016, by Governor Edmund G. Brown for the County of Los Angeles due to the natural gas leak.

Response System (NRS) that consists of 15 Federal agencies specified in Section 300.175(b) of the National Oil and Hazardous Substances Pollution Contingency Plan (NCP) and is responsible for carrying out national response and preparedness planning, coordinating regional planning, and providing policy guidance and support to incident-specific Regional Response Teams (RRTs).[80, 81] On January 7, 2016, the EPA activated its Regional Response Team 9 (RRT9).

The full NRT convened on January 11, 2016, to discuss the Aliso Canyon incident where RRT9 briefed the NRT on the incident. RRT9 requested that the NRT convene a Federal interagency panel of well-control experts to advise and consult on the safety and operation of the gas capture and disposition system being proposed by SoCalGas, which would have captured the leaking natural gas at the surface of SS-25. The gas capture system was essentially a giant, inverted funnel and flare system that would capture the gas escaping at the surface, direct it away from the wellhead through pipes, and incinerate it. As noted above, this proposal to capture and incinerate the leaking gas was ultimately abandoned due to significant safety concerns.

PHMSA leadership met with the CEOs of the American Petroleum Institute, American Gas Association, and Interstate Natural Gas Association on January 15, 2016, to discuss the industry's response efforts and encourage its support to SoCalGas with technical assistance and to ensure that the industry was reviewing UGS safety across the country.

Starting on January 20, 2016, PHMSA's Office of Pipeline Safety, Emergency Support and Security Division, began leading an ad-hoc Federal Government information exchange group. The group included representatives from the EPA (HQ and Region), DOE, BSEE, and PHMSA. The group met on a weekly basis until it was confirmed that the well was permanently sealed.

On February 5, 2016, PHMSA published an advisory bulletin entitled "Safe Operations of UGS Facilities for Natural Gas." The bulletin reminded all owners and operators of UGS facilities used for the storage of natural gas (as defined in 49 CFR Part 192) to consider the overall integrity of the facilities to ensure the safety of the public and operating personnel, and to protect the environment.

Public Meeting with State Leadership

On January 15, 2016, the State of California convened a public meeting in Porter Ranch. In attendance were a number of State leaders, representatives of EPA Region 9, and approximately 1,200 community members. The State leaders gave an overview of their agencies and authorities, and described the actions their agencies had taken thus far in the response to the gas leak at Aliso Canyon. Several other meetings took place between community members and agency leads during the leak, in an ongoing effort to communicate with the impacted community.

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[80] 40 CFR Part 300. The NCP, which is authorized by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), the Clean Water Act § 311, and the Oil Pollution Act of 1990 (OPA), provides, among other authorities, an organizational structure and procedures, known as the National Response.

[81] The NRS is an organized network of agencies, programs, and resources with authorities and responsibilities in oil and hazardous materials preparedness and response at the local, state, tribal, territorial, insular area, and Federal levels. The RRTs and NRT include representatives from 13 additional Federal agencies that provide oil and hazardous materials expertise and support, and some have specific responsibilities for natural resource protection. (40 CFR § 300.115).

Formation of Unified Command and Bottom Kill Planning

By November 2, 2015, SoCalGas had established an Incident Command with daily briefings about the leak at SS-25. The Incident Commander designation revolved between several senior officials from SoCalGas. It was not until January 22, 2016, that the SoCalGas incident command transitioned into a Unified Command (UC) with LA County Fire and the LADPH. As a component of the Incident Command System (ICS), the UC is a structure that brings together the individual Incident Commanders of all major organizations involved in the incident to coordinate an effective response, while at the same time carrying out their own jurisdictional responsibilities. The UC links the organizations responding to the incident and provides a forum for these agencies to make consensus decisions. This was a significant organizational change that provided the local agencies with much greater control over on-site actions and improved communication to the public. PHMSA and the EPA participated in daily briefings with the Unified Command. CPUC ordered SoCalGas on January 21, 2016, to continue withdrawing gas from the Aliso Canyon storage field until it reached 15 Bcf of working gas. The withdrawal of natural gas from the Aliso Canyon storage field was intended to reduce the pressure at the field and therefore minimize the rate of the gas leak. The remaining 15 Bcf of working gas was to ensure energy reliability on high-demand days. On January 23, 2016, SoCalGas had all wells shut off from withdrawal.

On February 2, 2016, the Los Angeles County District Attorney filed a criminal lawsuit against SoCalGas, alleging misdemeanor violations for neglecting to report the release of hazardous materials and releasing air contaminants.

On February 8, 2016, the EPA participated in a Federal interagency call with PHMSA, DOE, and DOI. The EPA solicited technical help from well-drilling experts in DOI's Bureau of Safety and Environmental Enforcement to evaluate the drilling and bottom kill plans for SS-25.

On February 16, Secretary of Energy Ernest Moniz, Under Secretary for Science and Energy Franklin Orr, and PHMSA Administrator Marie Therese Dominguez visited the Aliso Canyon site and participated in a roundtable with key Federal, State, and local agencies involved in the response to the leak at Aliso Canyon.

On February 18, 2016, DOGGR issued a determination that SS-25 had been permanently sealed on February 17. This determination was preceded by a "soft touch" encounter between the relief well and SS-25 on February 10, wireline logging and testing to make sure that the relief well was properly oriented to conduct the bottom kill operation, a milling operation to establish communication between the relief well and the target well, and pumping in mud and cement to seal the well. The Unified Command for the Aliso Canyon incident stood down on February 19, 2016, when the CPUC began its lead role in the investigation phase of the incident. On September 13, 2016, SoCalGas agreed to pay $4 million to settle criminal charges filed by the Los Angeles County District Attorney alleging misdemeanor violations for neglecting to report releases of hazardous materials and air contaminants.

Federal Task Force

Motivated by the incident at Aliso Canyon, Federal officials, including many concerned members of Congress, sought to better understand the overall safety of our Nation's natural gas storage infrastructure. To support these efforts, in April 2016, the Federal Government formed an Interagency Task Force on Natural Gas Storage Safety. DOE and DOT's PHMSA co-chair the Task Force. Congress codified the Task Force through the PIPES Act of 2016, which was signed into law by President Obama on June 22, 2016.

The legislation created a Task Force established by the Secretary of Energy and consisting of representatives from the DOT, EPA, FERC, and DOI and tasked the group with performing an analysis of the Aliso Canyon event and making recommendations to reduce the occurrence of similar incidents in the future. The PIPES Act also required that PHMSA promulgate minimum safety standards for UGS that would take effect within two years.

The Task Force established three primary areas of study and chartered working groups for each: well integrity of natural gas wells at the storage facilities, vulnerability to energy reliability in the case of future leaks, and public health and environmental effects from natural gas leaks.

The Well Integrity Working Group is led by DOE's Office of Fossil Energy (FE), with technical leadership and coordination from a team of scientists and engineers from the DOE National Labs, including the National Energy Technology Laboratory (NETL), Lawrence Livermore National Laboratory (LLNL), Sandia National Laboratories (SNL), and Lawrence Berkeley National Laboratory (LBNL). DOE tasked these labs to review the state of well integrity in natural gas storage in the United States. The group's objective is to review, gather, analyze, catalog, and disseminate information and recommendations that can lead to improved natural gas storage safety and security and thus reduce the risk of future events. The DOE National Lab team is an expansion of the original "Lab Team" comprising scientists and engineers from SNL, LLNL, and LBNL which was formed to support the State of California's response to the Aliso Canyon incident and operated under the Governor of California's Aliso Canyon Emergency Order (January 6, 2016). The Lab Team played a key role in advising DOGGR in its oversight of SoCalGas during and after the incident.

The Reliability Working Group is led by DOE's Office of Electricity Delivery and Energy Reliability (OE) with technical leadership and coordination by scientists and engineers from Argonne National Laboratory, the U.S. Energy Information Administration (EIA), and FERC. The working group developed methodology and models to assess the risk to energy delivery from the potential loss of natural gas storage facilities located within the United States. The models estimated the impacts of a failure of each of the more than 400 underground storage (UGS) facilities on their owners/operators, including (1) LDCs, (2) directly-connected transporting pipelines and thus customers in downstream States, and (3) third-party entities and thus contracted customers expecting gas shipments. The working group also assessed impacts of the Aliso Canyon incident on energy reliability and energy prices.

The Health and Environment Working Group is led by scientists at EPA and the Centers for Disease Control (CDC), with support from NOAA and PHMSA. The Working Group has been in close contact with State and local officials to summarize and analyze the actions taken to address the impacts to public health and the environment from the Aliso Canyon leak. The multiple agency responses to address health and environmental concerns, both during the leak and after the well was sealed, included air quality monitoring, health risk assessments, and consideration of health symptoms reported by the public. The Working Group also addressed efforts taken to measure the volume of greenhouse gases emitted during the Aliso Canyon leak, and California's plan to mitigate those greenhouse gas effects.

During summer 2016, the Task Force held three workshops. In June, DOE's Office of Energy Policy and Systems Analysis convened a Technical Workshop on the Implications of Increasing Electric Sector Natural Gas Demand. The workshop convened stakeholders from the gas and electricity sectors for an in-depth discussion on natural gas and electricity modeling and planning. An important element of that conversation was the role of underground gas storage facilities in ensuring reliability of electric power generation and heating during periods of high demand.

In July, the Well Integrity Working Group convened a technical workshop on Well Integrity for Natural Gas Storage in Depleted Reservoirs and Aquifers in Broomfield, CO, assembling approximately 200 people, including a mix of operators, regulators, and trade industry, academic, and National Laboratory personnel. Opening remarks were provided by the Task Force co-chairs, DOE Undersecretary for Science and Energy Franklin Orr, and DOT/PHMSA Administrator Marie-Therese Dominquez. The two-day forum consisted of presentations on wellbore integrity risks, operational and wellbore construction practices, monitoring and testing of subsurface storage integrity, accident management (e.g., controlling leakage and blowouts), gaps in knowledge about wellbore integrity, and ways to improve the state of knowledge to address those gaps. There were also three panel/expert-led discussions addressing regulatory issues, performance of downhole safety valves, and a general recap of open issues to conclude the meeting.

Also in July, PHMSA convened a public workshop on Underground Natural Gas Storage Safety Regulation in Broomfield, CO. As part of its effort to initiate regulatory actions to help ensure the safety of natural gas storage facilities, PHMSA brought together stakeholders—including Federal and State agencies, industry, and the public—to discuss the response, investigation, and impact of the Aliso Canyon incident, well integrity, safe UGS operating practices, and Federal and State safety regulations for UGS. The one-day forum consisted of presentations by Federal and State regulators, the LA County Fire Department and Department of Public Health, Environmental Defense Fund, Porter Ranch Neighborhood Council, industry groups, and industry service providers.

Between April and September 2016, the National Economic Council and the Domestic Policy Council convened the Task Force at the White House on five occasions. The research results of the Task Force, including knowledge learned at the workshops, contributed to this final report of the Task Force.

Chapter 3. Task Force Observations and Recommendations

The following recommendations are based on extensive research and analysis by Task Force experts, including extensive engagement with industry representatives, State regulators, environmental groups, and other stakeholders. These recommendations will advise UGS operators on how to address well integrity, energy reliability, and health and environment risks. They will also serve as a guide to State and Federal regulators on future regulatory developments. The working groups produced reports that contain additional background on the three sets of recommendations and will be released later this year.

Well Integrity

UGS facilities are an essential component in the efficient and consistent delivery of natural gas to consumers by pipeline. These facilities provide a consistent source of energy during periods of peak consumer demand. Across the Nation, UGS facilities include wells that range in age from less than 5 years to more than 125 years old. Well completion technology has changed significantly over that time period, which means that many wells are outdated and may be in similar condition to the one at Aliso Canyon. In response to the leak at Aliso Canyon, DOE commissioned a review of the issues related to well integrity at UGS facilities. The review included an examination of issues related to regulating natural gas storage facilities, an analysis of the data that is available on natural gas storage wells across the country, and expert review of wellbore integrity risks, operational and wellbore construction practices, monitoring and testing of subsurface storage integrity, and accident management.

The Task Force recognizes that the assessment of maintenance and integrity of UGS facilities involves complex engineering concepts and methodologies. Owners and operators of UGS facilities are responsible for ensuring proper maintenance and integrity of their systems, while regulators provide oversight to determine operators' compliance with the established regulatory requirements.

Based on its review and analysis, the Task Force provides the following observations and recommendations related to well integrity, risk management, and additional research and data needs.

Topic I: Ensuring Well Integrity

1. **Operators should phase out wells with single point of failure designs.**

   Observation: SS-25 was operated with gas flowing through both production tubing and well casing, leaving the well casing as a single point of failure for a gas leak. Producing through casing as well as tubing was a common practice at Aliso Canyon and is a common practice at other gas fields, particularly those with older wells. While the failure investigation remains ongoing, preliminary indications are that the inspection program, monitoring, and risk management plan for SS-25 were inadequate to ensure safety. If a second barrier had been in place at SS-25, the uncontrolled leak would likely have been avoided.

   Discussion: About 80% of natural gas storage wells with known completion years were drilled before 1980, and many predate modern materials and technology standards. These wells have been subject to environmental processes and mechanical stresses from injection and withdrawal of natural gas across multiple decades. These stresses may be particularly acute for wells in depleted oil fields that may have been designed for lower pressures than they must now contain. Modern design practices dictate that new wells must be designed with two complete barriers. Tubing and packer installed within a properly engineered casing string with fluid in the casing-tubing annulus provides one method for achieving a double barrier system. However, many different well designs can achieve the same purpose, such as through the use of multiple strings of casing. The most appropriate design will often be site-specific and must include design safety factors to determine maximum and minimum operating pressures. It should be noted for this discussion that a casing string and cement are considered a single barrier system that does not provide independent double-barrier protection against failure.

Recommendation: Given harsh subsurface conditions and engineered components that may become unreliable due to lack of adequate metallurgy or corrosion coatings and cathodic protection, underground gas storage wells should be designed so that a single point of failure cannot lead to leakage and uncontrolled flow. New wells can readily be designed to have double barriers. Operators who have existing wells with single-point-of-failure designs should have a risk management plan to maintain safe well operating pressure that includes a rigorous monitoring program, well integrity evaluation, leakage surveys, mechanical integrity tests, conservative assessment intervals, and in most cases a plan to phase out these designs. An operator seeking to continue utilizing a single-barrier well design should prepare and make available for regulatory review during inspections a rigorous and fully documented engineering analysis of the design that considers the potential impacts and consequences of a leak at any point for each well without benefit of a double barrier. For single-barrier wells, the operator should demonstrate that a failure will not lead to pressure that can exceed the fracture gradient of the surrounding formation, and that the design protects water resources. The operator's technical justification for continued use of a single barrier should also include analysis as to why a double barrier is not practicable. While a transition plan to a double-barrier system is being developed and implemented, integrity management procedures with robust safety factors should be implemented to maintain safe maximum well operating pressures. Well integrity evaluation, risk management plans, and transition plans are discussed further below.

2. **Operators should undertake rigorous well integrity evaluation programs.**

   Observation: The incident at the Aliso Canyon storage field has highlighted the issues of aging natural gas infrastructure, inadequate integrity procedures to maintain safe operating pressures, and inadequate monitoring practices for UGS wells. Federal officials have raised concerns about how many other wells in natural gas storage fields could fail and cause similar events with serious economic implications, environmental implications, or even loss of life.

   Discussion: The natural gas storage industry faces the challenge of improving the safety of storage infrastructure while continuing to provide reliable and cost-effective service. Infrastructure maintenance and upgrade plans must therefore be prioritized, based on relative risk. Risk-based planning, in turn, requires a complete understanding of the baseline conditions of all wells within a gas storage field, whether they are active, idle, or abandoned. Without an adequate baseline, high-risk and low-risk wells cannot be identified with confidence.

   Recommendation: All operators should undertake a rigorous evaluation of the current state of their well inventories. This is consistent with PHMSA's Advisory Bulletin ADB-2016-02, which recommended that all operators of UGS facilities begin a systematic evaluation of their wells and implement voluntary consensus standards (API RP 1170 and API RP 1171). Evaluations should include: (1) a compilation and standardization of all available well records relevant to mechanical integrity; (2) an integrity testing program that includes usage of leakage surveys and cement bond and corrosion logs to establish that all wells are currently performing as expected; (3) documentation of a risk management plan to guide future monitoring, maintenance, and upgrades; (4) establishment of design standards for new well casing and tubing; and (5) establishment of safe operating pressures for existing casing and tubing. Many operators already apply these risk management practices in their operations. These approaches should be applied industry-wide.

3. **Operators should prioritize integrity tests that provide hard data on well performance.**

Observation: Maintaining well integrity is of critical importance for mitigating risk of leakage. Several, but not all, States with UGS facilities have already implemented regulations that address wellbore integrity across a well's lifespan. For example, Pennsylvania requires mechanical integrity testing at least every 5 years.

At Aliso Canyon, logging of SS-25 was performed only as a means to detect the presence of leaks. Since 1979, there are no records of logs performed for the purpose of evaluating the condition of the casing that could be used to assess the risk of a leak. For example, no logs were located that could indicate metal loss in the production casing, which is the primary barrier to the surrounding environment.

Discussion: There are considerable uncertainties in predicting the long-term behavior of wells. Operators have indicated that some very old wells perform fine—despite not conforming to modern design practices—while some newer wells need frequent maintenance. This is one of the basic tenets of risk management, i.e., that each operator's system is unique and must be continuously monitored for changing risks and modified accordingly. Given intrinsic variation in site conditions and individual well performance, frequent monitoring, logging, and mechanical integrity testing are useful tools to reduce risks to well integrity. If carried out properly, these tests provide hard information about the performance of a well and can help identify problematic situations before they become crises. However, concerns have been raised that excessively frequent logging and other well work can actually increase the overall risk when personnel risk and other operational risks are considered. Risk management plans (see Topic II) should balance these risks.

Recommendations:

a. **Monitoring, logging, and mechanical integrity testing must be top priorities for lowering risk to well integrity, as they provide hard data on well performance.** Noise and temperature logs should be run to detect leaks annually unless other methods (such as continuously monitoring casing-tubing annulus pressure) are in place to monitor for leaks—or a risk management program is in place to evaluate threats with assessment intervals based on maintaining safe operating pressures until the next re-assessment interval. As soon as possible, operators should also perform integrity assessments for casing wall thickness (corrosion) inspections on all wells for which recent data are unavailable to assess the current state of corrosion and other casing damage, and to determine the maximum safe operating pressure. Using data from this baseline assessment, the frequency of subsequent casing thickness inspections and pressure testing can be determined, based on the risk of loss of integrity for individual wells and a rational balancing of other operational risks—e.g., potential well damage during workovers, personnel safety concerns, etc. Lower risk wells (such as wells with lower operating pressure, storage volumes, and flow capacity) should receive less frequent attention in order to focus available resources on the pool of higher-risk wells. Operators should maintain detailed integrity and maintenance records and well diagrams of piping and other equipment on the well, and should review the records in aggregate periodically to estimate typical corrosion rates and other field-wide trends in well performance. These aggregate trends should be used to inform the frequency of logging and mechanical integrity testing.

b. **Well integrity testing should be executed with the goal of minimizing total risk, which includes risks to storage integrity associated with the testing, risks to personnel, etc.** To address concerns that frequent logging and other well work might increase risk, note that many types of well work can be coordinated so that the number of well interventions is reduced. Good safety procedures and safety training can be instituted to protect personnel, and appropriate well control measures can be used when a well is taken outside normal operations. Specifically, the risks associated with downhole measurements and other interventions (e.g., damage to well, injury to personnel) should be weighed against the benefits. To that end, well integrity testing should use a tiered approach, with less invasive, routine testing performed more frequently and comprehensive testing performed less frequently and as needed.

c. **Well integrity testing should use multiple methods and not rely on a single diagnostic.** Relying on a single diagnostic tool to assess well integrity can result in overlooking adverse well integrity conditions and incipient or impending failures. Temperature and noise logs are used ubiquitously in UGS to identify leaks, but the sensitivity of the measurements is limited, and the data provide no hint of impending problems. Casing corrosion logs and cement bond logs can identify integrity defects, and a time-progression of casing diagnostics can identify where well integrity is deteriorating. However, casing diagnostic logs provide no information concerning whether a leak is ongoing. A pressure test can identify a casing leak below the sensitivity of temperature and noise logs, but that test alone provides no spatial information as to where the leak is occurring. An ideal well integrity testing program will incorporate multiple methods that recognize the benefits, limitations, and complementary nature of data from each diagnostic test. The optimal diagnostic program will be site-specific and may change over time as data are collected and evaluated.

4. **Operators should deploy continuous monitoring for wells and critical gas handling infrastructure.**

Observation: To a great extent, the gas storage industry has relied on subsurface measurements to detect subsurface leaks. Noise logs, used to listen for noise irregularities (perhaps indicative of a leak), and temperature logs, used to detect thermal anomalies (perhaps indicative of subsurface flow), are commonplace in the industry.

SS-25 was monitored for gas leaks in a similar manner to other wells at the Aliso Canyon field, annually in recent time, bi-annually in less recent time, and ranging to sporadic monitoring in historic time. Logs that could be used to assess the risk of the well system (e.g., metal loss in the casing) were not located. While the failure investigation remains ongoing, there are preliminary indications that the practices for monitoring and assessing leaks and leak potential at the Aliso Canyon facility were inadequate to maintain safe operations.

Discussion: New sensors and monitoring systems, along with advanced communication technologies, are available to monitor, measure, diagnose, notify, and respond to suspected changes in gas storage field conditions. These technologies are increasingly less expensive and easy to use. They can allow a gas storage field to be operated as remotely as desired, similar to other high-hazard industrial facilities, and any necessary engineering, safety, or emergency responses can be immediate. It must be noted, however, that automated control and management systems have potential cyber vulnerabilities that pose security risks for these vital national assets.

Recommendation: Gas storage operators should deploy continuous monitoring systems at the ground surface and through the multiple casing strings for wells and critical gas handling infrastructure. This includes monitoring of annular and tubing pressure, as well as surface leak detection. Potential cyber security risks should be addressed as part of an operator's risk assessment, especially if the monitoring network is tied to a real-time control system.

Topic II. Risk Management Recommendations

1. **Risk Management Plans should be comprehensive and reviewed periodically.**

Observation: Some operators have comprehensive and systematic approaches to subsurface risk management. Others lack a formal approach or plan. Risk management practices vary across the gas storage industry, ranging from simple leak response to electronic data management systems that make use of statistics on failure rates. During DOE's July 2016 Workshop on Well Integrity for Natural Gas Storage in Depleted Reservoirs and Aquifers, one gas storage operator described a state-of-the-art web-based integrity management planning system for gas storage wells that was implemented when the operator was required to recertify several hundred wells. The gas storage community is making significant progress in developing and implementing processes that manage risk. This progress can be attributed to contributions from operators, regulators, trade associations, and other experts.

Discussion: Risk management planning is an ongoing process for identifying, assessing, and addressing potential threats that have adverse consequences and a finite probability of occurring. PHMSA's Integrity Management (IM)[82] regulations for pipeline systems have been in place for more than 12 years, resulting in thousands of defects being removed from pipeline systems before the defects could possibly cause a failure. IM programs also involve a cycle of continuous learning with a management of change process that applies lessons learned to the program. The pipeline industry has robust IM programs that may serve as a basis for applying the methodology to UGS facilities. Recent industry UGS standards, such as API RP 1170 and 1171, present key elements that should be included in a UGS risk management plan.[83] The European ISO/TS 16530-2:2014 standard discusses risk management but focuses more narrowly on well integrity management, which is one of several key elements in a broader risk management plan. Emergency response planning was identified during the workshop as a required element in every risk management plan. Discussions at the PHMSA workshop

[82]PHMSA's IM regulations are a type of risk management regime in 49 CFR Part 192 that requires gas pipeline operators to (1) identify riskier "High Consequence Areas" (HCAs) along the route of their pipelines that warrant extra safeguards; (2) determine and prioritize the potential threats facing each pipeline segment that could affect an HCA; (3) conduct baseline assessments of these segments, using methods tailored to those specific threats; (4) remediate any anomalies or conditions that could pose integrity threats; (5) take extra preventative and mitigative measures aimed at avoiding future problems; and (6) continually reassess the effectiveness of their IM programs and make needed improvements. A similar process is outlined in API RPs 1170/71 for UGS facilities.

[83]Use of the phrase "Risk Management Planning" throughout this report is unrelated to EPA's Clean Air Act Section 112(r)(7) risk management planning regulations for chemical accident prevention under 40 CFR Part 68. Risk management planning is a standard concept in the oil and gas industry and is discussed in industry documents, including those published by the American Petroleum Institute (API) and the International Organization for Standards (ISO).

held on July 14, 2016, identified the need to bring key stakeholders into the emergency response planning process.

Risk assessments have inherent limitations in that they cannot account for unknown threats, and they often rely on assumptions and/or estimates. Effective risk management relies on continuous improvement to ensure that decisions are based on current information and the most relevant methods. Having a risk management plan in place, and particularly one that is backed with data kept in an accessible records management system, will allow a company to apply its resources to higher-risk systems and to assure regulators and the public that it is committed to maintaining a high level of safety.

Recommendation: UGS operators should develop comprehensive risk management plans that address risks based on their potential severity and probability of occurrence. Gas storage operators should implement formal risk management plans that document their risk management strategy, identify risks, define responsibilities among stakeholders, assess risks, and provide appropriate responses. A risk management plan should include preventative and mitigation measures. As risk management will be needed for the life of a project, the plan should include a methodology by which its effectiveness can be tracked and reported, and by which the plan can be periodically reviewed and updated. Operators should develop risk management plans, and regulators should review those plans as part of the standard inspection and oversight process. The inspection and oversight process should prioritize and adjust inspection frequency based on level of risk. The inspection and oversight process should also include a periodic review cycle to adjust methods, based on data collected through the inspection and enforcement process and other means.

2. **Operators should institute more complete and standardized records management systems.**

   Observation: Records management practices vary across the gas storage industry. Guidance documents, such as API RP 1170 and 1171, indicate the need for records management, but there is not a recognized industry practice or standard.

   Discussion: Having an effective records management system allows an operator to know that all important information is current, approved as appropriate, and accessible. In addition, such a system allows operators to track information that is indicative of failures and successes within their field. Collecting data that can be analyzed and used to generate statistics on the wells in their fields will help them to manage their fields more efficiently and cost-effectively.

   Recommendations: Operators should institute records management processes within their risk management plans. These processes should ensure that documentation of essential information is created, maintained, protected, and retrievable when needed. Essential information consists of all records related to evidence of compliance with statutory and regulatory requirements. Operator data should include detailed well-completion diagrams, including casing and tubing strength, wall thickness, and coupling type schedules, maximum and minimum allowable operating pressures, safety valve locations and testing results, maximum withdrawal and injection rates, reservoir depth, well maintenance records, and incidents of failure. The latter may be particularly useful for power-sector risk management planning, as discussed in the reliability section of this report, especially if incident reports include impacts on deliverability to customers. Well records should also include how the well is used (injection, withdrawal, observation) and some volumetric flow or capacity data, so that reliability planning can assess the significance of given wells. The UGS field working and base gas capacities should also be reported and updated periodically, as they are likely to change slowly over time as field deliverability changes.

Critical information that should be preserved for the life of a facility includes findings of conditions adverse to the integrity of a well, whether or not the condition led to a release or required mitigation. Records should include information about the factors that contributed to the adverse condition and, in the event of a leak, the failure mechanisms, the size and duration of the leak, the conditions under which the leak occurred, the age and condition of the well, and its maintenance schedule. Such data can be aggregated across a field, as well as industry-wide, to provide help in understanding the relationships among completion, monitoring, and maintenance practices and well failures.

The records management processes should allow an operator to track records throughout their entire information life cycle, so that it is clear at all times where a record exists, which is the most current version of the record, and the history of change or modification of the record. The processes should ensure appropriate identification and description of records, including information such as title, date, author, reference number, etc., when records are created or modified. Record change control (version control) processes should be established to ensure that records are changed in a controlled and coordinated manner.

3. **Operators should develop and implement risk management transition plans within one year from the date when new minimum Federal standards are issued to compliance.**

   Observation: The activities required for operators to comply with new well integrity requirements will compete for resources with other risk mitigation investments, such as updating pipelines or gathering systems. Operators must contend with gaps that may exist for their operations relative to newly developed requirements and guidelines.

   Discussion: Operators will need time to become compliant with new guidelines and regulations for well integrity practices. Should risk assessments carried out by the operator identify an unacceptable level of risk, storage fields may have to curtail operations and limit availability. Well remediation will reduce the availability of storage fields to serve consumers. Discussions between operators and regulators about timelines for compliance must take into account energy reliability concerns.

   Recommendation: Operators should develop and begin implementation of transition plans within one year of the date of adoption of new regulations/standards. The transition plans should describe planned activities and a schedule that will be followed to reach compliance. Regulators should consider impacts to ratepayers and reliability through cost-benefit analyses. The transition plans should address how activities are prioritized in order to mitigate overall risk, and they may include enhanced monitoring measures that operators can use during transition to mitigate risks. Regulators should inspect operators' records during routine inspections in an effort to ensure that the transition plans have been properly implemented.

4. **Operators and regulators should account for a broad range of risk factors.**

   Observation: New industry guidelines and regulations should enhance the capability to detect/anticipate scenarios that resemble historical events (e.g., Aliso Canyon) but should also be flexible enough to address vulnerabilities that have not yet led to failure events. This is best achieved through rigorous implementation of an objective risk assessment that accounts for uncertainties rather than simply applying reactive protocols to address specific scenarios. This includes geologic and engineering factors, as well as the potential for human error, geographically relevant weather-related disruptions, geologic factors, or complications to emergency response.

Discussion: API RP 1170 and 1171 mention the use of procedures and training as mitigation measures for controlling risk. They also mention that procedures and training can embed human and organizational competence (human factors) in the management of storage facilities. Human factors are an important consideration in avoiding errors that can lead to accidents. API RPs 1170 and 1171 do not provide guidance or recommendations related to human factors; they provide only very general guidance for developing relevant procedures and training. One of the workshop presenters indicated that human factors is one of the "future directions" that the API RP Committee has discussed. There is an existing body of work that has examined human factors (or similarly, human performance, safety culture, etc.) in many contexts.

In some parts of the country, severe weather events, such as hurricanes, tornados, and floods, also can pose risks to gas storage wells and fields; and in some locations, seismic activity or landslides can pose risks. For example, at the Aliso Canyon field, there is a geologic fault that runs through the field, and the wells in the field were drilled across that fault. Although the fault has not had any seismic activity since those wells were drilled, sections of the fault that are within 50 miles of the storage field have shown seismic slip within the past 30 years.

Recommendations:

a. New regulations and voluntary industry guidelines should both anticipate future events and address past events, including geologic factors, changes in the proximity of human population centers relative to gas storage facilities, and weather-related complications to field operations and emergency response.

b. Risk management and emergency response plans should consider human factors in procedures and training.

c. Industry should create a guidance document that discusses human factors principles in mitigating risk in underground gas storage facilities.

Topic III. Research and Data Gathering Recommendations

1. **DOE and DOT should conduct a joint study of downhole safety valves.**

Observation: The value of downhole safety valves (DHSVs) for natural gas storage is a source of significant controversy.

Discussion: DHSVs can provide a direct safeguard for preventing many uncontrolled flow scenarios, but their reliability and impact on production capacity raise concerns among operators. While DHSVs have seen widespread use in the offshore oil and gas industry and in European natural gas storage, it remains unclear whether DHSVs should be more widely deployed in U.S. storage facilities.

Recommendation: A quantitative study to evaluate key uncertainties related to the costs and benefits of DHSVs for the U.S. natural gas storage industry should be carried out by DOE and DOT, subject to appropriations. The study should include: (a) malfunction and failure rates of modern DHSV designs; (b) the cost and frequency of additional well work associated with their deployment; (c) the frequency of well failures for which a DHSV would provide a sufficient safeguard; (d) alternative emergency valve designs that could provide similar protection; (e) the impact of widespread DHSV deployment on UGS delivery and cost; and (f) optimal placement in wells for mitigation of well integrity failures.

2. **DOE and DOT should conduct a joint study of casing-wall thickness assessment tools.**

   Observation: Identifying deterioration in well casing is a critical component of maintaining well integrity.

   Discussion: Several casing wall thickness logging tools—e.g., various electromagnetic and ultrasonic tools—are now commonly used by natural gas storage operators to support well integrity assessments. Industry continues to improve the capabilities of wireline tools, and products with higher spatial resolution and the ability to assess multiple casing strings simultaneously are being marketed. Improving knowledge about the relative sensitivity, accuracy, and overall effectiveness of these tools will aid in developing optimal well integrity management practices and assessing residual risk.

   Recommendation: A systematic assessment of casing wall thickness assessment tools should be carried out by the DOE and DOT, subject to appropriations, with multiple tool types used to test manufactured articles and one or more reference wells with well-characterized corrosion issues. The goal should be to rigorously test and compare the ability of these techniques to identify, locate, and characterize corroded casings. Such a study could also inform better log interpretation practices.

3. **Industry and other stakeholders should review and evaluate wellbore simulation tools.**

   Observation: The Aliso Canyon event highlighted potential limitations of existing tools and analytical methods for simulating complex well processes, such as the processes associated with well kill events.

   Discussion: The SS-25 top kills were hindered by the tortuous fluid pathways governed by both tubing exits and re-entrances. The initial simulations used to support the Boots and Coots top kill efforts lacked sufficient detail to correctly predict that the well kill attempts would fail. Incorporating "real world" conditions in a wellbore simulation, such as complex fluid pathways or high-density non-Newtonian fluids, is a challenging task to conduct during a rapidly evolving crisis, particularly with the inherent limitations in knowledge of the boundary conditions and the exact configuration of a damaged well. This is also important because poorly executed top kills can have a detrimental effect on the well condition and on future kill attempts.

   Recommendation: A review of existing well simulation codes that can be, or currently are, applied for analyzing adverse well events should be undertaken by DOE (subject to appropriations), industry, and other stakeholders. The assumptions underlying each code, as well as code adaptability for a variety of geologic and reservoir settings, should be carefully considered. Working with industry providers, universities, and national laboratories, DOE, industry, and other stakeholders can develop a set of benchmark problems and well failure scenarios to exercise the codes and to compare results. Similar code comparison studies have been used in the past to support critical national programs (e.g., radioactive waste isolation). Based on the review of existing analytical capabilities, the identification of knowledge gaps and limitations can then be used to improve the toolkit of software to assist in response to future loss of well control events. Learnings from such a review should be disseminated at forums, as they are seen as broadly applicable throughout the oil and gas industry. Ultimately these tools, used by knowledgeable engineers, should be applied to the development of well integrity plans that identify weaknesses in a given design and consider failure modes that could lead to a loss of pressure control.

4. **Data gathering gaps should be addressed.**

   Observation: There is limited data available to regulators and the public on well locations and other characteristics. Collecting and aggregating this information can help stakeholders understand risks related to individual facilities and regional risks that could be posed by loss of availability at multiple facilities.

   Discussion: The records for wellbores that were drilled decades, or more than a century, ago may be inaccurate or irrecoverable. The well record for SS-25, for example, contained ambiguous and likely incorrect information regarding key aspects of the tubing-to-casing connections. There are also a number of instances, such as Aliso Canyon, where wells and fields that were originally far from population centers are now quite close to significant numbers of people.

   Recommendations:

   a. State and/or Federal agencies should consider undertaking a phased-data gathering project to identify the locations of unknown wells at or near UGS facilities, particularly in areas where known exploration and production activities have occurred in the past. This data gathering and recordkeeping may include site-scale geophysical or ground truth surveys, as well as collection and integration of data from multiple historical sources, such as maps, property records, leases, or aerial photography.

   b. State and/or Federal agencies or other stakeholders should collect and analyze data on the proximity of UGS facilities to population centers to help better quantify some of the risk factors. Best management practices and policies should take into account projected changes to land use, infrastructure, and human population centers relative to UGS facilities.

   c. State regulators and PHMSA should collaborate to collect and make data (e.g., data on fires, leaks, or other hazardous incidents) publicly available in a format that allows easy aggregation to provide better understanding of individual and system risks. It is particularly important to work with States that already collect and/or publish limited data.

Topic IV. Immediate Regulatory Actions

1. **Existing industry recommended practices should be incorporated into applicable regulatory codes.**

   Findings: Currently, the Federal gas pipeline safety regulations in 49 CFR Part 192 do not include any regulatory requirements for storage wells and wellbore tubing located at underground gas storage facilities. The Part 192 regulations apply only to the surface piping up to the wellhead at these facilities. As a result, there are no safety regulations at all for the thousands of storage wells located at the approximately 200 interstate facilities in the U.S. In addition, there is no uniform "floor" of minimum regulations for those States that already exercise limited jurisdiction over existing intrastate facilities.

   Discussion: A broad group of stakeholders, including industry and regulators, recently developed two new consensus-based standards for underground gas storage. They were developed under an ANSI-approved process and published in September 2015 as the following API Recommended Practices (RPs): API RP 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage," and API RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon

Reservoirs and Aquifer Reservoirs." Both API RPs 1170 and 1171 recommend that operators of underground natural gas storage facilities implement a wide range of current recommended practices, including operating, maintenance, risk management, qualification and training, and emergency response preparedness activities.

The incorporation of API RP 1170 and 1171 into the Part 192 regulations will be an important step in improving the safety and reliability of underground gas storage facilities. It will impose minimum requirements for all UGS operators to assess the operational safety of their underground natural gas storage facilities, and it will ensure that operators document the implementation of identified safety solutions. PHMSA will be able to enforce API RP 1170 and 1171 directly at interstate facilities. Because certified State agencies will eventually adopt the latest version of Part 192 as part of their annual certifications under 49 U.S.C. 60105, these State authorities will also be able to enforce API RP 1170 and 1171 at intrastate facilities. These State agencies will also be able to continue issuing and enforcing additional or more stringent State regulations for their intrastate facilities. PHMSA and its State partners will monitor operators' implementation of API RP 1170 and 1171 and begin inspecting facilities for compliance. PHMSA plans to build on its minimum regulations as necessary in order to ensure that operators fully address the safety issues presented by underground natural gas storage.

Recommendation: PHMSA should consider incorporating existing industry-recommended practices API RP 1170 and 1171 into the Part 192 regulations, and they should be adopted in a manner that can be enforced. They should be supplemented with reporting and recordkeeping requirements as necessary. Experience with inspections and oversight of the written plans called for in API RP 1170 and 1171 and their implementation, along with the recommendations and studies discussed elsewhere in this report, should inform additional requirements in the future.

Health and Environment

The EPA, CDC, PHMSA, and NOAA assessed the public health and environmental impacts associated with the leak at Aliso Canyon. To support their assessment, they summarized the actions taken by local, State, and Federal agencies to monitor and mitigate impacts on public health and the environment, and they have reported the best estimates of those impacts. Based on their work, the Task Force recommends the following actions to be taken by local, State, and Federal agencies in order to be prepared in the event of a future from a natural gas storage facility.

Topic I: Agency Responses to Address Gas Leak Health Concerns

1. **Unified Command**

Observation: During the initial leak period, a number of regulatory agencies and emergency response providers were involved in addressing various aspects of the leak, including public health and environmental impacts, well-control operations, community involvement, media communications, and public outreach. However, SoCalGas was acting as the single incident commander during this period.

Discussion: For 92 days, from discovery of the leak at SS-25 until January 22, 2016, SoCalGas acted as the incident commander. On January 22, 2016, SoCalGas, LA County Fire/HazMat, and LADPH formally entered into a Unified Command (UC). Entering into a UC earlier might have improved the response in terms of environmental and public health messaging and communication with external parties.

Recommendation: When human health and environmental threats are present and multiple jurisdictions are involved in the response effort, a Unified Command should be formed early in response to a UGS release. The jurisdictions involved could be represented by geographical boundaries, government levels (e.g., Federal, State, local, tribal), functional responsibilities (e.g., fire, oil spill, emergency medical services), statutory responsibilities (e.g., Federal Land Managers, Responsible Party), or some combination thereof. The Unified Command should identify a liaison to the affected communities to ensure direct communication with affected residents.

2. **Expert Advisory Group**

Observation: SoCalGas mobilized crews and equipment immediately upon discovery of the leak and, within 24 hours, determined that its standard procedures to abate leaks were not working and called in additional experts. Within 48 hours, SoCalGas had well-control experts on-site.

Discussion: The issues under consideration during the Aliso Canyon incident were complex and wide-ranging. They included subjects such as well-control techniques, public health effects of exposure to mercaptans or other chemicals, environmental impacts of a greenhouse-gas release of this magnitude, public communication, and regulatory oversight. It is essential that decisionmakers have access to accurate and complete information to make well-informed decisions. A readily accessible group of subject matter experts might have improved the decisionmaking process—especially for the complex engineering and health and safety issues associated with top kill attempts and surface gas collection.

Recommendation: In jurisdictions with significant natural gas storage, facility operators, regulatory agencies, and other responding agencies should consider compiling and maintaining a roster of potential subject matter expert advisors. The Unified Command could consult the roster to quickly convene a group that would be able to provide decisionmakers with advice on complex technical issues. Such an advisory group would be separate from the technical experts that are a normal component of the typical Incident Command System.

3. **Regulator Coordination and Regulatory Authority Review**

Observation: In the Aliso Canyon incident, local and State agencies in California had an existing regulatory framework and adequate authority and expertise to respond effectively to the incident. Federal agencies provided additional expertise and support for the State response efforts. However, this is not true across the country or for interstate gas storage facilities. This lack of uniformity prompted Congress, PHMSA, the gas storage industry, and State regulators (generally oil and gas boards) to examine the need for Federal and State regulators to work together more closely to produce a more effective and seamless set of safety standards and regulations.

Discussion: Federal agencies such as the EPA and the PHMSA have assessed their respective regulatory and injunctive authorities. It was determined that, in this case, State and local authorities were fully engaged, had adequate authority, and were ordering relief that was similar to what Federal authorities would have pursued.

However, in the event of a release from an interstate facility or facilities in other States, there is currently no set of mandatory safety standards that can be enforced uniformly across the country. Under PHMSA's State certification program for intrastate gas pipelines, States voluntarily file annual certifications with PHMSA, representing that they have the adequate authority and resources to effectively inspect intrastate pipelines and enforce the applicable requirements. Under this State certification program, which currently is in place in 48 States, PHMSA monitors State programs and provides Federal funding. To the extent that State oil and gas agencies other than the State pipeline safety agency will be responsible for the wells and downhole facilities, these agencies may also need to become certified. In June 2016, Congress directed PHMSA to move forward expeditiously with the adoption of minimum safety standards for underground storage. That process is currently underway. In addition, other Federal agencies may need to fill gaps and order additional relief to ensure that public health and the environment are protected.

Recommendation: Regulatory agencies at Federal, State, and, as appropriate, local levels should review their existing authorities and regulations related to natural gas storage facilities to identify potential gaps and address them in a collaborative manner that builds upon the existing State certification program for intrastate gas pipelines.

Topic II: Ambient Air Pollutant Monitoring During the Incident and Public Health Risk Assessment

1. **Monitoring Network**

Observation: The network of ambient air monitors deployed in the community and facility property was appropriate for the objective.

Discussion: Generally, the monitoring network that California state and local agencies established after the leak was discovered provided a detailed and robust characterization of ambient air quality in the vicinity of the SoCalGas natural gas leak and the surrounding community of Porter Ranch. Jurisdictions throughout the United States may not have ready access to similar resources.

Recommendation: State and local monitoring agencies with natural gas storage facilities within their jurisdictions should have the ability to establish a robust ambient air monitoring network in the surrounding communities, in order to adequately characterize the potential health impacts associated with natural gas leaks if resources are available. This includes access to real-time monitoring equipment for sulfur additive compounds, VOCs (hydrocarbons and aromatic compounds), SVOCs (e.g., naphthalene), methane, $PM_{2.5}$, H_2S, metals, and any other chemicals of concern identified by source data, as well as capability for instantaneous grab and 24-hour integrated samples.

2. **Timeliness and Data Availability**

Observation: Ambient air monitoring was deployed quickly in response to community concerns. Posting of ambient air samples in near-real time helped keep the community and public health agencies well informed.

Discussion: SCAQMD was able to initiate the collection of instantaneous grab samples on October 26, 2015—three days after the leak was discovered—in direct response to community complaints, providing a timely response to the community's concerns. Additional data were collected by SoCalGas, CARB, and LAUSD in the days that followed. All entities that collected ambient air quality data on facility property or within the surrounding communities posted the results on publicly accessible websites. CARB and SCAQMD specifically posted results from both instantaneous grab and 24-hour integrated samples, as well as near-real-time data from continuous monitors at the eight fixed locations within the community. Efforts were made to synthesize the data so that community members could understand the results.

Recommendation: State and local monitoring agencies should have an emergency air monitoring plan established for expeditious deployment of an ambient air monitoring network if a similar leak were to occur. Having data early in the process would enable agencies to reach timely decisions most consistent with public health protection (such as a decision to relocate residents). State and local monitoring agencies should also post their collected ambient air quality data in a prompt, easily accessible, and easy-to-understand manner.

3. **Pollutants of Concern**

Observation: Pollutants of concern were not identified prior to the leak event, and the composition of the kill fluids was unknown.

Discussion: It is common practice in the petrochemical industry to "fingerprint" each oil refinery's oil. [84] This type of analysis could be conducted periodically for each natural gas storage facility, in order to develop an understanding of what chemical compounds constitute the gas in each well or facility. This process could also be undertaken for any of the kill attempt fluids in order to better understand the chemical composition of the material used and its potential impact on public health. Having these analyses available would further enable health agencies and air quality agencies to develop comprehensive environmental sampling plans that could be used in the event of a leak. The analyses would also aid in determining the scope of monitoring, sampling, and analyses required, ultimately saving valuable resources and time.

Recommendation: State and local monitoring agencies in jurisdictions with natural gas storage facilities should consider collaboration with those facilities to develop facility-specific chemical fingerprints of the natural gas. If kill attempts are considered for sealing a leaking well, the kill fluid should also be analyzed for metals and other potential pollutants of concern. Once the chemical fingerprints are known, targeted monitoring plans should be developed in order to facilitate a quick and targeted response to a leak event. Such a plan should prioritize the sampling of pollutants of greatest health concern, which could include benzene, toluene, ethyl benzene and xylenes (BTEX), $PM_{2.5}$, and hydrogen sulfide.

4. **Background Concentrations of Pollutants**

Observation: Background concentrations of methane and other pollutants of concern were not specifically known for the areas surrounding the SoCalGas facility and SS-25.

Discussion: While SCAQMD, CARB, LAUSD, and SoCalGas performed extensive monitoring throughout the community and on the facility's property during the leak, there were no prior measurements for methane, benzene, mercaptans, hydrogen sulfide, or other compounds in the immediate area that would have established local background levels for those pollutants in the affected communities. Without local background levels, it is inherently difficult to interpret monitoring results accurately during the life cycle of the leak event.

Recommendation: State and local monitoring agencies should consider collaborating with stakeholders to determine local background levels of methane and other pollutants of concern.

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[84]This analysis is typically done by GC/MSD or other GC detectors using either EPA Method TO-14, Method TO-15, EPA Method EPA-18, or Method TO-3.

5. **Health Effects**

Observation: The full range of health risks from exposures to air pollutants released from the leaking well is not known, including health risks that may manifest over the long term.

Discussion: OEHHA and SCAQMD investigated the acute health risks from exposures to pollutants for which REL values existed. Chronic risks were also evaluated, although the exposure period during the well leak was much shorter than typical chronic exposures. OEHHA searched for REL-equivalent values for the natural gas odorants (t-butyl mercaptan and tetrahydrothiophene) but found that there are insufficient studies available to establish an REL and to determine the long-term effects of exposure to these odorizing additives.

SCAQMD's independent Hearing Board approved a legal order that requires SoCalGas to fund a study (to be completed by a third party) of the potential health effects of exposure to the gas leak.[85] According to the order, the study will include exposure to the odorants added to natural gas, for which there are currently no established RELs or cancer toxicity values. The status of this study is pending.

Recommendation: Further research is needed to determine the acute and chronic effects of exposure to natural gas odorants (t-butyl mercaptan and tetrahydrothiophene). Relevant agencies should review the results of the SoCalGas-funded study ordered by the SCAQMD Hearing Board and consider any relevant findings or recommendations. Monitoring and analysis by State and local agencies should continue, and risk data should be updated if conditions change.

6. **Coordination and Expertise**

Observation: A breadth of local and State expertise, along with frequent interagency coordination, aided in the assessment of air pollution-related health risks to the community.

Discussion: Beginning in November 2015, twice-weekly calls were held to discuss air monitoring activities, sampling results, and health risk assessment with experts in those fields. Participating agencies included SCAQMD, OEHHA, CARB, LA DPH, LA County Fire/HazMat, LAUSD, SoCalGas, and others.

Recommendation: In the event of a future well leak, responding agencies should include health-related expertise in the response. Responding agencies should consider establishing a network of health and risk assessment professionals prior to a leak event. After a leak has been identified, the network should be convened regularly to assess collected air sampling data and the potential for health impacts from related pollutant exposures.

7. **Detection Methods**

Observation: The analytical methods used to detect sulfur compounds were not able to identify the ambient concentrations experienced by the community and workers at the site, because detection was limited by the sampling method.

Discussion: Methods ASTM D5504-12 and SCAQMD 307-91 were used to test for sulfur compounds in ambient air. As a result, the parts-per-billion level detection limits of these methods were above the

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[85] http://www.aqmd.gov/docs/default-source/compliance/aliso-cyn/findings-and-decision-(complete).pdf?sfvrsn=4.

odor threshold for some of the sulfur-based odorants. Methods have been developed to sample and analyze sulfur compounds in ambient air at parts-per-trillion levels, which are more similar to levels detected by the human nose.

There are published methods for low-level sulfur compound testing that have been used in research studies. However, laboratories would need time and resources to prepare for analyses at the lower detection limits. In conjunction with methane sampling, these methods could aid in detecting leaks from natural gas infrastructure at lower concentrations and could reliably discern leaks that otherwise would not be detected due to background methane concentrations.

Recommendation: Natural gas facilities and local and State agencies should consider identifying laboratories with the capability to measure sulfur compounds at lower detection limits. If feasible, analytical methods to detect odorants at concentrations below odor thresholds should be available and should be used during incidents.

8. **Source Testing and Characterization**

   Observation: Source testing of emissions from SS-25 was not comprehensive.

   Discussion: Emissions from SS-25 were not characterized for the full range of compounds released. It would have been informative if, immediately after the release occurred, emissions of all chemical constituents had been evaluated, followed by continuous monitoring of some chemical constituents and periodic measurement of others. SCAQMD and SoCalGas collected a limited number of speciated air samples near SS-25 during the release. Characterization of the source was limited due to safety concerns.

   Recommendation: State and local air monitoring agencies should consider developing systems to collect source samples safely during a release and also should consider conducting robust source testing/characterization. Information collected on the chemical constituents of sources could be used in conjunction with air dispersion and deposition modeling to help inform decisions.

Topic III: Greenhouse Gas Emissions

1. **Baseline Data**

   Observation: The Aliso Canyon release occurred in a heavily populated region with several pre-existing ambient air monitoring stations measuring methane, and with robust State and local agency capacity to respond to threats to air quality.

   Discussion: Baseline monitoring data on methane concentrations in areas with storage facilities would greatly improve detection and quantification of leaks.

   Recommendation: State and local air monitoring agencies should consider having a methane monitoring framework. Baseline methane measurements would improve understanding of the magnitude of a leak. The framework and measurements should build on data already reported to Federal, State, and/or local agencies.

2. **Release Uncertainty and Multiple Measurements**

   Observation: Multiple measurement techniques were employed at Aliso Canyon to estimate the total quantity of methane released; however, uncertainties remain.

Discussion: Data from a wide variety of monitoring and measurement methods are available to quantify emissions from the leak, including information collected through grab samples, aircraft studies, mobile tracer flux ratio studies, satellite data, and inventory methods. Several groups quantified emissions using various sets of these data. Studies using different measurement and quantification methods converge around an estimate of roughly 90,000 metric tons of methane for the total quantity of methane emitted. The State's final methane emission estimate, which will consider all available data, is anticipated to be released by the end of 2016.

Other natural gas storage facilities would not typically be covered by multiple existing monitoring networks, and they also might not have access to multiple measurement technologies that are rapidly deployable to the site.

Despite multiple measurements, there are two overarching uncertainties that affect most of the measurement techniques. First, for a 15-day period between the leak's discovery on October 23, 2015, and the initial methane sampling flight on November 7, 2015, only limited data were available to estimate the rate of methane emissions. Second, it is unclear whether or to what extent any of the methane measurement efforts collected data during the eight "top kill" attempts. The "top kill" attempts may have affected the rate of natural gas release by altering the subsurface flow paths of the leaking natural gas.

Recommendation: State and local air agencies should begin methane monitoring as soon as possible following the initial detection of a leak. All monitoring should be coordinated with attempts to stop the leak, in order to determine whether those attempts decrease, increase, or stop fugitive methane emissions. When possible, future leaks from natural gas storage facilities should be measured with multiple methods to confirm measurements. State and local air agencies should consider coordination with existing measurement and quantification efforts, such as those by universities and Federal and State agencies active in methane and other air emissions monitoring efforts. These entities may have data or experience with monitoring in the area that could be of use.

3. **Measurement Technology**

Observation: Rapid deployment of measurement technologies following the release helped agencies understand the scale of the leak. Recent advancements in methane monitoring technologies may offer less costly, more portable, and more precise measurements.

Discussion: Scientific Aviation, a company that operates aircraft modified for atmospheric research, collected its first round of samples on November 7. (Initial safety concerns expressed by SoCalGas prevented earlier aircraft sampling.) It was fortunate that the State had an existing contract in place with the University of California, Davis, which allowed it to move quickly to initiate aircraft-based data collection. The data collected were used by the State to keep the public informed as work to stop the leak was ongoing.

Entities such as DOE's Advanced Projects Research Agency-Energy (ARPA-E) are seeking to spur development of other advanced methane leak detection technologies that could, within 10 years, detect a broad range of leak sizes. The Environmental Defense Fund (EDF) is also seeking to speed deployment of technologies to monitor for leaks on a continuous basis.[86] On July 18, 2016, the EPA

[86]https://www.edf.org/energy/natural-gas-policy/methane-detectors-challenge.

published a Request for Information inviting oil and gas owners and operators, along with States, nongovernmental organizations, academic experts, and others, to provide information on innovative strategies to locate, measure, and mitigate methane emissions accurately and cost-effectively.[87] The response period will end on November 15, 2016.

Recommendation: In advance of a leak, State emergency management agencies should determine whether they have access to aircraft and/or other mobile measurement technologies that can be deployed rapidly. Safety should be a consideration when aircraft are flying in zones with high methane concentrations. Air agencies should also consider formalizing pilot projects, involving State/local agencies, facility operators, and Federal agencies, to deploy and evaluate some of the evolving methane measurement methods.

4. **Inventory Tracking**

Observation: EPA tracks greenhouse gas emissions over time using the Inventory of U.S. Greenhouse Gas Emissions and Sinks. Many States track greenhouse gas emissions over time using State-level inventories.

Discussion: Emissions estimates from leak events like Aliso Canyon can be incorporated into emissions inventories if data are available. The EPA noted in the most recent Greenhouse Gas Inventory that it plans to include the Aliso Canyon event in its estimates of 2015 and 2016 emissions, which are to be published in 2017 and 2018, respectively.

Recommendation: Studies of natural gas releases should quantify emissions in such a way that they can be included in inventories. An emissions estimate of the total mass of gas emitted by an event can be included directly in an inventory, whereas methane concentration estimates at a given time cannot be included in an inventory without other information.

Topic IV: Post Well Closure Indoor Air and Source Sampling/CASPER Health Assessment

1. **Contaminant Identification**

Observation: A substantial effort was made to identify potential contaminants associated with the Aliso Canyon gas leak in the homes of Porter Ranch residents.

Discussion: In at least one of the top kill attempts, a significant volume of kill fluid was expelled; it was hypothesized to be part of an oily coating found on and within many homes in the Porter Ranch community. The results of a comprehensive effort to collect indoor air, surface wipe, and soil samples informed the response to citizen complaints, which culminated in a comprehensive cleaning effort by SoCalGas.

Indoor air sampling results were similar to those found in comparison homes and were within normal ranges for home indoor air. However, wipe sampling results found that a group of metals—barium, manganese, vanadium, aluminum, and iron—appeared together consistently, suggesting a common source. Soil sampling indicated elevated levels of chemicals, including hydrocarbons up to C_{40}, barium, and naphthalene.

[87]Oil and Natural Gas Sector; Request for Information; Emerging Technologies, 81 FR 46670, July 18, 2016.

Recommendation: Given the evidence that materials used in well-kill fluids may be re-expelled and may contaminate the surrounding area, facility operators and emergency responders should use caution when determining the composition of well-kill fluids and should consider the possible health risks that might result from exposure to toxic substances present in the fluids. Knowing the composition of the fluids would also facilitate environmental testing in the event of an accidental release. If a situation should occur in which a large volume of kill fluid or other material was expelled along with natural gas, the appropriate State or local agency should test exposed homes for the presence of potential or known constituents before residents returned. Soil samples taken at or near the source should be collected and analyzed for contaminants associated with the release, especially if residues resulting from a leak were found on or within structures at the facility, or in a community, and it was thought that the contaminants could pose a potential ingestion or inhalation risk. If enough information was known about the source and the expelled contaminants, dispersion modeling could be used to help make decisions regarding additional soil, surface water, and indoor sampling within the affected community.

2. **Source-Receptor Evaluation**

Observation: From the perspective of making a connection between the source of emissions (SS-25) and the locations affected by those emissions (the "receptors," e.g., residences, schools, and other locations downwind from SS-25, and ultimately the people in those locations), the conditions of the Aliso Canyon leak were relatively straightforward. The conditions aided the LADPH's evaluation of the relationships between source and receptors. The LADPH Public Health Assessment analysis also relied on the common occurrence of metals in the source and receptor samples to indicate the connection between source and receptor. The analytical methods used to evaluate trace metal content of residues from residences and schools were limited to total elemental levels.

Discussion: The conditions that allowed for a straightforward demonstration of the connections between the source and receptors included a single, large-volume emissions source, relatively consistent weather patterns, and fairly well-defined trace element composition of the source. More complex situations are possible in future incidents, which could result in an inability to demonstrate adequately the connections between the source and receptors. A lower emissions rate relative to similar surrounding sources (which might be the case with a slower leak from a storage site located in an operational oil and gas production area), greater variability in weather conditions, or more complex terrain could result in substantially less confidence in the ability to connect an emissions source to health and environmental impacts than was possible with the Aliso Canyon leak.

The metals identified as suggestive of a single source due to their common occurrence in source and receptor samples are not unique to the sources. While it is likely that the common occurrence of aluminum, barium, iron, manganese, and vanadium in both source and receptor samples provides adequate evidence of SS-25 as the source of residential and school contamination in this case, in a more complex situation it might be more appropriate to evaluate the ratios of various tracer species in multiple sources and receptor sites. The metals of interest here are present in numerous sources, from crustal dust to building materials, and the ratios of those trace elements will be different for different sources.

Recommendation: Collection and analysis of source and ambient samples should be conducted to enable evaluations of links between receptors (such as ambient monitors and residential surface samples), emissions from the leak, and emissions from other emission sources nearby and to support evaluations of health risks associated with exposure to the mix of constituents emitted. A more in-depth analysis of multiple relevant source trace element ratios, the ratios of samples from receptor sites, and use of sequential extraction would be appropriate in more complex leak situations like those noted above.

3. **Post-Incident Sample Collection**

   Observation: The process of post-incident indoor testing was responsive to ongoing health symptoms, but it was time consuming because information regarding potential contaminants was lacking.

   Discussion: When ongoing health complaints from the public and the initial evaluation of the CASPER survey provided evidence of potential indoor exposures, an indoor testing protocol needed to be developed and implemented expeditiously. The process of preparing and conducting the sampling, performing the laboratory analysis, and interpreting the data resulted in an effort that took several months to complete before conclusions could be developed and shared with the community.

   Recommendation: Responding agencies should develop a plan for post-incident sample collection and analysis and should integrate the plan into the initial incident response, in order to mitigate post-incident exposures and compress post-incident timelines.

4. **Home Cleaning**

   Observation: Indoor cleaning activities were completed in an inconsistent manner.

   Discussion: SoCalGas used its environmental mitigation contractor to implement cleaning activities. Many of the cleaning subcontractors did not have experience with the type of cleaning required to mitigate residences and schools. LADPH provided significant oversight of cleaning and was able to determine that much of the cleaning conducted was inadequate.

   Recommendation: In-home pollutant mitigation and cleaning activities should only be performed by certified professionals under adequate supervision.

Public Health Hazard Assessment

Observation: The LADPH Public Health Assessment notes the possibility of metals, particularly barium, in household dust as causing symptoms observed in the CASPER survey.

Discussion: As LADPH summarized in its Public Health Assessment, barium was the most frequently detected metal, found in 19% of the Porter Ranch homes with concentrations ranging from 0.05 to 1.0 $\mu g/cm^2$. Along with barium, four other metals (manganese, vanadium, aluminum and iron) consistently appeared together in the Porter Ranch home samples. LADPH noted that barium and the other metal contaminants can cause respiratory and skin irritation, and their presence could have contributed to the reported symptoms.

Although barium was the metal most commonly identified at sampling locations within the Porter Ranch community, there are no surface wipe reference standards for barium for either occupational or residential exposure. The absence of methods to extrapolate from surface wipe samples to air concentrations makes it difficult to draw conclusions about human exposures to indoor concentrations of air pollutants. Similarly, the absence of human studies or reports that correlate a particular surface wipe concentration of metals to any health effects or outcomes makes it difficult to draw conclusions about health impacts from those exposures.

Recommendation: State and local health and environmental agencies should consider developing standardized approaches for collecting health information and linking it with environmental monitoring data for use in public health hazard assessment in the event of similar leaks at other well sites.

Topic V: Greenhouse Gas Mitigation Plan

1. Mitigating Releases of Short-lived Climate Forcers

Observation: There are no Federal or State requirements to mitigate the environmental (i.e., climate) impacts of methane leaks from underground natural gas storage facilities, nor are there established standards to guide voluntary mitigation of the climate impacts of fugitive releases of a short-lived climate forcer such as methane.[88]

Discussion: There are no Federal or State mitigation requirements for the fugitive greenhouse gases released from the Aliso Canyon leak. Nonetheless, during the release, SoCalGas publicly acknowledged the impacts it was having on the environment and voluntarily committed to mitigating its climate impacts. Shortly after the SoCalGas commitment, Governor Brown ordered CARB to develop a plan for full mitigation of the leak's methane emissions. The combination of corporate leadership and public agency guidance is noteworthy. However, due to the litigation, it remains uncertain whether the leak will be "fully" mitigated per Governor Brown's proclamation, and mitigation is likely to be affected by the court decision.

CARB's March 31, 2016, Mitigation Program for Aliso Canyon discusses complexities associated with mitigation and differing stakeholder opinions on approaches. For example, methane's lifetime in the atmosphere is much shorter than that of carbon dioxide, but methane is more efficient than carbon dioxide at trapping radiation. Using the metric of "global warming potential" (GWP), pound for pound, the comparative impact of methane on climate change is approximately 28 to 36 times the impact of carbon dioxide over a 100-year period and approximately 84 to 87 times the impact of carbon dioxide over a 20-year period.[89]

In the context of the Aliso Canyon incident, with approximately 90,000 metric tons of methane released, full mitigation could be considered as ranging between about 2 million and 8 million metric tons of carbon dioxide equivalent, depending on whether a 100-year or 20-year time horizon is considered.

CARB's plan includes offsetting an amount of methane equivalent to the amount of methane leaked from Aliso Canyon or, if the emissions of a different greenhouse gas are reduced, to calculate equivalence using the 20-year GWP of methane. CARB ultimately decided on a 20-year time period for conversion into carbon dioxide equivalents, in order to "...properly incorporate current scientific knowledge, underscore the influence of SLCPs [short lived climate pollutants] as immediate climate-forcing agents and emphasize the need for immediate action on climate change." SoCalGas, in

[88]The term "short lived climate forcer" is generally used to denote a class of climate pollutants, including methane, that have relatively shorter atmospheric lifespans and relatively stronger climate impacts compared to carbon dioxide.
[89]Fifth Assessment Report of the United Nations Intergovernmental Panel on Climate Change (AR5), Synthesis Report, Box 3.2.

comments on CARB's approach stated, "...using the 20-year GWP in this situation is inappropriate as well as contrary to California and Federal law. Therefore, we do not intend to use a 20-year GWP as we evaluate mitigation projects."[90]

Recommendation: States with underground natural gas storage should review their legal authorities to require greenhouse gas mitigation of fugitive emissions from underground natural gas storage facilities. States interested in mitigation should review California's approach as outlined in its Mitigation Plan.

Reliability

The DOE commissioned an analysis of the impacts of a failure at each of the 400+ UGS facilities in the United States on their customers, quantified in terms of natural gas-fired electricity generation capacity potentially affected from the loss of a UGS facility. The methodology and models developed to assess the impacts are summarized below. All models and analyses are based on publicly available data. Based on the analysis, the Task Force presents observations and recommendations in terms of the need to improve gas/electric industry coordination for electric and gas reliability, the need for further analyses, the need for data for additional gas/electric reliability studies, and changes to regulatory requirements and standards. A supplementary Technical Report, which will be released by the end of the year, provides more details and extends the analysis. The analysis also assessed the impact of the Aliso Canyon incident on energy reliability and energy prices.

Topic I: Ensuring Electric Reliability and Managing Gas-Electric Interdependency Risks

1. **Aliso Canyon Event Has Implications Beyond Management of UGS Facilities**

   Observation: The Aliso Canyon event was a wake-up call, alerting us to the need for better understand of the implications and risks associated with growing interdependence between the electric and natural gas industries, and the need to take appropriate actions to mitigate such risks.

   Discussion: Aliso Canyon is not a unique UGS facility in terms of its potential, if disrupted, to have adverse impacts on electric reliability in the affected area. A total of 12 UGS facilities appear to have the potential to affect 2 GW or more of available generation capacity. Note, however, that these figures are preliminary, because the operators of the affected power plants may or may not have dual-fuel capability (i.e., diesel or equivalent liquid fuels, with sufficient inventories), access at short notice to alternative sources of natural gas, or access to alternative generation via transmission.

   Recommendations:

   a. Power system planners and operators, working with their natural gas counterparts, should study and understand the electric reliability impacts of prolonged disruptions of large-scale natural gas infrastructure (e.g., storage facilities, processing plants, key pipeline segments and compressor stations, LNG terminals).

   b. Power system planners and operators should communicate and share the results of their analyses with State and Federal officials to ensure that policymakers fully understand the risks to electric reliability and can develop appropriate mitigation policies and strategies.

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[90]Letter from SoCalGas to CARB chair Mary Nichols re: Aliso Canyon Methane Leak, Climate Impacts Mitigation Program (Draft), dated March 14, 2016.

c. Regulators, electric and gas operators, and other market participants should strive to disseminate planning and operational information to all facets of the electric and gas industries, so that key operating parameters, such as those pertaining to gas balancing, are defined, solutions can be developed, and coordination achieved. By sharing information, entities can develop and train on new operating/market procedures, increase situational awareness, prepare to implement procedures to maintain the operation of the electric and gas systems under constrained conditions, and avoid gas and electric curtailments.

2. **Backup Strategies Can Reduce Risks**

   Observation: The availability and use of a backup fuel source for electricity generation (or some functional equivalent) can enable a generation facility to operate in isolation from a potential natural gas infrastructure disruption.

   Discussion: Greater reliance on such measures as dual-fuel capabilities (i.e., diesel or equivalent liquid fuels, with sufficient inventories), energy storage options, and maintaining alternative sources of natural gas may help electricity operators bridge the gap between the uncertainties of gas availability during extreme events and maintaining a reliable source of operable capacity available to meet seasonal peak demands. This approach could include natural gas storage at or near electricity generation plants, if feasible and affordable.

   Recommendation: NERC, generators, and Federal and state agencies should consider broader usage of back-up strategies, including dual-fuel capabilities, energy storage options, and alternate sources of natural gas supply, to reduce reliability risks associated with the possible abrupt loss of a major source of natural gas for electricity generation.

3. **Joint Gas/Electric Planning and Coordination Should be Strengthened**

   Observation: Opportunities exist for DOE, FERC, NERC, and the electric and gas trade associations to strengthen joint gas-electric planning and coordination, with the objectives of seeing the electric and natural gas systems as interdependent critical infrastructures and minimizing risks (including physical and cyber security) to both sectors and their customers.

   Discussion: Enhanced operational coordination between the gas and electric industries would decrease the impacts of widespread outages. As an example, joint actions could be taken to optimize real-time gas flows across regional and local systems.[91]

   Recommendation: Federal and State agencies should work with NERC and the electric and gas trade associations to develop reliability guidelines, as well as identifying best practices for improved procedures, practices, and market designs to reduce and manage the impacts of gas curtailment events and related electricity contingencies.

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[91] http://western.wp.naruc.org/wp-content/uploads/sites/2/2016/06/GasSafety-All.pdf.

1. **Analyze a Broader Range of UGS-Related Contingencies**

Observation: The Task Force's current analysis of the potential loss of UGS facilities considered only the loss of one such facility at a time. A wider range of regionally relevant contingencies is plausible and merits review by electric system planners.

Discussion: Earthquakes or other disasters could disable multiple UGS facilities in an affected area, or they could take out combinations of UGS facilities and other important gas supply infrastructure. Further, planning to make gas/electric infrastructure more resilient against such events should take into account the need to ensure the availability of adequate "black start" capability in appropriate locations. (In the event of a regional-scale blackout, it is important to have some generation units in the affected area that can be restarted without electricity from an external source. Once running, these black-start-capable units can be used to help reactivate the broader network.)

Recommendation: DOE should work with the Department of Homeland Security (DHS) and other organizations to leverage the capabilities of DHS's National Infrastructure Simulation and Analysis Center (as defined in 6 USC 321) to review a variety of UGS disruption scenarios.

2. **Special Reliability Assessment by NERC**

Observation: The current Task Force analysis of the impacts of losing service from a given UGS facility relied on publicly available information on UGS characteristics and operations. The accuracy and confidence of the analytic results could be improved through the use of additional but proprietary or restricted-access information on UGS and their relationship to pipeline operations, which is available from sources such as EIA (Form 191, "Monthly Underground Gas Storage Report") and FERC (Form 567, "System Flow Diagrams").

Discussion: While ensuring appropriate protections for proprietary information, DOE intends to determine how these additional data can be re-analyzed to determine the potential consequences of the disruption of UGS operations—with particular attention to the 12 UGS sites of interest noted above. DOE also plans to work with NERC on its Special Reliability Assessment on Single Points of Disruption to Natural Gas Infrastructure, which will examine transmission-level reliability impacts on the bulk power system in the event of disruptions of service from key UGS facilities.

Recommendation: DOE, NERC, and appropriate National Laboratories should proceed with the proposed analysis (subject to appropriations, as necessary) and give particular attention to those UGS facilities that, if disrupted, appear in the current analysis to have significant potential to create electric reliability problems in affected communities.

3. **Need for Combined Gas/Electric Models to Analyze Short-Term Dynamics**

Observation: As delivery systems, the existing pipeline and storage networks must cope with short-term changes in operating conditions that affect the deliverability of gas to wholesale customers—particularly, gas-fired generators whose gas requirements are highly changeable from hour to hour. As the interdependence between the industries increases, the need to understand and cope with such rapid changes in both gas demand and gas deliverability becomes more acute.

Discussion: Combined gas/electric models are needed to determine in near-real-time the dynamic capability and adequacy of the combined regional systems. Such models would enable planners and operators to identify constraints and potential sources of disruption (e.g., storage facilities, key pipeline segments and compressor stations, LNG terminals), so as to operate both systems reliably. The models could be used to determine what facilities should be added, define adequate operating parameters (such as balancing on the gas system or ramping on the electric system), or estimate the impacts of facility outages, additions, or retirements. The models should include all planning periods (future years) and operations (current year and real-time) so that resource adequacy, steady-state, and dynamic analysis can be performed on both gas and electric systems. This work could include using the pipeline simulation models that interstate pipeline companies use when providing support for their applications to FERC to construct and operate pipeline facilities. In addition, development of pipeline simulation models by local gas distribution companies could be considered.

Recommendation: Power and gas system planners and operators should jointly develop, validate, and apply combined models to improve the capability and ensure the adequacy of the combined infrastructure.

4. **Tools for Analysis of Short-Term Gas Deliverability**

Observation: The electric industry needs the capability to produce quick-response analyses of rapidly changing conditions affecting the short-term deliverability of natural gas for electricity generation.

Discussion: During a July 2016 DOE workshop in Washington, DC, on resilient electric distribution systems, electric industry participants identified a need for a real-time tool that would access natural gas system operations data, starting with the existing gas electronic bulletin board (EBB) data. Once developed, this tool or capability could be used to perform quick-response contingency analyses related to the deliverability of natural gas for electricity generation.

Recommendation: DOE (subject to appropriations), in coordination with NERC, the ISOs, and others should consider performing a scoping study to examine the quality and relevance of EBB data and data from other sources for assessing real-time reliability risks, determine the costs of developing and testing a computer-based analytic tool capability for this purpose, examine who would pay to maintain the tool on a long-term basis, and consider whether user fees would be an effective way to fund its maintenance.

Topic III: Data Needed for Additional Gas/Electric Reliability Studies

1. **Collect Additional Information on EIA surveys**

Observation: EIA's Form 860 could be modified immediately to collect additional information on connections between individual gas-fired power plants and the natural gas supply system. In addition, currently withheld information on the availability of backup fuel oil at gas-fired power plants could be made public information.

Discussion: Making this information more readily available would aid analysts in determining the potential implications of any future disruptions to natural gas supply for regional or local electric reliability.

Recommendation: EIA should consider modifying Form EIA-923 and Form EIA-860 to include additional data that would be useful for analysis of issues related to maintaining the reliability of existing gas-fired electric generation capacity. This information might include, for example, information on the capacity of the pipelines connecting to power plants and data on a plant's reliance on firm and non-firm natural gas transportation.

Topic IV: Regulatory Requirements and Standards

1. Reduce Likelihood and Impacts of Gas Curtailments

Observation: Actions may be taken to reduce the likelihood of natural gas curtailments, but curtailments may occur nonetheless due to changes in market conditions, weather, equipment failures, natural disasters, physical attacks, cyber intrusion, etc. The growing interdependence between the gas and electric industries calls for greater preparedness by and among the affected companies to avert potential curtailments and reduce the impacts of those that occur.

Discussion: Natural gas service is generally available to electricity generators, subject to the regulatory and physical constraints of the natural gas system, although "firm" (non-interruptible) service typically costs considerably more than "interruptible" service. Regulators and policymakers need to understand the broad terms of the contractual arrangements for supplying gas to generators in areas under their jurisdictions, and to understand the physical limitations of the natural gas infrastructure for serving the needs of electric generators. Increased coordination between natural gas and power industry regulating agencies could help ensure improved cross-capture of information as the role of natural gas as a fuel source for power generation continues to grow.

Recommendations:

a. State PUCs or other relevant agencies should consider requiring natural gas LDCs and electric utilities under their jurisdiction to collaborate in the joint development of specific and clear procedures for managing future natural gas curtailments to minimize impacts, and to submit the procedures for regulatory approval.

b. State PUCs should consider whether to make changes in current LDC tariffs to establish more specific provisions concerning the allocation of gas among electric generators in advance of curtailment of service from an LDC-owned UGS facility. This review should also address the States' end-use curtailment rules, which may include *force majeure* policies under which service to natural gas-fired power plants with firm contracts could be curtailed.

2. Managing Short-term Variability of Generators' Demand for Gas

Observation: Natural gas-fired generators often demand fuel in large quantities at short notice that may strain pipelines' ability to deliver. Many older pipeline systems are not designed to accommodate this pattern of withdrawal behavior on a large scale. However, rising dependence in many areas on natural gas for electricity generation suggests that this strain will become more acute.

Discussion: Tariffs for wholesale gas purchases by utilities that would promote generator bids and reflect gas system limitations are needed, with the aims of reducing the chance that ISOs/RTOs will dispatch generators in a way that harms gas system reliability and permitting ISOs/RTOs to reserve sufficient internal electric transmission transfer capability to react to changes in the gas system.

Recommendation: Federal and State regulators should consider the operational demand characteristics of natural gas-fired generation when developing or reviewing the regulatory framework for planning, building, and operating the natural gas delivery system.

3. Avoiding Mismatches Between Nominated Gas Flows and Actual Gas Demand

Observation: The timing of the nomination processes for the electric and gas markets do not coincide, and this increases the risk of a mismatch between nominated gas flow and actual gas demand.

Discussion: If sufficient gas for electricity generation is not procured in advance, the result may be may be gas procurement, including from UGS facilities, during more illiquid periods and lead to higher costs for electric generation and increased reliability risk.[92]

Recommendation: Both gas and electric industries should continue to review and improve existing processes and the timing of information flows pertaining to energy bidding and/or gas nominations processes so that both systems are balanced and can operate within their respective reliability parameters. Similarly, the two industries should work together to develop flexible pipeline services to accommodate the changing needs of the electricity industry.

[92]http://western.wp.naruc.org/wp-content/uploads/sites/2/2016/06/GasSafety-All.pdf; and https://www.caiso.com/Documents/Agenda_Presentation_AlisoCanyonGasElectricCoordination.pdf.

Glossary

Blowout prevention

One or more valves installed at the wellhead to prevent the uncontrolled escape of fluids from the well, particularly during drilling and completion operations. A variety of blowout preventers (BOPs) can be used to cover casing, tubing, and even an open hole. BOPs are a critical component to keep workers safe in the event of a loss of well control event.

Bridge plugs

Downhole tools that are located and set to isolate the lower part of the well. Bridge plugs may be permanent or retrievable, enabling the lower portion of a well to be permanently sealed from production or temporary isolated from a treatment conducted on an upper zone.

Casing thickness inspections

A test that measures the thickness of the casing, looking for changes that could be due to deformation, physical wear, or corrosion. A number of different downhole logs, including fingered calipers, magnetic field, and acoustic tests can be used to perform or contribute to a casing thickness inspection. If the inspection reveals thinning of the casing, the casing strength is calculated to ensure that it can safely withstand authorized operating pressures for the well.

Cementing procedures

Cement is used to hold casing in place and to prevent fluid migration between subsurface formations. Cement plugs also prevent fluid migration within the well's casing, and are often put in place during abandonment procedures. Cementing is the process of mixing unhydrated cement, cement additives and water and pumping the cement slurry down casing to critical points in the annulus around the casing or in the open hole below the casing string. The three principal purposes of cementing are to: 1) restrict fluid movement between the formations, 2) bond and support the casing, and 3) restrict fluid movement between casings and within the well.

Corrosion inspections

Physical inspection of a metallic structure (e.g., casing and tubing strings) to locate damage by means of corrosion in a structure, as well as gaining insight to the amount and severity of that damage.

Gas well "freeze offs"

Freeze offs occur when the ambient temperature drops below freezing, and water or other liquids freeze in the wellhead and block the flow of gas, thereby stopping or significantly limiting production. Such freeze offs can be prevented by protecting the wellhead from cold temperatures.

Geophysical logging (also known as "borehole geophysics")

The practice of recording and analyzing measurements of physical properties made in wells by lowering equipment via wire line into the wellbore. State-of-the-art logging systems collect multiple logs with one pass of the tool and can measure properties of casing, cement, and subsurface rock and fluid, and can be performed in open hole or cased wells.

Kill the well

To stop a well from flowing or having the ability to flow into the wellbore. Kill procedures typically involve circulating reservoir fluids out of the wellbore or pumping higher density fluid into the wellbore, or both, and are typically used during normal well maintenance operations or after a loss of well control.

Lost circulation material

The collective term for substances added to drilling fluids when drilling fluids are being lost to a formations downhole. Commonly used lost circulation materials are fibrous (cedar bark, shredded cane stalks, mineral fiber and hair), flaky (mica flakes and pieces of plastic or cellophane sheeting) or granular (ground and sized limestone or marble, wood, nut hulls, Formica, corncobs and cotton hulls). Less conventional materials include ball sealers, steel balls, golf balls, and junk.

Mechanical integrity testing

Mechanical integrity testing (MIT) is a set of tests used to ensure that a well systems conforms to its design specifications and that there are no significant leaks in the casing, tubing, or packer system or vertically around the outside of the casing-cement system. Several different types of tests have been used to demonstrate mechanical integrity, including an annulus pressure test or radioactive tracer surveys. Cement bond logs, casing inspection logs, temperature logs, and noise logs have also been used for MIT.

Noise log

A highly sensitive acoustic sensor capable of detecting the sound of gas flowing will be lowered down the length of the well above the gas reservoir. This sensor detect the source of any gas escaping from or around the well bore. If the well has a leak, gas will bubble up from the well bore causing a sound that can be detected by the sensor.

Packer

A packer or "mechanical seal" is a device lowered into a well to produce a liquid-tight seal to hydrologically separate two or more sections of a well. These seals can be set in place near the bottom of the well, within the portion of the well surrounded by cement. This method is an industry standard practice for isolating a well from reservoir gases or fluids and will further protect the casing from internal gas pressure.

Plugging and abandonment

This procedure is used to prepare a well to be closed permanently, usually after it is deemed no longer cost-effective to operate. Different regulatory bodies have their own requirements for plugging operations. Most require that cement plugs be placed and tested across any open hydrocarbon-bearing formations, across all casing shoes, across freshwater aquifers, and perhaps several other areas near the surface, including the top 20 to 50 feet [6 to 15 meters] of the wellbore. The well designer may choose to set bridge plugs in conjunction with cement slurries to ensure that higher density cement sets at the desired interval. In that case, the bridge plug would be set and cement pumped on top of the plug.

Pressure testing

A pressure test is a deliberate modification to the pressure within the interior of the well and the measurement of subsequent pressure changes, for example in the annular space between the production tubing and the well's intermediate casing, to determine the well's ability to withstand expected operating pressures. Pressure testing can also evaluate the integrity of packers that seal the annular space between the tubing and casing.

Primary and secondary well barrier construction

In a system with two barriers in place, there shall be always one barrier that acts as a first level of protection and one as a second level of protection. The primary barrier's function is to prevent unintentional flow to the environment or other formations. The secondary barrier is to prevent unintentional flow if the primary barrier fails. To function effectively as two different barriers, they must be able to be independently tested for failure.

Production casing

Production casing refers to the deepest section of casing that is above the producing reservoir. It may penetrate into the reservoir or a liner may be hung off it to penetrate the reservoir. It isolates the gas formation from other subsurface formations.

Relief well

A relief well is a well drilled to intersect an oil or gas well that has experienced a blowout. Specialized liquid, such as heavy (dense) drilling mud followed by cement, can then be pumped down the relief well in order to stop the flow from the reservoir in the damaged well.

Surface leak detection

In addition to a mechanical integrity test (described above), monitoring and inspection for leaks includes surface, near surface, atmospheric, and remote sensing monitoring to detect leaks to the atmosphere or the shallow subsurface. Such monitoring can include soil gas sensors, eddy flux towers, LIDAR, or gas flux monitors.

Temperature log

A sensor can be lowered down the depth of the well to measure the temperature within the well at different depths (usually continuously or at high resolution intervals). If the casing in the well is not intact, Joule-Thompson cooling of the escaping gas will appear as a reduced temperature anomaly.

Top kill

In this method dense fluids are pumped from the surface into the well and against the upward flowing gas to cease its flow.

Tubing

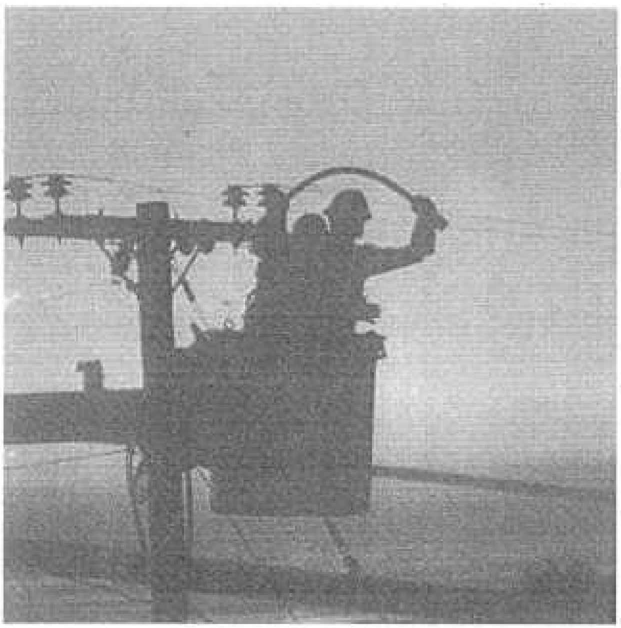
Injection tubing is a smaller diameter uncemented casing string hung inside the other casing strings and used to convey fluids between the surface and subsurface formations. Tubing is often used during injection or production activities, as subsurface fluids can be corrosive to steel casing, and the tubing can be more easily pulled and replaced than cemented casing strings.

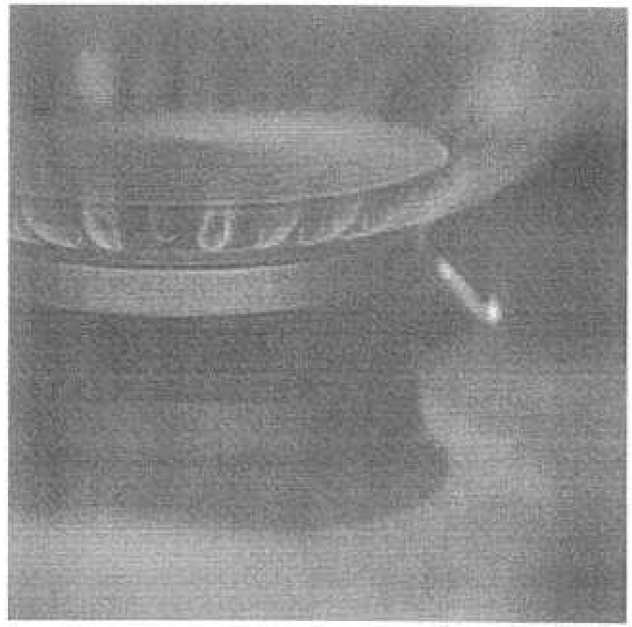
http://energy.gov/downloads/report-ensuring-safe-and-reliable-underground-natural-gas-storage

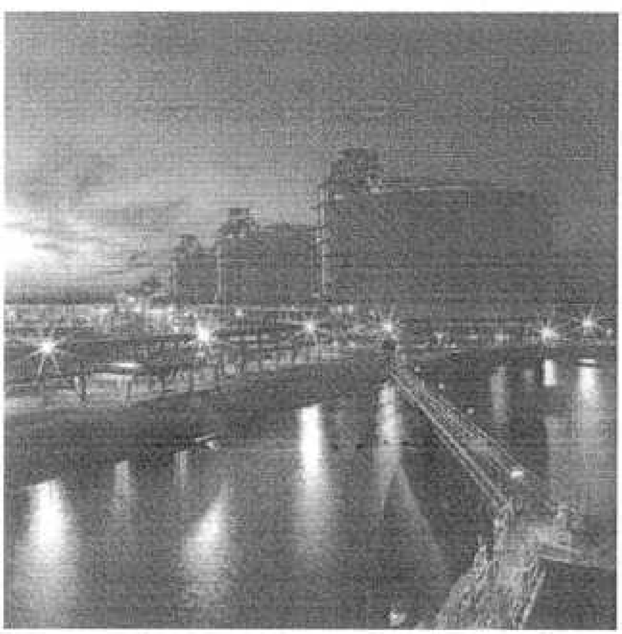
EXHIBIT E

Sempra Energy®

2016 FORM 10-K







UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2016

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ______ to ______

Commission File No.	Exact Name of Registrants as Specified in their Charters, Address and Telephone Number	State of Incorporation	I.R.S. Employer Identification Nos.
1-14201	SEMPRA ENERGY 488 8th Avenue San Diego, California 92101 (619) 696-2000	California	33-0732627
1-03779	SAN DIEGO GAS & ELECTRIC COMPANY 8326 Century Park Court San Diego, California 92123 (619) 696-2000	California	95-1184800
1-01402	SOUTHERN CALIFORNIA GAS COMPANY 555 West Fifth Street Los Angeles, California 90013 (213) 244-1200	California	95-1240705

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Each Exchange on Which Registered
Sempra Energy Common Stock, without par value	NYSE

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Southern California Gas Company Preferred Stock, $25 par value
6% Series A, 6% Series

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

	Yes	No
Sempra Energy	X	
San Diego Gas & Electric Company		X
Southern California Gas Company		X

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

	Yes	No
Sempra Energy		X
San Diego Gas & Electric Company		X
Southern California Gas Company		X

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

	Yes X	No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Sempra Energy	Yes X	No
San Diego Gas & Electric Company	Yes X	No
Southern California Gas Company	Yes X	No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Sempra Energy	
San Diego Gas & Electric Company	X
Southern California Gas Company	X

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
Sempra Energy	[X]	[ ]	[ ]	[ ]
San Diego Gas & Electric Company	[ ]	[ ]	[X]	[ ]
Southern California Gas Company	[ ]	[ ]	[X]	[ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Sempra Energy	Yes	No X
San Diego Gas & Electric Company	Yes	No X
Southern California Gas Company	Yes	No X

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2016:

Sempra Energy	$28.4 billion (based on the price at which the common equity was last sold as of the last business day of the most recently completed second fiscal quarter)
San Diego Gas & Electric Company	$0
Southern California Gas Company	$0

Common Stock outstanding, without par value, as of February 21, 2017:

Sempra Energy	250,543,688 shares
San Diego Gas & Electric Company	Wholly owned by Enova Corporation, which is wholly owned by Sempra Energy
Southern California Gas Company	Wholly owned by Pacific Enterprises, which is wholly owned by Sempra Energy

SAN DIEGO GAS & ELECTRIC COMPANY MEETS THE CONDITIONS OF GENERAL INSTRUCTIONS I(1)(a) AND (b) OF FORM 10-K AND IS THEREFORE FILING THIS REPORT WITH A REDUCED DISCLOSURE FORMAT AS PERMITTED BY GENERAL INSTRUCTION I(2).

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the 2016 Annual Report to Shareholders of Sempra Energy, San Diego Gas & Electric Company and Southern California Gas Company are incorporated by reference into Parts I, II and IV.

Portions of the Sempra Energy Proxy Statement prepared for its May 2017 annual meeting of shareholders are incorporated by reference into Part III.

Portions of the Southern California Gas Company Information Statement prepared for its May 2017 annual meeting of shareholders are incorporated by reference into Part III.

SEMPRA ENERGY FORM 10-K
SAN DIEGO GAS & ELECTRIC COMPANY FORM 10-K
SOUTHERN CALIFORNIA GAS COMPANY FORM 10-K
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SEMPRA ENERGY FORM 10-K
SAN DIEGO GAS & ELECTRIC COMPANY FORM 10-K
SOUTHERN CALIFORNIA GAS COMPANY FORM 10-K
TABLE OF CONTENTS (CONTINUED)

This combined Form 10-K is separately filed by Sempra Energy, San Diego Gas & Electric Company and Southern California Gas Company. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes representations only as to itself and makes no other representation whatsoever as to any other company.

You should read this report in its entirety as it pertains to each respective reporting company. No one section of the report deals with all aspects of the subject matter. Separate Item 6 and 8 sections are provided for each reporting company, except for the Notes to Consolidated Financial Statements in Item 8. The Notes to Consolidated Financial Statements for all of the reporting companies are combined. All Items other than Items 6 and 8 are combined for the reporting companies.

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

We make statements in this report that are not historical fact and constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements are based upon assumptions with respect to the future, involve risks and uncertainties, and are not guarantees of performance. These forward-looking statements represent our estimates and assumptions only as of the filing date of this report. We assume no obligation to update or revise any forward-looking statement as a result of new information, future events or other factors.

In this report, when we use words such as "believes," "expects," "anticipates," "plans," "estimates," "projects," "forecasts," "contemplates," "assumes," "depends," "should," "could," "would," "will," "confident," "may," "potential," "possible," "proposed," "target," "pursue," "outlook," "maintain," or similar expressions, or when we discuss our guidance, strategy, plans, goals, opportunities, projections, initiatives, objectives or intentions, we are making forward-looking statements.

Factors, among others, that could cause our actual results and future actions to differ materially from those described in forward-looking statements include

- actions and the timing of actions, including decisions, new regulations, and issuances of permits and other authorizations by the California Public Utilities Commission, U.S. Department of Energy, California Division of Oil, Gas, and Geothermal Resources, Federal Energy Regulatory Commission, U.S. Environmental Protection Agency, Pipeline and Hazardous Materials Safety Administration, Los Angeles County Department of Public Health, states, cities and counties, and other regulatory and governmental bodies in the United States and other countries in which we operate;
- the timing and success of business development efforts and construction projects, including risks in obtaining or maintaining permits and other authorizations on a timely basis, risks in completing construction projects on schedule and on budget, and risks in obtaining the consent and participation of partners;
- the resolution of civil and criminal litigation and regulatory investigations;
- deviations from regulatory precedent or practice that result in a reallocation of benefits or burdens among shareholders and ratepayers; modifications of settlements; and delays in, or disallowance or denial of, regulatory agency authorizations to recover costs in rates from customers (including with respect to regulatory assets associated with the San Onofre Nuclear Generating Station facility and 2007 wildfires) or regulatory agency approval for projects required to enhance safety and reliability;
- the availability of electric power, natural gas and liquefied natural gas, and natural gas pipeline and storage capacity, including disruptions caused by failures in the transmission grid, moratoriums on the withdrawal or injection of natural gas from or into storage facilities, and equipment failures;
- changes in energy markets; volatility in commodity prices; moves to reduce or eliminate reliance on natural gas; and the impact on the value of our investment in natural gas storage and related assets from low natural gas prices, low volatility of natural gas prices and the inability to procure favorable long-term contracts for storage services;
- risks posed by actions of third parties who control the operations of our investments, and risks that our partners or counterparties will be unable or unwilling to fulfill their contractual commitments;
- weather conditions, natural disasters, accidents, equipment failures, explosions, terrorist attacks and other events that disrupt our operations, damage our facilities and systems, cause the release of greenhouse gases, radioactive materials and harmful emissions, cause wildfires and subject us to third-party liability for property damage or personal injuries, fines and penalties, some of which may not be covered by insurance (including costs in excess of applicable policy limits) or may be disputed by insurers;
- cybersecurity threats to the energy grid, storage and pipeline infrastructure, the information and systems used to operate our businesses and the confidentiality of our proprietary information and the personal information of our customers and employees;
- the ability to win competitively bid infrastructure projects against a number of strong and aggressive competitors;
- capital markets and economic conditions, including the availability of credit and the liquidity of our investments; fluctuations in inflation, interest and currency exchange rates and our ability to effectively hedge the risk of such fluctuations;
- changes in the tax code as a result of potential federal tax reform, such as the elimination of the deduction for interest and non-deductibility of all, or a portion of, the cost of imported materials, equipment and commodities;
- changes in foreign and domestic trade policies and laws, including border tariffs, revisions to favorable international trade agreements, and changes that make our exports less competitive or otherwise restrict our ability to export;
- expropriation of assets by foreign governments and title and other property disputes;
- the impact on reliability of San Diego Gas & Electric Company's (SDG&E) electric transmission and distribution system due to increased amount and variability of power supply from renewable energy sources;

- the impact on competitive customer rates due to the growth in distributed and local power generation and the corresponding decrease in demand for power delivered through SDG&E's electric transmission and distribution system and from possible departing retail load resulting from customers transferring to Direct Access and Community Choice Aggregation; and
- other uncertainties, some of which may be difficult to predict and are beyond our control.

We caution you not to rely unduly on any forward-looking statements. You should review and consider the risks, uncertainties and other factors that affect our business as described in this report and other reports that we file with the Securities and Exchange Commission.

PART I.

ITEM 1. BUSINESS

DESCRIPTION OF BUSINESS

We provide a description of Sempra Energy and its subsidiaries in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and additional information by reporting segment in Note 16 of the Notes to Consolidated Financial Statements, both of which are included in the 2016 Annual Report to Shareholders (Annual Report), which is attached as Exhibit 13.1 to this report and is incorporated herein by reference.

This report includes information for the following separate registrants:

- Sempra Energy and its consolidated entities
- San Diego Gas & Electric Company (SDG&E) and its consolidated variable interest entity (VIE)
- Southern California Gas Company (SoCalGas)

References in this report to "we," "our," "us," "our company" and "Sempra Energy Consolidated" are to Sempra Energy and its consolidated entities, collectively, unless otherwise indicated by the context. SDG&E and SoCalGas are collectively referred to as the California Utilities. They are subsidiaries of Sempra Energy, and Sempra Energy indirectly owns all of the capital stock of SDG&E and all of the common stock and substantially all of the voting stock of SoCalGas.

Sempra Energy's principal operating units are

- Sempra Utilities, which includes our SDG&E, SoCalGas and Sempra South American Utilities reportable segments; and
- Sempra Infrastructure, which includes our Sempra Mexico, Sempra Renewables and Sempra LNG & Midstream reportable segments.

Prior to December 31, 2016, our reportable segments were grouped under the following operating units:

- California Utilities (which included the SDG&E and SoCalGas segments)
- Sempra International (which included the Sempra South American Utilities and Sempra Mexico segments)
- Sempra U.S. Gas & Power (which included the Sempra Renewables and Sempra Natural Gas segments)

The grouping of our segments within our operating units as of December 31, 2016 reflects a realignment of management oversight of our operations. As part of this realignment, we changed the name of our "Sempra Natural Gas" segment to "Sempra LNG & Midstream." This name change and the realignment of our segments within our new operating units had no impact on our historical financial position, results of operations, cash flows or segment results previously reported.

All references to "Sempra Utilities" and "Sempra Infrastructure" and their respective principal segments are not intended to refer to any legal entity with the same or similar name. Sempra Infrastructure also owns or owned (during periods presented in the report) utilities which are not included in our references to the Sempra Utilities. We provide financial information about all of our reportable segments and about the geographic areas in which we do business in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 16 of the Notes to Consolidated Financial Statements in the Annual Report.

COMPANY WEBSITES

Company website addresses are

- Sempra Energy – www.sempra.com
- SDG&E – www.sdge.com
- SoCalGas – www.socalgas.com

We make available free of charge on our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). The charters of the audit, compensation and corporate governance committees of Sempra Energy's board of directors (the board), the board's corporate governance guidelines, and Sempra Energy's code of business conduct and ethics for directors and officers (which also applies to directors and officers of SDG&E and SoCalGas) are posted on Sempra Energy's website.

SDG&E and SoCalGas make available free of charge via a hyperlink on their websites their annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC.

Printed copies of all of these materials may be obtained by writing to our Corporate Secretary at Sempra Energy, 488 8th Avenue, San Diego, CA 92101-7123.

The SEC also maintains a website that contains reports, proxy and information statements and other information we file with the SEC at www.sec.gov. Copies of these reports, proxy and information statements and other information may also be obtained, after paying a duplicating fee, by electronic request at certified@sec.gov, or by writing the SEC's Public Reference Room, 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330.

The information on the websites of Sempra Energy, SDG&E and SoCalGas is not part of this report or any other report that we file with or furnish to the SEC, and is not incorporated herein by reference.

GOVERNMENT REGULATION

California State Utility Regulation

The California Utilities are principally regulated by the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and the California Air Resources Board (CARB).

The CPUC:

- consists of five commissioners appointed by the Governor of California for staggered, six-year terms.
- regulates SDG&E's and SoCalGas' rates and conditions of service, sales of securities, rates of return, capital structure, rates of depreciation, and long-term resource procurement, except as described below in "United States Utility Regulation."
- has jurisdiction over the proposed construction of major new electric generation, transmission and distribution, and natural gas storage, transmission and distribution facilities in California.
- conducts reviews and audits of utility performance and compliance with regulatory guidelines, and conducts investigations into various matters, such as safety, deregulation, competition and the environment, to determine its future policies.
- regulates the interactions and transactions of the California Utilities with Sempra Energy and its other affiliates.

The CPUC also oversees and regulates new products and services, including solar and wind energy, bioenergy, alternative energy storage and other forms of renewable energy. In addition, the CPUC's safety and enforcement role includes inspections, investigations and penalty and citation processes for safety violations.

We provide further discussion in Notes 13, 14 and 15 of the Notes to Consolidated Financial Statements in the Annual Report.

The CEC publishes electric demand forecasts for the state and for specific service territories. Based on these forecasts, the CEC:

- determines the need for additional energy sources and conservation programs;
- sponsors alternative-energy research and development projects;
- promotes energy conservation programs to reduce demand within the state of California for electricity and natural gas;
- maintains a statewide plan of action in case of energy shortages; and
- certifies power-plant sites and related facilities within California.

The CEC conducts a 20-year forecast of available supplies and prices for every market sector that consumes natural gas in California. This forecast includes resource evaluation, pipeline capacity needs, natural gas demand and wellhead prices, and costs of transportation and distribution. This analysis is one of many resource materials used to support the California Utilities' long-term investment decisions.

The state of California requires certain California electric retail sellers, including SDG&E, to deliver a percentage of their retail energy sales from renewable energy sources. The rules governing this requirement, administered by both the CPUC and the CEC, are generally known as the Renewables Portfolio Standard (RPS) Program. We discuss this requirement as it applies to SDG&E in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" in the Annual Report.

Certification of a generation project by the CEC as an Eligible Renewable Energy Resource (ERR) allows the purchase of output from such generation facility to be counted towards fulfillment of the RPS Program requirements, if such purchase meets the provisions of California Senate Bill X1-2. This may affect the demand for output from renewables projects developed by Sempra Renewables and Sempra Mexico, particularly from California utilities. We have obtained or plan to obtain ERR certification for all of our renewable facilities operating in and/or providing power to California as they become operational.

California Assembly Bill (AB) 32, the California Global Warming Solutions Act of 2006, assigns responsibility to CARB for monitoring and establishing policies for reducing greenhouse gas (GHG) emissions. The bill requires CARB to develop and adopt a comprehensive plan for achieving real, quantifiable and cost-effective GHG emission reductions, including a statewide GHG emissions cap, mandatory reporting rules, and regulatory and market mechanisms to achieve reductions of GHG emissions. CARB is a department within the California Environmental Protection Agency, an organization that reports directly to the Governor's Office in the Executive Branch of California State Government. Sempra LNG & Midstream and Sempra Mexico are also subject to the rules and regulations of CARB. We provide further discussion of GHG emissions in Note 1 of the Notes to Consolidated Financial Statements in the Annual Report.

The operation and maintenance of SoCalGas' natural gas storage facilities are regulated by the California Department of Conservation's Division of Oil, Gas, and Geothermal Resources (DOGGR), in accordance with various other state and local agencies described below in "Other State and Local Regulation Within the U.S."

United States Utility Regulation

The California Utilities are also regulated by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), the U.S. Environmental Protection Agency (EPA), the U.S. Department of Energy (DOE) and the U.S. Department of Transportation (DOT).

In the case of SDG&E, the FERC regulates the interstate sale and transportation of natural gas, the transmission and wholesale sales of electricity in interstate commerce, transmission access, rates of return on transmission investment, the uniform systems of accounts, rates of depreciation and electric rates involving sales for resale. The National Energy Policy Act governs procedures for requests for transmission service. The FERC approved the California investor-owned utilities' (IOUs) transfer of operation and control of their transmission facilities to the Independent System Operator (ISO) in 1998.

In the case of SoCalGas, the FERC regulates the interstate sale and transportation of natural gas and the uniform systems of accounts.

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities in the United States, including the San Onofre Nuclear Generating Station (SONGS), in which SDG&E owns a 20-percent interest. NRC and various state regulations require extensive review of the safety, radiological and environmental aspects of these facilities. The majority owner of SONGS, Southern California Edison Company (Edison), made a decision to permanently retire the facility in June 2013. We provide further discussion of current SONGS matters involving the NRC and the closure of the facility in Note 13 of the Notes to Consolidated Financial Statements in the Annual Report.

The DOT, through its Pipeline and Hazardous Materials Safety Administration (PHMSA), has established regulations regarding engineering standards and operating procedures applicable to the California Utilities' natural gas transmission and distribution pipelines. The DOT has certified the CPUC to administer oversight and compliance with these regulations for the entities they regulate in California. The PHMSA also is in the process of promulgating regulations applicable to the California Utilities' natural gas storage facilities. See "Other U.S. Regulation" below.

Other State and Local Regulation Within the U.S.

The South Coast Air Quality Management District (SCAQMD) is the air pollution control agency responsible for regulating stationary sources of air pollution in the South Coast Air Basin in Southern California. The district's territory covers all of Orange County and the urban portions of Los Angeles, San Bernardino and Riverside counties.

SoCalGas has natural gas franchises with the 12 counties and the 223 cities in its service territory. These franchises allow SoCalGas to locate, operate and maintain facilities for the transmission and distribution of natural gas. Most of the franchises have indefinite lives with no expiration date. Some franchises have fixed expiration dates, ranging from 2017 to 2062. SoCalGas seeks to renew or extend these agreements prior to their expiration. Major franchise agreements include those for Los Angeles County and the City of Los Angeles. The Los Angeles County franchise agreement was entered into in 1955, with the current extension expiring in December 2017. The City of Los Angeles franchise was entered into in 1992, with the current extension expiring in June 2017.

SDG&E has

- electric franchises with the two counties served and the 27 cities in or adjoining its electric service territory; and
- natural gas franchises with the one county and the 18 cities in its natural gas service territory.

These franchises allow SDG&E to locate, operate and maintain facilities for the transmission and distribution of electricity and/or natural gas. Most of the franchises have indefinite lives with no expiration dates. Some natural gas and some electric franchises have fixed expiration dates that range from 2021 to 2035.

Sempra Renewables has operations, investments or development projects in various U.S. markets. Sempra LNG & Midstream develops and invests in liquefied natural gas (LNG)-related infrastructure in North America, develops and operates natural gas storage facilities in Alabama and Mississippi and owns a 50.2-percent interest in a liquefaction project in Louisiana. It is also seeking authorization to develop an LNG natural gas liquefaction and export terminal in Port Arthur, Texas.

Other U.S. Regulation

The FERC regulates certain Sempra Renewables and Sempra LNG & Midstream assets pursuant to the Federal Power Act (FPA) and Natural Gas Act, which provide for FERC jurisdiction over, among other things, sales of wholesale power in interstate commerce, transportation and storage of natural gas in interstate commerce, and siting and permitting of LNG terminals. In addition, certain Sempra Renewables power generation assets are required under the FPA to comply with reliability standards developed by the North American Electric Reliability Corporation. Bay Gas Storage Company, Ltd.'s (Bay Gas) natural gas storage operations are also regulated by the Alabama Public Service Commission.

Sempra LNG & Midstream also has an investment in Cameron LNG Holdings, LLC (Cameron LNG JV), located in Louisiana, that is subject to regulations of the DOE regarding the export of LNG. We discuss Sempra LNG & Midstream's investments further in Note 4 of the Notes to Consolidated Financial Statements in the Annual Report.

The FERC may regulate rates and terms of service based on a cost-of-service approach or, in geographic and product markets determined by the FERC to be sufficiently competitive, rates may be market-based. FERC-regulated rates at the following businesses are

- Sempra Renewables and Sempra LNG & Midstream: market-based for wholesale electricity sales
- Sempra LNG & Midstream: cost-based for the transportation of natural gas
- Sempra LNG & Midstream: market-based for the storage of natural gas, as well as the purchase and sale of LNG and natural gas

The California Utilities, Sempra LNG & Midstream and businesses that Sempra LNG & Midstream invests in are subject to DOT rules and regulations regarding pipeline safety. PHMSA, acting through the Office of Pipeline Safety, is responsible for administering the DOT's national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline, including pipelines associated with natural gas storage, and develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. The California Utilities, Sempra LNG & Midstream, Sempra Renewables and Sempra Mexico are also subject to regulation by the U.S. Commodity Futures Trading Commission.

Foreign Regulation

Our Sempra Mexico segment owns, develops and operates the following in Mexico:

- natural gas pipelines, ethane systems and a liquid petroleum gas pipeline and associated storage terminal
- electric generation facilities, including wind and solar power generation facilities and a natural gas-fired power plant in Baja California, Mexico; in February 2016, management approved a plan to market and sell the natural gas-fired power plant, as we discuss in Note 3 of the Notes to Consolidated Financial Statements in the Annual Report
- natural gas distribution systems in Mexicali, Chihuahua, and the La Laguna-Durango zone in north-central Mexico
- the Energía Costa Azul LNG regasification terminal located in Baja California, Mexico

These operations and projects are subject to regulation by the Energy Regulatory Commission (Comisión Reguladora de Energía, or CRE), the Safety, Energy and Environment Agency (Agencia de Seguridad, Energía y Ambiente), the Secretary of Energy (Secretaría de Energía) and other labor and environmental agencies of city, state and federal governments in Mexico.

Sempra Mexico's operations in Mexico include the Sempra Energy subsidiary Infraestructura Energética Nova, S.A.B. de C.V. (IEnova), which has common stock held by noncontrolling interests. The issuance of shares was approved and is subject to regulation by the Mexican National Banking and Securities Commission (Comisión Nacional Bancaria y de Valores, or

CNBV) for registration of the shares with the Mexican National Securities Registry (Registro Nacional de Valores) maintained by the CNBV. IEnova's shares are traded on the Mexican Stock Exchange (La Bolsa Mexicana de Valores, S.A.B. de C.V., or BMV) under the symbol "IENOVA."

Sempra South American Utilities has two utilities in South America that are subject to laws and regulations in the localities and countries in which they operate. Chilquinta Energía S.A. (including its subsidiaries, Chilquinta Energía) is an electric distribution utility serving customers in the region of Valparaíso in central Chile. Luz del Sur S.A.A. (including its subsidiaries, Luz del Sur) is an electric distribution utility in the southern zone of metropolitan Lima, Peru. These utilities serve primarily regulated customers, and their revenues are based on tariffs that are set by the National Energy Commission (Comisión Nacional de Energía) in Chile and the Energy and Mining Investment Supervisory Body (Organismo Supervisor de la Inversión en Energía y Minería, or OSINERGMIN) in Peru. Luz del Sur has common stock held by noncontrolling interests. The shares are subject to regulation by the Superintendencia del Mercado de Valores (Superintendency of Securities Market, or SMV). Luz del Sur's shares are traded on the Lima Stock Exchange (Bolsa de Valores de Lima) under the symbol LUSURC1.

Licenses and Permits

The California Utilities obtain numerous permits, authorizations and licenses in connection with the transmission and distribution of natural gas and electricity and the operation and construction of related assets, including electric generation and natural gas storage facilities, some of which may require periodic renewal.

Sempra Mexico and Sempra South American Utilities obtain numerous permits, authorizations and licenses for their electric and natural gas distribution, generation and transmission systems from the local governments where the service is provided. The permits for generation, transportation, storage and distribution operations at Sempra Mexico are generally for 30-year terms, with options for renewal under certain regulatory conditions. The respective energy ministry in Chile or Peru granted the concessions to operate Chilquinta Energía's and Luz del Sur's distribution operations for indefinite terms, not requiring renewal.

Sempra Mexico and Sempra LNG & Midstream obtain licenses and permits for the construction, operation and expansion of LNG facilities, and the import and export of LNG and natural gas.

Sempra Renewables obtains a number of permits, authorizations and licenses in connection with the construction and operation of power generation facilities, and in connection with the wholesale distribution of electricity.

Sempra LNG & Midstream obtains a number of permits, authorizations and licenses in connection with the construction and operation of natural gas storage facilities and pipelines, and with participation in the wholesale electricity market.

Most of the permits and licenses associated with construction and operations within the Sempra Renewables and Sempra LNG & Midstream businesses are for periods generally in alignment with the construction cycle or life of the asset and in many cases greater than 20 years.

We describe other regulatory matters related to our projects in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Our Business" in the Annual Report.

ELECTRIC UTILITY OPERATIONS

SDG&E

Customers

SDG&E's service area covers 4,100 square miles. At December 31, 2016, SDG&E had approximately 1.4 million electric customer meters consisting of approximately:

- 1,275,600 residential
- 151,100 commercial
- 400 industrial
- 5,000 direct access
- 2,000 street and highway lighting

We describe various matters impacting customer growth at SDG&E in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" in the Annual Report.

Resource Planning and Power Procurement

SDG&E's resource planning, power procurement and related regulatory matters are discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" and in Notes 14 and 15 of the Notes to Consolidated Financial Statements in the Annual Report.

Electric Resources

The supply of electric power available to SDG&E for resale is based on CPUC-approved purchased-power contracts currently in place with various suppliers, SDG&E's wholly owned generating facilities, and purchases on a spot basis. This supply as of December 31, 2016 is as follows:

SDG&E ELECTRIC RESOURCES

Resource	Number of contracts	Expiration date	Megawatts
Purchased-power contracts:			
Contracts with Qualifying Facilities (QFs)(1):			
Cogeneration	6	2017 and thereafter	139
Cogeneration tolling contracts(2)	2	2024, 2025	101
Total			240
Other contracts with renewable sources:			
Wind	15	2018 to 2035	1,233
Solar PV	21	2030 to 2041	1,306
Bio-gas/Hydro	16	2017 and thereafter	38
Total			2,577
Tolling(2) and other contracts:			
Natural gas tolling contracts	4	2019 to 2039	800
Hydro/Pump storage	1	2037	40
Market(3)	2	2019, 2022	193
Total			1,033
Total contracted			3,850
Owned generation, natural gas:			
Palomar Energy Center			566
Desert Star Energy Center			485
Miramar Energy Center			96
Cuyamaca Peak Energy Plant			47
Total owned generation			1,194
Total contracted and owned generation			5,044

(1) A QF is a generating facility which meets the requirements for QF status under the Public Utility Regulatory Policies Act of 1978. It includes cogeneration facilities, which produce electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, residential or institutional purposes.

(2) Tolling contracts are purchased-power agreements under which SDG&E provides natural gas for generation to the energy supplier.

(3) Agreements to purchase firm energy during specific periods at fixed prices.

Charges under most of the contracts with QFs are based on what it would incrementally cost SDG&E to produce the power or procure it from other sources. Charges under the remaining contracts are for firm and as-generated energy, and are based on the amount of energy received or are tolls based on available capacity. The prices under these contracts are based on the market value at the time the contracts were negotiated.

Natural Gas Supply

SDG&E buys natural gas under short-term contracts for its owned generation facilities and for certain tolling contracts associated with purchased-power arrangements. Purchases are from various southwestern U.S. suppliers and are primarily priced based on published monthly bid-week indices.

Power Pool

SDG&E is a participant in the Western Systems Power Pool, which includes an electric-power and transmission-rate agreement that allows access to power trading with more than 300 member utilities, power agencies, energy brokers and power marketers located throughout the United States and Canada. Participants are able to make power transactions on standardized terms, including market-based rates, preapproved by the FERC. Participation in the Western Systems Power Pool is intended to assist members in managing power delivery and price risk.

Electric Transmission System

Service to SDG&E's customers is supported by the electric transmission system. SDG&E's 500-kilovolt (kV) Southwest Powerlink transmission line, which is shared with Arizona Public Service Company and Imperial Irrigation District, extends from Palo Verde, Arizona to San Diego, California. SDG&E's share of the line is 1,162 megawatts (MW), although it can be less under certain system conditions. SDG&E's Sunrise Powerlink is a 500-kV transmission line constructed and operated by SDG&E with import capability of 1,000 MW of power.

Mexico's Baja California system is connected to SDG&E's system via two 230-kV interconnections with combined capacity up to 408 MW in the north-to-south direction and 800 MW in the south-to-north direction, although it can be less under certain system conditions.

Edison's transmission is connected to SDG&E's system at SONGS via five 230-kV transmission lines.

Chilquinta Energía

Customers

Chilquinta Energía has approximately 688,000 customer meters in the region of Valparaíso in central Chile, with a service area covering 4,400 square miles. At December 31, 2016, its customer meters consisted of approximately:

- 634,700 residential
- 38,700 commercial
- 1,400 industrial
- 7,700 street and highway lighting
- 5,300 agricultural

In Chile, customers are classified as regulated and non-regulated customers based on installed capacity. Regulated customers are those whose installed capacity is less than 500 kilowatts (kW). Non-regulated customers are those whose installed capacity is greater than 2,000 kW. Customers with installed capacity between 500 kW and 2,000 kW may choose to be classified as regulated or non-regulated. Non-regulated customers can buy power from other sources, such as directly from the generator.

In 2016, Chilquinta Energía added approximately 16,000 new customer meters at a growth rate of 2.3 percent. Chilquinta Energía's electric energy sales increased by approximately 13,000 megawatt hours (MWh) and decreased by approximately 57,000 MWh in 2016 and 2015, respectively, representing an annual growth rate of 0.4 percent in 2016 and a decline of 1.9 percent in 2015. The decrease in electric energy sales in 2015 was primarily due to the transfer of certain non-regulated customers from Chilquinta Energía to the energy-services company, Tecnored S.A., a subsidiary of Sempra South American Utilities in Chile.

Electric Resources

The supply of electric power available to Chilquinta Energía comes from purchased-power contracts currently in place with its various suppliers and its suppliers' generating facilities. This supply as of December 31, 2016 was as follows:

CHILQUINTA ENERGÍA ELECTRIC RESOURCES

Resource	Number of contracts	Expiration date	Megawatts
Purchased-power contracts(1)(2):			
Thermal/Hydro/Wind/Solar/Biomass	29	2020 to 2026	447
Small generation plants:			
Thermal			8
Total			455

(1) Contracts with fuel sources that include natural gas, coal or diesel are collectively referred to as thermal.

(2) In 2016, energy contracts in the Central Interconnected System, where Chilquinta Energía operates, were supplied 53 percent from thermal, 37 percent from hydro, 4 percent from wind, 3 percent from solar and 3 percent from biomass sources.

Power Generation System

Centers for Economic Load Dispatch (Centros de Despacho Económico de Carga, or CDEC), private organizations, were in charge of coordinating the operation of the electricity system until December 31, 2016. Each interconnected system was subject to its own CDEC. Chilquinta Energía operates within CDEC-SIC (Sistema Interconectado Central, or Central Interconnected System).

Effective January 1, 2017, the National Electric System is operated and coordinated by the National Electric Coordinator (Coordinador Eléctrico Nacional), a new independent entity. This institution is managed by a Directive Council (Consejo Directivo) formed by five members designated through a public tender. This new entity functions as a continuation of the CDEC for the central and northern interconnected system.

Transmission System and Access

Transmission lines in Chile are either part of its main transmission system (sistema de transmisión troncal) or its sub-transmission system (sistema de subtransmisión). Sub-transmission systems, including those owned by Chilquinta Energía, are comprised of infrastructure that is interconnected to the electricity system to supply non-regulated and regulated end-users located in the distribution service area.

We discuss transmission line projects that have been completed or are ongoing at Chilquinta Energía's joint ventures in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Our Business" in the Annual Report.

Luz del Sur

Customers

Luz del Sur has approximately 1,078,000 customer meters in the southern zone of metropolitan Lima, Peru, with a service area covering approximately 1,394 square miles. At December 31, 2016, its customer meters consisted of approximately:

- 1,011,500 residential
- 56,600 commercial
- 4,100 industrial
- 5,100 street and highway lighting
- 500 agricultural

In Peru, customers are classified as regulated and non-regulated customers based on capacity demand. Regulated customers are those whose capacity demand is less than 200 kW and their energy supply is considered public service. Non-regulated customers are those whose capacity demand is greater than 2,500 kW. Customers with capacity demand between 200 kW and 2,500 kW may choose to be classified as regulated or non-regulated.

In 2016, Luz del Sur added approximately 25,000 new customer meters at a growth rate of 2.4 percent. However, Luz del Sur's electric energy sales decreased by approximately 162,000 MWh in 2016, compared to an increase of approximately 262,000 MWh in 2015, representing a decrease in annual growth rate of 2.1 percent in 2016 and an increase of 3.6 percent in 2015. The decrease in electric energy sales in 2016 is primarily due to the migration of regulated and non-regulated customers to tolling customers, who only pay a tolling fee and do not contribute to customer load.

Electric Resources

The supply of electric power available to Luz del Sur comes from purchased-power contracts currently in place with various suppliers, as well as purchases made on an as-needed basis. Luz del Sur also uses the supply of power generated by Santa Teresa, its wholly owned 100-MW hydroelectric power plant in Peru's Cusco region.

Luz del Sur's electric power supply as of December 31, 2016 was as follows:

LUZ DEL SUR ELECTRIC RESOURCES

Resource	Number of contracts	Expiration date	Megawatts
Purchased-power contracts(1):			
Bilateral contract:			
Hydro/Thermal	1	2019	25
Auction contracts:			
Hydro	14	2021 to 2025	233
Thermal	21	2021 to 2025	687
Hydro/Thermal	26	2021 to 2025	537
Total contracted			1,482
Owned generation, Hydro:			
Santa Teresa(2)			61
Total contracted and owned generation			1,543

(1) Contracts with fuel sources that include natural gas, coal or diesel are collectively referred to as thermal.

(2) Firm capacity is estimated at 61 MW based on guidelines established by the system operator in Peru and historical water flows. Available excess capacity is sold on the spot market.

Power Generation System

The Sistema Eléctrico Interconectado Nacional (SEIN) is the Peruvian national interconnected system. The OSINERGMIN, in addition to setting tariffs as discussed above, supervises the bidding processes for energy purchases between distribution companies and generators.

The Committee of Economic Operation of the National Interconnected System (Comité de Operación Económica del Sistema Interconectado Nacional) coordinates the operation and dispatch of electricity of the SEIN.

Transmission System and Access

Transmission lines in Peru are divided into principal and secondary systems. The principal system lines are accessible by all generators and allow the flow of energy through the national grid. The secondary system lines connect principal transmission with the network of distribution companies or connect directly to certain final customers. The transmission company receives tariff revenues and collects tolls based on a charge per unit of electricity.

We discuss ongoing transmission line and substation projects at Luz del Sur in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Our Business" in the Annual Report.

CALIFORNIA NATURAL GAS UTILITY OPERATIONS

SoCalGas and SDG&E sell, distribute and transport natural gas. SoCalGas purchases and stores natural gas for its core customers and SDG&E's core customers on a combined portfolio basis and provides natural gas storage services for others. We discuss the California Utilities' resource planning, natural gas procurement, contractual commitments, and related regulatory matters below. We also provide further discussion in "Management's Discussion and Analysis of Financial Condition and Results of Operations," and in Notes 14 and 15 of the Notes to Consolidated Financial Statements in the Annual Report.

Customers

At December 31, 2016, SoCalGas had approximately 5.9 million customer meters consisting of approximately:

- 5,656,500 residential
- 247,300 commercial
- 26,000 industrial
- 50 electric generation and wholesale

At December 31, 2016, SDG&E had approximately 878,000 natural gas customer meters consisting of approximately:

- 845,600 residential
- 28,600 commercial
- 3,900 electric generation and transportation

For regulatory purposes, end-use customers are classified as either core or noncore customers. Core customers are primarily residential and small commercial and industrial customers. Noncore customers at SoCalGas consist primarily of electric generation, wholesale, large commercial and industrial, and enhanced oil recovery customers. SoCalGas' wholesale customers are primarily other IOUs, including SDG&E, or municipally owned natural gas distribution systems. Noncore customers at SDG&E consist primarily of electric generation and large commercial customers.

Most core customers purchase natural gas directly from SoCalGas or SDG&E. While core customers are permitted to purchase directly from producers, marketers or brokers, the California Utilities are obligated to provide reliable supplies of natural gas to serve the requirements of their core customers. Noncore customers are responsible for the procurement of their natural gas requirements.

Natural Gas Procurement and Transportation

SoCalGas purchases natural gas under short-term and long-term contracts for the California Utilities' residential and smaller business customers. SoCalGas purchases natural gas from various sources, including from Canada, the U.S. Rockies and the southwestern regions of the U.S. Purchases of natural gas are primarily priced based on published monthly bid-week indices.

To help ensure the delivery of the natural gas supplies to its distribution system and to meet the seasonal and annual needs of customers, SoCalGas has firm interstate pipeline capacity contracts that require the payment of fixed reservation charges to reserve firm transportation rights. Pipeline companies, primarily El Paso Natural Gas Company, Transwestern Pipeline Company, Pacific Gas and Electric Company (PG&E) and Kern River Gas Transmission Company, provide transportation services into SoCalGas' intrastate transmission system for supplies purchased by SoCalGas or its transportation customers from outside of California.

Natural Gas Storage

SoCalGas owns four natural gas storage facilities. The facilities have a combined working gas capacity of 137 billion cubic feet (Bcf) and have over 200 injection, withdrawal and observation wells. Natural gas withdrawn from storage is important for ensuring service reliability during peak demand periods, including heating needs in the winter, as well as peak electric generation needs in the summer. The Aliso Canyon natural gas storage facility represents 63 percent of SoCalGas' natural gas storage capacity. SoCalGas discovered a natural gas leak at one of its wells at the Aliso Canyon facility in October 2015, and permanently sealed the well in February 2016. SoCalGas has not injected natural gas into Aliso Canyon since October 25, 2015, pursuant to orders from DOGGR and the Governor, and Senate Bill (SB) 380, all discussed in Note 15 of the Notes to Consolidated Financial Statements in the Annual Report. Limited withdrawals of natural gas from Aliso Canyon have been made in 2017 to augment natural gas supplies during critical demand periods. SoCalGas completed its measurement of the natural gas lost from the leak and calculated that approximately 4.62 Bcf of natural gas was released from the Aliso Canyon natural gas storage facility as a result of the leak. In November 2016, SoCalGas submitted a request to DOGGR seeking authorization to resume injection operations at the Aliso Canyon storage facility. In accordance with SB 380, DOGGR held public meetings on February 1 and 2, 2017 to receive public comment on DOGGR's findings from its gas storage and well safety review and proposed pressure limits for the Aliso Canyon natural gas storage facility. The public comment period has expired. It remains for DOGGR to issue its safety determination, after which the CPUC must concur with DOGGR's determination, before injections at the facility can resume. We discuss the Aliso Canyon natural gas storage facility gas leak in "Risk Factors" below and in Note 15 of the Notes to Consolidated Financial Statements in the Annual Report.

SoCalGas also provides natural gas storage services directly to its customers. It uses the majority of its natural gas storage capacity to provide service to its residential and smaller business customers and offers the remaining storage capacity for sale to others.

Demand for Natural Gas

Demand for natural gas largely depends on the health and expansion of the Southern California economy, prices of alternative energy products, consumer preference, environmental regulations, legislation, California's energy policy supporting increased electrification and renewable power generation, and the effectiveness of energy efficiency programs. Other external factors such as weather, the price of electricity, the use of hydroelectric power, development of renewable energy resources, development of new natural gas supply sources, demand for natural gas outside the state of California, and general economic conditions can also result in significant shifts in market price, which may in turn impact demand.

One of the larger sources for natural gas demand is electric generation. Natural gas-fired electric generation within Southern California (and demand for natural gas supplied to such plants) competes with electric power generated throughout the western United States. Natural gas transported for electric generating plant customers may be affected by the overall demand for electricity, growth in renewable generation (including rooftop solar), the addition of more efficient gas technologies, new energy efficiency initiatives, and the extent that regulatory changes in electric transmission infrastructure investment divert electric generation from the California Utilities' respective service areas. The demand may also fluctuate due to volatility in the demand for electricity due to climate change, weather conditions and other impacts, and the availability of competing supplies of electricity such as hydroelectric generation and other renewable energy sources. We provide additional information regarding the electric industry and related infrastructure projects and regulatory impacts at the California Utilities in "Our Business" and "Factors Influencing Future Performance" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 14 of the Notes to Consolidated Financial Statements in the Annual Report.

The natural gas distribution business is seasonal, and cash provided from operating activities generally is greater during and immediately following the winter heating months. As is prevalent in the industry, but subject to current regulatory limitations, SoCalGas usually injects natural gas into storage during the summer months (April through October), which reduces cash provided from operating activities during this period, for withdrawal from storage usually during the winter months (November through March), which increases cash provided from operating activities, when customer demand is higher.

RATES AND REGULATION

We provide information concerning rates and regulation applicable to our utilities in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 1, 13 and 14 of the Notes to Consolidated Financial Statements in the Annual Report.

SEMPRA INFRASTRUCTURE

We provide descriptions of Sempra Infrastructure's segments and information concerning their operations in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 1, 3, 4, 15 and 16 of the Notes to Consolidated Financial Statements in the Annual Report.

Competition

Sempra Energy's non-utility businesses are among many others in the energy industry providing similar services. They are engaged in competitive activities that require significant capital investments and skilled and experienced personnel. Among these competitors there may be significant variation in financial, personnel and other resources compared to Sempra Infrastructure.

Generation – Renewables

Sempra Renewables primarily competes for wholesale contracts for the generation and sale of electricity through its development of and investments in wind and solar power generation facilities. Sempra Renewables also competes with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, and other energy service companies for sales of non-contracted renewable energy. The number and type of competitors may vary based on location, generation type and project size. Also, regulatory initiatives designed to enhance energy consumption from renewable resources for regulated utility companies may increase competition from these types of institutions. These utilities may have a cost of capital that differs from most independent renewable power producers and often are able to recover fixed costs through rate base mechanisms. This allows them to build, buy and upgrade renewable generation projects without relying exclusively on market clearing prices to recover their investments. Additionally, generation from Sempra Renewables' renewable energy assets is exposed to fluctuations in naturally occurring conditions such as wind, inclement weather and hours of sunlight.

Our renewable energy competitors include, among others:

- Avangrid
- First Solar
- Invenergy
- MidAmerican Energy
- NextEra Energy Resources
- NRG Energy

Because Sempra Mexico sells the power that it generates at its Energía Sierra Juárez wind power generation facility into California, it is also impacted by these competitive factors.

LNG

Technological advances associated with shale gas and tight oil production have significantly reduced the need for North American LNG import facilities and increased interest in liquefaction and export opportunities.

At current forward gas prices, U.S. Gulf Coast liquefaction is among the most price competitive potential LNG supply in the world. Brownfield liquefaction is particularly price competitive, resulting from many factors, including:

- high levels of developed and undeveloped North American unconventional natural gas and tight oil resources relative to domestic consumption levels;
- increasing gas and oil drilling productivity and decreasing unit costs of gas production;
- low breakeven prices of marginal North American unconventional gas production;
- proximity to ample existing gas transmission pipeline and underground gas storage capacity; and
- existing LNG tankage and berths.

Global LNG competition may limit U.S. LNG exports, as international liquefaction projects attempt to match U.S. Gulf Coast LNG production costs and customer contractual rights such as volume and destination flexibility. Host governments for international liquefaction projects are altering fiscal and tax regimes in an effort to make projects in their jurisdictions competitive relative to U.S. projects; however, sustained low oil prices may cause some of the international projects to become unfeasible due to their LNG price formulas' link to oil prices. It is expected that U.S. LNG exports will increase competition for current and future global natural gas demand, and thereby facilitate development of a global commodity market for natural gas and LNG.

Sempra LNG & Midstream has a 50.2-percent equity interest in Cameron LNG JV, which owns a regasification facility in Hackberry, Louisiana. The joint venture began construction in the second half of 2014 on a natural gas liquefaction export facility using some of the existing regasification infrastructure. The joint venture has authorization to export LNG to both Free Trade Agreement (FTA) countries and to countries that do not have an FTA with the United States.

Cameron LNG JV has 20-year liquefaction and regasification tolling capacity agreements in place with ENGIE S.A. and affiliates of Mitsubishi Corporation and Mitsui & Co., Ltd., which subscribe the full nameplate capacity of three trains at the facility. In addition, Cameron LNG JV is working on the development of up to two additional trains. We discuss Cameron LNG JV in Notes 3 and 4 of the Notes to Consolidated Financial Statements and the construction of the first three trains in "Our Business" and "Factors Influencing Future Performance" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Annual Report. Our joint venture partners, affiliates of ENGIE S.A., Mitsubishi Corporation (through a related company jointly established with Nippon Yusen Kabushiki Kaisha), and Mitsui & Co., Ltd., compete globally to market and sell LNG to end users, including gas and electric utilities located in LNG importing countries around the world. By providing liquefaction services, Cameron LNG JV will compete indirectly with liquefaction projects currently operating and those under development in the global LNG market. In addition to the U.S., these competitors are located in the Middle East, Southeast Asia, Africa, South America, Australia and Europe.

Sempra Energy is also taking steps to explore the development of additional LNG export facilities at Sempra LNG & Midstream's Port Arthur, Texas property and Sempra Mexico's Energía Costa Azul regasification facility.

Our LNG liquefaction business' major domestic and international competitors will include, among others, the following companies and their related LNG affiliates:

- BP
- Cheniere Energy
- Chevron
- ConocoPhillips
- ExxonMobil
- Kinder Morgan
- Petronas
- Qatar Petroleum
- Royal Dutch Shell
- Total
- Woodside

Natural Gas Pipelines and Storage Facilities

Within their respective market areas, Sempra LNG & Midstream's and Sempra Mexico's pipeline businesses and Sempra LNG & Midstream's storage facilities businesses compete with other regulated and unregulated storage facilities and pipelines. They compete primarily on the basis of price (in terms of storage and transportation fees), available capacity and interconnections to downstream markets.

Sempra LNG & Midstream's competitors include, among others:

- Boardwalk Pipeline Partners
- Cardinal Gas Storage Partners
- Columbia Energy
- Enbridge
- Energy Transfer Partners
- Enterprise Products Partners
- Kinder Morgan
- Macquarie Infrastructure Partners
- Plains All American Pipeline
- Southern Company Gas
- TransCanada
- The Williams Companies

Sempra Mexico's competitors include, among others:

- Carso Energy
- Enagás
- ENGIE S.A.
- Fermaca
- Kinder Morgan
- TransCanada

ENVIRONMENTAL MATTERS

We discuss environmental issues affecting us in Note 15 of the Notes to Consolidated Financial Statements in the Annual Report. You should read the following additional information in conjunction with those discussions.

Hazardous Substances

The CPUC's Hazardous Waste Collaborative mechanism allows California's IOUs to recover hazardous waste cleanup costs for certain sites, including those related to certain Superfund sites. This mechanism permits the California Utilities to recover in rates 90 percent of hazardous waste cleanup costs and related third-party litigation costs, and 70 percent of the related insurance-litigation expenses. In addition, the California Utilities have the opportunity to retain a percentage of any recoveries from insurance carriers and other third parties to offset the cleanup and associated litigation costs not recovered in rates.

We record estimated liabilities for environmental remediation when amounts are probable and estimable. In addition, we record amounts authorized to be recovered in rates under the Hazardous Waste Collaborative mechanism as regulatory assets.

Air and Water Quality

The electric and natural gas industries are subject to increasingly stringent air-quality and greenhouse gas standards, such as those established by the EPA, the CARB and SCAQMD. The California Utilities generally recover in rates the costs to comply with these standards. We discuss greenhouse gas standards and credits further in Note 1 of the Notes to Consolidated Financial Statements in the Annual Report.

We discuss environmental matters concerning SoCalGas' Aliso Canyon natural gas storage facility in "Risk Factors" below, and in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" and Note 15 of the Notes to Consolidated Financial Statements in the Annual Report.

EXECUTIVE OFFICERS OF THE REGISTRANTS

EXECUTIVE OFFICERS OF SEMPRA ENERGY

Name	Age(1)	Positions Held Over Last Five Years	Time in Position
Debra L. Reed(2)	60	Chairman	December 2012 to present
		Chief Executive Officer	June 2011 to present
Mark A. Snell(3)	60	President	October 2011 to present
Joseph A. Householder	61	Corporate Group President - Infrastructure Businesses	January 2017 to present
		Executive Vice President and Chief Financial Officer	October 2011 to December 2016
Steven D. Davis	61	Corporate Group President - Utilities	January 2017 to present
		Executive Vice President - External Affairs and Corporate Strategy	September 2015 to December 2016
		President and Chief Operating Officer, SDG&E	January 2014 to September 2015
		Senior Vice President - External Affairs	March 2012 to December 2013
		Vice President - Investor Relations	May 2010 to March 2012
J. Walker Martin	55	Executive Vice President and Chief Financial Officer	January 2017 to present
		Chairman, SDG&E	November 2015 to December 2016
		President, SDG&E	October 2015 to December 2016
		Chief Executive Officer, SDG&E	January 2014 to December 2016
		President and Chief Executive Officer, Sempra U.S. Gas & Power	October 2011 to December 2013
Martha B. Wyrsch	59	Executive Vice President and General Counsel	September 2013 to present
		President, Vestas American Wind Systems	June 2009 to December 2012
Dennis V. Arriola	56	Executive Vice President - Corporate Strategy and External Affairs	January 2017 to present
		Chairman, SoCalGas	November 2015 to December 2016
		Chief Executive Officer, SoCalGas	March 2014 to December 2016
		President, SoCalGas	August 2012 to September 2016
		Chief Operating Officer, SoCalGas	August 2012 to January 2014
		Executive Vice President and Chief Financial Officer, SunPower Corporation	January 2008 to January 2012
Trevor I. Mihalik	50	Senior Vice President	December 2013 to present
		Controller and Chief Accounting Officer	July 2012 to present
		Senior Vice President of Finance, Iberdrola Renewables Holdings, Inc.	July 2010 to July 2012
G. Joyce Rowland	62	Senior Vice President, Chief Human Resources Officer and Chief Administrative Officer	September 2014 to present
		Senior Vice President - Human Resources, Diversity and Inclusion	May 2010 to September 2014

(1) Ages are as of February 28, 2017.

(2) Ms. Reed also becomes President effective on March 1, 2017.

(3) Mr. Snell will be retired as of March 1, 2017.

EXECUTIVE OFFICERS OF SDG&E

Name	Age(1)	Positions Held Over Last Five Years	Time in Position
Scott D. Drury	51	President	January 2017 to present
		Chief Energy Supply Officer	June 2015 to December 2016
		Vice President - Human Resources, Diversity and Inclusion	March 2011 to June 2015
James P. Avery(2)	60	Chief Development Officer	June 2015 to present
		Senior Vice President - Power Supply	April 2009 to June 2015
J. Chris Baker	57	Chief Information Officer	June 2015 to present
		Senior Vice President and Chief Information Technology Officer	January 2014 to June 2015
		Senior Vice President - Strategic Planning and Technology	September 2012 to January 2014
		Senior Vice President - Support Services	April 2010 to August 2012
Lee Schavrien	62	Chief Administrative Officer	June 2015 to present
		Senior Vice President of Regulatory Affairs and Operations Support	February 2015 to June 2015
		Senior Vice President - Finance, Regulatory and Legislative Affairs	April 2010 to February 2015
Erbin B. Keith	56	Chief Regulatory and Risk Officer and General Counsel	September 2016 to present
		Senior Vice President and General Counsel	October 2014 to September 2016
		Vice President and Special Projects Counsel, Sempra Energy	May 2014 to October 2014
		Senior Vice President and General Counsel, SoCalGas	August 2012 to August 2014
		General Counsel, SoCalGas	April 2010 to August 2014
		Senior Vice President - External Affairs	April 2010 to August 2012
Caroline A. Winn	53	Chief Operating Officer	January 2017 to present
		Chief Energy Delivery Officer	June 2015 to December 2016
		Vice President - Customer Services	April 2010 to June 2015
Bruce A. Folkmann	49	Vice President, Controller, Chief Financial Officer, Chief Accounting Officer and Treasurer	March 2015 to present
		Vice President and Chief Financial Officer, Sempra U.S. Gas & Power	July 2013 to March 2015
		Vice President and Controller, Sempra U.S. Gas & Power	August 2012 to September 2013
		Assistant Controller, Sempra Energy	July 2012 to August 2012
		Acting Controller, Sempra Energy	October 2011 to July 2012

(1) Ages are as of February 28, 2017.
(2) Mr. Avery will be retired as of April 1, 2017.

EXECUTIVE OFFICERS OF SOCALGAS

Name	Age(1)	Positions Held Over Last Five Years	Time in Position
Patricia K. Wagner	54	Chief Executive Officer	January 2017 to present
		Executive Vice President, Sempra Energy	September 2016 to December 2016
		President and Chief Executive Officer, Sempra U.S. Gas & Power	January 2014 to September 2016
		Vice President of Audit Services, Sempra Energy	February 2012 to December 2013
		Vice President of Accounting and Finance, SoCalGas	November 2010 to February 2012
J. Bret Lane	57	President	September 2016 to present
		Chief Operating Officer	January 2014 to present
		Senior Vice President - Gas Operations and System Integrity, SDG&E and SoCalGas	August 2012 to January 2014
		Vice President - Field Services, SDG&E and SoCalGas	April 2010 to August 2012
J. Chris Baker	57	Chief Information Officer	June 2015 to present
		Senior Vice President and Chief Information Technology Officer	January 2014 to June 2015
		Senior Vice President - Strategic Planning and Technology	September 2012 to January 2014
		Senior Vice President - Support Services	April 2010 to August 2012
Lee Schavrien	62	Chief Administrative Officer	June 2015 to present
		Senior Vice President of Regulatory Affairs and Operations Support	February 2015 to June 2015
		Senior Vice President - Finance, Regulatory and Legislative Affairs	April 2010 to February 2015
Sharon L. Tomkins	51	Vice President and General Counsel	August 2014 to present
		Assistant General Counsel	April 2010 to August 2014
Bruce A. Folkmann	49	Vice President, Controller, Chief Financial Officer, Chief Accounting Officer and Treasurer	March 2015 to present
		Vice President and Chief Financial Officer, Sempra U.S. Gas & Power	July 2013 to March 2015
		Vice President and Controller, Sempra U.S. Gas & Power	August 2012 to September 2013
		Assistant Controller, Sempra Energy	July 2012 to August 2012
		Acting Controller, Sempra Energy	October 2011 to July 2012

(1) Ages are as of February 28, 2017.

OTHER MATTERS

Employees of the Registrants

At December 31, each company has the following number of employees:

NUMBER OF EMPLOYEES

	December 31,	
	2016	2015
Sempra Energy Consolidated(1)	16,575	17,387
SDG&E(1)	4,134	4,315
SoCalGas	8,042	8,438

(1) Excludes employees of variable interest entities as defined by accounting principles generally accepted in the United States of America.

Labor Relations

SDG&E

Field employees and some clerical and technical employees at SDG&E are represented by the International Brotherhood of Electrical Workers. Provisions of the collective bargaining agreement covering wages and working conditions for these employees are in effect through August 31, 2020 (subject to wage renegotiation on September 1, 2019). For these same employees, the agreement covering pension and savings plan benefits is in effect through October 1, 2017 and the agreement covering health and welfare benefits is in effect through December 31, 2017. At December 31, 2016, 29 percent of SDG&E employees are covered by these agreements.

SoCalGas

Field, technical and most clerical employees at SoCalGas are represented by the Utility Workers Union of America or the International Chemical Workers Union Council (collectively "Union") under a single collective bargaining agreement. The provisions of the collective bargaining agreement for these employees covering wages, hours, working conditions, medical and all other benefit plans are in effect through September 30, 2018. At December 31, 2016, 60 percent of SoCalGas employees are represented by the Union.

Sempra South American Utilities

Field, technical and administrative employees at Luz del Sur are represented by various labor unions. In January 2017, two collective bargaining agreements were signed covering these employees, which will also be extended to 141 nonrepresented employees. It will cover wages, working conditions and other benefit plans, and will be in effect from January 1, 2017 through December 31, 2017.

Field, technical and administrative employees at Chilquinta Energía are represented under various collective bargaining agreements with different labor unions. The collective bargaining agreements for employees represented by these unions and negotiating groups cover wages, hours, working conditions and medical and other benefit plans and expire between 2017 and 2020.

Professional employees at Chilquinta Energía are represented by the Professional Union. The collective bargaining agreement for these employees covers wages, hours, working conditions and medical and other benefit plans and is in effect through July 2017.

At December 31, 2016, Sempra South American Utilities has a total of 1,140 employees in Peru, of whom 23 percent are covered under a labor agreement, and 1,464 employees in Chile, of whom 45 percent are covered under labor agreements.

Sempra Mexico

At December 31, 2016, Sempra Mexico has 883 employees, 4 percent of whom are covered by various collective bargaining agreements with different labor unions. The collective bargaining agreements are subject to renegotiation on an annual basis with respect to wages, and otherwise on a bi-annual basis.

ITEM 1A. RISK FACTORS

When evaluating our company and its subsidiaries, you should consider carefully the following risk factors and all other information contained in this report. These risk factors could materially adversely affect our actual results and cause such results to differ materially from those expressed in any forward-looking statements made by us or on our behalf. We may also be materially harmed by risks and uncertainties not currently known to us or that we currently deem to be immaterial. If any of the following occurs, our businesses, cash flows, results of operations, financial condition and/or prospects could be materially negatively impacted. In addition, the trading prices of our securities and those of our subsidiaries could substantially decline due to the occurrence of any of these risks. These risk factors should be read in conjunction with the other detailed information concerning our company set forth in the Annual Report, including, without limitation, the information set forth in the Notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations." In this section, when we state that a risk or uncertainty may, could or will have a "material adverse effect" on us or may, could or will "materially adversely affect" us, we mean that the risk or uncertainty may, could or will, as the case may be, have a material adverse effect on our businesses, cash flows, results of operations, financial condition, prospects and/or the trading prices of our securities or those of our subsidiaries.

Sempra Energy's cash flows, ability to pay dividends and ability to meet its debt obligations largely depend on the performance of its subsidiaries and the ability to utilize the cash flows from those subsidiaries.

Sempra Energy's ability to pay dividends and meet its debt obligations depends almost entirely on cash flows from its subsidiaries and, in the short term, its ability to raise capital from external sources. In the long term, cash flows from the subsidiaries depend on their ability to generate operating cash flows in excess of their own expenditures, common and preferred stock dividends (if any), and long-term debt obligations. In addition, the subsidiaries are separate and distinct legal entities that are not obligated to pay dividends and could be precluded from making such distributions under certain circumstances, including, without limitation, as a result of legislation, regulation, court order, contractual restrictions or in times of financial distress.

A significant portion of our worldwide cash reserves are generated by, and therefore held in, foreign jurisdictions. Some jurisdictions impose taxes on cash transferred to the United States, which could reduce the cash available to us. To the extent we have excess cash in foreign locations that could be used in, or is needed by, our United States operations, we may incur significant U.S. and foreign taxes to repatriate these funds.

Conditions in the financial markets and economic conditions generally may materially adversely affect us.

Our businesses are capital intensive and we rely significantly on long-term debt to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations.

Limitations on the availability of credit and increases in interest rates or credit spreads may materially adversely affect our businesses, cash flows, results of operations, financial condition and/or prospects, as well as our ability to meet contractual and other commitments. In difficult credit market environments, we may find it necessary to fund our operations and capital expenditures at a higher cost or we may be unable to raise as much funding as we need to support new business activities. This could cause us to reduce capital expenditures and could increase our cost of servicing debt, both of which could significantly reduce our short-term and long-term profitability.

The availability and cost of credit for our businesses may be greatly affected by credit ratings. If SoCalGas or SDG&E were to have their credit ratings downgraded, their cash flows and results of operations could be materially adversely affected, and any downgrades of Sempra Energy's credit ratings could materially adversely affect the cash flows and results of operations of Sempra Energy. If the credit ratings of Sempra Energy or any of its subsidiaries were downgraded, especially below investment grade, financing costs and the principal amount of borrowings would likely increase due to the additional risk of our debt and because certain counterparties may require collateral in the form of cash, a letter of credit or other forms of security for new and existing transactions. Such amounts may be material and could adversely affect our cash flows, results of operations and financial condition.

Sempra Energy has substantial investments in Mexico and South America which expose us to foreign currency, inflation, legal, tax, economic, geo-political and management oversight risk.

We have significant foreign operations in Mexico and South America. Our foreign operations pose complex management, foreign currency, inflation, legal, tax and economic risks, which we may not be able to fully mitigate with our actions. These risks differ from and potentially may be greater than those associated with our domestic businesses. All of our international businesses are sensitive to geo-political uncertainties, and our non-utility international businesses are sensitive to changes in the priorities and budgets of international customers, all of which may be driven by changes in their environments and potentially volatile worldwide economic conditions, and various regional and local economic and political factors, risks and uncertainties, as well as U.S. foreign policy. Foreign currency exchange and inflation rates and fluctuations in those rates may have an impact on our revenue, costs or cash flows from our international operations, which could materially adversely affect our financial performance. Our currency exposures are to the Mexican, Peruvian and Chilean currencies. Our Mexican subsidiaries have U.S. dollar denominated monetary assets and liabilities that give rise to Mexican currency exchange rate movements for Mexican income tax purposes. They also have deferred income tax assets and liabilities, which are significant, denominated in the Mexican peso that must be translated to U.S. dollars for financial reporting purposes. In addition, monetary assets and liabilities and certain nonmonetary assets and liabilities are adjusted for Mexican inflation for Mexican income tax purposes. Our primary objective in reducing foreign currency risk is to preserve the economic value of our foreign investments and to reduce earnings volatility that would otherwise occur due to exchange rate fluctuations. We may attempt to offset material cross-currency transactions and earnings exposure through various means, including financial instruments and short-term investments. Because we generally do not hedge our net investments in foreign countries, we are susceptible to volatility in other comprehensive income caused by exchange rate fluctuations, primarily related to our South American subsidiaries, whose functional currency is not the U.S. dollar. We generally do not hedge our deferred income tax assets and liabilities, which makes us susceptible to volatility in income tax expense. We discuss our foreign currency exposure at our Mexican subsidiaries in "Results of Operations – Impact of Foreign Currency and Inflation Rates on Results of Operations" and "Market Risk – Foreign Currency and Inflation Rate Risk" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Annual Report.

Mexico has developed a new legal framework for the regulation of the hydrocarbons and electric power sectors based on a package of constitutional amendments approved by the Mexican Congress in December 2013 and implementing legislation enacted in 2014 and the issuance of new regulations thereunder. However, given the relatively recent creation of this legal framework, it is uncertain how it will be interpreted in practice. We also cannot predict the manner in which the new legal framework will affect any new business opportunities that IEnova may wish to pursue. The changes introduced by the new legal framework may require IEnova to obtain amendments to its existing permits or secure additional permits to operate its energy facilities or to provide its services, to take additional actions to secure rights-of-way for its projects, to perform social impact assessments, and to obtain the consent of indigenous communities for the development of certain projects, any or all of which may cause IEnova to incur additional material costs in connection with the development of its projects.

The current U.S. administration has previously indicated its intention to renegotiate trade agreements, such as the North American Free Trade Agreement, or NAFTA, and implement U.S. immigration policy changes. The current U.S. administration has stated that it is reviewing various options, including tariffs, for funding new Mexico–U.S. border security infrastructure. Such actions could result in changes in the Mexican, U.S. and other markets. In addition, if this occurs, the Mexican government could implement retaliatory actions, such as the imposition of restrictions or import fees on Mexican imports of natural gas from the U.S. or imports and exports of electricity to and from the U.S. Any of these actions by either or both governments could adversely affect imports and exports between Mexico and the U.S. and negatively impact the Mexican economy and the companies with whom we conduct business in Mexico, which could materially adversely affect our business, financial condition, results of operations, cash flows, or prospects.

Risks Related to All Sempra Energy Subsidiaries

Severe weather conditions, natural disasters, accidents, equipment failures, explosions or acts of terrorism could materially adversely affect our businesses, financial condition, results of operations, cash flows and/or prospects.

Like other major industrial facilities, ours may be damaged by severe weather conditions, natural disasters such as earthquakes, hurricanes, tsunamis and fires, accidents, equipment failures, explosions or acts of terrorism. Because we are in the business of using, storing, transporting and disposing of highly flammable and explosive materials, as well as radioactive materials, and operating highly energized equipment, the risks such incidents may pose to our facilities and infrastructure, as well as the risks to the surrounding communities, are substantially greater than the risks such incidents may pose to a typical business. The facilities and infrastructure that we own and in which we have interests that may be subject to such incidents include, but are not limited to:

- natural gas, propane and ethane pipelines, storage and compression facilities
- electric transmission and distribution
- power generation plants, including natural gas-fired and renewable energy generation
- LNG terminals and storage
- nuclear fuel and nuclear waste storage facilities
- nuclear power facilities (currently being decommissioned)

Such incidents could result in severe business disruptions, prolonged power outages, property damage, injuries or loss of life, significant decreases in revenues and earnings, and/or significant additional costs to us. Any such incident could have a material adverse effect on our businesses, financial condition, results of operations, cash flows and/or prospects.

Depending on the nature and location of the facilities and infrastructure affected, any such incident also could cause catastrophic fires; natural gas, natural gas odorant, propane or ethane leaks; releases of other greenhouse gases; radioactive releases; explosions, spills or other significant damage to natural resources or property belonging to third parties; personal injuries, health impacts or fatalities; or present a nuisance to impacted communities. Any of these consequences could lead to significant claims against us. In some cases, we may be liable for damages even though we are not at fault, such as in cases where the concept of inverse condemnation applies. Insurance coverage may significantly increase in cost, may be disputed by the insurers, or may become unavailable for certain of these risks, and any insurance proceeds we receive may be insufficient to cover our losses or liabilities due to the existence of limitations, exclusions, high deductibles, failure to comply with procedural requirements, and other factors, which could materially adversely affect our businesses, financial condition, results of operations, cash flows and/or prospects.

Severe weather conditions may also impact our businesses, including our international operations. Drought conditions in California and the western United States increase the risk of catastrophic wildfires in SDG&E's and SoCalGas' service territories, which could place third party property and our electric and natural gas infrastructure in jeopardy. Drought conditions also reduce the amount of power available from hydro-electric generation facilities in the Northwest United States, which could adversely impact the availability of a reliable energy supply into the California electric grid managed by the California ISO. If alternate supplies of electric generation are not available to replace the lower level of power available from hydro-electric generation facilities, this could result in temporary power shortages in SDG&E's service territory. In addition, severe weather conditions could result in delays and/or cost increases to our capital projects.

Another example of weather impacting operations is a strong El Niño weather pattern in the Pacific Ocean, which can cause severe rainstorms in coastal areas. Significant rainstorms and associated high winds, such as those caused by a strong El Niño weather pattern, could damage our electric and natural gas infrastructure, resulting in increased expenses, including higher maintenance and repair costs, and interruptions in electricity and natural gas delivery services. As a result, these events can have significant financial consequences, including regulatory penalties and disallowances if the California Utilities or our utilities in Mexico or South America encounter difficulties in restoring service to their customers on a timely basis. Further, the cost of storm restoration efforts may not be fully recoverable through the regulatory process. Any such events could have a material adverse effect on our businesses, financial condition, results of operations and cash flows.

Our businesses are subject to complex government regulations and tax requirements and may be materially adversely affected by changes in these regulations or requirements or in their interpretation or implementation.

In recent years, the regulatory environment that applies to the electric power and natural gas industries has undergone significant changes, on the federal, state and local levels. These changes have affected the nature of these industries and the manner in which their participants conduct their businesses. These changes are ongoing, and we cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on our businesses. Moreover, existing regulations, laws and tariffs may be revised or reinterpreted, and new regulations, laws and tariffs may be adopted or become applicable to us and our facilities. Special tariffs may also be imposed on components used in our businesses that could increase costs.

Our businesses are subject to increasingly complex accounting and tax requirements, and the regulations, laws and tariffs that affect us may change in response to economic or political conditions. Compliance with these requirements could increase our operating costs, and new tax legislation, regulations or other interpretations in the U.S. and other countries in which we operate could materially adversely affect our tax expense and/or tax balances. Changes in tax policies, including potential tax reform provisions, such as the elimination of the deduction for interest and non-deductibility of all or a portion of the cost of imported materials, equipment and commodities, could materially adversely impact our business. Changes in regulations, laws and tariffs and how they are implemented and interpreted may have a material adverse effect on our businesses, cash flows, financial condition, results of operations and/or prospects. We discuss potential U.S. federal tax reform further in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" in the Annual Report.

Our operations are subject to rules relating to transactions among the California Utilities and other Sempra Energy businesses. These rules are commonly referred to as "affiliate rules," which primarily impact commodity and commodity-related transactions. These businesses could be materially adversely affected by changes in these rules or to their interpretations, or by additional CPUC or FERC rules that further restrict our ability to sell electricity or natural gas to, or to trade with, the California Utilities and with each other. Affiliate rules also could require us to obtain prior approval from the CPUC before entering into any such transactions with the California Utilities. Any such restrictions on or approval requirements for transactions among affiliates could materially adversely affect the LNG terminals, natural gas pipelines, electric generation facilities, or other operations of our subsidiaries, which could have a material adverse effect on our businesses, results of operations and/or prospects.

Our businesses require numerous permits, licenses, franchise agreements, and other governmental approvals from various federal, state, local and foreign governmental agencies; any failure to obtain or maintain required permits, licenses or approvals could cause our sales to materially decline and/or our costs to materially increase, and otherwise materially adversely affect our businesses, cash flows, financial condition, results of operations and/or prospects.

All of our existing and planned development projects require multiple approvals. The acquisition, construction, ownership and operation of LNG terminals; natural gas pipelines and distribution and storage facilities; electric generation, transmission and distribution facilities; and propane and ethane systems require numerous permits, licenses, franchise agreements, certificates and other approvals from federal, state, local and foreign governmental agencies. Once received, approvals may be subject to litigation, and projects may be delayed or approvals reversed or modified in litigation. In addition, permits, licenses, franchise agreements, certificates, and other approvals may be modified, rescinded or fail to be extended by one or more of the governmental agencies and authorities that oversee our businesses. SoCalGas' franchise agreements with the City of Los Angeles and Los Angeles County, where the Aliso Canyon facility is located, are due to expire in 2017. If there is a delay in obtaining required regulatory approvals or failure to obtain or maintain required approvals or to comply with applicable laws or regulations, we may be precluded from constructing or operating facilities, or we may be forced to incur additional costs. Further, accidents beyond our control may cause us to violate the terms of conditional use permits, causing delays in projects. Any such delay or failure to obtain or maintain necessary permits, licenses, certificates and other approvals could cause our sales to materially decline, and/or our costs to materially increase, and otherwise materially adversely affect our businesses, cash flows, financial condition, results of operations and/or prospects.

Our businesses have significant environmental compliance costs, and future environmental compliance costs could have a material adverse effect on our cash flows and results of operations.

Our businesses are subject to extensive federal, state, local and foreign statutes, rules and regulations and mandates relating to environmental protection, including, air quality, water quality and usage, wastewater discharge, solid waste management, hazardous waste disposal and remediation, conservation of natural resources, wetlands and wildlife, renewable energy resources, climate change and greenhouse gas, or GHG, emissions. We are required to obtain numerous governmental permits, licenses, certificates and other approvals to construct and operate our businesses. Additionally, to comply with these legal requirements, we must spend significant amounts on environmental monitoring, pollution control equipment, mitigation costs and emissions fees. The California Utilities may be materially adversely affected if these additional costs for projects are not recoverable in rates. In addition, we may be ultimately responsible for all on-site liabilities associated with the environmental condition of our LNG terminals; natural gas transmission, distribution and storage facilities; electric generation, transmission and distribution facilities; and other energy projects and properties; regardless of when the liabilities arose and whether they are known or unknown, which exposes us to risks arising from contamination at our former or existing facilities or with respect to offsite waste disposal sites that have been used in our operations. In the case of our California and other regulated utilities, some of these costs may not be recoverable in rates. Our facilities, including those in our joint ventures, are subject to laws and regulations protecting migratory birds, which have recently been the subject of increased enforcement activity with respect to wind farms. Failure to comply with applicable environmental laws, regulations and permits may subject our businesses to substantial penalties and fines and/or significant curtailments of our operations, which could materially adversely affect our cash flows and/or results of operations.

Increasing international, national, regional and state-level concerns as well as new or proposed legislation and regulation may have substantial negative effects on our operations, operating costs, and the scope and economics of proposed expansion, which could have a material adverse effect on our results of operations, cash flows and/or prospects. In particular, state-level laws and regulations, as well as proposed state, national and international legislation and regulation relating to the control and reduction of GHG emissions, may materially limit or otherwise materially adversely affect our operations. The implementation of recent and proposed California and federal legislation and regulation may materially adversely affect our non-utility businesses by imposing, among other things, additional costs associated with emission limits, controls and the possible requirement of carbon taxes or the purchase of emissions credits. Similarly, California Senate Bill 350 requires all load-serving entities, including SDG&E, to file integrated resource plans that will ultimately enable the electric sector to achieve reductions in greenhouse gas emissions of 40 percent compared to 1990 levels by 2030. Our California Utilities may be materially adversely affected if these additional costs are not recoverable in rates. Even if recoverable, the effects of existing and proposed greenhouse gas emission reduction standards may cause rates to increase to levels that substantially reduce customer demand and growth and may have a material adverse effect on the California Utilities' cash flows. SDG&E may also be subject to significant penalties and fines if certain mandated renewable energy goals are not met.

In addition, existing and future laws, orders and regulations regarding mercury, nitrogen and sulfur oxides, particulates, methane or other emissions could result in requirements for additional monitoring, pollution monitoring and control equipment, safety practices or emission fees, taxes or penalties that could materially adversely affect our results of operations and/or cash flows. Moreover, existing rules and regulations may be interpreted or revised in ways that may materially adversely affect our results of operations and/or cash flows.

We provide further discussion of these matters in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 15 of the Notes to Consolidated Financial Statements in the Annual Report.

Our businesses, results of operations, financial condition and/or cash flows may be materially adversely affected by the outcome of litigation against us.

Sempra Energy and its subsidiaries are defendants in numerous lawsuits and arbitration proceedings. We have spent, and continue to spend, substantial amounts of money and time defending these lawsuits and proceedings, and in related investigations and regulatory proceedings. We discuss pending proceedings in Note 15 of the Notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Annual Report. The uncertainties inherent in lawsuits, arbitrations and other legal proceedings make it difficult to estimate with any degree of certainty the costs and effects of resolving these matters. In addition, juries have demonstrated a willingness to grant large awards, including punitive damages, in personal injury, product liability, property damage and other claims. Accordingly, actual costs incurred may differ materially from insured or reserved amounts and may not be recoverable in whole or in part in rates from our customers, which in each case could materially adversely affect our businesses, cash flows, results of operations and/or financial condition.

We cannot and do not attempt to fully hedge our assets or contract positions against changes in commodity prices. In addition, for those contract positions that are hedged, our hedging procedures may not mitigate our risk as planned.

To reduce financial exposure related to commodity price fluctuations, we may enter into contracts to hedge our known or anticipated purchase and sale commitments, inventories of natural gas and LNG, natural gas storage and pipeline capacity and electric generation capacity. As part of this strategy, we may use forward contracts, physical purchase and sales contracts, futures, financial swaps, and options. We do not hedge the entire exposure to market price volatility of our assets or our contract positions, and the coverage will vary over time. To the extent we have unhedged positions, or if our hedging strategies do not work as planned, fluctuating commodity prices could have a material adverse effect on our results of operations, cash flows and/or financial condition. Certain of the contracts we use for hedging purposes are subject to fair value accounting. Such accounting may result in gains or losses in earnings for those contracts. In certain cases, these gains or losses may not reflect the associated losses or gains of the underlying position being hedged.

In addition, possible changes in federal regulation of over-the-counter derivatives regulated by the U.S. Commodity Futures Trading Commission could impact the cost and effectiveness of our hedging programs, as we discuss in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" in the Annual Report.

Risk management procedures may not prevent losses.

Although we have in place risk management and control systems that use advanced methodologies to quantify and manage risk, these systems may not always prevent material losses. Risk management procedures may not always be followed as required by our businesses or may not always work as planned. In addition, daily value-at-risk and loss limits are based on historic price movements. If prices significantly or persistently deviate from historic prices, the limits may not protect us from significant losses. As a result of these and other factors, there is no assurance that our risk management procedures will prevent losses that would materially adversely affect our results of operations, cash flows and/or financial condition.

The operation of our facilities depends on good labor relations with our employees.

Several of our businesses have entered into and have in place collective bargaining agreements with different labor unions. Our collective bargaining agreements are generally negotiated on a company-by-company basis. Any failure to reach an agreement on new labor contracts or to negotiate these labor contracts might result in strikes, boycotts or other labor disruptions. Labor disruptions, strikes or significant negotiated wage and benefit increases, whether due to union activities, employee turnover or otherwise, could have a material adverse effect on our businesses, results of operations and/or cash flows.

New business technologies implemented by us or developed by others present a risk for increased attacks on our information systems and the integrity of our energy grid and our natural gas pipeline and storage infrastructure.

In addition to general information and cyber risks that all Fortune 500 corporations face (e.g. malware, malicious intent by insiders and inadvertent disclosure of sensitive information), the utility industry faces evolving cybersecurity risks associated with protecting sensitive and confidential customer information, Smart Grid infrastructure, and natural gas pipeline and storage infrastructure. Deployment of new business technologies represents a new and large-scale opportunity for attacks on our information systems and confidential customer information, as well as on the integrity of the energy grid and the natural gas infrastructure. While our computer systems have been, and will likely continue to be, subjected to computer viruses or other malware, unauthorized access attempts, and cyber- or phishing-attacks, to date we have not detected a material breach of cybersecurity. Addressing these risks is the subject of significant ongoing activities across Sempra Energy's businesses, but we cannot ensure that a successful attack has not and will not occur. An attack on our information systems, the integrity of the energy grid, our natural gas, ethane, or propane pipeline and storage infrastructure or one of our facilities, or unauthorized access to confidential customer information, could result in energy delivery service failures, financial loss, violations of privacy laws, customer dissatisfaction and litigation, any of which, in turn, could have a material adverse effect on our businesses, cash flows, financial condition, results of operations and/or prospects.

In the ordinary course of business, Sempra Energy and its subsidiaries collect and retain sensitive information, including personal identification information about customers and employees, customer energy usage and other information. The theft, damage or improper disclosure of sensitive electronic data can subject us to penalties for violation of applicable privacy laws, subject us to claims from third parties, require compliance with notification and monitoring regulations, and harm our reputation.

Finally, as seen with recent cyber-attacks around the world, the goal of a cyber-attack may be primarily to inflict large-scale harm on a company and the places where it operates. Any such cyber-attack could cause widespread disruptions to our operating and administrative systems, including the destruction of critical information and programming, that could materially adversely affect our business operations and the integrity of the power grid, and/or release confidential information about our company and our customers, employees and other constituents.

Our businesses will need to continue to adapt to technological change which may cause us to incur significant expenditures to adapt to these changes and which efforts may not be successful.

Emerging technologies may be superior to, or may not be compatible with, some of our existing technologies, investments and infrastructure, and may require us to make significant expenditures to remain competitive, or may result in the obsolescence of certain of our operating assets or the operating assets of our equity method investments. Our future success will depend, in part, on our ability and our investment partners' abilities to anticipate and successfully adapt to technological changes, to offer services that meet customer demands and evolving industry standards and to recover all, or a significant portion of, any unrecovered investment in obsolete assets. If we incur significant expenditures in adapting to technological changes, fail to adapt to significant technological changes, fail to obtain access to important new technologies, fail to recover a significant portion of any remaining investment in obsolete assets, or if implemented technology fails to operate as intended, our businesses, operating results and financial condition could be materially and adversely affected. Examples of technological changes that could negatively impact our businesses include

- Sempra Utilities – Technologies that could change the utilization of natural gas distribution and electric generation, transmission and distribution assets including
  - energy storage technology, and
  - the expanded cost-effective utilization of distributed generation (e.g., rooftop solar and community solar projects).
- Sempra Infrastructure
  - At Sempra Renewables, technological advances in distributed and local power generation and energy storage could reduce the demand for large-scale renewable electricity generation. Sempra Renewables' power sales customers' ability to perform under long-term agreements could be impacted by changes in utility rate structures and advances in distributed and local power generation.
  - At Sempra LNG & Midstream, technological advances could reduce the demand for natural gas. These technologies include cost-effective batteries for renewable electricity generation, economic improvements to gas-to-liquids conversion processes, and advances in alternative fuels and other alternative energy sources.

Risks Related to the California Utilities

The California Utilities are subject to extensive regulation by state, federal and local legislative and regulatory authorities, which may materially adversely affect us.

The CPUC regulates the California Utilities' rates, except SDG&E's electric transmission rates which are regulated by the FERC. The CPUC also regulates the California Utilities':

- conditions of service
- capital structure
- rates of return
- rates of depreciation
- long-term resource procurement
- sales of securities

The CPUC conducts various reviews and audits of utility performance, safety standards and practices, compliance with CPUC regulations and standards, affiliate relationships and other matters. These reviews and audits may result in disallowances, fines and penalties that could materially adversely affect our financial condition, results of operations and/or cash flows. SoCalGas and SDG&E may be subject to penalties or fines related to their operation of natural gas pipelines and storage and, for SDG&E, electric operations, under regulations concerning natural gas pipeline safety and citation programs concerning both gas and electric safety, which could have a material adverse effect on their results of operations, financial condition and/or cash flows. We discuss various CPUC proceedings relating to the California Utilities' rates, costs, incentive mechanisms, and performance-based regulation in Notes 13, 14 and 15 of the Notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Annual Report.

The CPUC periodically approves the California Utilities' rates based on authorized capital expenditures, operating costs, including income taxes, and an authorized rate of return on investment. Delays by the CPUC on decisions authorizing recovery or authorizations for less than full recovery may adversely affect the working capital and financial condition of each of the California Utilities. If the California Utilities receive an adverse CPUC decision and/or actual capital expenditures and/or operating costs were to exceed the amounts approved by the CPUC, our results of operations, financial condition, cash flows and/or prospects could be materially adversely affected. Reductions in key benchmark interest rates may trigger automatic adjustment mechanisms which would reduce the California Utilities' authorized rates of return, changes in which could materially adversely affect their results of operations, financial condition, cash flows and/or prospects.

In December 2014, the CPUC issued a decision incorporating a risk-based decision-making framework into all future general rate case (GRC) application filings for major natural gas and electric utilities in California. As the framework is still in the developing stages, we cannot estimate whether its application in future GRC applications will result in full recovery of costs. We discuss this further in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" in the Annual Report.

The CPUC applies performance-based measures and mechanisms to all California utilities. Under these, earnings potential over authorized base margins is tied to achieving or exceeding specific performance and operating goals, and reductions in authorized base margins are tied to not achieving specific performance and operating goals. At both of the California Utilities, the areas that are currently eligible for performance mechanisms are operational activities designated by the CPUC and energy efficiency programs; at SDG&E, electric reliability performance; and, at SoCalGas, natural gas procurement and unbundled natural gas storage and system operator hub services. Although the California Utilities have received incentive awards in the past, there can be no assurance that they will receive awards in the future, or that any future awards earned would be in amounts comparable to prior periods. Additionally, if the California Utilities fail to achieve certain minimum performance levels established under such mechanisms, they may be assessed financial disallowances, penalties and fines which could have a material adverse effect on their results of operations, financial condition and/or cash flows.

In September 2016, California adopted new laws concerning the CPUC that establish rules governing, among other subjects, communications between CPUC officials, CPUC staff and regulated utilities. Changes to the rules and processes around *ex parte* communications could result in delayed decisions, increased investigations, enforcement actions and penalties. In addition, the CPUC or other parties may initiate investigations of past communications between public utilities and CPUC officials and staff that could result in reopening completed proceedings for reconsideration.

The FERC regulates electric transmission rates, the transmission and wholesale sales of electricity in interstate commerce, transmission access, the rates of return on investments in electric transmission assets, and other similar matters involving SDG&E.

The California Utilities may be materially adversely affected by new legislation, regulations, decisions, orders or interpretations of the CPUC, the FERC or other regulatory bodies. In addition, existing legislation or regulations may be revised or reinterpreted. New, revised or reinterpreted legislation, regulations, decisions, orders or interpretations could change how the California Utilities operate, could affect their ability to recover various costs through rates or adjustment mechanisms, or could require them to incur substantial additional expenses.

The construction and expansion of the California Utilities' natural gas pipelines, SoCalGas' storage facilities, and SDG&E's electric transmission and distribution facilities require numerous permits, licenses, rights-of-way and other approvals from federal, state and local governmental agencies, including approvals and renewals of rights-of-way over Native American tribal land held in trust by the federal government. If there are delays in obtaining these approvals, failure to obtain or maintain these approvals, difficulties in renewing rights-of-way and other property rights, or failure to comply with applicable laws or regulations, the California Utilities' businesses, cash flows, results of operations, financial condition and/or prospects could be materially adversely affected. Coordinating these projects for successful completion requires good execution from our employees and contractors, cooperation of third parties and the absence of litigation and regulatory delay. In the event that one or more of these projects is delayed or experiences significant cost overruns, this could have a material adverse effect on the California Utilities. The California Utilities could experience difficulties in renewing rights-of-way or other forms of property rights for existing assets, which could have a material adverse effect on the California Utilities. The California Utilities may invest a significant amount of money in a major capital project prior to receiving regulatory approval. If the project does not receive regulatory approval, if the regulatory approval is conditioned on major changes, or if management decides not to proceed with the project, they may be unable to recover any or all amounts invested in that project, which could materially adversely affect their financial condition, results of operations, cash flows and/or prospects.

Our California Utilities are also affected by the activities of organizations such as The Utility Reform Network (TURN), Utility Consumers' Action Network, Sierra Club and other stakeholder, advocacy and activist groups. Operations that may be influenced by these groups include

- the rates charged to our customers;
- our ability to site and construct new facilities;
- our ability to purchase or construct generating facilities;
- safety;
- the issuance of securities;
- accounting and income tax matters;
- transactions between affiliates;
- the installation of environmental emission controls equipment;
- our ability to decommission generating and other facilities and recover the remaining carrying value of such facilities and related costs;
- our ability to recover costs incurred in connection with nuclear decommissioning activities from trust funds established to pay for such costs;
- the amount of certain sources of energy we must use, such as renewable sources; limits on the amount of certain energy sources we can use, such as natural gas; and programs to encourage reductions in energy usage by customers; and
- the amount of costs associated with these and other operations that may be recovered from customers.

SoCalGas will incur significant costs and expenses related to remediating the natural gas leak at its Aliso Canyon natural gas storage facility and to mitigate local community and environmental impacts from the leak, some or a substantial portion of which may not be recoverable through insurance, and SoCalGas also may incur significant liabilities for fines, penalties, damages and greenhouse gas mitigation activities as a result of this incident, some or a significant portion of which may not be recoverable through insurance.

In October 2015, SoCalGas discovered a leak at one of its injection-and-withdrawal wells, SS25, at its Aliso Canyon natural gas storage facility, located in the northern part of the San Fernando Valley in Los Angeles County. The Aliso Canyon facility has been operated by SoCalGas since 1972. SS25 is more than one mile away from and 1,200 feet above the closest homes. It is one of more than 100 injection-and-withdrawal wells at the storage facility. SoCalGas worked closely with several of the world's leading experts to stop the leak, and in February 2016, DOGGR confirmed that the well was permanently sealed.

Local Community Mitigation Efforts

Pursuant to a stipulation and order by the Los Angeles County Superior Court (Superior Court), SoCalGas provided temporary relocation support to residents in the nearby community who requested it before the well was permanently sealed, at significant expense to SoCalGas. Following the permanent sealing of the well and the completion of the Los Angeles County Department of Public Health's (DPH) indoor testing of certain homes in the Porter Ranch community, which concluded that indoor conditions did not present a long-term health risk and that it was safe for residents to return home, the Superior Court issued an order in May 2016 ruling that currently relocated residents be given the choice to request residence cleaning prior to returning home, with such cleaning to be performed according to the DPH's proposed protocol and at SoCalGas' expense. SoCalGas completed the cleaning program, and the relocation program ended in July 2016.

Apart from the Superior Court order, in May 2016 the DPH also issued a directive that SoCalGas professionally clean (in accordance with the proposed protocol prepared by the DPH) the homes of all residents located within the Porter Ranch Neighborhood Council boundary, or who participated in the relocation program, or who are located within a five mile radius of the Aliso Canyon natural gas storage facility and have experienced symptoms from the natural gas leak (the Directive). SoCalGas disputes the Directive, contending that it is invalid and unenforceable, and has filed a petition for writ of mandate to set aside the Directive.

The total costs incurred to mitigate local community impacts of the leak are significant and may increase, and to the extent not covered by insurance (including any costs in excess of applicable policy limits), or if there were to be significant delays in receiving insurance recoveries, such costs could have a material adverse effect on SoCalGas' and Sempra Energy's cash flows, financial condition and results of operations.

Governmental Investigations and Civil and Criminal Litigation

Various governmental agencies, including DOGGR, DPH, SCAQMD, CARB, Los Angeles Regional Water Quality Control Board, California Division of Occupational Safety and Health, CPUC, PHMSA, EPA, Los Angeles County District Attorney's Office and California Attorney General's Office, have investigated or are investigating this incident. Other federal agencies (e.g., the DOE and U.S. Department of the Interior) investigated the incident in conjunction with the preparation of an Interagency Task Force report, *Ensuring Safe and Reliable Underground Natural Gas Storage*, published in October 2016. In January 2016, DOGGR and the CPUC selected Blade Energy Partners to conduct an independent analysis under their supervision and to be funded by SoCalGas to investigate the technical root cause of the Aliso Canyon gas leak. This investigation is currently ongoing.

As of February 27, 2017, 250 lawsuits, including over 14,000 plaintiffs, have been filed against SoCalGas, some of which have also named Sempra Energy. These various lawsuits assert causes of action for negligence, negligence per se, strict liability, property damage, fraud, public and private nuisance (continuing and permanent), trespass, inverse condemnation, fraudulent concealment, unfair business practices and loss of consortium, among other things. A complaint alleging violations of Proposition 65 was also filed. Many of these complaints seek class action status, compensatory and punitive damages, civil penalties, injunctive relief, costs of future medical monitoring and attorneys' fees.

In addition to the lawsuits described above, a federal securities class action alleging violation of the federal securities laws has been filed against Sempra Energy and certain of its officers and directors, and four shareholder derivative actions alleging breach of fiduciary duties have been filed against certain officers and directors of Sempra Energy and/or SoCalGas. Three complaints have also been filed by public entities, including the California Attorney General, the SCAQMD and the County of Los Angeles. These complaints seek various remedies, including injunctive relief, abatement of the public nuisance, civil penalties, payment of the cost of a longitudinal health study, and money damages, as well as punitive damages and attorneys' fees. In February 2017, SoCalGas entered into a settlement agreement with the SCAQMD under which SoCalGas will pay $8.5 million and SCAQMD will dismiss its complaint and petition for dismissal of a stipulated abatement order issued by its Hearing Board. Separately, in February 2016, the Los Angeles County District Attorney's Office filed a misdemeanor criminal complaint against SoCalGas seeking penalties and other remedies for alleged failure to provide timely notice of the leak and for allegedly violating certain California Health and Safety Code provisions. On November 29, 2016, the court approved a settlement between SoCalGas and the District Attorney's Office whereby SoCalGas agreed to plead no contest to a misdemeanor for the alleged failure to provide timely notice of the leak and to spend approximately $4.3 million on reimbursement of government agency expenses, operational commitments, and fines and penalties, in exchange for the dismissal of the remaining counts. Certain individuals residing near Aliso Canyon who objected to the settlement have filed a notice of appeal of the judgment, as well as a petition asking the Superior Court to set aside the November 29, 2016 order and grant them restitution.

Additional litigation may be filed against us in the future related to the Aliso Canyon incident or our responses thereto. For a more detailed description of the governmental investigations and civil and criminal lawsuits brought against us, see Note 15 of the Notes to Consolidated Financial Statements in the Annual Report.

The costs of defending against the civil and criminal lawsuits, cooperating with the various investigations, and any damages, restitution, and civil and criminal fines, costs and other penalties, if awarded or imposed, could be significant and to the extent not covered by insurance (including any costs in excess of applicable policy limits), or if there were to be significant delays in receiving insurance recoveries, such costs could have a material adverse effect on SoCalGas' and Sempra Energy's cash flows, financial condition and results of operations.

Governmental Orders and Additional Regulation

In January 2016, the Governor of the State of California issued an Order proclaiming a state of emergency to exist in Los Angeles County due to the natural gas leak at the Aliso Canyon facility. The Governor's Order imposed various orders with respect to: stopping the leak; protecting public health and safety; ensuring accountability; and strengthening oversight. Also in January 2016, the Hearing Board of the SCAQMD ordered SoCalGas to take various actions in connection with injections and withdrawals of natural gas at Aliso Canyon, sealing the well, monitoring, reporting, safety and funding a health study, among other things. As discussed above, SoCalGas has entered into a settlement agreement with the SCAQMD that calls for the SCAQMD to petition its Hearing Board for dismissal of the order. We provide further detail regarding the Governor's Order and SCAQMD's order in Note 15 of the Notes to Consolidated Financial Statements in the Annual Report.

In December 2015, SoCalGas made a commitment to mitigate the actual natural gas released from the leak and has been working on a plan to accomplish the mitigation. In March 2016, pursuant to the Governor's Order, the CARB issued its recommended approach to achieve full mitigation of the climate impacts from the Aliso Canyon natural gas leak, which includes recommendations that:

- reductions in short-lived climate pollutants and other greenhouse gases be at least equivalent to the amount of the emissions from the leak,
- a 20-year global warming potential be used in deriving the amount of reductions required (rather than the 100-year term the CARB and other state and federal agencies use in regulating emissions), and
- all of the mitigation occur in California over the next five to ten years without the use of allowances or offsets.

In October 2016, CARB issued a final report concluding that the incident resulted in total emissions from 90,350 to 108,950 metric tons of methane, and asserting that SoCalGas should mitigate 109,000 metric tons of methane to fully mitigate the greenhouse gas impacts of the leak. Although we have not agreed with CARB's estimate of methane released, we continue to work with CARB on developing a mitigation plan. The costs of mitigating the actual natural gas released could be significant and to the extent not covered by insurance (including any costs in excess of applicable policy limits), or if there were to be significant delays in receiving insurance recoveries, such costs could have a material adverse effect on SoCalGas' and Sempra Energy's cash flows, financial condition and results of operations.

In June 2016, the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016" or the "PIPES Act of 2016" was enacted. Among other things, the PIPES Act requires PHMSA to issue, within two years of passage, "minimum safety standards for underground natural gas storage facilities," and imposes a "user fee" on underground storage facilities as needed to implement the safety standards. In October 2016, the Interagency Task Force formed by the DOE and PHMSA in response to the leak at Aliso Canyon issued its report, recommending that PHMSA adopt new safety regulations and providing 44 specific recommendations to industry and to federal, state, and local regulators and governments, which may result in additional regulations.

PHMSA, DOGGR, SCAQMD, EPA and CARB have each commenced separate rulemaking proceedings to adopt further regulations covering natural gas storage facilities and injection wells. DOGGR has issued new draft regulations for all storage fields in California, and in 2016, the California Legislature enacted four separate bills providing for additional regulation of natural gas storage facilities. Also, the Los Angeles County Board of Supervisors formed a task force to review and potentially implement new, more stringent land use (zoning) requirements and associated regulations and enforcement protocols for oil and gas activities, including natural gas storage field operations. We provide further detail regarding new regulations and legislation in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" and Note 15 of the Notes to Consolidated Financial Statements in the Annual Report.

Additional hearings in the California Legislature, as well as with various other federal and state regulatory agencies, have been or may be scheduled, additional legislation has been proposed in the California Legislature, and additional laws, orders, rules and regulations may be adopted. Higher operating costs and additional capital expenditures incurred by SoCalGas as a result of new laws, orders, rules and regulations arising out of the Aliso Canyon incident or our responses thereto could be significant and may not be recoverable through insurance or in customer rates, and SoCalGas' and Sempra Energy's cash flows, financial condition and results of operations may be materially adversely affected by any such new laws, orders, rules and regulations.

Natural Gas Storage Operations and Reliability

Natural gas withdrawn from storage is important for service reliability during peak demand periods, including peak electric generation needs in the summer and heating needs in the winter. Aliso Canyon, with a storage capacity of 86 Bcf (which represents 63 percent of SoCalGas' natural gas storage inventory capacity), is the largest SoCalGas storage facility and an important element of SoCalGas' delivery system. SoCalGas has not injected natural gas into Aliso Canyon since October 25, 2015, pursuant to orders by DOGGR and the Governor, and SB 380. Limited withdrawals of natural gas from Aliso Canyon have been made in 2017 to augment natural gas supplies during critical demand periods. In November 2016, SoCalGas submitted a request to DOGGR seeking authorization to resume injection operations at the Aliso Canyon storage facility. In accordance with SB 380, DOGGR held public meetings on February 1 and 2, 2017 to receive public comment on DOGGR's findings from its gas storage and well safety review and proposed pressure limits for the Aliso Canyon natural gas storage facility. The public comment period has expired. It remains for DOGGR to issue its safety determination, after which the CPUC must concur with DOGGR's determination, before injections at the facility can resume.

If the Aliso Canyon facility were to be taken out of service for any meaningful period of time, it could result in an impairment of the facility, significantly higher than expected operating costs and/or additional capital expenditures, and natural gas reliability and electric generation could be jeopardized. At December 31, 2016, the Aliso Canyon facility has a net book value of $531 million, including $217 million of construction work in progress for the project to construct a new compression station. Any significant impairment of this asset could have a material adverse effect on SoCalGas' and Sempra Energy's results of operations for the period in which it is recorded. Higher operating costs and additional capital expenditures incurred by SoCalGas may not be recoverable in customer rates, and SoCalGas' and Sempra Energy's results of operations, cash flows and financial condition may be materially adversely affected.

Insurance and Estimated Costs

Excluding directors and officers liability insurance, we have four kinds of insurance policies that together provide between $1.2 billion to $1.4 billion in insurance coverage, depending on the nature of the claims. These policies are subject to various policy limits, exclusions and conditions. We have been communicating with our insurance carriers, and we have received $169 million of insurance proceeds for control of well expenses and temporary relocation costs. We intend to pursue the full extent of our insurance coverage for the costs we have incurred or may incur. Our recorded estimate as of December 31, 2016 of $780 million of certain costs in connection with the Aliso Canyon storage facility leak may rise significantly as more information becomes available. In addition, any costs not included in the $780 million estimate could be material. The $780 million estimate does not include unsettled damage claims, restitution, or civil, administrative or criminal fines, costs and other penalties. In addition, such estimate excludes the costs to clean additional homes pursuant to the DPH Directive, future legal costs to defend litigation and other potential costs that we currently do not anticipate incurring or that we cannot reasonably estimate. There can be no assurance that we will be successful in obtaining insurance coverage for these costs under the applicable policies, and to the extent we are not successful in obtaining coverage, or if such costs are not covered by insurance (including any costs in excess of applicable policy limits), or if there were to be significant delays in receiving insurance recoveries, such costs could have a material adverse effect on SoCalGas' and Sempra Energy's cash flows, financial condition and results of operations.

Additional Information

We discuss Aliso Canyon matters further in Note 15 of the Notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" in the Annual Report.

Natural gas pipeline safety assessments may not be fully or adequately recovered in rates.

Pending the outcome of various regulatory agency evaluations of natural gas pipeline safety regulations, practices and procedures, Sempra Energy, including the California Utilities, may incur incremental expense and capital investment associated with their natural gas pipeline operations and investments. The California Utilities filed implementation plans with the CPUC to test or replace natural gas transmission pipelines located in populated areas that either have not been pressure tested or lack sufficient documentation of a pressure test, to enhance existing valve infrastructure and to retrofit pipelines to allow for the use of in-line inspection technology, referred to as SoCalGas' and SDG&E's Pipeline Safety Enhancement Plan (PSEP).

In June 2014, the CPUC issued a final decision approving the utilities' plan for implementing PSEP, and established criteria to determine the amounts related to PSEP that may be recovered from ratepayers and the processes for recovery of such amounts, including providing that such costs are subject to a reasonableness review. In the future, certain PSEP costs may be subject to recovery as determined by separate regulatory filings with the CPUC, including GRC filings.

Various PSEP-related proceedings are regularly pending before the CPUC regarding the California Utilities' reasonableness review and cost recovery requests, which are often challenged by intervening parties. These proceedings are described in more detail in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" in the Annual Report. In the future, consumer advocacy groups may similarly challenge the

California Utilities' petitions for recovery and recommend disallowances in whole or in part with respect to applications to recover PSEP costs.

From 2011 through 2016, SoCalGas and SDG&E have invested $1.1 billion and $302 million, respectively, in PSEP. As of December 31, 2016, SoCalGas has received approval for recovery of $33 million. If the CPUC were to deny rate recovery for PSEP and other gas pipeline safety costs incurred by SoCalGas and SDG&E, it could materially adversely affect the respective company's cash flows, financial condition, results of operations and prospects.

The California Utilities are subject to increasingly stringent safety standards and the potential for significant penalties if regulators deem either SDG&E or SoCalGas to be out of compliance.

California Senate Bill (SB) 291 requires the CPUC to develop and maintain a safety enforcement program that includes procedures for monitoring, data tracking and analysis, and investigations, and delegates citation authority to CPUC staff personnel under the direction of the CPUC Executive Director. In exercising this citation authority, the CPUC staff is to take into account voluntary reporting of potential violations, voluntary resolution efforts undertaken, prior history of violations, the gravity of the violation, and the degree of culpability. The CPUC previously implemented both electric and gas safety enforcement programs whereby electric and gas utilities may be cited by CPUC staff for violations of the CPUC's safety requirements or applicable federal standards.

Under each enforcement program, each day of an ongoing violation may be counted as an additional offense. The maximum penalty is $50,000 per offense. Citations under either program may be appealed to the CPUC. Penalties imposed under these programs can be significant, exceeding $1.5 billion in one instance. In September 2016, the CPUC issued a decision making further refinements to the electric and gas safety enforcement programs. The decision harmonizes the rules for the two programs, further defines the criteria for issuing a citation and penalty, sets an administrative limit of $8 million per citation issued by staff under its delegated authority and makes certain other changes to rules related to self-reporting and notifying local officials.

If the CPUC or its staff determine that either of SDG&E's or SoCalGas' operations and practices are not in compliance with applicable safety standards and operating procedures, the corrective or mitigation actions required to be in conformance, if not sufficiently funded in customer rates, and any penalties imposed could materially adversely affect that company's cash flows, financial condition, results of operations and prospects.

The failure by the CPUC to continue reforms of SDG&E's rate structure, including the implementation of a more significant fixed charge, could have a material adverse effect on its business, cash flows, financial condition, results of operations and/or prospects.

The current electric rate structure in California is primarily based on consumption volume, which places an undue burden on residential customers with higher electric use while subsidizing lower use customers. As higher electric use residential customers switch to self-generation or obtain local off-the-grid sources of power, such as wind, the burden on the remaining higher electric use customers increases, which in turn encourages more self-generation, further increasing rate pressure on existing customers. In July 2015, the CPUC adopted a decision that establishes comprehensive reform and a framework for rates that are more transparent, fair and sustainable. The decision provides for a minimum monthly bill, fewer rate tiers and a gradual reduction in the differences between the tiered rates, directs the utilities to pursue expanded time of use rates, and implements a super-user electric surcharge in 2017 for usage that exceeds average customer usage by approximately 400 percent within each climate zone. The surcharge will increase over time, ultimately reaching a rate of more than double the first tier rate. The decision will be implemented over a five year period from 2015 to 2020, and should result in significant relief for higher-use customers that do not exceed the super-user threshold and a rate structure that better aligns rates with actual costs to serve customers. The decision also establishes a process for utilities to seek implementation of a fixed charge for residential customers in 2020 (but it also sets certain conditions for the implementation of a fixed charge), after the initial reforms are implemented. The establishment of a fixed charge for residential customers may become more critical to help ensure rates are fair for all customers as distributed energy resources could generally reduce delivered volumes and increase fixed costs.

If the CPUC fails to continue to reform SDG&E's rate structure by implementing a rate structure that maintains reasonable, cost-based electric rates that are competitive with alternative sources of power and adequate to maintain the reliability of the electric transmission and distribution system, such failure could have a material adverse effect on SDG&E's business, cash flows, financial condition, results of operations and/or prospects.

Meaningful net energy metering, or NEM, reform must continue to progress to ensure that SDG&E is authorized to recover its costs in providing services to NEM customers while minimizing the cost shift (or subsidy) being borne by non-solar customers.

Due to current rate structures and state policies, customers who self-generate their own power using eligible renewable resources (primarily solar installations) currently do not pay their proportionate cost of maintaining and operating the electric transmission and distribution system, subject to certain limitations, while they still receive power from the system when their self-generation is inadequate to meet their electricity needs. The proportionate costs not paid by NEM customers are paid (i.e., subsidized) by consumers not participating in NEM. In addition, the continuing increase of self-generated solar, other forms of self-generation and other local off-the-grid sources of power adversely impacts the reliability of the electric transmission and distribution system.

Appropriate NEM reforms are necessary to ensure that SDG&E is authorized to recover, from NEM customers, the costs incurred in providing grid and energy services, as well as mandated legislative and regulatory public policy programs. SDG&E believes this design would be preferable to recovering these costs from customers not participating in NEM. If NEM self-generating installations were to increase substantially between 2016 and when more significant reforms take effect in 2019 or later, as described below, the rate structure adopted by the CPUC could have a material adverse effect on SDG&E's business, cash flows, financial condition, results of operations and/or prospects.

In July 2014, the CPUC initiated a rulemaking proceeding to develop a successor tariff to the state's existing NEM program pursuant to the provisions of AB 327. The NEM program was originally established in 1995 and is an electric billing tariff mechanism designed to promote the installation of on-site renewable generation. Under NEM, qualifying customer-generators receive a full retail rate for the energy they generate that is fed back to the utility's power grid. This occurs during times when the customer's generation exceeds their own energy usage. In addition, if a NEM customer generates any electricity over the annual measurement period that exceeds its annual consumption, they receive compensation at a rate equal to a wholesale energy price.

In January 2016, the CPUC adopted a decision making modest changes to the NEM program, which require NEM customers to pay some costs that would otherwise be borne by non-NEM customers and moves new NEM customers to time-of-use rates. Together with a reduction in tiered rate differentials and the potential implementation of a fixed charge component in 2020, these changes to the NEM program begin a process of reducing the cost burden on non-NEM customers, but SDG&E believes that further reforms are necessary and appropriate. In March 2016, SDG&E, Edison, PG&E, TURN and the California Coalition of Utility Employees filed applications with the CPUC requesting rehearing of its January 2016 decision. In September 2016, the CPUC issued an order denying the rehearing requests in all respects. SDG&E implemented the adopted successor NEM tariff in July 2016, after reaching the 617-MW cap established for the prior NEM program.

The electricity industry is undergoing significant change, including increased deployment of distributed energy resources, technological advancements, and political and regulatory developments.

Electric utilities in California are experiencing increasing deployment of distributed energy resources, such as solar, energy storage, energy efficiency and demand response technologies. This growth will eventually require modernization of the electric distribution grid to, among other things, accommodate two-way flows of electricity and increase the grid's capacity to interconnect distributed energy resources. The CPUC is conducting proceedings: to evaluate changes to the planning and operation of the electric distribution grid in order to prepare for higher penetration of distributed energy resources; to consider future grid modernization and grid reinforcement investments; to evaluate if traditional grid investments can be deferred by distributed energy resources, and if feasible, what, if any, compensation would be appropriate; and to clarify the role of the electric distribution grid operator. These proceedings may result in new regulations, policies and/or operational changes that could materially adversely affect SDG&E's business, cash flows, financial condition, results of operations and/or prospects.

SDG&E provides bundled electric procurement service through various resources that are typically procured on a long-term basis. While SDG&E provides such procurement service for the majority of its customer load, customers do have the ability to receive procurement service from a load serving entity other than SDG&E, through programs such as Direct Access and Community Choice Aggregation (CCA). Direct Access is currently closed, but utility customers have the ability to receive procurement through CCA, if the customer's local jurisdiction (city) offers such a program. A number of cities in our service territory have expressed interest in CCA, which, if widely adopted, could result in substantial reductions in the load we are required to serve. When customers are served by another load serving entity, SDG&E no longer serves this departing load and the associated costs of the utility's procured resources are borne by its remaining bundled procurement customers. This issue is addressed by rate mechanisms that attempt to ensure bundled ratepayer indifference in the event of departing load, but these existing mechanisms may not be sufficient to address the full extent of the potential cost shift in the event of significant departing load, and SDG&E bears some risk that its procured resources become stranded and the associated costs are not recoverable.

In addition, the FERC has adopted changes that have opened transmission development to competition from independent developers, allowing such developers to compete with incumbent utilities for the construction and operation of transmission facilities. These changes could materially adversely affect SDG&E's business and prospects.

Recovery of 2007 wildfire litigation costs requires future regulatory approval, and insurance coverage for future wildfires may not be sufficient to cover losses we may incur.

SDG&E is seeking to recover in rates its reasonably incurred costs of resolving 2007 wildfire claims in excess of its liability insurance coverage and amounts recovered from third parties. Through December 31, 2016, SDG&E's payments for claim settlements plus funds estimated to be required for settlement of outstanding claims and legal fees have exceeded its liability insurance coverage and amounts recovered from third parties. However, SDG&E has concluded that it is probable that it will be permitted to recover in rates a substantial portion of the reasonably incurred costs of resolving wildfire claims in excess of its liability insurance coverage and amounts recovered from third parties. At December 31, 2016, Sempra Energy's and SDG&E's Consolidated Balance Sheets included $352 million in Other Regulatory Assets (long-term) related to CPUC-regulated operations for these costs incurred and the estimated resolution of pending claims.

In December 2012, the CPUC issued a final decision allowing SDG&E to maintain an authorized memorandum account, enabling SDG&E to file applications with the CPUC requesting recovery of amounts properly recorded in the memorandum account, subject to reasonableness review, at a later date. In September 2015, SDG&E filed an application with the CPUC requesting rate recovery of such costs, and is proposing to recover the costs in rates over a six- to ten-year period. The CPUC has scheduled a two-phased proceeding to address SDG&E's request. SDG&E has responded to testimony submitted by intervening parties raising various concerns with SDG&E's operations and management prior to and during the 2007 wildfires, and have asked the CPUC to reject SDG&E's request for cost recovery. We discuss these cost recovery proceedings in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" and in Note 15 of the Notes to Consolidated Financial Statements in the Annual Report.

Recovery of these costs in rates will require future regulatory approval. SDG&E will continue to assess the likelihood, amount and timing of such recoveries in rates. Should SDG&E conclude that recovery of excess wildfire costs in rates is no longer probable, at that time SDG&E would record a charge against earnings. If SDG&E had concluded that the recovery of regulatory assets related to CPUC-regulated operations was no longer probable or was less than currently estimated at December 31, 2016, the resulting after-tax charge against earnings would have been up to approximately $208 million. A failure to obtain substantial or full recovery of these costs from customers, or any negative assessment of the likelihood of recovery, would likely have a material adverse effect on Sempra Energy's and SDG&E's financial condition, cash flows and results of operations. We discuss how we assess the probability of recovery of our regulatory assets in Note 1 of the Notes to Consolidated Financial Statements in the Annual Report.

We have experienced increased costs and difficulties in obtaining insurance coverage for wildfires that could arise from the California Utilities' operations. In addition, the insurance that has been obtained for wildfire liabilities may not be sufficient to cover all losses that we may incur. Uninsured losses and increases in the cost of insurance may not be recoverable in customer rates. A loss which is not fully insured or cannot be recovered in customer rates could materially adversely affect Sempra Energy's and the affected California Utility's financial condition, cash flows and results of operations. Furthermore, insurance for wildfire liabilities may not continue to be available at all or at rates or with terms similar to those presently available.

SDG&E may incur substantial costs and liabilities as a result of its partial ownership of a nuclear facility that is being decommissioned.

SDG&E has a 20-percent ownership interest in SONGS, a 2,150-MW nuclear generating facility near San Clemente, California, that is in the process of being decommissioned by Edison, the majority owner of SONGS. SONGS is subject to the jurisdiction of the NRC and the CPUC. On June 6, 2013, Edison notified SDG&E that it had reached a decision to permanently retire SONGS and seek approval from the NRC to start the decommissioning activities for the entire facility. SDG&E, and each of the other owners, holds its undivided interest as a tenant in common in the property, and each owner is responsible for financing its share of expenses and capital expenditures, including decommissioning activities. Although the facility is being decommissioned, SDG&E's ownership interest in SONGS continues to subject it to the risks of owning a partial interest in a nuclear generation facility, which include

- the potential that a natural disaster such as an earthquake or tsunami could cause a catastrophic failure of the safety systems in place that are designed to prevent the release of radioactive material. If such a failure were to occur, a substantial amount of radiation could be released and cause catastrophic harm to human health and the environment;

- the potential harmful effects on the environment and human health resulting from the prior operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with operations and the decommissioning of the facility; and
- uncertainties with respect to the technological and financial aspects of decommissioning the facility.

In addition, SDG&E maintains nuclear decommissioning trusts for the purpose of providing funds to decommission SONGS. Trust assets have been generally invested in equity and debt securities, which are subject to significant market fluctuations. A decline in the market value of trust assets or an adverse change in the law regarding funding requirements for decommissioning trusts could increase the funding requirements for these trusts, which in each case may not be fully recoverable in rates. Furthermore, CPUC approval is required in order to make withdrawals from these trusts. CPUC approval for certain expenditures may be denied by the CPUC altogether if the CPUC determines that the expenditures are unreasonable. Finally, decommissioning may be materially more expensive than we currently anticipate and therefore decommissioning costs may exceed the amounts in the trust funds. Rate recovery for overruns would require CPUC approval, which may not occur.

Interpretations of tax regulations could impact access to nuclear decommissioning trust funds for reimbursement of spent nuclear fuel management costs. Depending on how the Internal Revenue Service (IRS) or the U.S. Department of Treasury ultimately interprets or alters regulations addressing the taxation of a qualified nuclear decommissioning trust, SDG&E may be restricted from withdrawing amounts from its qualified decommissioning trusts to pay for spent fuel management where Edison and SDG&E are seeking, or plan to seek, recovery of spent fuel management costs in litigation against, or in settlements with, the DOE. In December 2016, the IRS and the U.S. Department of Treasury issued proposed regulations that clarify the definition of "nuclear decommissioning costs" that may be paid for or reimbursed from a qualified fund. These proposed regulations are not yet finalized, but SDG&E is working with outside counsel to clarify with the IRS some of the provisions in the proposed regulations to confirm that the proposed regulations will allow SDG&E to access the trust funds for reimbursement or payment of the spent fuel management costs incurred in 2016 and subsequent years. Until the DOE litigation is resolved, and/or IRS regulations regarding spent fuel management costs are confirmed to apply, SDG&E expects to continue to pay for such spent fuel management costs. If SDG&E is unable to obtain timely access to the trusts for these costs, SDG&E's cash flows could be negatively impacted.

In November 2014, the CPUC approved the Amended Settlement Agreement that resolved the investigation into the steam generator replacement project that ultimately led to the shut-down of SONGS. Various petitions have since been filed to reopen the settlement. In December 2016, the Commissioner and Administrative Law Judge assigned to the proceeding issued a ruling directing SDG&E and Edison to "meet and confer" with other parties to the proceeding to determine whether an agreement could be reached to modify the Amended Settlement Agreement previously approved by the CPUC to resolve allegations that unreported *ex parte* communications between Edison and the CPUC resulted in an unfair advantage at the time the settlement agreement was negotiated. If no agreement to modify the Amended Settlement Agreement is reached by April 28, 2017, the CPUC will consider other options, including entertaining additional testimony, hearings and briefs. We cannot assure you that the Amended Settlement Agreement will not be renegotiated, modified or set aside as a result of this proceeding. We provide additional detail in Note 13 of the Notes to the Consolidated Financial Statements in the Annual Report.

The occurrence of any of these events could result in a substantial reduction in our expected recovery and have a material adverse effect on SDG&E's and Sempra Energy's businesses, cash flows, financial condition, results of operations and/or prospects.

Risks Related to our Sempra South American Utilities and Sempra Infrastructure Businesses

Our businesses are exposed to market risks, including fluctuations in commodity prices, and our businesses, financial condition, results of operations, cash flows and/or prospects may be materially adversely affected by these risks. Energy-related commodity prices impact LNG liquefaction and regasification, the transport and storage of natural gas, and power generation from renewable and conventional sources, among other businesses that we operate and invest in.

We buy energy-related commodities from time to time, for LNG terminals or power plants to satisfy contractual obligations with customers, in regional markets and other competitive markets in which we compete. Our revenues and results of operations could be materially adversely affected if the prevailing market prices for natural gas, LNG, electricity or other commodities that we buy change in a direction or manner not anticipated and for which we had not provided adequately through purchase or sale commitments or other hedging transactions. In particular, North American natural gas prices, when in decline, negatively impact profitability at Sempra LNG & Midstream.

Unanticipated changes in market prices for energy-related commodities result from multiple factors, including:

- weather conditions
- seasonality
- changes in supply and demand
- transmission or transportation constraints or inefficiencies
- availability of competitively priced alternative energy sources
- commodity production levels
- actions by oil and natural gas producing nations or organizations affecting the global supply of crude oil and natural gas
- federal, state and foreign energy and environmental regulation and legislation
- natural disasters, wars, embargoes and other catastrophic events
- expropriation of assets by foreign countries

The FERC has jurisdiction over wholesale power and transmission rates, independent system operators, and other entities that control transmission facilities or that administer wholesale power sales in some of the markets in which we operate. The FERC may impose additional price limitations, bidding rules and other mechanisms, or terminate existing price limitations from time to time. Any such action by the FERC may result in prices for electricity changing in an unanticipated direction or manner and, as a result, may have a material adverse effect on our businesses, cash flows, results of operations and/or prospects.

When our businesses enter into fixed-price long-term contracts to provide services or commodities, they are exposed to inflationary pressures such as rising commodity prices, and interest rate risks.

Sempra Mexico, Sempra Renewables and Sempra LNG & Midstream generally endeavor to secure long-term contracts with customers for services and commodities to optimize the use of their facilities, reduce volatility in earnings, and support the construction of new infrastructure. However, if these contracts are at fixed prices, the profitability of the contract may be materially adversely affected by inflationary pressures, including rising operational costs, costs of labor, materials, equipment and commodities, and rising interest rates that affect financing costs. We may try to mitigate these risks by using variable pricing tied to market indices, anticipating an escalation in costs when bidding on projects, providing for cost escalation, providing for direct pass-through of operating costs or entering into hedges. However, these measures, if implemented, may not ensure that the increase in revenues they provide will fully offset increases in operating expenses and/or financing costs. The failure to fully or substantially offset these increases could have a material adverse effect on our financial condition, cash flows and/or results of operations.

Business development activities may not be successful and projects under construction may not commence operation as scheduled or be completed within budget, which could have a material adverse effect on our businesses, financial condition, cash flows, results of operations and/or prospects.

The acquisition, development, construction and expansion of LNG terminals; natural gas, propane and ethane pipelines and storage facilities; electric generation, transmission and distribution facilities; and other energy infrastructure projects involve numerous risks. We may be required to spend significant sums for preliminary engineering, permitting, fuel supply, resource exploration, legal, and other expenses before we can determine whether a project is feasible, economically attractive, or capable of being built.

Success in developing a particular project is contingent upon, among other things:

- negotiation of satisfactory engineering, procurement and construction (EPC) agreements
- negotiation of supply and natural gas sales agreements or firm capacity service agreements

- timely receipt of required governmental permits, licenses, authorizations, and rights of way and maintenancc or extension of these authorizations
- timely implementation and satisfactory completion of construction
- obtaining adequate and reasonably priced financing for the project

Successful completion of a particular project may be materially adversely affected by, among other factors:

- unforeseen engineering problems
- construction delays and contractor performance shortfalls
- work stoppages
- failure to obtain, maintain or extend required governmental permits, licenses, authorizations, and rights of way
- equipment unavailability or delay and cost increases
- adverse weather conditions
- environmental and geological conditions
- litigation
- unsettled property rights

If we are unable to complete a development project or if we have substantial delays or cost overruns, this could have a material adverse effect on our businesses, financial condition, cash flows, results of operations and/or prospects.

The operation of existing and future facilities also involves many risks, including the breakdown or failure of electric generation, transmission and distribution facilities, or natural gas regasification, liquefaction and storage facilities or other equipment or processes, labor disputes, fuel interruption, environmental contamination and operating performance below expected levels. In addition, weather-related incidents and other natural disasters can disrupt generation, regasification, liquefaction, storage, transmission and distribution systems. The occurrence of any of these events could lead to our facilities being idled for an extended period of time or our facilities operating well below expected capacity levels, which may result in lost revenues or increased expenses, including higher maintenance costs and penalties. Such occurrences could materially adversely affect our businesses, financial condition, cash flows, results of operations and/or prospects.

The design, development and construction of the Cameron LNG liquefaction facility involves numerous risks and uncertainties.

With respect to our project to add LNG export capability at the Cameron LNG facility, the Cameron LNG Holdings, LLC joint venture (Cameron LNG JV) is building an LNG export facility consisting of three liquefaction trains designed to a total nameplate capacity of 13.9 million tonnes per annum (Mtpa) of LNG with an expected export capability of 12 Mtpa of LNG, or approximately 1.7 Bcf per day. The anticipated incremental investment in the three-train liquefaction project is estimated to be approximately $7 billion, including the cost of the lump-sum, turnkey construction contract, development engineering costs and permitting costs, but excluding capitalized interest and other financing costs. The total cost of the facility, including the cost of our original regasification facility contributed to the joint venture plus interest during construction, financing costs and required reserves, is estimated to be approximately $10 billion. If construction, financing or other project costs are higher than we currently expect, we may have to contribute additional cash exceeding our current estimates. The majority of the incremental investment in the joint venture will be project-financed and the balance provided by the project partners. Any failure by the project partners to make their required investments on a timely basis could result in project delays and could materially adversely affect the development of the project. In addition, Sempra Energy has guaranteed a maximum of $3.9 billion related to the project financing and financing-related agreements. These guarantees terminate upon Cameron LNG JV's achieving "financial completion" of the initial three-train liquefaction project, including all three trains achieving commercial operation and meeting certain operational performance tests. If, due to the joint venture's failure to satisfy the financial completion criteria, we are required to repay some or all of the $3.9 billion under our guarantees, any such repayments could have a material adverse effect on our business, results of operations, cash flows, financial condition, and/or prospects.

Large-scale construction projects like the design, development and construction of the Cameron LNG liquefaction facility involve numerous risks and uncertainties, including among others, the potential for unforeseen engineering problems, substantial construction delays and increased costs. Cameron LNG JV has a turnkey EPC contract with a joint venture contractor comprised of subsidiaries of Chicago Bridge & Iron Company N.V. and Chiyoda Corporation, who are jointly and severally liable for performance under the contract. If the contractor becomes unwilling or unable to perform according to the terms and timetable of the EPC contract, Cameron LNG JV may be required to engage a substitute contractor, which would result in project delays and increased costs, which could be significant. The construction of this facility requires a large and specialized work force, necessary equipment and materials, and sophisticated engineering. There can be no assurance that

Cameron LNG JV's contractor will not encounter delays due to disruptions in obtaining the necessary equipment and materials, inability to field the necessary workforce, weather conditions, or engineering issues that were not contemplated. In October 2016, Cameron LNG JV received an indication from the EPC contractor that the respective in-service dates for each train may be delayed. Any such construction delays will defer a portion of the 2018 and 2019 earnings anticipated from the Cameron LNG project. As construction progresses, Cameron LNG JV may decide or be forced to submit change orders to the contractor that could result in longer construction periods and higher construction costs or both. In addition, new regulations, labor disputes, breakdown or failure of equipment and litigation could substantially delay the project. As we do not control Cameron LNG JV, we are dependent on reaching a consensus with one or more of our joint venture partners to resolve a variety of issues that could transpire. The inability to timely resolve issues, including construction issues, could cause substantial delays to the completion of this project. A substantial delay could result in cost overruns, substantially postpone the earnings we anticipate deriving from this facility, and require additional cash investments by us and our joint venture partners. The anticipated cost of this project is based on a number of assumptions that may prove incorrect, and the ultimate cost could significantly exceed the current estimate of approximately $7 billion of incremental investment, excluding capitalized interest and other financing costs. These risks could have a material adverse effect on our business, results of operations, cash flows, financial condition, and/or prospects.

We face many challenges to develop and complete our contemplated LNG export facilities.

In addition to the three-train Cameron LNG liquefaction facility described above, we are looking at several other LNG export terminal development opportunities, including a greenfield project in Port Arthur, Texas, a brownfield project at our existing Energía Costa Azul regasification facility in Baja California, Mexico and an expansion of up to two additional liquefaction trains to the Cameron liquefaction facility. Each of these contemplated projects faces numerous risks and must overcome significant hurdles before we can proceed with construction. Common to all of these projects is the risk that an extended decline in current and forward projections of crude oil prices could reduce the demand for natural gas in some sectors and cause a corresponding reduction in projected global demand for LNG. This could result in increased competition among those working on projects in an environment of declining LNG demand, such as the Sempra Energy-sponsored export initiatives. Such reduction in natural gas demand could also occur from higher penetration of coal in new power generation, which could also lead to increased competition among the LNG suppliers for the declining LNG demand. Oil prices at certain moderate levels could also make LNG projects in other parts of the world still feasible and competitive with LNG projects from North America, thus increasing supply and the competition for the available LNG demand. A decline in natural gas prices outside the United States (which in many foreign countries are based on the price of crude oil) may also materially adversely affect the relative pricing advantage that has existed in recent years in favor of domestic natural gas prices (based on Henry Hub pricing).

Sempra LNG & Midstream has entered into a project development agreement for the joint development of the proposed Port Arthur liquefaction project with an affiliate of Woodside Petroleum Ltd. The agreement specifies how the parties will share costs, and establishes a framework for the parties to work jointly on permitting, design, engineering, and commercial and marketing activities associated with developing the Port Arthur liquefaction project. Also, Sempra LNG & Midstream, IEnova and a subsidiary of Petróleos Mexicanos (or PEMEX, the Mexican state-owned oil company) entered into a project development agreement for the joint development of the proposed liquefaction project at IEnova's existing Energía Costa Azul regasification facility in Mexico. The agreement specifies how the parties will share costs, and establishes a framework for the parties to work jointly on permitting, design, engineering, and commercial activities associated with developing the potential liquefaction project. We are sharing costs with PEMEX on the development efforts. Any decisions by the parties to proceed with binding agreements with respect to the formation of these potential joint ventures and the potential development of these projects will require, among other things, completion of project assessments and achieving other necessary internal and external approvals of each such party. In addition, all of our proposed projects are subject to a number of risks and uncertainties, including the receipt of a number of permits and approvals; finding suitable partners and customers; obtaining financing and incentives; negotiating and completing suitable commercial agreements, including joint venture agreements, tolling capacity agreements or natural gas supply and LNG sales agreements and construction contracts; and reaching a final investment decision.

Expansion of the Cameron LNG liquefaction facility beyond the first three trains is subject to certain restrictions and conditions under the joint venture project financing agreements, including among others, timing restrictions on expansion of the project unless appropriate prior consent is obtained from the project lenders. Under the Cameron LNG JV equity agreements, the expansion of the project requires the unanimous consent of all of the partners, including with respect to the equity investment obligation of each partner. One of the partners indicated to Sempra Energy and the other partners that it does not intend to invest additional capital in Cameron LNG JV with respect to the expansion. As a result, discussions among the partners have occurred, and we are considering a variety of options to attempt to move the expansion project forward. These activities have contributed to delays in developing firm pricing information and securing customer commitments. In light of these developments, we cannot assure you that the various consents required for expansion of the Cameron LNG project will be obtained.

Furthermore, there are a number of potential new projects under construction or in the process of development by various project developers in North America, in addition to ours, and given the projected global demand for LNG, the vast majority of these projects likely will not be completed. With respect to our Port Arthur, Texas project, this is a greenfield site, and therefore it may not have the advantages often associated with brownfield sites. The Energía Costa Azul facility in Mexico is subject to on-going land disputes that could make project financing difficult as well as finding suitable partners and customers. In addition, while we have completed the regulatory process for an LNG export facility in the U.S., the regulatory process in Mexico and the overlay of U.S. regulations for natural gas exports to an LNG export facility in Mexico are not well developed. There can be no assurance that such a facility could be permitted and constructed without facing significant legal challenges and uncertainties, which in turn could make project financing, as well as finding suitable partners and customers, difficult. Finally, Energía Costa Azul has profitable long-term regasification contracts for 100 percent of the facility, making the decision to pursue a new liquefaction facility dependent in part on whether the investment in a new liquefaction facility would, over the long term, be more beneficial than continuing to supply regasification services under our existing contracts.

There can be no assurance that our contemplated LNG export facilities will be completed, and our inability to complete one or more of our contemplated LNG export facilities could have a material adverse effect on our future cash flows, results of operations and prospects.

We discuss these projects further in "Our Business" and "Factors Influencing Future Performance" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Annual Report.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could reduce or eliminate LNG export opportunities and demand.

Several states have adopted or are considering adopting regulations to impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing operations. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict the performance of or prohibit the well drilling in general and/or hydraulic fracturing in particular. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but federal agencies have asserted regulatory authority over certain hydraulic fracturing activities. For example, the EPA issued permitting guidance in February 2014 under the federal Safe Drinking Water Act (SDWA) for hydraulic fracturing activities involving the use of diesel fuels. In April 2015, the EPA issued a proposed rule that would prevent the discharge of hydraulic fracturing wastewater into publicly owned treatment works, and in March 2015, the Bureau of Land Management of the U.S. Department of the Interior adopted rules imposing new requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure of hydraulic fracturing chemicals, as well as wellbore integrity and handling of flowback water. In addition, the U.S. Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. There are also certain governmental reviews that have been conducted or are underway on deep shale and other formation completion and production practices, including hydraulic fracturing. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate or even ban such activities. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process.

We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, natural gas prices in North America could rise, which in turn could materially adversely affect the relative pricing advantage that has existed in recent years in favor of domestic natural gas prices (based on Henry Hub pricing). Increased regulation or difficulty in permitting of hydraulic fracturing, and any corresponding increase in domestic natural gas prices, could materially adversely affect demand for LNG exports and our ability to develop commercially viable LNG export facilities beyond the three train Cameron LNG facility currently under construction.

Increased competition and changes in trade policies could materially adversely affect us.

The markets in which we operate are characterized by numerous strong and capable competitors, many of whom have extensive and diversified developmental and/or operating experience (including both domestic and international) and financial resources similar to or greater than ours. Further, in recent years, the natural gas pipeline, storage and LNG market segments have been characterized by strong and increasing competition both with respect to winning new development projects and acquiring existing assets. In Mexico, despite the commissioning of many new energy infrastructure projects by the Federal Electricity Commission (Comisión Federal de Electricidad, or CFE) and other governmental agencies in connection with energy reforms, competition for recent pipeline projects has been intense with numerous bidders competing aggressively for these projects. There can be no assurance that we will be successful in bidding for new development opportunities in the U.S., Mexico or South America. In addition, as noted above, there are a number of potential new LNG liquefaction projects under construction or in the process of being developed by various project developers in North America, including our contemplated new projects, and given the projected global demand for LNG, it is likely that most of these projects will not be completed. Finally, as existing contracts expire at our natural gas storage assets in the Gulf Coast region, we compete with other facilities for storage customers that could continue to support the existing book value of these assets, and for anchor customers that could support development of new capacity. These competitive factors could have a material adverse effect on our business, results of operations, cash flows and/or prospects.

In addition, the current U.S. administration has previously indicated its intention to renegotiate trade agreements, such as the North American Free Trade Agreement, or NAFTA. A shift in U.S. trade policies could materially adversely affect our LNG development opportunities, as well as opportunities for trade between Mexico and the United States.

We may elect not to, or may not be able to, enter into, extend or replace expiring long-term supply and sales agreements or long-term firm capacity agreements for our projects, which would subject our revenues to increased volatility and our businesses to increased competition. Such long-term contracts, once entered into, increase our credit risk if our counterparties fail to perform or become unable to meet their contractual obligations on a timely basis due to bankruptcy, insolvency, or otherwise.

The Energía Costa Azul LNG facility and the Cameron LNG facility (within the Cameron LNG JV) have entered into long-term capacity agreements with a limited number of counterparties at each facility. Under these agreements, customers pay capacity reservation and usage fees to receive, store and regasify the customers' LNG. We also may enter into short-term and/or long-term supply agreements to purchase LNG to be received, stored and regasified for sale to other parties. The long-term supply agreement contracts are expected to reduce our exposure to changes in natural gas prices through corresponding natural gas sales agreements or by tying LNG supply prices to prevailing natural gas market price indices. If the counterparties, customers or suppliers to one or more of the key agreements for the LNG facilities were to fail to perform or become unable to meet their contractual obligations on a timely basis, it could have a material adverse effect on our results of operations, cash flows and/or prospects.

At Cameron LNG JV, although the Cameron LNG terminal is partially contracted for regasification, there is a termination agreement in place that will result in the termination of the regasification contract at the point during the construction of the new liquefaction facilities where piping tie-ins to the existing regasification terminal become necessary.

For the three-train liquefaction facility currently under construction, Cameron LNG JV has 20-year liquefaction and regasification tolling capacity agreements in place with ENGIE S.A. (formerly GDF SUEZ S.A.) and affiliates of Mitsubishi Corporation and Mitsui & Co. Ltd., that subscribe for the full nameplate capacity of the facility. If the counterparties to these tolling agreements were to fail to perform or become unable to meet their contractual obligations to Cameron LNG JV on a timely basis, it could have a material adverse effect on our results of operations, cash flows and/or prospects.

Sempra Mexico's and Sempra LNG & Midstream's ability to enter into or replace existing long-term firm capacity agreements for their natural gas pipeline operations are dependent on demand for and supply of LNG and/or natural gas from their transportation customers, which may include our LNG facilities. A significant sustained decrease in demand for and supply of LNG and/or natural gas from such customers could have a material adverse effect on our businesses, results of operations, cash flows and/or prospects.

Our natural gas storage assets include operational and development assets at Bay Gas Storage Company, Ltd. (Bay Gas) in Alabama and Mississippi Hub, LLC (Mississippi Hub) in Mississippi, as well as our development project, LA Storage, LLC (LA Storage) in Louisiana. LA Storage could be positioned to support LNG export from the Cameron LNG JV terminal and other liquefaction projects, if anticipated cash flows support further investment. However, changes in the U.S. natural gas market could also lead to diminished natural gas storage values. Historically, the value of natural gas storage services has positively correlated with the difference between the seasonal prices of natural gas, among other factors. In general, over the past several years, seasonal differences in natural gas prices have declined, which have contributed to lower prices for storage services. As our legacy (higher rate) sales contracts mature at our Bay Gas and Mississippi Hub facilities, replacement sales contract rates have been and could continue to be lower than has historically been the case. Lower sales revenues may not be offset by cost reductions, which could lead to depressed asset values. In addition, our LA Storage development project may be unable to either attract cash flow commitments sufficient to support further investment or extend its FERC construction permit beyond its current expiration date of June 2017. The LA Storage project also includes an existing 23.3-mile pipeline header system, the LA Storage Pipeline, that is not contracted. Market conditions could result in the need to perform recovery testing of our recorded asset values. In the event such values are not recoverable, we would consider the fair value of these assets relative to their recorded value. To the extent the recorded (carrying) value is in excess of the fair value, we would record a noncash impairment charge. The recorded value of our long-lived natural gas storage assets at December 31, 2016 was $1.5 billion. A significant impairment charge related to our natural gas storage assets would have a material adverse effect on our results of operations in the period in which it is recorded.

The electric generation and wholesale power sales industries are highly competitive. As more plants are built and competitive pressures increase, wholesale electricity prices may become more volatile. Without the benefit of long-term power sales agreements, our revenues may be subject to increased price volatility, and we may be unable to sell the power that Sempra Renewables' and Sempra Mexico's facilities are capable of producing or to sell it at favorable prices, which could materially adversely affect our results of operations, cash flows and/or prospects.

We provide information about these matters in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Annual Report.

Our businesses depend on counterparties, business partners, customers, and suppliers performing in accordance with their agreements. If they fail to perform, we could incur substantial expenses and business disruptions and be exposed to commodity price risk and volatility, which could materially adversely affect our businesses, financial condition, cash flows, results of operations and/or prospects.

Our businesses, and the businesses that we invest in, are exposed to the risk that counterparties, business partners, customers, and suppliers that owe money or commodities as a result of market transactions or other long-term agreements or arrangements will not perform their obligations in accordance with such agreements or arrangements. Should they fail to perform, we may be required to enter into alternative arrangements or to honor the underlying commitment at then-current market prices. In such an event, we may incur additional losses to the extent of amounts already paid to such counterparties or suppliers. In addition, many such agreements are important for the conduct and growth of our businesses. The failure of any of the parties to perform in accordance with these agreements could materially adversely affect our businesses, results of operations, cash flows, financial condition and/or prospects. Finally, we often extend credit to counterparties and customers. While we perform significant credit analyses prior to extending credit, we are exposed to the risk that we may not be able to collect amounts owed to us.

In November 2015, a major U.S. credit rating agency revised PEMEX's global foreign currency and local currency credit ratings from A3 to Baa1 and changed the outlook for its credit ratings to negative. In March 2016, the same major credit rating agency further downgraded PEMEX's global foreign currency and local currency credit ratings from Baa1 to Baa3. In May, October and December 2016, in connection with debt offerings by PEMEX, the same major credit agency reaffirmed that the outlook on PEMEX's credit ratings remains negative. PEMEX is also subject to the control of the Mexican government, which could limit its ability to satisfy its external debt obligations. Although PEMEX is a State Productive Enterprise of Mexico, its financing obligations are not guaranteed by the Mexican government. As both a partner in a Sempra Mexico joint venture that holds a 50-percent interest in the Los Ramones Norte pipeline project and a customer with capacity contracts for transportation services on Sempra Mexico's ethane pipelines, if PEMEX were unable to meet any or all of its obligations to Sempra Mexico, it could have a material adverse effect on our financial condition, results of operations, cash flows and prospects.

Sempra Mexico's and Sempra LNG & Midstream's obligations and those of their suppliers for LNG supplies are contractually subject to (1) suspension or termination for "force majeure" events beyond the control of the parties; and (2) substantial limitations of remedies for other failures to perform, including limitations on damages to amounts that could be substantially less than those necessary to provide full recovery of costs for breach of the agreements, which in either event could have a material adverse effect on our results of operations, cash flows, financial condition and/or prospects.

Our businesses are subject to various legal actions challenging our property rights and permits.

We are engaged in disputes regarding our title to the properties adjacent to and properties where our LNG terminal in Mexico is located, as we discuss in Note 15 of the Notes to Consolidated Financial Statements in the Annual Report. In the event that we are unable to defend and retain title to the properties on which our LNG terminal is located, we could lose our rights to occupy and use such properties and the related terminal, which could result in breaches of one or more permits or contracts that we have entered into with respect to such terminal. In addition, our ability to convert the LNG terminal into an export facility may be hindered by these disputes, and they could make project financing such a facility and finding suitable partners and customers very difficult. If we are unable to occupy and use such properties and the related terminal, it could have a material adverse effect on our businesses, financial condition, results of operations, cash flows and/or prospects.

We are also engaged in disputes regarding permits at our Energía Sierra Juárez wind project in Mexico, as we discuss in Note 15 of the Notes to Consolidated Financial Statements in the Annual Report.

We rely on transportation assets and services, much of which we do not own or control, to deliver electricity and natural gas.

We depend on electric transmission lines, natural gas pipelines, and other transportation facilities owned and operated by third parties to:

- deliver the electricity and natural gas we sell to wholesale markets,
- supply natural gas to our gas storage and electric generation facilities, and
- provide retail energy services to customers.

Sempra Mexico and Sempra LNG & Midstream also depend on natural gas pipelines to interconnect with their ultimate source or customers of the commodities they are transporting. Sempra Mexico and Sempra LNG & Midstream also rely on specialized ships to transport LNG to their facilities and on natural gas pipelines to transport natural gas for customers of the facilities. Sempra Renewables, Sempra South American Utilities and Sempra Mexico rely on transmission lines to sell electricity to their customers. If transportation is disrupted, or if capacity is inadequate, we may be unable to sell and deliver our commodities, electricity and other services to some or all of our customers. As a result, we may be responsible for damages incurred by our customers, such as the additional cost of acquiring alternative electricity, natural gas supplies and LNG at then-current spot market rates, which could have a material adverse effect on our businesses, financial condition, cash flows, results of operations and/or prospects.

Our international businesses are exposed to different local, regulatory and business risks and challenges.

In Mexico, we own or have interests in natural gas distribution and transportation, liquid petroleum gas storage and transportation facilities, ethane transportation, electricity generation, distribution and transmission facilities, and an LNG terminal. In Peru and Chile, we own or have interests in electricity generation, transmission and distribution facilities and operations. Developing infrastructure projects, owning energy assets, and operating businesses in foreign jurisdictions subject us to significant political, legal, regulatory and financial risks that vary by country, including:

- changes in foreign laws and regulations, including tax and environmental laws and regulations, and U.S. laws and regulations, in each case, that are related to foreign operations
- governance by and decisions of local regulatory bodies, including setting of rates and tariffs that may be earned by our businesses
- high rates of inflation
- volatility in exchange rates between the U.S. dollar and currencies of the countries in which we operate, as we discuss below
- foreign cash balances that may be unavailable to fund U.S. operations, or available only at unfavorable U.S. and/or foreign tax rates upon repatriation of such amounts or changes in tax law
- changes in government policies or personnel
- trade restrictions
- limitations on U.S. company ownership in foreign countries
- permitting and regulatory compliance
- changes in labor supply and labor relations
- adverse rulings by foreign courts or tribunals, challenges to permits and approvals, difficulty in enforcing contractual and property rights, and unsettled property rights and titles in Mexico and other foreign jurisdictions
- expropriation of assets
- adverse changes in the stability of the governments in the countries in which we operate
- general political, social, economic and business conditions
- compliance with the Foreign Corrupt Practices Act and similar laws
- valuation of goodwill

Our international businesses also are subject to foreign currency risks. These risks arise from both volatility in foreign currency exchange and inflation rates and devaluations of foreign currencies. In such cases, an appreciation of the U.S. dollar against a local currency could materially reduce the amount of cash and income received from those foreign subsidiaries. We may or may not choose to hedge these risks, and any hedges entered into may or may not be effective. Fluctuations in foreign currency exchange and inflation rates may result in significantly increased taxes in foreign countries and materially adversely affect our cash flows, financial condition, results of operations and/or prospects.

We discuss litigation related to Sempra Mexico's Energía Costa Azul LNG terminal and other international energy projects in Note 15 of the Notes to Consolidated Financial Statements and in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Annual Report.

IEnova's completed acquisitions of the remaining 50-percent interest in the Gasoductos de Chihuahua joint venture and of the Ventika wind power generation facilities will subject IEnova to integration challenges and risks.

IEnova's completed acquisitions of the remaining 50-percent interest in the Gasoductos de Chihuahua joint venture from Pemex TRI and of the Ventika I and Ventika II wind power facilities from Fisterra Energy and certain minority shareholders will subject IEnova to substantial integration challenges and risks. IEnova's expectations for the operating performance of the existing projects and the projects under construction by Gasoductos de Chihuahua are based on assumptions and estimates derived from its prior experience in the development of joint venture projects with Pemex TRI, and IEnova's expectations regarding the results of operations of the Ventika wind power generation facilities are based on its due diligence and assumptions and estimates regarding the future productivity of those assets. The ability of these entities to achieve their expected results is subject to the risks inherent in the development, construction and management of energy projects generally. Following these acquisitions, Gasoductos de Chihuahua and/or the Ventika wind power generation facilities may not perform as expected, and the revenues generated by such acquisitions may prove insufficient to support the financing utilized to acquire such entities or to maintain such acquisitions. Furthermore, the successful integration and consolidation of any acquisition requires significant human, financial and other resources, which may distract the attention of IEnova's management from IEnova's existing projects, give rise to disruptions in such projects or result in an acquisition not being adequately integrated. IEnova may be unsuccessful at integrating either of these businesses with its own, or may experience difficulties in connection with the integration of their operations and systems (including IT, accounting, financial, control, risk management and safety systems). Any failure by IEnova to achieve the expected results, synergies and/or economies of scale from the integration of these businesses could have a material adverse effect on IEnova's business, financial condition, results of operations, cash flows, and/or prospects.

Other Risks

Sempra Energy has substantial investments in and obligations arising from businesses that it does not control or manage or in which it shares control.

Sempra Energy makes investments in entities that we do not control or manage or in which we share control. As described above, SDG&E holds a 20-percent ownership interest in SONGS, which is in the process of being decommissioned by Edison, its majority owner. Sempra LNG & Midstream accounts for its investment in the Cameron LNG JV under the equity method, which investment is approximately $1 billion at December 31, 2016. At December 31, 2016, Sempra Renewables had investments totaling $844 million in several joint ventures to operate renewable generation facilities. Sempra Mexico has a 40-percent interest in a joint venture with a subsidiary of TransCanada Corporation to build, own and operate the Sur de Texas-Tuxpan natural gas marine pipeline in Mexico, a 50-percent interest in a renewables wind project in Baja California, and a 50-percent interest in a joint venture with PEMEX which, in turn, owns a 50-percent interest in the Los Ramones Norte pipeline in Mexico. At December 31, 2016, these various joint venture investments by Sempra Mexico totaled $180 million. Sempra Energy has an investment balance of $67 million at December 31, 2016 that reflects remaining distributions expected to be received from the RBS Sempra Commodities LLP (RBS Sempra Commodities) partnership as it is dissolved. The timing and amount of distributions may be impacted by the matters we discuss related to RBS Sempra Commodities in Notes 6 and 15 of the Notes to Consolidated Financial Statements in the Annual Report. The failure to collect all or a substantial portion of our remaining investment in the RBS Sempra Commodities partnership could have a corresponding impact on our cash flows, financial condition and results of operations.

Sempra Renewables and Sempra LNG & Midstream have provided guarantees related to joint venture financing agreements, and Sempra South American Utilities and Sempra Mexico have provided loans to joint ventures in which they have investments and to other affiliates. We discuss the guarantees in Note 4, and affiliate loans in Note 1 of the Notes to Consolidated Financial Statements in the Annual Report.

We have limited influence over these ventures and other businesses in which we do not have a controlling interest. In addition to the other risks inherent in these businesses, if their management were to fail to perform adequately or the other investors in the businesses were unable or otherwise failed to perform their obligations to provide capital and credit support for these businesses, it could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. We discuss our investments further in Notes 3, 4 and 10 of the Notes to Consolidated Financial Statements in the Annual Report.

Market performance or changes in other assumptions could require Sempra Energy, SDG&E and/or SoCalGas to make significant unplanned contributions to their pension and other postretirement benefit plans.

Sempra Energy, SDG&E and SoCalGas provide defined benefit pension plans and other postretirement benefits to eligible employees and retirees. A decline in the market value of plan assets may increase the funding requirements for these plans. In addition, the cost of providing pension and other postretirement benefits is also affected by other factors, including the assumed rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, levels of assumed interest rates and future governmental regulation. An adverse change in any of these factors could cause a material increase in our funding obligations which could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects.

Impairment of goodwill would negatively impact our consolidated results of operations and net worth.

As of December 31, 2016, Sempra Energy had approximately $2.4 billion of goodwill, which represented approximately 4.9 percent of the total assets on its Consolidated Balance Sheet, primarily related to investments in Gasoductos de Chihuahua in Mexico, Chilquinta Energía in Chile and Luz Del Sur in Peru. Goodwill is not amortized, but we test it for impairment annually on October 1 or whenever events or changes in circumstances necessitate an evaluation, which could result in our recording a goodwill impairment loss. We discuss our annual goodwill impairment testing process and the factors considered in such testing in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates" and in Note 1 of the Notes to Consolidated Financial Statements in the Annual Report. A goodwill impairment loss could materially adversely affect our results of operations for the period in which such charge is recorded.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

SEMPRA UTILITIES

Electric Properties

SDG&E

At December 31, 2016, SDG&E owns and operates four natural gas-fired power plants:

- a 566-MW electric generation facility (the Palomar generation facility) in Escondido, California
- a 485-MW electric generation facility (the Desert Star generation facility) in Boulder City, Nevada
- a 96-MW electric generation peaking facility (the Miramar Energy Center) in San Diego, California
- a 47-MW electric generation facility (the Cuyamaca Peak Energy Plant) in El Cajon, California

SDG&E's interest in SONGS, as well as matters related to SONGS' retirement and related issues, are discussed in Note 13 of the Notes to Consolidated Financial Statements in the Annual Report.

At December 31, 2016, SDG&E's electric transmission and distribution facilities included substations and overhead and underground lines. These electric facilities are located in San Diego, Imperial and Orange counties of California, and in Arizona and Nevada. The facilities consist of 2,083 miles of transmission lines, 23,371 miles of distribution lines and 161 substations. Periodically, various areas of the service territory require expansion to accommodate customer growth, reliability and safety.

Sempra South American Utilities

Sempra South American Utilities operates Chilquinta Energía, which serves customers in the region of Valparaíso in central Chile. Its property consists of 10,118 miles of distribution lines, 352 miles of transmission lines and 48 substations. Chilquinta Energía and Sociedad Austral de Electricidad Sociedad Anónima are 50-percent partners in Eletrans S.A., an electric transmission company that operates a 100-mile double circuit 220-kV transmission line, which extends from Cardones to Diego de Almagro in Chile.

Sempra South American Utilities operates Luz del Sur, which serves customers in the southern zone of metropolitan Lima, Peru. Its property consists of 13,763 miles of distribution lines, 194 miles of transmission lines and 39 substations. Luz del Sur operates Santa Teresa, a 100-MW hydroelectric power plant located in the Cusco region of Peru.

Natural Gas Properties

SDG&E

At December 31, 2016, SDG&E's natural gas facilities consisted of one compressor station, 168 miles of transmission pipelines, 8,647 miles of distribution pipelines and 6,457 miles of service pipelines.

SoCalGas

At December 31, 2016, SoCalGas' natural gas facilities included 2,964 miles of transmission and storage pipelines, 50,296 miles of distribution pipelines and 47,676 miles of service pipelines. They also included 10 transmission compressor stations and four underground natural gas storage reservoirs with a combined working capacity of 137 Bcf. We discuss recent events concerning SoCalGas' Aliso Canyon natural gas storage facility in "Risk Factors" above and in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Influencing Future Performance" and Note 15 of the Notes to Consolidated Financial Statements in the Annual Report.

SEMPRA INFRASTRUCTURE

Energy Properties

At December 31, 2016, Sempra Mexico and Sempra Renewables operate or own interests in a power plant and/or renewable generation facilities in North America with a total capacity of 3,329 MW. Our share of this capacity is 2,345 MW. We provide additional information in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Notes 3 and 4 of the Notes to Consolidated Financial Statements in the Annual Report.

At December 31, 2016, Sempra Mexico's operations included 2,336 miles of natural gas distribution pipelines, 710 miles of natural gas transmission pipelines and eight compressor stations, 140 miles of ethane pipelines and 118 miles of liquid petroleum gas pipelines. Sempra Mexico operates its Energía Costa Azul LNG regasification terminal on land it owns in Baja California, Mexico and operates a liquid petroleum gas storage terminal in Jalisco, Mexico.

Sempra Renewables leases properties in Nevada and Michigan and owns property in California, Arizona and Michigan for potential development and/or for currently operating solar and wind electric generation facilities and intermittency solutions. Sempra Mexico leases properties in Mexico for current and potential development of solar and wind electric generation facilities.

Sempra LNG & Midstream and its partner, ProLiance Transportation and Storage, LLC, own land in Cameron Parish, Louisiana, with potential to develop 19 Bcf of salt cavern natural gas storage capacity at the LA Storage development project.

In Washington County, Alabama, Sempra LNG & Midstream operates a 20 Bcf natural gas storage facility, Bay Gas, under a land lease. Sempra LNG & Midstream also owns land in Simpson County, Mississippi, on which it operates a 22 Bcf natural gas storage facility, Mississippi Hub. We will evaluate additional cavern and associated pipeline expansion opportunities at Bay Gas and Mississippi Hub based on regional market demand for natural gas storage services.

Sempra LNG & Midstream owns land in Port Arthur, Texas, for potential LNG liquefaction development. Sempra LNG & Midstream also has an equity interest in Cameron LNG JV, which owns land and an LNG regasification terminal and has a land lease in Hackberry, Louisiana. The joint venture is constructing an LNG liquefaction terminal at the facility.

OTHER PROPERTIES

Sempra Energy occupies its 16-story corporate headquarters building in San Diego, California, pursuant to a 25-year, build-to-suit lease that expires in 2040. The lease has five five-year renewal options. We discuss the details of this lease further in Note 15 of the Notes to Consolidated Financial Statements in the Annual Report.

SoCalGas leases approximately one-fourth of a 52-story office building in downtown Los Angeles, California, pursuant to an operating lease expiring in 2026. The lease has four five-year renewal options.

SDG&E occupies a six-building office complex in San Diego, California, pursuant to two separate operating leases, both ending in December 2024. One lease has four five-year renewal options and the other lease has three five-year renewal options.

Sempra South American Utilities owns or leases office facilities at various locations in Chile and Peru, with the leases ending from 2017 to 2021. Sempra Infrastructure owns or leases office facilities at various locations in the United States and Mexico, with the leases ending from 2017 to 2021.

We own or lease other land, easements, rights of way, warehouses, offices, operating and maintenance centers, shops, service facilities and equipment necessary to conduct our businesses.

ITEM 3. LEGAL PROCEEDINGS

We are not party to, and our property is not the subject of, any material pending legal proceedings (other than ordinary routine litigation incidental to our businesses) except for the matters (1) described in Notes 13, 14 and 15 of the Notes to Consolidated Financial Statements in the Annual Report, or (2) referred to in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Annual Report.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

COMMON STOCK AND RELATED SHAREHOLDER MATTERS

The common stock, related shareholder, and dividend restriction information required by Item 5 is included in "Common Stock Data" in the Annual Report.

SEMPRA ENERGY EQUITY COMPENSATION PLANS

Sempra Energy has a long-term incentive plan that permits the grant of a wide variety of equity and equity-based incentive awards to directors, officers and key employees. At December 31, 2016, outstanding awards consisted of stock options and restricted stock units held by 434 employees.

The following table sets forth information regarding our equity compensation plan at December 31, 2016.

EQUITY COMPENSATION PLAN

	Number of shares to be issued upon exercise of outstanding options, warrants and rights(1)	Weighted-average exercise price of outstanding options, warrants and rights(2)	Number of additional shares remaining available for future issuance(3)
Equity compensation plan approved by shareholders:			
2013 Long-Term Incentive Plan	2,620,313	$ 52.46	5,627,118

(1) Consists of 360,255 options to purchase shares of our common stock, all of which were granted at an exercise price of 100% of the grant date fair market value of the shares subject to the option, 1,954,322 performance-based restricted stock units and 305,736 restricted stock units that are service-based or issued in connection with certain other criteria. Each performance-based restricted stock unit represents the right to receive from zero to 1.5 shares (2.0 shares for awards granted during or after 2014) of our common stock if applicable performance conditions are satisfied. The 2,620,313 shares also includes awards granted under two previously shareholder-approved long-term incentive plans (Predecessor Plans). No new awards may be granted under these Predecessor Plans.

(2) Represents only the weighted-average exercise price of the 360,255 outstanding options to purchase shares of common stock.

(3) The number of shares available for future issuance is increased by the number of shares or units withheld or surrendered to satisfy the exercise price or to satisfy tax withholding obligations relating to any plan awards, and is also increased by the number of shares subject to awards that expire or are forfeited, canceled or otherwise terminated without the issuance of shares.

We provide additional discussion of share-based compensation in Note 8 of the Notes to Consolidated Financial Statements in the Annual Report.

PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PURCHASERS

On September 11, 2007, the Sempra Energy board of directors authorized the repurchase of Sempra Energy common stock provided that the amounts spent for such purpose do not exceed the greater of $2 billion or amounts spent to purchase no more than 40 million shares. No shares have been repurchased under this authorization since 2011. Approximately $500 million remains authorized by the board for the purchase of additional shares, not to exceed approximately 12 million shares.

We also may, from time to time, purchase shares of our common stock from long-term incentive plan participants who elect to sell a sufficient number of vesting restricted shares to meet minimum statutory tax withholding requirements.

ITEM 6. SELECTED FINANCIAL DATA

The information required by Item 6 is included in "Five-Year Summaries" in the Annual Report.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The information required by Item 7 is set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Annual Report, on pages 2 through 75.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by Item 7A is set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk" in the Annual Report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by Item 8 is set forth on pages 86 through 219 of the Annual Report. Item 15(a)1 of Part IV of this report includes a listing of financial statements included.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

The information required by Item 9A is provided in "Controls and Procedures" in the Annual Report.

ITEM 9B. OTHER INFORMATION

None.

PART III.

Because SDG&E meets the conditions of General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this report with a reduced disclosure format as permitted by General Instruction I(2), the information required by Items 10, 11, 12 and 13 below is not required for SDG&E. We have, however, provided the information required by Item 10 with respect to SDG&E's executive officers in Part I, Item 1. Business in "Executive Officers of the Registrants – Executive Officers of SDG&E."

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

SEMPRA ENERGY

We provide the information required by Item 10 with respect to executive officers for Sempra Energy in Part I, Item 1. Business in "Executive Officers of the Registrants – Executive Officers of Sempra Energy." All other information required by Item 10 is incorporated by reference from "Corporate Governance" and "Share Ownership" in the Proxy Statement prepared for the May 2017 annual meeting of shareholders.

SOCALGAS

We provide the information required by Item 10 with respect to executive officers for SoCalGas in Part I, Item 1. Business in "Executive Officers of the Registrants – Executive Officers of SoCalGas." All other information required by Item 10 is incorporated by reference from the company's Information Statement prepared for its May 2017 annual meeting of shareholders.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated by reference from "Corporate Governance" and "Executive Compensation," including "Compensation Discussion and Analysis" and "Compensation Committee Report" in the Proxy Statement prepared for the May 2017 annual meeting of shareholders for Sempra Energy and from the Information Statement prepared for the May 2017 annual meeting of shareholders for SoCalGas.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

Information regarding securities authorized for issuance under equity compensation plans as required by Item 12 is included in Item 5.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

The security ownership information required by Item 12 is incorporated by reference from "Share Ownership" in the Proxy Statement prepared for the May 2017 annual meeting of shareholders for Sempra Energy and in the Information Statement prepared for the May 2017 annual meeting of shareholders for SoCalGas.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by Item 13 is incorporated by reference from "Corporate Governance" in the Proxy Statement prepared for the May 2017 annual meeting of shareholders for Sempra Energy and from the Information Statement prepared for the May 2017 annual meeting of shareholders for SoCalGas.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information regarding principal accountant fees and services, as required by Item 14, is presented below for Sempra Energy, SDG&E and SoCalGas. The following table shows the fees paid to Deloitte & Touche LLP, the independent registered public accounting firm for Sempra Energy, SDG&E and SoCalGas, for services provided for 2016 and 2015.

PRINCIPAL ACCOUNTANT FEES
(Dollars in thousands)

	Sempra Energy Consolidated		SDG&E		SoCalGas	
	Fees	Percent of total	Fees	Percent of total	Fees	Percent of total
2016:						
Audit fees:						
Consolidated financial statements and internal controls audits, subsidiary and statutory audits	$ 9,525		$ 2,513		$ 2,627	
Regulatory filings and related services	117		31		31	
Total audit fees	9,642	88%	2,544	90%	2,658	83%
Audit-related fees:						
Employee benefit plan audits	460		138		240	
Other audit-related services, accounting consultation	706		12		304	
Total audit-related fees	1,166	11	150	5	544	17
Tax planning and compliance fees	175	1	143	5	—	—
All other fees	15	—	3	—	—	—
Total fees	$ 10,998	100%	$ 2,840	100%	$ 3,202	100%
2015:						
Audit fees:						
Consolidated financial statements and internal controls audits, subsidiary and statutory audits(1)	$ 11,269		$ 2,430		$ 2,516	
Regulatory filings and related services	200		58		59	
Total audit fees	11,469	91%	2,488	89%	2,575	87%
Audit-related fees:						
Employee benefit plan audits	430		134		218	
Other audit-related services, accounting consultation	229		32		95	
Total audit-related fees	659	5	166	6	313	11
Tax planning and compliance fees	440	4	140	5	54	2
All other fees	46	—	8	—	9	—
Total fees	$ 12,614	100%	$ 2,802	100%	$ 2,951	100%

(1) Sempra Energy Consolidated includes $1.8 million of audit services relating to a confidential submission of a subsidiary's Form S-1 to the Securities and Exchange Commission for the formation of a master limited partnership and initial public offering, which have been indefinitely suspended.

The Audit Committee of Sempra Energy's board of directors is directly responsible for the appointment, compensation, retention and oversight of the independent registered public accounting firm for Sempra Energy and its subsidiaries, including SDG&E and SoCalGas. As a matter of good corporate governance, the SDG&E and SoCalGas boards of directors also reviewed the performance of Deloitte & Touche LLP and concurred with the determination by the Sempra Energy Audit Committee to retain them as the independent registered public accounting firm for each of Sempra Energy, SDG&E and SoCalGas. Sempra Energy's board has determined that each member of its Audit Committee is an independent director and is financially literate, and that Mr. Taylor, the chair of the committee, is an audit committee financial expert as defined by the rules of the SEC.

Except where pre-approval is not required by SEC rules, Sempra Energy's Audit Committee pre-approves all audit and permissible non-audit services provided by Deloitte & Touche LLP for Sempra Energy and its subsidiaries. The committee's pre-approval policies and procedures provide for the general pre-approval of specific types of services and give detailed guidance to management as to the services that are eligible for general pre-approval. They require specific pre-approval of all other permitted services. For both types of pre-approval, the committee considers whether the services to be provided are consistent with maintaining the firm's independence. The policies and procedures also delegate authority to the chair of the committee to address any requests for pre-approval of services between committee meetings, with any pre-approval decisions to be reported to the committee at its next scheduled meeting.

PART IV.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

1. FINANCIAL STATEMENTS

	Page in Annual Report(1)		
	Sempra Energy	**San Diego Gas & Electric Company**	**Southern California Gas Company**
Consolidated Statements of Operations for the years ended December 31, 2016, 2015 and 2014	86	94	102
Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2016, 2015 and 2014	87	95	103
Consolidated Balance Sheets at December 31, 2016 and 2015	88	96	104
Consolidated Statements of Cash Flows for the years ended December 31, 2016, 2015 and 2014	90	98	106
Consolidated Statements of Changes in Equity for the years ended December 31, 2016, 2015 and 2014	92	100	N/A
Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2016, 2015 and 2014	N/A	N/A	107
Notes to Consolidated Financial Statements	109	109	109

(1) Incorporated by reference from the indicated pages of the 2016 Annual Report to Shareholders, filed as Exhibit 13.1

2. FINANCIAL STATEMENT SCHEDULES

Sempra Energy

Schedule I--Sempra Energy Condensed Financial Information of Parent may be found on page 60 of this report.

Any other schedule for which provision is made in Regulation S-X is not required under the instructions contained therein, is inapplicable or the information is included in the Consolidated Financial Statements and Notes thereto in the Annual Report.

3. EXHIBITS

See Exhibit Index on page 70 of this report.

CONSENTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM AND REPORT ON SCHEDULE

SEMPRA ENERGY

To the Board of Directors and Shareholders of Sempra Energy:

We consent to the incorporation by reference in Registration Statement No. 333-198572 on Form S-3 and Nos. 333-200828, 333-188526, 333-182225, 333-56161, 333-50806, 333-49732, 333-121073, 333-151184, 333-155191 and 333-129774 on Form S-8 of our reports dated February 28, 2017, relating to the consolidated financial statements of Sempra Energy and subsidiaries (the "Company"), and the effectiveness of the Company's internal control over financial reporting, incorporated by reference in this Annual Report on Form 10-K of Sempra Energy for the year ended December 31, 2016.

Our audits of the financial statements referred to in our aforementioned report relating to the consolidated financial statements also included the financial statement schedule of the Company, listed in Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

San Diego, California
February 28, 2017

SAN DIEGO GAS & ELECTRIC COMPANY

To the Board of Directors and Shareholder of San Diego Gas & Electric Company:

We consent to the incorporation by reference in Registration Statement No. 333-205410 on Form S-3 of our reports dated February 28, 2017, relating to the consolidated financial statements of San Diego Gas & Electric Company (the "Company"), and the effectiveness of the Company's internal control over financial reporting, incorporated by reference in this Annual Report on Form 10-K of San Diego Gas & Electric Company for the year ended December 31, 2016.

/s/ DELOITTE & TOUCHE LLP

San Diego, California
February 28, 2017

SOUTHERN CALIFORNIA GAS COMPANY

To the Board of Directors and Shareholders of Southern California Gas Company:

We consent to the incorporation by reference in Registration Statement No. 333-205950 on Form S-3 of our reports dated February 28, 2017, relating to the financial statements of Southern California Gas Company (the "Company"), and the effectiveness of the Company's internal control over financial reporting, incorporated by reference in this Annual Report on Form 10-K of Southern California Gas Company for the year ended December 31, 2016.

/s/ DELOITTE & TOUCHE LLP

San Diego, California
February 28, 2017

SCHEDULE I – SEMPRA ENERGY CONDENSED FINANCIAL INFORMATION OF PARENT

SEMPRA ENERGY
CONDENSED STATEMENTS OF OPERATIONS
(Dollars in millions, except per share amounts)

	Years ended December 31,		
	2016	2015	2014
Interest expense	$ (277)	$ (261)	$ (235)
Operation and maintenance	(81)	(66)	(78)
Other (expense) income, net	(2)	7	50
Income tax benefit	181	150	133
Loss before equity in earnings of subsidiaries	(179)	(170)	(130)
Equity in earnings of subsidiaries, net of income taxes	1,549	1,519	1,291
Net income/earnings	$ 1,370	$ 1,349	$ 1,161
Basic earnings per common share	$ 5.48	$ 5.43	$ 4.72
Weighted-average number of shares outstanding (thousands)	250,217	248,249	245,891
Diluted earnings per common share	$ 5.46	$ 5.37	$ 4.63
Weighted-average number of shares outstanding (thousands)	251,155	250,923	250,655

See Notes to Condensed Financial Information of Parent.

SEMPRA ENERGY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Dollars in millions)

	Years ended December 31,		
	Pretax amount	Income tax benefit	Net-of-tax amount
2016:			
Net income	$ 1,189	$ 181	$ 1,370
Other comprehensive income (loss):			
Foreign currency translation adjustments	42	—	42
Financial instruments	(6)	11	5
Pension and other postretirement benefits	(13)	4	(9)
Total other comprehensive income	23	15	38
Comprehensive income	$ 1,212	$ 196	$ 1,408
2015:			
Net income	$ 1,199	$ 150	$ 1,349
Other comprehensive income (loss):			
Foreign currency translation adjustments	(260)	—	(260)
Financial instruments	(80)	33	(47)
Pension and other postretirement benefits	(3)	1	(2)
Total other comprehensive loss	(343)	34	(309)
Comprehensive income	$ 856	$ 184	$ 1,040
2014:			
Net income	$ 1,028	$ 133	$ 1,161
Other comprehensive income (loss):			
Foreign currency translation adjustments	(193)	—	(193)
Financial instruments	(106)	42	(64)
Pension and other postretirement benefits	(20)	8	(12)
Total other comprehensive loss	(319)	50	(269)
Comprehensive income	$ 709	$ 183	$ 892

See Notes to Condensed Financial Information of Parent.

SEMPRA ENERGY
CONDENSED BALANCE SHEETS
(Dollars in millions)

	December 31, 2016	December 31, 2015
Assets:		
Cash and cash equivalents	$ 12	$ 4
Due from affiliates	73	62
Other current assets	2	4
Total current assets	87	70
Investments in subsidiaries	17,329	15,586
Due from affiliates	—	457
Deferred income taxes	2,570	2,188
Other assets	592	641
Total assets	$ 20,578	$ 18,942
Liabilities and shareholders' equity:		
Current portion of long-term debt	$ 600	$ 752
Due to affiliates	359	332
Income taxes payable	153	42
Other current liabilities	374	310
Total current liabilities	1,486	1,436
Long-term debt	5,100	5,195
Due to affiliates	517	—
Other long-term liabilities	524	502
Shareholders' equity	12,951	11,809
Total liabilities and shareholders' equity	$ 20,578	$ 18,942

See Notes to Condensed Financial Information of Parent.

SEMPRA ENERGY
CONDENSED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Years ended December 31,		
	2016	2015	2014
Net cash used in operating activities	$ (178)	$ (255)	$ (260)
Dividends received from subsidiaries	175	350	300
Expenditures for property, plant and equipment	(5)	(43)	(15)
Purchase of trust assets	—	(5)	(4)
Decrease (increase) in loans to affiliates, net	457	(457)	627
Cash provided by (used in) investing activities	627	(155)	908
Common stock dividends paid	(686)	(628)	(598)
Issuances of common stock	51	52	56
Repurchases of common stock	(56)	(74)	(38)
Issuances of long-term debt	499	1,248	499
Payments on long-term debt	(750)	—	(800)
Increase (decrease) in loans from affiliates, net	504	(230)	234
Tax benefit related to share-based compensation	—	52	—
Other	(3)	(9)	(4)
Cash (used in) provided by financing activities	(441)	411	(651)
Increase (decrease) in cash and cash equivalents	8	1	(3)
Cash and cash equivalents, January 1	4	3	6
Cash and cash equivalents, December 31	$ 12	$ 4	$ 3
SUPPLEMENTAL DISCLOSURE OF NONCASH FINANCING ACTIVITIES			
Financing of build-to-suit property	$ —	$ 61	$ 61
Common dividends issued in stock	53	55	42
Dividends declared but not paid	189	174	163

See Notes to Condensed Financial Information of Parent.

NOTES TO CONDENSED FINANCIAL INFORMATION OF PARENT

Note 1. Basis of Presentation

Sempra Energy accounts for the earnings of its subsidiaries under the equity method in this unconsolidated financial information.

Other Income, Net, on the Condensed Statements of Operations includes $23 million, $3 million and $27 million of gains on dedicated assets in support of our executive retirement and deferred compensation plans in 2016, 2015 and 2014, respectively.

Because of its nature as a holding company, Sempra Energy Parent classifies dividends received from subsidiaries as an investing cash flow.

Note 2. New Accounting Standards

We describe below recent pronouncements that have had or may have a significant effect on Sempra Energy Parent's financial condition, results of operations, cash flows or disclosures.

Accounting Standards Update (ASU) 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities": In addition to the presentation and disclosure requirements for financial instruments, ASU 2016-01 requires entities to measure equity investments, other than those accounted for under the equity method, at fair value and recognize changes in fair value in net income. Entities will no longer be able to use the cost method of accounting for equity securities. However, for equity investments without readily determinable fair values, entities may elect a measurement alternative that will allow those investments to be recorded at cost, less impairment, and adjusted for subsequent observable price changes. Upon adoption, entities must record a cumulative-effect adjustment to the balance sheet as of the beginning of the first reporting period in which the standard is adopted. The guidance on equity securities without readily determinable fair values will be applied prospectively to all equity investments that exist as of the date of adoption of the standard.

For public entities, ASU 2016-01 is effective for fiscal years beginning after December 15, 2017. We will adopt ASU 2016-01 on January 1, 2018 as required and do not expect it to materially affect our financial condition, results of operations or cash flows. We will make the required changes to our disclosures upon adoption.

ASU 2016-02, "Leases": ASU 2016-02 requires entities to include substantially all leases on the balance sheet by requiring the recognition of right-of-use assets and lease liabilities for all leases. Entities may elect to exclude from the balance sheet those leases with a maximum possible term of less than 12 months. For lessees, a lease is classified as finance or operating and the asset and liability are initially measured at the present value of the lease payments. For lessors, accounting for leases is largely unchanged from previous provisions of accounting principles generally accepted in the United States of America (U.S. GAAP), other than certain changes to align lessor accounting to specific changes made to lessee accounting and ASU 2014-09, "Revenue from Contracts with Customers." ASU 2016-02 also requires new qualitative and quantitative disclosures for both lessees and lessors.

For public entities, ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, with early adoption permitted, and is effective for interim periods in the year of adoption. The standard requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The modified retrospective approach includes optional practical expedients that may be elected, which would allow entities to continue to account for leases that commence before the effective date of the standard in accordance with previous U.S. GAAP unless the lease is modified, except for the lessee requirement to begin recognizing right-of-use assets and lease liabilities for all operating leases on the balance sheet at the reporting date. We are currently evaluating the effect of the standard on our ongoing financial reporting and have not yet selected the year in which we will adopt the standard. As part of our evaluation, we formed a steering committee comprised of members from relevant Sempra Energy business units. Based on our assessment to date, we have determined that we will adopt ASU 2016-02 using the modified retrospective approach and will elect the practical expedients available under the transition guidance.

ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting": ASU 2016-09 is intended to simplify several aspects of the accounting for employee share-based payment transactions. Under ASU 2016-09, excess tax benefits and tax deficiencies are required to be recorded in earnings, and the requirement to reclassify excess tax benefits from operating to financing activities on the statement of cash flows has been eliminated. ASU 2016-09 also allows entities to withhold taxes up to the maximum individual statutory tax rate without resulting in liability classification of the award and clarifies that cash payments made to taxing authorities in connection with withheld shares should be classified as financing activities in the statement of cash flows. Additionally, the standard provides for an accounting policy election to either continue to estimate forfeitures or account for them as they occur. For public entities, ASU 2016-09 is effective for fiscal years beginning after December 15, 2016, with early adoption permitted, and is effective for interim periods in the year of adoption.

We early adopted the provisions of ASU 2016-09 during the three months ended September 30, 2016, with an effective date of January 1, 2016. Upon adoption:

- Sempra Energy Parent recognized a cumulative-effect adjustment to retained earnings and a deferred tax asset as of January 1, 2016 of $49 million for previously unrecognized excess tax benefits from share-based compensation.
- Sempra Energy Parent recognized earnings consisting of excess tax benefits on the Condensed Statements of Operations of $17 million in the year ended December 31, 2016, all of which related to the three months ended March 31, 2016. Excess tax benefits of $34 million were previously recorded in Sempra Energy Parent Shareholders' Equity in Common Stock prior to adoption of ASU 2016-09.
- The excess tax benefits from share-based compensation for Sempra Energy Parent were previously classified as a financing activity on Sempra Energy Parent's Condensed Statement of Cash Flows. As now required, excess tax benefits for Sempra Energy Parent are included in Cash Flows From Operating Activities on the Condensed Statements of Cash Flows for the year ended December 31, 2016. This amendment was adopted prospectively, and therefore, we have not adjusted the Condensed Statements of Cash Flows for the prior periods presented.
- As a result of the provision to recognize excess tax benefits in earnings, these benefits are no longer included in the calculation of diluted earnings per share (EPS) effective January 1, 2016. The weighted-average number of common shares outstanding for diluted EPS increased by 75 thousand shares for the three months ended March 31, 2016 and 98 thousand shares and 89 thousand shares for the three months and six months ended June 30, 2016, respectively.

Upon adoption of ASU 2016-09, we elected to continue estimating the number of awards expected to be forfeited and adjusting our estimate on an ongoing basis. All other provisions of ASU 2016-09 did not impact our financial condition, results of operations or cash flows.

ASU 2016-13, "Measurement of Credit Losses on Financial Instruments": ASU 2016-13 changes how entities will measure credit losses for most financial assets and certain other instruments. The standard introduces an "expected credit loss" impairment model that requires immediate recognition of estimated credit losses expected to occur over the remaining life of most financial assets measured at amortized cost, including trade and other receivables, loan commitments and financial guarantees. ASU 2016-13 also requires use of an allowance to record estimated credit losses on available-for-sale debt securities and expands disclosure requirements regarding an entity's assumptions, models and methods for estimating the credit losses.

For public entities, ASU 2016-13 is effective for fiscal years beginning after December 15, 2019, with early adoption permitted for fiscal years beginning after December 15, 2018. We are currently evaluating the effect of the standard on our ongoing financial reporting and have not yet selected the year in which we will adopt the standard.

ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments": ASU 2016-15 provides guidance on how certain cash receipts and cash payments are to be presented and classified in the statement of cash flows in order to reduce diversity in practice.

For public entities, ASU 2016-15 is effective for fiscal years beginning after December 15, 2017, with early adoption permitted, and is effective for interim periods in the year of adoption. An entity that elects early adoption must adopt all of the amendments in the same period. Entities must apply the guidance retrospectively to all periods presented, but may apply it prospectively if retrospective application would be impracticable. We are currently evaluating the effect of the standard on our ongoing financial reporting and have not yet selected the year in which we will adopt the standard.

ASU 2017-05, "Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets": ASU 2017-05 clarifies the scope of accounting for the derecognition or partial sale of nonfinancial assets to exclude all businesses and nonprofit activities. ASU 2017-05 also provides a definition for in-substance nonfinancial assets and additional guidance on partial sales of nonfinancial assets. For public entities, ASU 2017-05 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, with early adoption permitted. An entity may elect to apply the amendments under a retrospective or modified retrospective approach. We are currently evaluating the effect of the standard on our ongoing financial reporting and plan to adopt in conjunction with ASU 2014-09 on January 1, 2018, but have not yet selected the method of adoption.

Note 3. Long-Term Debt

The following table shows the detail and maturities of long-term debt outstanding:

LONG-TERM DEBT
(Dollars in millions)

	December 31, 2016	December 31, 2015
6.5% Notes June 1, 2016, including $300 at variable rates after fixed-to-floating rate swaps effective January 2011 (4.77% at December 31, 2015)	$ —	$ 750
2.3% Notes April 1, 2017	600	600
6.15% Notes June 15, 2018	500	500
9.8% Notes February 15, 2019	500	500
1.625% Notes October 7, 2019	500	—
2.4% Notes March 15, 2020	500	500
2.85% Notes November 15, 2020	400	400
2.875% Notes October 1, 2022	500	500
4.05% Notes December 1, 2023	500	500
3.55% Notes June 15, 2024	500	500
3.75% Notes November 15, 2025	350	350
6% Notes October 15, 2039	750	750
Market value adjustments for interest rate swaps, net	(3)	(2)
Build-to-suit lease	137	136
	5,734	5,984
Current portion of long-term debt	(600)	(752)
Unamortized discount on long-term debt	(10)	(10)
Unamortized debt issuance costs	(24)	(27)
Total long-term debt	$ 5,100	$ 5,195

Excluding the build-to-suit lease and market value adjustments for interest rate swaps, maturities of long-term debt are $600 million in 2017, $500 million in 2018, $1 billion in 2019, $900 million in 2020 and $2.6 billion thereafter.

Additional information on Sempra Energy's long-term debt is provided in Note 5 of the Notes to Consolidated Financial Statements in the Annual Report.

Note 4. Commitments and Contingencies

For contingencies and guarantees related to Sempra Energy, refer to Notes 4, 5 and 15 of the Notes to Consolidated Financial Statements in the Annual Report.

Sempra Energy:

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SEMPRA ENERGY,
(Registrant)

By: /s/ Debra L. Reed

Debra L. Reed
Chairman and Chief Executive Officer

Date: February 28, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

Name/Title	Signature	Date
Principal Executive Officer: Debra L. Reed Chief Executive Officer	/s/ Debra L. Reed	February 28, 2017
Principal Financial Officer: J. Walker Martin Executive Vice President and Chief Financial Officer	/s/ J. Walker Martin	February 28, 2017
Principal Accounting Officer: Trevor I. Mihalik Senior Vice President, Controller and Chief Accounting Officer	/s/ Trevor I. Mihalik	February 28, 2017
Directors:		
Debra L. Reed, Chairman	/s/ Debra L. Reed	February 28, 2017
Alan L. Boeckmann, Director	/s/ Alan L. Boeckmann	February 28, 2017
Kathleen L. Brown, Director	/s/ Kathleen L. Brown	February 28, 2017
Pablo A. Ferrero, Director	/s/ Pablo A. Ferrero	February 28, 2017
William D. Jones, Director	/s/ William D. Jones	February 28, 2017
William G. Ouchi, Ph.D., Director	/s/ William G. Ouchi	February 28, 2017
William C. Rusnack, Director	/s/ William C. Rusnack	February 28, 2017
William P. Rutledge, Director	/s/ William P. Rutledge	February 28, 2017
Lynn Schenk, Director	/s/ Lynn Schenk	February 28, 2017
Jack T. Taylor, Director	/s/ Jack T. Taylor	February 28, 2017
James C. Yardley, Director	/s/ James C. Yardley	February 28, 2017

San Diego Gas & Electric Company:

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SAN DIEGO GAS & ELECTRIC COMPANY,
(Registrant)

By: /s/ Scott D. Drury

Scott D. Drury
President

Date: February 28, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934 (the Act), this report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

Name/Title	Signature	Date
Principal Executive Officer: Scott D. Drury President	/s/ Scott D. Drury	February 28, 2017
Principal Financial and Accounting Officer: Bruce A. Folkmann Vice President, Controller, Chief Financial Officer and Chief Accounting Officer	/s/ Bruce A. Folkmann	February 28, 2017
Directors:		
Steven D. Davis, Non-Executive Chairman	/s/ Steven D. Davis	February 28, 2017
Scott D. Drury, Director	/s/ Scott D. Drury	February 28, 2017
J. Walker Martin, Director	/s/ J. Walker Martin	February 28, 2017
Trevor I. Mihalik, Director	/s/ Trevor I. Mihalik	February 28, 2017
G. Joyce Rowland, Director	/s/ G. Joyce Rowland	February 28, 2017
Caroline A. Winn, Director	/s/ Caroline A. Winn	February 28, 2017
Martha B. Wyrsch, Director	/s/ Martha B. Wyrsch	February 28, 2017

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(d) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT:

No annual report, proxy statement, form of proxy or other soliciting material has been sent to security holders during the period covered by this Annual Report on Form 10-K, and no such materials are to be furnished to security holders subsequent to the filing of this Annual Report on Form 10-K.

Southern California Gas Company:

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SOUTHERN CALIFORNIA GAS COMPANY,
(Registrant)

By: /s/ Patricia K. Wagner

Patricia K. Wagner
Chief Executive Officer

Date: February 28, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

Name/Title	Signature	Date
Principal Executive Officer: Patricia K. Wagner Chief Executive Officer	/s/ Patricia K. Wagner	February 28, 2017
Principal Financial and Accounting Officer: Bruce A. Folkmann Vice President, Controller, Chief Financial Officer and Chief Accounting Officer	/s/ Bruce A. Folkmann	February 28, 2017
Directors:		
Steven D. Davis, Non-Executive Chairman	/s/ Steven D. Davis	February 28, 2017
J. Bret Lane, Director	/s/ J. Bret Lane	February 28, 2017
J. Walker Martin, Director	/s/ J. Walker Martin	February 28, 2017
Trevor I. Mihalik, Director	/s/ Trevor I. Mihalik	February 28, 2017
G. Joyce Rowland, Director	/s/ G. Joyce Rowland	February 28, 2017
Patricia K. Wagner, Director	/s/ Patricia K. Wagner	February 28, 2017
Martha B. Wyrsch, Director	/s/ Martha B. Wyrsch	February 28, 2017

EXHIBIT INDEX

The exhibits filed under the Registration Statements, Proxy Statements and Forms 8-K, 10-K and 10-Q that are incorporated herein by reference were filed under Commission File Number 1-14201 (Sempra Energy), Commission File Number 1-40 (Pacific Lighting Corporation), Commission File Number 1-03779 (San Diego Gas & Electric Company) and/or Commission File Number 1-01402 (Southern California Gas Company).

The following exhibits relate to each registrant as indicated.

EXHIBIT 3 -- BYLAWS AND ARTICLES OF INCORPORATION

Sempra Energy

3.1 Amended and Restated Articles of Incorporation of Sempra Energy effective May 23, 2008 (Appendix B to the 2008 Sempra Energy Definitive Proxy Statement, filed on April 15, 2008).

3.2 Bylaws of Sempra Energy (as amended through December 15, 2015) (Sempra Energy Form 8-K filed on December 17, 2015, Exhibit 3.1).

San Diego Gas & Electric Company (SDG&E)

3.3 Amended and Restated Articles of Incorporation of San Diego Gas & Electric Company effective August 15, 2014 (2014 SDG&E Form 10-K, Exhibit 3.4).

3.4 Bylaws of San Diego Gas & Electric (as amended through October 26, 2016) (SDG&E September 30, 2016 Form 10-Q, Exhibit 3.1).

Southern California Gas Company (SoCalGas)

3.5 Restated Articles of Incorporation of Southern California Gas Company effective October 7, 1996 (1996 SoCalGas Form 10-K, Exhibit 3.01).

3.6 Bylaws of Southern California Gas Company (as amended through January 30, 2017) (SoCalGas Form 8-K filed on January 31, 2017, Exhibit 3.1).

EXHIBIT 4 -- INSTRUMENTS DEFINING THE RIGHTS OF SECURITY HOLDERS, INCLUDING INDENTURES

The companies agree to furnish a copy of each such instrument to the Commission upon request.

Sempra Energy

4.1 Description of rights of Sempra Energy Common Stock (Amended and Restated Articles of Incorporation of Sempra Energy effective May 23, 2008, Exhibit 3.1 above).

4.2 Indenture dated as of February 23, 2000, between Sempra Energy and U.S. Bank Trust National Association, as Trustee (Sempra Energy Registration Statement on Form S-3 (No. 333-153425), filed on September 11, 2008, Exhibit 4.1).

Southern California Gas Company

4.3 Description of preferences of Preferred Stock, Preference Stock and Series Preferred Stock (Southern California Gas Company Restated Articles of Incorporation, Exhibit 3.5 above).

Sempra Energy / San Diego Gas & Electric Company

4.4 Mortgage and Deed of Trust dated July 1, 1940 (SDG&E Registration Statement No. 2-4769, Exhibit B-3).

4.5 Second Supplemental Indenture dated as of March 1, 1948 (SDG&E Registration Statement No. 2-7418, Exhibit B-5B).

4.6 Ninth Supplemental Indenture dated as of August 1, 1968 (SDG&E Registration Statement No. 333-52150, Exhibit 4.5).

4.7 Tenth Supplemental Indenture dated as of December 1, 1968 (SDG&E Registration Statement No. 2-36042, Exhibit 2-K).

4.8 Sixteenth Supplemental Indenture dated August 28, 1975 (SDG&E Registration Statement No. 33-34017, Exhibit 4.2).

Sempra Energy / Southern California Gas Company

4.9 First Mortgage Indenture of Southern California Gas Company to American Trust Company dated October 1, 1940 (Registration Statement No. 2-4504 filed by Southern California Gas Company on September 16, 1940, Exhibit B-4).

4.10 Supplemental Indenture of Southern California Gas Company to American Trust Company dated as of August 1, 1955 (Registration Statement No. 2-11997 filed by Pacific Lighting Corporation on October 26, 1955, Exhibit 4.07).

4.11 Supplemental Indenture of Southern California Gas Company to American Trust Company dated as of December 1, 1956 (2006 Sempra Energy Form 10-K, Exhibit 4.09).

4.12 Supplemental Indenture of Southern California Gas Company to Wells Fargo Bank dated as of June 1, 1965 (2006 Sempra Energy Form 10-K, Exhibit 4.10).

4.13 Supplemental Indenture of Southern California Gas Company to Wells Fargo Bank, National Association dated as of August 1, 1972 (Registration Statement No. 2-59832 filed by Southern California Gas Company on September 6, 1977, Exhibit 2.19).

4.14 Supplemental Indenture of Southern California Gas Company to Wells Fargo Bank, National Association dated as of May 1, 1976 (Registration Statement No. 2-56034 filed by Southern California Gas Company on April 14, 1976, Exhibit 2.20).

4.15 Supplemental Indenture of Southern California Gas Company to Wells Fargo Bank, National Association dated as of September 15, 1981 (Registration Statement No. 333-70654, Exhibit 4.24).

EXHIBIT 10 -- MATERIAL CONTRACTS

Sempra Energy / San Diego Gas & Electric Company / Southern California Gas Company

10.1 Form of Continental Forge and California Class Action Price Reporting Settlement Agreement dated as of January 4, 2006 (Form 8-K filed on January 5, 2006, Exhibit 99.1).

Sempra Energy / San Diego Gas & Electric Company

10.2 Amended and Restated Operating Order between San Diego Gas & Electric Company and the California Department of Water Resources effective March 10, 2011 (Sempra Energy March 31, 2011 Form 10-Q, Exhibit 10.4).

10.3 Amended and Restated Servicing Order between San Diego Gas & Electric Company and the California Department of Water Resources effective March 10, 2011 (Sempra Energy March 31, 2011 Form 10-Q, Exhibit 10.5).

Compensation

Sempra Energy / San Diego Gas & Electric Company / Southern California Gas Company

10.4 Form of Indemnification Agreement with Directors and Executive Officers (executed after January 2011) (Sempra Energy March 31, 2016 Form 10-Q, Exhibit 10.1).

10.5 Form of Sempra Energy Shared Services Executive Incentive Compensation Plan (2013 Sempra Energy Form 10-K, Exhibit 10.19).

10.6 Amended and Restated Sempra Energy 2013 Long-Term Incentive Plan (2015 Sempra Energy Form 10-K, Exhibit 10.5).

10.7 Form of Sempra Energy 2013 Long-Term Incentive Plan 2017 Performance-Based Restricted Stock Unit Award - Relative Total Shareholder Return Performance Measure - S&P 500 Index.

10.8 Form of Sempra Energy 2013 Long-Term Incentive Plan 2017 Performance-Based Restricted Stock Unit Award - Relative Total Shareholder Return Performance Measure - S&P 500 Utilities Index.

10.9 Form of Sempra Energy 2013 Long-Term Incentive Plan 2017 Performance-Based Restricted Stock Unit Award - EPS Growth Performance Measure.

10.10 Form of Sempra Energy 2013 Long-Term Incentive Plan 2016 Performance-Based Restricted Stock Unit Award - Relative Total Shareholder Return Performance Measure (2015 Sempra Energy Form 10-K, Exhibit 10.6).

10.11 Form of Sempra Energy 2013 Long-Term Incentive Plan 2016 Performance-Based Restricted Stock Unit Award - EPS Growth Performance Measure (2015 Sempra Energy Form 10-K, Exhibit 10.7).

10.12 Form of Sempra Energy 2013 Long-Term Incentive Plan 2016 and 2017 Restricted Stock Unit Award (2015 Sempra Energy Form 10-K, Exhibit 10.8).

10.13 Form of Sempra Energy 2013 Long-Term Incentive Plan 2015 Performance-Based Restricted Stock Unit Award - Relative Total Shareholder Return Performance Measure (2014 Sempra Energy Form 10-K, Exhibit 10.19).

10.14 Form of Sempra Energy 2013 Long-Term Incentive Plan 2015 Performance-Based Restricted Stock Unit Award - EPS Growth Performance Measure (2014 Sempra Energy Form 10-K, Exhibit 10.20).

10.15 Form of Sempra Energy 2013 Long-Term Incentive Plan 2015 Performance-Based Restricted Stock Unit Award - Cameron LNG and Cumulative Net Income (2014 Sempra Energy Form 10-K, Exhibit 10.21).

10.16 Form of Sempra Energy 2013 Long-Term Incentive Plan 2015 Restricted Stock Unit Award Agreement (2015 Sempra Energy Form 10-K, Exhibit 10.12).

10.17 Form of Sempra Energy 2013 Long-Term Incentive Plan 2014 Restricted Stock Unit Award (Sempra Energy March 31, 2014 Form 10-Q, Exhibit 10.1).

10.18 Form of Sempra Energy 2013 Long-Term Incentive Plan 2014 Performance-Based Restricted Stock Unit Award - EPS Growth Performance Measure (Sempra Energy March 31, 2014 Form 10-Q, Exhibit 10.2).

10.19 Form of Sempra Energy 2013 Long-Term Incentive Plan 2014 Performance-Based Restricted Stock Unit Award - Relative Total Shareholder Return Performance Measure (Sempra Energy March 31, 2014 Form 10-Q, Exhibit 10.3).

10.20 Sempra Energy 2008 Long Term Incentive Plan (Appendix A to the 2008 Sempra Energy Definitive Proxy Statement, filed on April 15, 2008).

10.21 Sempra Energy 2008 Long Term Incentive Plan for EnergySouth, Inc. Employees and Other Eligible Individuals (Registration Statement on Form S-8 Sempra Energy Registration Statement No. 333-155191 dated November 7, 2008, Exhibit 10.1).

10.22 Form of Sempra Energy 2008 Long-Term Incentive Plan 2013 Restricted Stock Unit Award Agreement (2015 Sempra Energy Form 10-K, Exhibit 10.19).

10.23 Form of Sempra Energy 2008 Long Term Incentive Plan, 2009 Nonqualified Stock Option Agreement (March 31, 2009 Sempra Energy Form 10-Q, Exhibit 10.2).

10.24 Form of Sempra Energy 2008 Long Term Incentive Plan, 2008 Nonqualified Stock Option Agreement (June 30, 2008 Sempra Energy Form 10-Q, Exhibit 10.4).

10.25 Amended and Restated Sempra Energy 1998 Long-Term Incentive Plan (June 30, 2003 Sempra Energy Form 10-Q, Exhibit 10.2).

10.26 Form of Sempra Energy 1998 Long Term Incentive Plan, 2008 Non-Qualified Stock Option Agreement (2007 Sempra Energy Form 10-K, Exhibit 10.10).

10.27 Amended and Restated Sempra Energy 2005 Deferred Compensation Plan, now known as Sempra Energy Employee and Director Retirement Savings Plan.

10.28 Amended and Restated Sempra Energy Deferred Compensation and Excess Savings Plan.

10.29 2009 Amendment and Restatement of the Sempra Energy Supplemental Executive Retirement Plan effective July 1, 2009 (2015 Sempra Energy Form 10-K, Exhibit 10.28).

10.30 First Amendment to the 2009 Amendment and Restatement of the Sempra Energy Supplemental Executive Retirement Plan effective February 11, 2010 (2015 Sempra Energy Form 10-K, Exhibit 10.29).

10.31 Second Amendment to the 2009 Amendment and Restatement of the Sempra Energy Supplemental Executive Retirement Plan effective January 1, 2014 (2014 Sempra Energy Form 10-K, Exhibit 10.43).

10.32 2015 Amendment and Restatement of the Sempra Energy Cash Balance Restoration Plan effective November 10, 2015 (2015 Sempra Energy Form 10-K, Exhibit 10.31).

10.33 Sempra Energy Amended and Restated Executive Life Insurance Plan (2012 Sempra Energy Form 10-K, Exhibit 10.22).

10.34 Sempra Energy Executive Personal Financial Planning Program Policy Document (September 30, 2004 Sempra Energy Form 10-Q, Exhibit 10.11).

10.35 Form of Indemnification Agreement with Directors and Executive Officers (June 30, 2008 Sempra Energy Form 10-Q, Exhibit 10.2).

10.36 Sempra Energy Amended and Restated Executive Medical Plan (2008 Sempra Energy Form 10-K, Exhibit 10.26).

10.37 Sempra Energy Employee Stock Ownership Plan and Trust Agreement effective January 1, 2001 (September 30, 2008 Sempra Energy Form 10-Q, Exhibit 10.1).

Sempra Energy

10.38 Sempra Energy Executive Incentive Plan effective January 1, 2003 (2002 Sempra Energy Form 10-K, Exhibit 10.09).

10.39 Severance Pay Agreement between Sempra Energy and Steven D. Davis, dated January 1, 2017.

10.40 Severance Pay Agreement between Sempra Energy and Trevor Mihalik, dated January 1, 2017.

10.41 Severance Pay Agreement between Sempra Energy and Jeffrey W. Martin, dated January 1, 2017.

10.42 Severance Pay Agreement between Sempra Energy and Dennis Arriola, dated January 1, 2017.

10.43 Amended and Restated Sempra Energy Severance Pay Agreement between Sempra Energy and Debra L. Reed (Sempra Energy Form 8-K filed on July 1, 2011, Exhibit 10.1).

10.44 Amendment to the Amended and Restated Severance Pay Agreement between Sempra Energy and Mark A. Snell (Sempra Energy Form 8-K filed on September 15, 2011, Exhibit 10.1).

10.45 Amended and Restated Sempra Energy Severance Pay Agreement between Sempra Energy and Mark A. Snell, dated November 4, 2008 (2014 Sempra Energy Form 10-K, Exhibit 10.53).

10.46 Severance Pay Agreement between Sempra Energy and Joseph A. Householder (Sempra Energy Form 8-K filed on September 15, 2011, Exhibit 10.2).

10.47 Severance Pay Agreement between Sempra Energy and Martha B. Wyrsch, dated September 3, 2013 (2013 Sempra Energy Form 10-K, Exhibit 10.57).

10.48 Severance Pay Agreement between Sempra Energy and G. Joyce Rowland (2011 Sempra Energy Form 10-K, Exhibit 10.26).

10.49 Form of Sempra Energy Non-Employee Directors' Restricted Stock Unit Award (2014 Sempra Energy Form 10-K, Exhibit 10.59).

10.50 Form of Sempra Energy 2008 Non-Employee Directors' Stock Plan, Nonqualified Stock Option Agreement (June 30, 2008 Sempra Energy Form 10-Q, Exhibit 10.5).

10.51 Form of Sempra Energy 1998 Non-Employee Directors' Stock Plan Non-Qualified Stock Option Agreement (2006 Sempra Energy Form 10-K, Exhibit 10.09).

10.52 Amendment and Restatement of Sempra Energy 1998 Non-Employee Directors' Stock Plan effective March 2, 1999 (2014 Sempra Energy Form 10-K, Exhibit 10.63).

10.53 Sempra Energy 1998 Non-Employee Directors' Stock Plan (Registration Statement on Form S-8 Sempra Energy Registration Statement No. 333-56161 dated June 5, 1998, Exhibit 4.2).

10.54 Sempra Energy Amended and Restated Sempra Energy Retirement Plan for Directors (June 30, 2008 Sempra Energy Form 10-Q, Exhibit 10.7).

Sempra Energy / San Diego Gas & Electric Company

10.55 Form of Sempra Energy and San Diego Gas & Electric Company Executive Incentive Compensation Plan (2013 Sempra Energy Form 10-K, Exhibit 10.64).

10.56 Severance Pay Agreement between Sempra Energy and James P. Avery, dated February 18, 2013 (Sempra Energy March 31, 2013 Form 10-Q, Exhibit 10.2).

10.57 Severance Pay Agreement between Sempra Energy and Erbin Keith, dated February 18, 2013 (Sempra Energy March 31, 2013 Form 10-Q, Exhibit 10.5).

10.58 Severance Pay Agreement between Sempra Energy and Scott D. Drury dated March 5, 2011.

10.59 Severance Pay Agreement between Sempra Energy and Caroline A. Winn dated April 3, 2010.

Sempra Energy / Southern California Gas Company

10.60 Form of Sempra Energy and Southern California Gas Company Executive Incentive Compensation Plan (2013 Sempra Energy Form 10-K, Exhibit 10.71).

10.61 Severance Pay Agreement between Sempra Energy and John C. Baker, dated February 18, 2013 (2014 Sempra Energy Form 10-K, Exhibit 10.67).

10.62 Severance Pay Agreement between Sempra Energy and Lee Schavrien, dated February 18, 2013 (Sempra Energy March 31, 2013 Form 10-Q, Exhibit 10.3).

10.63 Severance Pay Agreement between Sempra Energy and J. Bret Lane, dated August 4, 2012 (2013 Sempra Energy Form 10-K, Exhibit 10.72).

10.64 Severance Pay Agreement between Sempra Energy and Robert M. Schlax, dated January 17, 2014 (2013 Sempra Energy Form 10-K, Exhibit 10.66).

10.65 Severance Pay Agreement between Sempra Energy and Bruce Folkmann, dated August 4, 2012 (2015 Sempra Energy Form 10-K, Exhibit 10.63).

10.66 Severance Pay Agreement between Sempra Energy and Sharon L. Tomkins, dated August 30, 2014 (2015 Sempra Energy Form 10-K, Exhibit 10.64).

10.67 Severance Pay Agreement between Sempra Energy and Patricia K. Wagner dated January 1, 2014.

Nuclear

Sempra Energy / San Diego Gas & Electric Company

10.68 Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station, approved November 25, 1987 (1992 SDG&E Form 10-K, Exhibit 10.7).

10.69 Amendment No. 1 to the Qualified CPUC Decommissioning Master Trust Agreement dated September 22, 1994 (see Exhibit 10.68 above) (1994 SDG&E Form 10-K, Exhibit 10.56).

10.70 Second Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.68 above) (1994 SDG&E Form 10-K, Exhibit 10.57).

10.71 Third Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.68 above) (1996 SDG&E Form 10-K, Exhibit 10.59).

10.72 Fourth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.68 above) (1996 SDG&E Form 10-K, Exhibit 10.60).

10.73 Fifth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.68 above) (1999 SDG&E Form 10-K, Exhibit 10.26).

10.74 Sixth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.68 above) (1999 SDG&E Form 10-K, Exhibit 10.27).

10.75 Seventh Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated December 24, 2003 (see Exhibit 10.68 above) (2003 Sempra Energy Form 10-K, Exhibit 10.42).

10.76 Eighth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated October 12, 2011 (see Exhibit 10.68 above) (2011 SDG&E Form 10-K, Exhibit 10.70).

10.77 Ninth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated January 9, 2014 (see Exhibit 10.68 above) (2013 Sempra Energy Form 10-K, Exhibit 10.83).

10.78 Tenth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated August 27, 2014 (see Exhibit 10.68 above) (Sempra Energy September 30, 2014 Form 10-Q, Exhibit 10.1).

10.79 Eleventh Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated August 27, 2014 (see Exhibit 10.68 above) (Sempra Energy September 30, 2014 Form 10-Q, Exhibit 10.2).

10.80 Twelfth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated August 27, 2014 (see Exhibit 10.68 above) (Sempra Energy September 30, 2014 Form 10-Q, Exhibit 10.3).

10.81 Thirteenth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated January 1, 2015 (see Exhibit 10.68 above) (Sempra Energy 2015 Form 10-K, Exhibit 10.78).

10.82 Fourteenth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated February 18, 2016 (see Exhibit 10.68 above) (Sempra Energy September 30, 2016 Form 10-Q, Exhibit 10.1).

10.83 Fifteenth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated August 31, 2016 (see Exhibit 10.68 above) (Sempra Energy September 30, 2016 Form 10-Q, Exhibit 10.2).

10.84 Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station, approved November 25, 1987 (1992 SDG&E Form 10-K, Exhibit 10.8).

10.85 First Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.84 above) (1996 SDG&E Form 10-K, Exhibit 10.62).

10.86 Second Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.84 above) (1996 SDG&E Form 10-K, Exhibit 10.63).

10.87 Third Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.84 above) (1999 SDG&E Form 10-K, Exhibit 10.31).

10.88 Fourth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station (see Exhibit 10.84 above) (1999 SDG&E Form 10-K, Exhibit 10.32).

10.89 Fifth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated December 24, 2003 (see Exhibit 10.84 above) (2003 Sempra Energy Form 10-K, Exhibit 10.48).

10.90 Sixth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated October 12, 2011 (see Exhibit 10.84 above) (2011 SDG&E Form 10-K, Exhibit 10.77).

10.91 Seventh Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated January 9, 2014 (see Exhibit 10.84 above) (2013 Sempra Energy Form 10-K, Exhibit 10.91).

10.92 Eighth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated August 27, 2014 (see Exhibit 10.84 above) (Sempra Energy September 30, 2014 Form 10-Q, Exhibit 10.4).

10.93 Ninth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated August 27, 2014 (see Exhibit 10.84 above) (Sempra Energy September 30, 2014 Form 10-Q, Exhibit 10.5).

10.94 Tenth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated August 27, 2014 (see Exhibit 10.84 above) (Sempra Energy September 30, 2014 Form 10-Q, Exhibit 10.6).

10.95 Eleventh Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated January 1, 2015 (see Exhibit 10.84 above) (2015 Sempra Energy Form 10-K, Exhibit 10.90)

10.96 Twelfth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated February 18, 2016 (see Exhibit 10.84 above) (Sempra Energy September 30, 2016 Form 10-Q, Exhibit 10.3).

10.97 Thirteenth Amendment to the San Diego Gas & Electric Company Nuclear Facilities Non-Qualified CPUC Decommissioning Master Trust Agreement for San Onofre Nuclear Generating Station dated August 31, 2016 (see Exhibit 10.84 above) (Sempra Energy September 30, 2016 Form 10-Q, Exhibit 10.4).

10.98 U. S. Department of Energy contract for disposal of spent nuclear fuel and/or high-level radioactive waste, entered into between the DOE and Southern California Edison Company, as agent for SDG&E and others; Contract DE-CR01-83NE44418, dated June 10, 1983 (1988 SDG&E Form 10-K, Exhibit 10N).

EXHIBIT 12 -- STATEMENTS RE: COMPUTATION OF RATIOS

Sempra Energy

12.1 Sempra Energy Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends for the years ended December 31, 2016, 2015, 2014, 2013 and 2012.

San Diego Gas & Electric Company

12.2 San Diego Gas & Electric Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends for the years ended December 31, 2016, 2015, 2014, 2013 and 2012.

Southern California Gas Company

12.3 Southern California Gas Company Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends for the years ended December 31, 2016, 2015, 2014, 2013, and 2012.

EXHIBIT 13 -- ANNUAL REPORT TO SECURITY HOLDERS

Sempra Energy / San Diego Gas & Electric Company / Southern California Gas Company

13.1 Sempra Energy 2016 Annual Report to Shareholders. (Such report, except for the portions thereof which are expressly incorporated by reference in this Annual Report, is furnished for the information of the Securities and Exchange Commission and is not to be deemed "filed" as part of this Annual Report).

EXHIBIT 14 -- CODE OF ETHICS

San Diego Gas & Electric Company / Southern California Gas Company

14.1 Sempra Energy Code of Business Conduct and Ethics for Board of Directors and Senior Officers (also applies to directors and officers of San Diego Gas & Electric Company and Southern California Gas Company) (2006 SDG&E and SoCalGas Forms 10-K, Exhibit 14.01).

EXHIBIT 21 -- SUBSIDIARIES

Sempra Energy

21.1 Sempra Energy Schedule of Certain Subsidiaries at December 31, 2016.

EXHIBIT 23 -- CONSENTS OF EXPERTS AND COUNSEL

23.1 Consents of Independent Registered Public Accounting Firm and Report on Schedule, pages 57 through 59.

EXHIBIT 31 -- SECTION 302 CERTIFICATIONS

Sempra Energy

31.1 Statement of Sempra Energy's Chief Executive Officer pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934.

31.2 Statement of Sempra Energy's Chief Financial Officer pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934.

San Diego Gas & Electric Company

31.3 Statement of San Diego Gas & Electric Company's Chief Executive Officer pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934.

31.4 Statement of San Diego Gas & Electric Company's Chief Financial Officer pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934.

Southern California Gas Company

31.5 Statement of Southern California Gas Company's Chief Executive Officer pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934.

31.6 Statement of Southern California Gas Company's Chief Financial Officer pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934.

EXHIBIT 32 -- SECTION 906 CERTIFICATIONS

Sempra Energy

32.1 Statement of Sempra Energy's Chief Executive Officer pursuant to 18 U.S.C. Sec. 1350.

32.2 Statement of Sempra Energy's Chief Financial Officer pursuant to 18 U.S.C. Sec. 1350.

San Diego Gas & Electric Company

32.3 Statement of San Diego Gas & Electric Company's Chief Executive Officer pursuant to 18 U.S.C. Sec. 1350.

32.4 Statement of San Diego Gas & Electric Company's Chief Financial Officer pursuant to 18 U.S.C. Sec. 1350.

Southern California Gas Company

32.5 Statement of Southern California Gas Company's Chief Executive Officer pursuant to 18 U.S.C. Sec. 1350.

32.6 Statement of Southern California Gas Company's Chief Financial Officer pursuant to 18 U.S.C. Sec. 1350.

EXHIBIT 101 -- INTERACTIVE DATA FILE

101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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GLOSSARY

AB	Assembly Bill
Annual Report	2016 Annual Report to Shareholders
ASU	Accounting Standards Update
Bay Gas	Bay Gas Storage Company, Ltd.
Bcf	Billion cubic feet (of natural gas)
California Utilities	San Diego Gas & Electric Company and Southern California Gas Company
Cameron LNG JV	Cameron LNG Holdings, LLC
CARB	California Air Resources Board
CCA	Community Choice Aggregation
CDEC	Centros de Despacho Económico de Carga (Centers for Economic Load Dispatch) (Chile)
CDEC-SIC	Sistema Interconectado Central (Central Interconnected System) (Chile)
CEC	California Energy Commission
CFE	Comisión Federal de Electricidad
Chilquinta Energía	Chilquinta Energía S.A. and its subsidiaries
CNBV	Comisión Nacional Bancaria y de Valores (Mexican National Banking and Securities Commission)
CPUC	California Public Utilities Commission
CRE	Comisión Reguladora de Energía (Energy Regulatory Commission) (Mexico)
DOE	U.S. Department of Energy
DOGGR	California Department of Conservation's Division of Oil, Gas, and Geothermal Resources
DOT	U.S. Department of Transportation
DPH	Los Angeles County Department of Public Health
Edison	Southern California Edison Company
EPA	U.S. Environmental Protection Agency
EPC	Engineering, procurement and construction
EPS	Earnings per common share
ERR	Eligible Renewable Energy Resource
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FTA	Free Trade Agreement
GHG	Greenhouse gas
The Governor's Order	Proclamation of a State of Emergency, by the Governor of the State of California, dated January 6, 2016
IEnova	Infraestructura Energética Nova, S.A.B. de C.V.
IOU	Investor-owned utility
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
kW	Kilowatt
LA Storage	LA Storage, LLC
LNG	Liquefied natural gas
Luz del Sur	Luz del Sur S.A.A. and its subsidiaries
Mississippi Hub	Mississippi Hub, LLC
Mtpa	Million tonnes per annum
MW	Megawatt
MWh	Megawatt hours
NAFTA	North American Free Trade Agreement
NEM	Net energy metering
NRC	Nuclear Regulatory Commission
OSINERGMIN	Organismo Supervisor de la Inversión en Energía y Minería (Energy and Mining Investment Supervisory Body) (Peru)
PEMEX	Petróleos Mexicanos (Mexican state-owned oil company)
PG&E	Pacific Gas and Electric Company
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSEP	Pipeline Safety Enhancement Plan
QF	Qualifying Facility
RBS Sempra Commodities	RBS Sempra Commodities LLP
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
SDG&E	San Diego Gas & Electric Company
SDWA	Safe Drinking Water Act
SEC	Securities and Exchange Commission
SEIN	Sistema Eléctrico Interconectado Nacional (Peruvian national interconnected system)
SMV	Superintendencia del Mercado de Valores (Superintendency of Securities Market) (Peru)
SoCalGas	Southern California Gas Company
SONGS	San Onofre Nuclear Generating Station
The board	Sempra Energy's board of directors
TURN	The Utility Reform Network
VIE	Variable interest entity
U.S. GAAP	Accounting principles generally accepted in the United States of America

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